HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 29, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2015
OR

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

For the transition period from__________ to__________
Commission File Number 001-32936
HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota	95–3409686
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas	77043
(Address of principal executive offices)	(Zip Code)

(281) 618-0400
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock (no par value)	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. þ 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 Act. ¨ Yes þ 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. þ 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No

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

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. (Check one):

Large accelerated filer þ	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 in Rule 12b-2 of the Exchange Act). ¨ Yes þ No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant’s Common Stock on June 30, 2015 was approximately $1.2 billion.

The number of shares of the registrant’s Common Stock outstanding as of February 25, 2016 was 107,543,215.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 12, 2016 are incorporated by reference into Part III hereof.

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Forward Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward-looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potent and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which are subject to change;
- statements relating to the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of our Q7000 vessel and the construction of the Siem Helix I and Siem Helix II chartered vessels to be used in connection with our contracts to provide well intervention services offshore Brazil (Note 14);
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital, debt and liquidity, and other financial items;
- statements regarding our backlog and long-term contracts;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding our trade receivables and their collectability;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements regarding our ability to retain key members of our senior management and key employees;
- statements regarding the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

Although we believe that the expectations reflected in our forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include:

- the impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- the impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the impact of any potential cancellation, deferral or modification of our work or contracts by our customers;
- unexpected delays in the delivery or chartering of new vessels for our well intervention and robotics fleet, including the Q7000, the Grand Canyon III and the Siem Helix I and Siem Helix II vessels to be used to perform contracted well intervention work offshore Brazil;
- unexpected future capital expenditures, including the amount and nature thereof;
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the effects of our indebtedness and our ability to reduce capital commitments;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;

- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations;

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- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" beginning on page 15 of this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

Item 1. Business

OVERVIEW

Helix Energy Solutions Group, Inc. (together with its subsidiaries, unless context requires otherwise, "Helix," the "Company," "we," "us" or "our") was incorporated in the state of Minnesota in 1979. We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We provide services primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. Our "life of field" services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities. For additional information regarding our strategy and business operations, see sections titled "Our Strategy" and "Our Operations" included elsewhere within Item 1. Business of this Annual Report.

Our principal executive offices are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas 77043; our phone number is 281-618-0400. Our common stock trades on the New York Stock Exchange ("NYSE") under the ticker symbol "HLX." Our Chief Executive Officer submitted the annual CEO certification to the NYSE as required under its Listed Company Manual in May 2015. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this Annual Report.

Please refer to the subsection "— Certain Definitions" on page 13 for definitions of additional terms commonly used in this Annual Report. Unless otherwise indicated any reference to Notes herein refers to Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data located elsewhere in this Annual Report.

OUR STRATEGY

Our focus is on growing our well intervention and robotics businesses. We believe that focusing on these services will deliver favorable long-term financial returns. From time to time, we make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention capacity expanded when we took delivery of the Q5000 in April 2015. Our well intervention fleet is expected to further expand following the construction of the Q7000, a newbuild semi-submersible vessel, and its delivery in late 2017 or in 2018, and the delivery in 2016 of the Siem Helix I and Siem Helix II vessels, which we will charter in connection with the well intervention agreements with Petróleo Brasileiro S.A. ("Petrobras"). With respect to our robotics business, we took delivery of the Grand Canyon II in April 2015 and we expect to take delivery of the Grand Canyon III in May 2016.

In order to accommodate the addition of these two chartered vessels to our robotics fleet, and as a response to the decline in industry market conditions, we returned the Olympic Canyon, a chartered vessel, to its owner early in November 2015, and intend to return a second chartered vessel, the Rem Installer, to its owner when the charter ends in July 2016.

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In January 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. (collectively, the "Parties") entered into a Strategic Alliance Agreement and related agreements for the Parties' strategic alliance to design, develop, manufacture, promote, market and sell on a global basis integrated equipment and services for subsea well intervention. The alliance is expected to leverage the Parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies. In April 2015, we and OneSubsea jointly ordered a 15,000 working p.s.i. intervention riser system ("IRS"), which is expected to be completed by July 2017 for a total cost of approximately $27.5 million (approximately $13.8 million for our 50% interest).

OUR OPERATIONS

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. We provide a full range of services primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Q5000, the Well Enhancer, the Seawell, the Helix 534 and the Skandi Constructor, which is a chartered vessel. Our Well Intervention segment also includes IRSs, some of which we rent out on a stand-alone basis, and subsea intervention lubricators ("SILs"). Our Robotics segment includes remotely operated vehicles ("ROVs"), trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates four chartered ROV support vessels. Our Production Facilities segment includes the Helix Producer I (the "HP I"), a dynamic positioning floating production vessel, the Helix Fast Response System (the "HFRS"), and our ownership interest in Independence Hub, LLC ("Independence Hub"). All of our production facilities activities are located in the Gulf of Mexico. We previously had an ownership interest in Deepwater Gateway, L.L.C. ("Deepwater Gateway"). In February 2016, we sold our ownership interest in Deepwater Gateway for $25 million. Our Subsea Construction results diminished following the sale in 2013 and early 2014 of essentially all of our assets related to this previously reported business segment. See Note 13 for financial results associated with our business segments. Previously, we had another reported business segment, Oil and Gas, which was sold in February 2013 (see "Discontinued Operations" below). Our current services include:

- Production. Well intervention; intervention engineering; production enhancement; inspection, repair and maintenance of production structures, trees, jumpers, risers, pipelines and subsea equipment; and life of field support.
- Reclamation. Reclamation and remediation services; well plugging and abandonment services; pipeline abandonment services; and site inspections.
- Development. Installation of subsea pipelines, flowlines, control umbilicals, manifold assemblies and risers; burial of pipelines; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection. We have experienced increased demand for our services from the alternative energy industry. Some of the services we provide to these alternative energy businesses include subsea power cable installation, trenching and burial, along with seabed coring and preparation for construction of wind turbine foundations.
- Production facilities. Provision of oil and natural gas processing facilities and services to oil and gas companies operating in the deepwater of the Gulf of Mexico, using our HP I vessel. Currently, the HP I is being utilized to process production from the Phoenix field.
- Fast Response System. Provision of the HFRS as a response resource that can be identified in permit applications to federal and state agencies and respond in the event of a well control incident.

Well Intervention

We engineer, manage and conduct well construction, intervention and abandonment operations in water depths ranging from 200 to 10,000 feet. As major and independent oil and gas companies expand operations in the deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were typically necessary for subsea well intervention to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Our vessels serve as work platforms for well intervention services at costs that historically have been less than offshore drilling rigs. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize operational time by performing a broad range of tasks related to intervention, construction, inspection, repair and maintenance. These services provide a cost advantage in the development and management of subsea reservoirs. Over time, we expect long-term demand for well intervention services to increase due to the growing number of subsea tree installations and the efficiency gains from specialized intervention assets and equipment.

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In the Gulf of Mexico, our multi-service semi-submersible vessel, the Q4000, has set a series of well intervention "firsts" in increasingly deeper water without the use of a traditional drilling rig. In 2010, the Q4000 served as a significant component in the Macondo well control and containment efforts. The Q4000 also serves an important role in the HFRS that was established in 2011. In August 2012, we acquired a drillship and performed upgrades and modifications to render it suitable for use as a well intervention vessel. We renamed the vessel the Helix 534 and it commenced well intervention operations in February 2014. We currently plan to cold stack the Helix 534 in 2016 due to low levels of activity. In April 2015, we took delivery of the Q5000, a newbuild semi-submersible well intervention vessel. The Q5000 commenced operations in the Gulf of Mexico during the fourth quarter of 2015. The vessel is expected to commence services in April 2016 under our five-year contract with BP.

In the North Sea, the Well Enhancer has performed well intervention, abandonment and coil tubing services since it joined our fleet in the North Sea region in 2009. The Seawell has provided well intervention and abandonment services since 1987. The vessel is currently warm stacked after undergoing major capital upgrades that extended its estimated useful economic life by approximately 15 years. The chartered Skandi Constructor has been performing well intervention services for us in the North Sea since September 2013. In September 2015, we extended the charter through April 1, 2017. The vessel has been warm stacked at reduced rates since November 2015.

In September 2013, we executed a contract for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is being built to North Sea standards. The contract is with the same shipyard in Singapore that constructed the Q5000. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract and subsequent amendments, 20% of the contract price was paid upon the signing of the contract. The remaining 80% will be paid in three installments, with 20% due on June 25, 2016, 20% due upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% due upon the delivery of the vessel, which at our option can be deferred until December 30, 2018.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, the Siem Helix I, which is expected to be in service for Petrobras in the second half of 2016, and the Siem Helix II, which is expected to be in service in 2017.

Robotics

We have been actively engaged in robotics for over three decades. We operate ROVs, trenchers and ROVDrills designed for offshore construction, maintenance and well intervention services. As global marine construction support moves to deeper waters, the use of ROV systems has increased and the scope of ROV services has become essential to deep water operations. Our chartered vessels add value by supporting deployment of our ROVs and trenchers. We provide our customers with vessel availability and schedule flexibility to meet the technological challenges of their subsea activities worldwide. Our robotics assets include 52 ROVs, five trenching systems and two ROVDrills. Our robotics business unit primarily operates in the Gulf of Mexico, North Sea, West Africa and Asia Pacific regions. We currently charter vessels on a long-term basis to support our robotics operations and we have historically engaged spot vessels on short-term charter agreements as needed. Vessels currently under long-term charter agreements include the Deep Cygnus, the Rem Installer, the Grand Canyon and the Grand Canyon II. We also have entered into a long-term charter agreement for the Grand Canyon III, which is scheduled for delivery in May 2016. We returned the Olympic Canyon to the vessel's owner early in November 2015. The Rem Installer's charter will end in July 2016, at which time we intend to return the vessel to its owner.

Over the last decade there has been an increase in offshore activity associated with the growing alternative (renewable) energy industry. Specifically there has been an increase in services performed for the offshore wind farm industry. As the level of activity for offshore alternative energy projects has increased, so has the need for reliable services and related equipment. Historically, this work was performed with the use of barges and other similar vessels, but these types of services are now being contracted to vessels such as our Deep Cygnus and Grand Canyon chartered vessels that are suitable for harsh weather conditions that can occur offshore, especially in northern Europe where offshore wind farming is currently concentrated. In 2015, revenues derived from offshore renewables contracts accounted for 14% of our global robotics revenues. We believe that over the long term our

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robotics business unit is positioned to continue the services it provides to a range of clients in the alternative energy business. This is expected to include the use of our chartered vessels, ROVs and trenchers to provide burial services relating to subsea power cable installations on key wind farm developments.

Production Facilities

We own the HP I, a ship-shaped dynamic positioning floating production unit capable of processing up to 45,000 barrels of oil and 80 million cubic feet (“MMcf”) of natural gas per day. The HP I is currently being used to process production from the Phoenix field. Our existing contract for service to the Phoenix field will not expire until at least December 31, 2016.

We own a 20% interest in Independence Hub, which owns the Independence Hub platform located in 8,000 feet of water in the eastern Gulf of Mexico. We previously owned a 50% interest in Deepwater Gateway, which owns the Marco Polo TLP located in 4,300 feet of water in the Gulf of Mexico. In February 2016, we sold our ownership interest in Deepwater Gateway for $25 million.

We developed the HFRS as a culmination of our experience as a responder in the 2010 Macondo well control and containment efforts. The HFRS centers on two of our vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates (“CGA”), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements, effective April 1, 2013, with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants, to perform the same functions as CGA with respect to the HFRS. In March 2015, HWCG LLC exercised an option to extend the agreement with us through March 31, 2018.

DISCONTINUED OPERATIONS

Our former Oil and Gas segment was engaged in prospect generation, exploration, development and production activities. We exited our oil and gas business in February 2013 upon the sale of our former domestic oil and gas subsidiary, Energy Resource Technology GOM, Inc. (“ERT”), for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain exploration prospects.

GEOGRAPHIC AREAS

We primarily operate in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. We are also expanding our operations offshore Brazil. See Note 13 for revenues as well as property and equipment, net of accumulated depreciation, by geographic areas.

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. The level of services required by any particular customer depends, in part, on the size of that customer’s capital expenditure budget in a particular year. Consequently, customers that account for a significant portion of revenues in one fiscal year may represent an immaterial portion of revenues in subsequent fiscal years. The percent of consolidated revenues from major customers, those whose total represented 10% or more of our consolidated revenues is as follows: 2015 — Shell (16%) and Talos (11%), 2014 — Anadarko (13%) and 2013 — Shell (14%). We provided services to over 50 customers in 2015.

COMPETITION

The oilfield services industry is highly competitive. While price is a factor, the ability to access specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record is also important. Our principal competitors include Aker Solutions ASA, DeepOcean Group, DOF ASA, Edison Chouest Offshore Companies, FTO Services, Fugro N.V., Island Offshore and Oceaneering International, Inc. Our competitors in the well intervention business also include international drilling contractors. Our competitors may have significantly more financial, personnel, technological and other resources available to them.

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TRAINING, SAFETY, HEALTH, ENVIRONMENT AND QUALITY ASSURANCE

Our corporate vision is based on the belief that all incidents should be preventable. Helix strives to achieve this by focusing on controlling major hazard risks and managing behavior. We have established a corporate culture in which QHSE has equal priority to our other business objectives. Should QHSE be in conflict with business objectives, then QHSE will take priority. Everyone at Helix has the authority and the duty to “STOP WORK” they believe is unsafe.

Our QHSE management systems and training programs were developed by management personnel based on common industry work practices and by employees with on-site experience who understand the risk and physical challenges of the ocean work site. As a result, we believe that our QHSE programs are among the best in the industry. We maintain a company-wide effort to continuously improve our control of QHSE risks and the behavior of our employees.

The process includes the assessment of risk through the use of selected risk analysis tools, control of work through management system procedures, job risk assessment of all routine and non-routine tasks, documentation of all daily observations, collection of data and data treatment to provide the mechanism for understanding our QHSE risks and at-risk behaviors. In addition, we schedule hazard hunts on each vessel and regularly audit QHSE management systems; both are completed with assigned responsibilities and action due dates.

The management systems of our well intervention and robotics business units have been independently assessed and registered compliant to ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management Systems).

GOVERNMENT REGULATION

Overview

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard (the “Coast Guard”), the U.S. Environmental Protection Agency (the “EPA”), three divisions of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (the “BOEM”), the Bureau of Safety and Environmental Enforcement (the “BSEE”) and the Office of Natural Resource Revenue (the “ONRR”), and the U.S. Customs and Border Protection (“CBP”) as well as classification societies such as the American Bureau of Shipping (the “ABS”). We are also subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state laws that regulate the protection of employee health and safety for our land-based operations.

In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea operations adhere to standards set by the International Marine Contractors Association and the International Maritime Organization. In addition, we operate in other foreign jurisdictions that have various types of governmental laws and regulations to which we are subject.

Coast Guard

The Coast Guard sets safety standards and is authorized to investigate vessel and diving accidents as well as other marine casualty incidents and to recommend improved safety standards. The Coast Guard also is authorized to inspect vessels at will. We are required by various governmental and quasi-governmental agencies to obtain various permits, licenses and certificates with respect to our operations.

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BOEM and BSEE

The development and operation of oil and gas properties located on the Outer Continental Shelf ("OCS") of the United States is regulated primarily by the BOEM and BSEE. Among other requirements, the BOEM requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. As a service company, we are not subject to these regulations, but do depend on the demand for our services from the oil and gas industry, and therefore, our business is affected by laws and regulations, as well as changing tax laws and policies, relating to the oil and gas industry in general.

The Deepwater Horizon incident in April 2010 resulted in enhanced standards being implemented for companies engaged in the development of offshore oil and gas wells. These standards are determined and implemented by BSEE. The applicable standards now include Notice to Lessees (NTL), NTL 2010-N06 (Environmental NTL), NTL 2010-N10 (Compliance and Evaluation NTL), NTL 2013-N02 (Significant Change to Oil Spill Response Plan Worst Case Scenario), the Final Drilling Safety Rule, and a rule regarding Production Measurement Documents.

On April 17, 2015, the BSEE announced its new proposed blowout preventer and well control requirements rule for the OCS federal waters, 30 C.F.R. Part 250. Several years in the making, the proposed rule aims to enhance well control and equipment reliability, and includes a suite of reforms in well design, well control, casing, cementing, real-time well monitoring, and subsea containment. Following the notice-and-comment period, the proposed regulations are currently undergoing BSEE's in-house review as the agency works to produce the final version. Once completed, the proposed rule will go before the U.S. Office of Information and Regulatory Affairs in the U.S. Office of Management and Budget for finalization. Although the BSEE is unable to say at this time when the final rule will be published, the agency stated that it expects to finish its review soon. The final form of these regulations may have an impact on our business.

The Jones Act

We are also subject to the Merchant Marine Act (commonly known as "the Jones Act"), which regulates the kind of vessels that can carry goods between ports of the U.S. and which has been applied to offshore oil and gas work in the U.S. The Jones Act is interpreted in large part by letter rulings of the CBP. The cumulative effect of these letter rulings has been to establish a framework for offshore operators to understand when an operation can be carried out by a foreign flag vessel and when it must be carried out by a coastwise qualified U.S. flag vessel.

In early 2010, the CBP and its parent agency, the Department of Homeland Security ("DHS"), initiated a proposed rulemaking that would have been subject to public comment following publication in the Federal Register. The proposed rulemaking would have largely reversed the holdings of years of letter rulings from the CBP regarding the application of the Jones Act to offshore oil and gas work. The agencies subsequently withdrew the proposed rulemaking before it was published in the Federal Register.

If DHS or CBP re-proposes a change to the application of the Jones Act similar to that originally proposed by CBP, and such proposal is adopted, or if CBP issues one or more letter rulings that interprets the Jones Act as being more restrictive to the operation of foreign flag vessels, such a development could potentially lead to operational delays or increased operating costs in instances where we would be required to hire coastwise U.S. flag qualified vessels that we currently do not own in order to transport certain merchandise to projects on the OCS. This could make it more difficult to perform our offshore services in the U.S.

Other Federal and State Regulatory Agencies

Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective.

These regulatory developments and legislative initiatives may curtail production and demand for fossil fuels such as oil and natural gas in areas of the world where our customers operate and thus adversely affect future demand for our services, which may in turn adversely affect our future results of operations.

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ENVIRONMENTAL REGULATION

Overview

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce these laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials (including oil) into the environment, and that liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

OPA 90

The Oil Pollution Act of 1990, as amended (“OPA”), imposes a variety of requirements on “Responsible Parties” related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A “Responsible Party” includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits equal to the greater of $939,800 or $1,100 per gross ton (effective December 21, 2015) for vessels other than tankers. Liability limits are higher for other types of facilities and could apply if our operations resulted in Responsible Party status for a spill from such a facility. The liability limits are not applicable, however, (i) if the spill is caused by gross negligence or willful misconduct, (ii) if the spill results from violation of a federal safety, construction or operating regulation, or (iii) if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA.

In addition, OPA requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate six vessels over 300 gross tons. We have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels.

Clean Water Act

The Clean Water Act imposes strict controls on the discharge of pollutants into the navigable waters of the United States and imposes potential liability for the costs of remediating releases of petroleum and other substances. The controls and restrictions imposed under the Clean Water Act have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the National Pollutant Discharge Elimination System Program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the exploration for, and production of, oil and natural gas into certain coastal and offshore waters.

The Clean Water Act provides for civil, criminal and administrative penalties for any unauthorized discharge of oil and other hazardous substances and imposes liability on Responsible Parties for the costs of cleaning up any environmental contamination caused by the release of a hazardous substance and for natural resource damages resulting from the release. Many states have laws that are analogous to the Clean Water Act and also require remediation of releases of petroleum and other hazardous substances in state waters. Our vessels carry diesel fuel for their own use. Offshore facilities and vessels operated by us have facility and vessel response plans to deal with potential spills. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

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Clean Air Act

The U.S. Supreme Court has held that greenhouse gasses are an air pollutant under the federal Clean Air Act and thus subject to regulation by the EPA. In October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. As of 2011, reporting of greenhouse gas emissions from such facilities is required on an annual basis under this expanded rule.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emissions of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. More stringent regulations under the Clean Air Act or other similar federal or state law could materially impact our business.

CERCLA

The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) contains provisions requiring the remediation of releases of hazardous substances into the environment and imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons including owners and operators of contaminated sites where the release occurred and those companies that transport, dispose of or arrange for disposal of hazardous substances released at the sites. Under CERCLA, those persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Third parties may also file claims for personal injury and property damage allegedly caused by the release of hazardous substances.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or that are owned or operated by our customers or our subcontractors.

OCSLA

The Outer Continental Shelf Lands Act, as amended (“OCSLA”), provides the federal government with broad discretion in regulating the production of offshore resources of oil and natural gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. Equally important, since August 2012, the agency has implemented policy guidelines (IPD No. 12-07) under which BSEE will issue incidents of noncompliance directly to contractors for serious violations of BSEE regulations.

MARPOL

The United States is one of approximately 170 member countries to the International Maritime Organization ("IMO"), a specialized agency of the United Nations that is responsible for developing measures to improve the safety and security of international shipping and to prevent marine pollution from ships. The IMO has negotiated the International Convention for the Prevention of Pollution from Ships ("MARPOL"). MARPOL imposes environmental standards on the shipping industry, to which we are subject. These standards relate to oil spills, management of garbage, the handling and disposal of noxious liquids, harmful substances in packaged forms, sewage and air emissions.

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Current Compliance and Potential Material Impact

We believe that we are in compliance in all material respects with the applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

INSURANCE MATTERS

Our businesses involve a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flows.

As discussed below, we maintain insurance policies to cover some of our risk of loss associated with our operations. We maintain the amount of insurance we believe is prudent based on our estimated loss potential. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage considering the underlying cost).

Our insurance is renewed annually on July 1 and covers a twelve-month period from July 1 to June 30.

We maintain Hull and Increased Value insurance, which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are $1.0 million on the Q4000, the Q5000, the HP I and the Well Enhancer, and $500,000 on the Seawell and the Helix 534. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 million. We also carry Protection and Indemnity ("P&I") insurance, which covers liabilities arising from the operation of the vessels, and General Liability insurance, which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees and marine crews are covered by a Maritime Employers Liability ("MEL") insurance policy, which covers Jones Act exposures, and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies described above, we currently carry various layers of Umbrella Liability for total limits of $500 million in excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We also maintain Operator Extra Expense coverage that provides up to $150 million of coverage per each loss occurrence for a well control issue. Separately, we also maintain $500 million of liability insurance and $150 million of oil pollution insurance. For any given oil spill event we have up to $650 million of insurance coverage.

We customarily have agreements with our customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements we are indemnified against third party claims related to the injury or death of our customers' or vendors' personnel, and vice versa. With respect to well work contracted to us, the customer is generally contractually responsible for pollution emanating from the well. We separately maintain additional coverage for an amount up to $100 million that would cover us under certain circumstances against any such third party claims associated with well control events.

We incur workers' compensation, MEL and other insurance claims in the normal course of business, which we believe are covered by insurance. We analyze each claim for potential exposure and estimate the ultimate liability of each claim. At December 31, 2015, we did not have any claims exceeding our deductible limits. We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations.

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EMPLOYEES

As of December 31, 2015, we had 1,445 employees, of which 525 were salaried personnel. As of December 31, 2015, we also contracted with third parties to utilize 15 non-U.S. citizens to crew our foreign flagged vessels. Our employees do not belong to a union nor are they employed pursuant to a collective bargaining agreement or any similar arrangement. We believe that our relationship with our employees and foreign crew members is favorable.

WEBSITE AND OTHER AVAILABLE INFORMATION

We maintain a website on the Internet with the address of www.HelixESG.com. From time to time, we also provide information about Helix on Twitter (@Helix ESG) and LinkedIn (www.linkedin.com/company/helix-energy-solutions-group). Copies of this Annual Report for the year ended December 31, 2015, and previous and subsequent copies of our Quarterly Reports on Form 10-Q and any Current Reports on Form 8-K, and any amendments thereto, are or will be available free of charge at our website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("SEC"). In addition, the Investor Relations portion of our website contains copies of our Code of Business Conduct and Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers. We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

The general public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We are an electronic filer, and the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. The Internet address of the SEC's website is www.sec.gov.

We satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Business Conduct and Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers and any waiver from any provision of those codes by posting that information in the Investor Relations section of our website at www.HelixESG.com.

CERTAIN DEFINITIONS

Defined below are certain terms helpful to understanding our business that are located through this Annual Report:

BOEM: The Bureau of Ocean Energy Management ("BOEM") is responsible for managing environmentally and economically responsible development of the U.S. offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act analysis and environmental studies.

BSEE: The Bureau of Safety and Environmental Enforcement ("BSEE") is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.

Cold Stack: A stored away state. A cold stacked vessel is secured in a safe location and all systems are shut down with required dehumidification equipment installed to prevent condensation. Cold stacking is a cost reduction measure that requires minimum ongoing maintenance of the hull structure and machinery. Re-commissioning may take an extended period of time and can be costly.

Deepwater: Water depths exceeding 1,000 feet.

Dynamic Positioning (DP): Computer directed thruster systems that use satellite based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling a vessel to maintain its position without the use of anchors.

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DP2: Two DP systems on a single vessel providing the redundancy that allows the vessel to maintain position even with the failure of one DP system.

DP3: Triple-redundant DP control system comprising a triple-redundant controller unit and three identical operator stations. The system has to withstand fire or flood in any one compartment without the system failing. Loss of position should not occur from any single failure, including a completely burnt fire subdivision or flooded watertight compartment.

Intervention Riser System (IRS): A subsea system that establishes a direct connection from a well intervention vessel, through a rigid riser, to a conventional or horizontal subsea tree in depths up to 3,000 meters (9,840 feet). The system can be utilized for wireline intervention, production logging, coiled-tubing operations, well stimulation, and full plug and abandonment operations. The system provides the well control in order to safely access the well bore for these activities.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the end of the economic life of an oil field, including installation, inspection, maintenance, repair, well intervention and abandonment.

QHSE: Quality, Health, Safety and Environmental programs to protect the environment, safeguard employee health and avoid injuries.

Pound Per Square Inch (p.s.i.): A unit of measurement for pressure or stress resulting from a force of one pound-force applied to an area of one square inch.

Remotely Operated Vehicle (ROV): A robotic vehicle used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

ROVDrill: ROV deployed coring system developed to take advantage of existing ROV technology. The coring package, deployed with the ROV system, is capable of taking cores from the seafloor in water depths up to 3,000 meters (9,840 feet). Because the ROV system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

Saturation Diving: Saturation diving, required for work in water depths between 200 and 1,000 feet, involves divers working from special chambers for extended periods at a pressure equivalent to the pressure at the work site.

Spot Vessels: Vessels not owned or under long-term charter but contracted on a short-term basis to perform specific projects.

Subsea Intervention Lubricator (SIL): A riserless system that facilitates access to subsea wells from a monohull vessel to provide safe, efficient and cost effective riserless well intervention and abandonment solutions. The system can be utilized for wire line, logging, light perforating, zone isolation, plug setting and removal, and decommissioning. The system provides access to the well bore while providing full well control safety for activities that do not require a riser conduit.

Tension Leg Platform (TLP): A floating production facility anchored to the seabed with tendons.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

Warm Stack: A deployable but idle state. A warm stacked vessel is typically with reduced crew on board and some elements of the vessel still operating. The vessel can be reactivated and ready for work with less cost, time and effort if a contract can be obtained.

Well Intervention Services: Activities related to well maintenance and production management/enhancement services. Our well intervention operations include the utilization of slickline and electric line services, pumping services, specialized tooling and coiled tubing services.

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Item 1A. Risk Factors

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. We operate globally in challenging and highly competitive markets and thus our business is subject to a variety of risks. The risks and uncertainties described below are not the only ones facing Helix. We are also subject to a variety of risks that affect many other companies generally, as well as additional risks and uncertainties not known to us or that, as of the date of this Annual Report, we believe are not as significant as the risks described below. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Annual Report could have a material adverse effect on our business, results of operations and financial position.

Our business is adversely affected by low oil and gas prices, which occur from time to time in a cyclical oil and gas industry.

Our services are substantially dependent upon the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, development, drilling and production operations. Although our services are used for other operations during the entire life cycle of a well, in a low price environment such as the one we are currently experiencing, oil and gas companies will likely continue to reduce their budgets for expenditures on all types of operations. The level of capital expenditures and operating expenditures generally depend on the prevailing view of future oil and gas prices, which are influenced by numerous factors, including:

- worldwide economic activity;
- supply and demand for oil and natural gas, especially in the United States, Europe, China and India;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the Organization of Petroleum Exporting Countries (“OPEC”);
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of onshore shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the level of excess production capacity;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- potential acceleration of the development of alternative fuels;
- shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- weather conditions and natural disasters;
- environmental and other governmental regulations; and
- tax laws, regulations and policies.

A prolonged period of low oil and gas prices may continue to adversely affect demand for and revenues from our services. Likewise, a low level of offshore activity by oil and gas operators could lead to an even greater surplus of available vessels and therefore increasingly downward pressure on the rates we can charge in the market for our services. In the short term our customers, in reaction to negative market conditions and low oil prices, may continue to seek to renegotiate their contracts with us or cancel earlier work and shift it to later years, or to cancel their contracts with us even if cancellation involves their paying a cancellation fee. The extent of the impact of low commodity prices on our results of operations and cash flows depends on the length and severity of the low price environment and the potential decreased demand for our services.

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Our current backlog for our services may not be ultimately realized, and our contracts may be terminated early.

As of December 31, 2015, backlog for our services supported by written agreements or contracts totaled $1.8 billion, of which $388.4 million is expected to be performed in 2016. Although historically our service contracts were of relatively short duration, over the last several years we have been entering into longer term contracts, such as the BP contract in the Gulf of Mexico and the Petrobras contracts for offshore Brazil. As a consequence, we may incur capital costs a substantial portion of which we expect to recover over the term of the contracts, we may charter vessels over the terms of and for the purpose of performing contracts, and/or we may forgo other contracting opportunities for the term of these contracts.

We may not be able to perform under our contracts due to events beyond our control. In addition, our customers may seek to cancel, terminate, suspend or renegotiate our contracts in the event of our customers' diminished demand for our services due to industry conditions affecting our customers and their own revenues. Some of these contracts provide for a cancellation fee that is substantially less than the expected rates from the contracts. Some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under the contract, which could lead a customer to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our customers to perform under our or their contractual obligations, or the early cancellation or termination of our contracts by our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

The majority of our current backlog is concentrated in a small number of long-term contracts.

As of December 31, 2015, a five-year contract with BP for work in the Gulf of Mexico and the Petrobras contracts for well intervention services offshore Brazil in the aggregate represent approximately 82% of our total backlog. Any cancellation, termination or breach of the BP and Petrobras contracts would have a larger impact on our operating results and our financial condition than shorter term contracts due to the value at risk. The cancellation or termination of, or unwillingness to perform, the BP or Petrobras contracts could have a material adverse effect on our financial position, results of operations and cash flows.

Time chartering of vessels requires us to make ongoing payments regardless of utilization of and revenue generation from those vessels.

Typically, we charter our ROV support vessels under long-term contracts. We also have entered into long-term charter agreements for the Siem Helix I and Siem Helix II vessels for the Petrobras contracts. Should contracts with customers be canceled, terminated or breached and/or we do not secure work for the chartered vessels, we are still required to make time charter payments. Making those payments absent revenue generation could have a material adverse effect on our financial position, results of operations and cash flows.

Because we have certain capital, debt and other obligations, a prolonged period of low demand and rates for our services could eventually lead to a material adverse effect on our liquidity.

Although we continue to seek to reduce the level of our capital and other expenses, in the event of a more prolonged period of low oil and gas prices, the failure of our customers to expend funds on our services or a longer period of lower rates for our services, coupled with certain fixed obligations that we have related to debt repayment, capital commitments, long-term time charter contracts for our vessels and certain other commitments related to ongoing operational activities, could eventually lead to a material adverse effect on our liquidity and financial position.

A sustained period of low oil and gas prices could jeopardize our customers' and other counterparties' ability to perform their obligations.

Continued market deterioration could also jeopardize the ability of certain of our counterparties to perform their obligations, including our customers, insurers and financial institutions. Although we assess the creditworthiness of our counterparties, prolonged business decline or disruptions as a result of even lower oil and gas prices could lead to changes in a counterparty's liquidity and increase our exposure to credit risk and bad debts. In particular, our robotics business unit tends to do business with smaller customers that may not be capitalized to the same extent as larger operators. In addition, we may offer extended payment terms to our customers in order to secure contracts. These circumstances may lead to more frequent collection issues. Our financial results and liquidity could be adversely affected and we could incur losses.

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We may not be able to compete successfully against current and future competitors.

The oilfield services business in which we operate is highly competitive. In a low price oil and gas environment such as the one we are currently experiencing, the oversupply of offshore drilling rigs coupled with the significant slowdown in industry activities results in increased competition from drilling rigs as well as substantially lower rates on work that is being performed. Several of our competitors are substantially larger and have greater financial and other resources to better withstand a prolonged downturn. In order to compete for customers, these larger competitors may undercut us substantially by reducing rates to levels we are unable to withstand. If other companies relocate or acquire vessels for operations in the regions in which we operate, levels of competition may increase further and our business could be adversely affected.

In addition, in a few countries, the national oil companies have formed subsidiaries to provide oilfield services for them, competing with services provided by us. To the extent this practice expands, our business could be adversely impacted.

Our indebtedness and the terms of our indebtedness could impair our financial condition and our ability to fulfill our debt obligations.

As of December 31, 2015, we had $761.3 million of consolidated indebtedness outstanding. The level of indebtedness may have an adverse effect on our future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;
- increasing our vulnerability to a continued general economic downturn, competition and industry conditions, which could place us at a disadvantage compared to our competitors that are less leveraged;
- increasing our exposure to potential rising interest rates because a portion of our current and potential future borrowings are at variable interest rates;
- reducing the availability of our cash flows to fund our working capital requirements, capital expenditures, acquisitions, investments and other general corporate requirements because we will be required to use a substantial portion of our cash flows to service debt obligations;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- limiting our ability to expand our business through capital expenditures or pursuit of acquisition opportunities due to negative covenants in senior secured credit facilities that place annual and aggregate limitations on the types and amounts of investments that we may make, and limit our ability to use proceeds from asset sales for purposes other than debt repayment (except in certain circumstances where proceeds may be reinvested under criteria set forth in our credit agreements).

A prolonged period of weak economic conditions and other events beyond our control may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. If we fail to comply with these covenants and other restrictions, it could lead to reduced liquidity, an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure against our collateral. These conditions and events may limit our access to the credit markets if we need to replace our existing debt, which could lead to increased costs and less favorable terms, including shorter repayment schedules and higher fees and interest rates.

Lack of access to the credit market could negatively impact our ability to operate our business and to execute our strategy.

Access to financing may be limited and uncertain, especially in times of economic weakness. If capital and credit markets are limited, we may incur increased costs and less favorable terms associated with any additional financing we may require for future operations. Limited access to the capital markets could adversely impact our ability to take advantage of business opportunities or react to changing economic and business conditions. Additionally, if capital and credit markets are limited, this could potentially result in our customers curtailing their capital and operating expenditure programs, which could result in a decrease in demand for our vessels and a reduction in fees and/or utilization. In addition, certain of our customers could experience an inability to pay suppliers, including us, in the event they are unable to access capital markets as needed to fund their operations. Likewise, our suppliers may be unable to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations, each of which could adversely affect our operations. Continued lower levels of economic activity and weakness in the credit markets could also adversely affect our ability to implement our strategic objectives and dispose of non-core business assets.

Our forward-looking statements assume that our lenders, insurers and other financial institutions will be able to fulfill their obligations under our various credit agreements, insurance policies and contracts. If any of our significant financial institutions were unable to perform under these agreements, and if we were unable to find suitable replacements at a reasonable cost, our results of operations, liquidity and cash flows could be adversely impacted.

A further decline in the offshore energy services market could result in additional impairment charges.

In December 2015, we recorded asset impairment charges of $205.2 million related to our Helix 534 vessel, $133.4 million related to our HP I vessel and $6.3 million related to certain capitalized vessel project costs. We also recognized a goodwill impairment charge of $16.4 million related to our U.K. well intervention reporting unit as well as losses totaling $124.3 million primarily reflecting our share of impairment charges that Deepwater Gateway and Independence Hub recorded in December 2015. Prolonged periods of low utilization and day rates could result in the recognition of additional impairment charges for our vessels and robotics assets if future cash flow estimates, based on information available to us at the time, indicate that their carrying value may not be recoverable. We may also record additional impairment losses in the future.

Vessel upgrade, repair and construction projects are subject to risks, including delays, cost overruns, and failure to secure contracts.

The Q7000, our newbuild semi-submersible well intervention vessel, is currently under construction. Additional ROVs and trenchers are also constructed from time to time. Depending on available opportunities and market conditions, additional vessels may be constructed for our fleet in the future without first obtaining service contracts covering those vessels. Specifically, our Q7000 vessel does not have any contracted backlog. Our failure to secure service contracts for vessels or other assets under construction could adversely affect our financial position, results of operations and cash flows. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. These projects are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- disputes with shipyards and suppliers; and
- work stoppages and other labor disputes.

Delays in the delivery of vessels being constructed or undergoing upgrades, refurbishment or repair may result in delay in contract commencement, resulting in a loss of revenue and cash flow to us, and may cause our customers to seek to terminate or shorten the terms of their contract, and/or seek delay damages, under applicable late delivery clauses, if any. The contracts for our chartered vessels in Brazil have penalty provisions for late delivery of the vessels to Petrobras. Those penalties can escalate and become significant with an extended delay, and if the vessels are late in delivery to Petrobras beyond a certain date, the contracts also may be terminated. In the event of termination of these and other contracts, we may not be able to secure a replacement contract on favorable terms, if at all.

The estimated capital expenditures for vessels, upgrades, refurbishments and construction projects could materially exceed our planned capital expenditures. Moreover, our vessels undergoing upgrades, refurbishment and repair may not earn a day rate during the period they are out of service. Additionally, as vessels age, they are more likely to be subject to higher maintenance and repair activities and thus suffer lower levels of utilization. Any significant period of unplanned maintenance and repairs related to our vessels could have a material adverse effect on our financial position, results of operations and cash flows.

Our contracting business typically declines in winter, and bad weather in the Gulf of Mexico or North Sea can adversely affect our operations.

Marine operations conducted in the Gulf of Mexico and North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest vessel utilization rates during the summer and fall when weather conditions are favorable for offshore exploration, development and construction activities. We typically have experienced our lowest utilization rates in the first quarter. As is common in the industry, we may bear the risk of delays caused by some adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

Certain areas in and near the Gulf of Mexico and North Sea experience unfavorable weather conditions including hurricanes and extreme storms on a relatively frequent basis. Substantially all of our facilities and assets offshore and along the Gulf of Mexico and the North Sea are susceptible to damage and/or total loss by these storms. Damage caused by high winds and turbulent seas could potentially cause us to curtail service operations for significant periods of time until damage can be assessed and repaired. Moreover, even if we do not experience direct damage from any of these weather events, we may experience disruptions in our operations because customers may curtail their offshore activities due to damage to their platforms, pipelines and other related facilities.

The operation of marine vessels is risky, and we do not have insurance coverage for all risks.

Vessel-based offshore services involve a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. Damage arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful liability claim for which we are not fully insured could have a material adverse effect on our financial condition. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts, and limitations for wind storm damages. The current insurance on our vessels is in amounts approximating replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure, collision or other event, insurance may not cover a substantial loss of revenue, increased costs and other liabilities, and therefore the loss of any of our vessels could have a material adverse effect on us.

Our customers may be unable or unwilling to indemnify us.

Consistent with standard industry practice, we typically obtain contractual indemnification from our customers whereby they agree to protect and indemnify us for liabilities resulting from various hazards associated with offshore operations. We can provide no assurance, however, that our customers will be willing or financially able to meet these indemnification obligations. Also, we may choose not to enforce these indemnities because of business reasons.

Enhanced regulations for deepwater offshore drilling may reduce the need for our services.

Exploration and development activities and the production and sale of oil and natural gas are subject to extensive federal, state, local and international regulations. To conduct deepwater drilling in the U.S. Gulf of Mexico, an operator is required to comply with existing and newly developed regulations and enhanced safety standards. Before drilling may commence, the BSEE conducts many inspections of deepwater drilling operations for compliance with its regulations, including the testing of blowout preventers. Operators also are required to comply with the Safety and Environmental Management System regulations (SEMS) within the deadlines specified by the regulations, and ensure that their contractors have SEMS compliant safety and environmental policies and procedures. Additionally, each operator must demonstrate that it has containment resources that are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. It is expected that the BOEM and the BSEE will continue to issue further regulations regarding deepwater offshore drilling. Our business, a significant portion of which is in the Gulf of Mexico, provides development services to newly drilled wells, and therefore relies heavily on the industry's drilling of new oil and gas wells. If the issuance of permits is significantly delayed, or if other oil and gas operations are delayed or reduced due to increased costs, demand for our services in the Gulf of Mexico may also decline. Moreover, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations would be materially adversely affected.

We cannot predict with any certainty the substance or effect of any new or additional regulations in the United States or in other areas around the world. If the United States or other countries where our customers operate enact stricter restrictions on offshore drilling or further regulate offshore drilling and thereby increase costs and/or cause delays for our customers, and this results in decreased demand for or profitability of our services, our business, financial condition and results of operations could be materially adversely affected.

Government regulations may affect our business operations.

Our business is affected by changes in public policy and by federal, state, local and foreign laws and regulations relating to the offshore oil and gas industry. Offshore oil and gas operations are affected by tax, environmental, safety and other laws, by changes in those laws, application or interpretation of existing laws, and changes in related administrative regulations. It is also possible that these laws and regulations may in the future add significantly to our operating costs or those of our customers or otherwise directly or indirectly affect our operations.

Risks of substantial costs and liabilities related to environmental compliance issues are inherent in our operations. Our operations are subject to extensive federal, state, local and foreign laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operations of various facilities, and those permits are subject to revocation, modification and renewal. Government authorities have the power to enforce compliance with their regulations, and violations are subject to fines, injunctions or both. In some cases, those governmental requirements can impose liability for the entire cost of cleanup on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from our operations, would result in substantial costs and liabilities. Our insurance policies and the contractual indemnity protection we seek to obtain from our customers may not be sufficient or effective to protect us under all circumstances or against all risk involving compliance with environmental laws and regulations.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have a material adverse impact on our business.

The U.S. Foreign Corrupt Practices Act (the "FCPA") and similar anti-bribery laws in other jurisdictions, including the United Kingdom Bribery Act 2010 and Brazil's Clean Company Act, generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. We operate in many parts of the world that have experienced governmental corruption to some degree. We have a robust ethics and compliance program that is designed to deter or detect violations of applicable laws and regulations through the application of our anti-corruption policies and procedures, Code of Business Conduct and Ethics, training, internal controls, investigation and remediation activities, and other measures. However, our ethics and compliance program may not be fully effective in preventing all employees, contractors or intermediaries from violating or circumventing our compliance requirements or applicable laws and regulations. Failure to comply with the FCPA or other anti-bribery legislation could subject us to civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial position, results of operations and cash flows, and cause reputational damage. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of vessels or other assets.

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Our operations outside of the United States subject us to additional risks.

Our operations outside of the United States are subject to risks inherent in foreign operations, including:

- the loss of revenue, property and equipment from expropriation, nationalization, war, insurrection, acts of terrorism and other political risks;
- increases in taxes and governmental royalties;
- changes in laws and regulations affecting our operations, including changes in customs, assessments and procedures, and changes in similar laws and regulations that may affect our ability to move our assets in and out of foreign jurisdictions;
- renegotiation or abrogation of contracts with governmental and quasi-governmental entities;
- changes in laws and policies governing operations of foreign-based companies;
- currency restrictions and exchange rate fluctuations;
- global economic cycles;
- restrictions or quotas on production and commodity sales;
- limited market access; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Certain countries have in place or are in the process of developing complex laws for foreign companies doing business in these countries, such as local content requirements. Some of these laws are difficult to interpret, making compliance uncertain, and others increase the cost of doing business, which may make it difficult for us in some cases to be competitive. In addition, laws and policies of the United States affecting foreign trade and taxation may also adversely affect our international operations.

Our international operations are exposed to currency devaluation and fluctuation risk.

Since we are a global company, our international operations are exposed to foreign currency exchange rate risks on all contracts denominated in foreign currencies. For some of our international contracts, a portion of the revenue and local expenses is incurred in local currencies and we are at risk of changes in the exchange rates between the U.S. dollar and foreign currencies. In some instances, we receive payments in currencies which are not easily traded and may be illiquid. The reporting currency for our consolidated financial statements is the U.S. dollar. Certain of our assets, liabilities, revenues and expenses are denominated in other countries' currencies. Those assets, liabilities, revenues and expenses are translated into U.S. dollars at the applicable exchange rates to prepare our consolidated financial statements. Therefore, increases or decreases in exchange rates between the U.S. dollar and those other currencies affect the value of those items as reflected in our consolidated financial statements, even if their value remains unchanged in their original currency.

The loss of the services of one or more of our key employees, or our failure to attract and retain other highly qualified personnel in the future, could disrupt our operations and adversely affect our financial results.

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in oil and gas prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations. The delivery of our services also requires personnel with specialized skills and experience. As a result, our ability to remain productive and profitable will depend upon our ability to employ and retain skilled workers. For certain projects we may have competition for personnel with the requisite skill set, including from drilling companies.

Cybersecurity breaches or business system disruptions may adversely affect our business.

We rely on our information technology infrastructure and management information systems to operate and record aspects of our business. Although we take measures to protect against cybersecurity risks, including unauthorized access to our confidential and proprietary information, our security measures may not be able to detect or prevent every attempted breach. Similar to other companies, we may be subject to cybersecurity breaches caused by, among other things, illegal hacking, computer viruses, or acts of vandalism or terrorism. A breach could result in an interruption in our operations, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws, and exposure to litigation. Any such breach could materially harm our business and operating results.

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Certain provisions of our corporate documents and Minnesota law may discourage a third party from making a takeover proposal.

Our Articles of Incorporation give our Board of Directors the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,994,000 shares of undesignated preferred stock, including dividend, liquidation and voting rights. In addition, our by-laws divide the Board of Directors into three classes. We are also subject to certain anti-takeover provisions of the Minnesota Business Corporation Act. We also have employment arrangements with all of our executive officers that require cash payments in the event of a "change of control." Any or all of the provisions or factors described above may discourage a takeover proposal or tender offer not approved by management and the Board of Directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

OUR VESSELS

We own a fleet of six vessels, four IRSs, four SILs, 52 ROVs, five trenchers and two ROVDrills. We also charter five vessels. Currently all of our vessels, both owned and chartered, have DP capabilities specifically designed to meet the needs of our customers' deepwater activities. Our Seawell and Well Enhancer vessels have built-in saturation diving systems.

Listing of Vessels and Other Assets Related to Operations (1)

	Flag State	Placed in Service (2)	Length (Feet)	Saturation Diving	DP
Floating Production Unit —					
Helix Producer I (3)	Bahamas	4/2009	528	—	DP2
Well Intervention —					
Q4000 (4)	U.S.	4/2002	312	—	DP3
Seawell (5)	U.K.	7/2002	368	Capable	DP2
Well Enhancer	U.K.	10/2009	432	Capable	DP2
Skandi Constructor (6)	Bahamas	4/2013	395	—	DP3
Helix 534	Bahamas	2/2014	534	—	DP2
Q5000 (7)	Bahamas	4/2015	358	—	DP3
4 IRSs and 4 SILs	—	Various	—	—	—
Robotics —					
52 ROVs, 5 Trenchers and 2 ROVDrills (3), (8)	—	Various	—	—	—
Deep Cygnus (6)	Panama	4/2010	400	—	DP2
Grand Canyon (6)	Panama	10/2012	419	—	DP3
Rem Installer (6)	Norway	7/2013	353	—	DP2
Grand Canyon II (6)	Panama	4/2015	419	—	DP3

(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the ABS, Bureau Veritas ("BV"), Det Norske Veritas ("DNV"), Lloyds Register of Shipping ("Lloyds"), and the Coast Guard. ABS, BV, DNV and Lloyds are classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards.
(2) Represents the date we placed the vessel in service and not the date of commissioning.
(3) Serves as security for our Credit Agreement described in Note 7.
(4) Subject to a vessel mortgage securing our MARAD debt described in Note 7.
(5) Currently warm stacked.
(6) Chartered vessel.
(7) Serves as security for our Nordea Q5000 Loan described in Note 7.
(8) Average age of our fleet of ROVs, trenchers and ROVDrills is approximately 6.9 years.

We incur routine dry dock, inspection, maintenance and repair costs pursuant to applicable statutory regulations in order to maintain our vessels under the rules of the applicable class society. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well-maintained, reliable vessels. In the normal course of business, we charter other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and additional robotics support vessels.

PRODUCTION FACILITIES

We own a 20% interest in Independence Hub, which owns the Independence Hub platform that serves as a regional hub located in the eastern Gulf of Mexico. We previously owned a 50% interest in Deepwater Gateway, which owns the Marco Polo TLP located in the Gulf of Mexico. In February 2016, we sold our ownership interest in Deepwater Gateway for $25 million.

FACILITIES

Our corporate headquarters are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas. We currently lease all of our facilities. The list of our facilities as of January 31, 2016 is as follows:

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office Helix Well Ops, Inc. Corporate Headquarters, Project Management and Sales Office Canyon Offshore, Inc. Corporate, Management and Sales Office Helix Subsea Construction, Inc. Corporate Headquarters Kommandor LLC Corporate Headquarters	118,630 square feet (including 30,104 square feet subject to two years remaining under a sub-lease agreement)

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Canyon Offshore, Inc. Warehouse and Storage Facility	5.5 acres (Building: 90,640 square feet)
Houston, Texas	Canyon Offshore, Inc. Warehouse and Storage Facility	3.7 acres (Building: 22,000 square feet) (subject to two years remaining under a sub-lease agreement)
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Corporate Offices and Operations Energy Resource Technology (U.K). Limited Corporate Offices	27,000 square feet
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Warehouse and Storage Facility	14,124 square feet
Aberdeen (Dyce), Scotland	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	3.9 acres (Building: 42,463 square feet, including 7,000 square feet subject to one year remaining under a sub-lease agreement)
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Office Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	22,486 square feet
Luxembourg	Helix Offshore International S.à r.l. and subsidiaries Corporate Offices and Operations	161 square feet
Brazil	Helix do Brasil Serviços de Petróleo Ltda Corporate, Operations and Sales Office	3,168 square feet

Item 3. Legal Proceedings

On July 31, 2015, a purported stockholder, Parviz Izadjoo, filed a class action lawsuit styled Parviz Izadjoo v. Owen Kratz and Helix Energy Solutions Group, Inc. against the Company and Owen Kratz, our President and Chief Executive Officer, in the United States District Court for the Southern District of Texas on behalf of a putative class of all purchasers of shares of our common stock between October 21, 2014, and July 21, 2015, inclusive. The lawsuit asserts violations of Section 10(b) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and SEC Rule 10b-5 as to both us and Mr. Kratz, and Section 20(a) of the Exchange Act against Mr. Kratz based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding projections for 2015 dry docks of two of our vessels working in the Gulf of Mexico that allegedly caused the price at which putative class members bought stock during the proposed class period to be artificially inflated. The deadline to apply for appointment as lead plaintiff was September 29, 2015. On January 28, 2016, the judge approved a motion for the appointment of lead plaintiff and lead counsel, and the plaintiff has until March 14, 2016 to amend the complaint. We believe this lawsuit to be without merit and intend to vigorously defend against it.

Item 4. Mine Safety Disclosures

Not applicable.

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Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	61	President, Chief Executive Officer and Chairman of the Board
Anthony Tripodo	63	Executive Vice President, Chief Financial Officer and Director
Scott A. Sparks	41	Executive Vice President and Chief Operating Officer
Alisa B. Johnson	58	Executive Vice President, General Counsel and Corporate Secretary

Owen Kratz is President and Chief Executive Officer of Helix. He was named Executive Chairman in October 2006 and served in that capacity until February 2008 when he resumed the position of President and Chief Executive Officer. He was appointed Chairman in May 1998 and served as Helix's Chief Executive Officer from April 1997 until October 2006. Mr. Kratz served as President from 1993 until February 1999, and has served as a director of Helix since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Helix in 1984 and held various offshore positions, including saturation diving supervisor, and management responsibility for client relations, marketing and estimating. From 1982 to 1983, Mr. Kratz was the owner of an independent marine construction company operating in the Bay of Campeche. Prior to 1982, he was a superintendent for Santa Fe and various international diving companies, and a diver in the North Sea. From February 2006 to December 2011, Mr. Kratz was a member of the Board of Directors of Cal Dive International, Inc., a publicly-traded company, which was formerly a subsidiary of Helix. Mr. Kratz has a Bachelor of Science degree from State University of New York (SUNY).

Anthony Tripodo was elected as Executive Vice President and Chief Financial Officer of Helix on June 25, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology and corporate planning functions. Mr. Tripodo was elected as a director of Helix in May 2015, and was also a director of Helix from February 2003 until June 2008 when he joined Helix. Prior to joining Helix, Mr. Tripodo was the Executive Vice President and Chief Financial Officer of Tesco Corporation. From 2003 through the end of 2006, he was a Managing Director of Arch Creek Advisors LLC, a Houston based investment banking firm. From 1997 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services, including serving as Executive Vice President, Chief Financial Officer and Treasurer of Veritas from 1997 to 2001. Previously, Mr. Tripodo served 16 years in various executive capacities with Baker Hughes, including serving as Chief Financial Officer of both the Baker Performance Chemicals and Baker Oil Tools divisions. Mr. Tripodo also has served as a director of three publicly-traded companies in the oilfield services industry in addition to his current service as a director of Helix. He graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

Scott A. Sparks is Executive Vice President and Chief Operating Officer of Helix, having joined Helix in 2001. He served as Executive Vice President — Operations of Helix from May 2015 until February 2016. From October 2012 until May 2015, he was Vice President — Commercial and Strategic Development of Helix. He has also served in various positions within Helix's robotics subsidiary, Canyon Offshore, Inc., including as Senior Vice President from 2007 to September 2012. Mr. Sparks has over 25 years of experience and in the subsea industry, including Operations Manager and Vessel Superintendent at Global Marine Systems and BT Marine Systems.

Alisa B. Johnson joined Helix as Senior Vice President, General Counsel and Secretary of Helix in September 2006 and in November 2008 became Executive Vice President, General Counsel and Corporate Secretary of Helix. Ms. Johnson oversees the legal, human resources and contracts and insurance functions. Ms. Johnson has been involved with the energy industry for over 25 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions of increasing responsibility, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec Energy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree Cum Laude from Rice University and her law degree Cum Laude from the University of Houston.

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PART II
Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "HLX." The following table sets forth, for the periods indicated, the high and low sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2014		
First Quarter	$24.16	$19.44
Second Quarter	$26.41	$21.59
Third Quarter	$28.00	$21.91
Fourth Quarter	$27.70	$19.48
2015		
First Quarter	$21.99	$13.06
Second Quarter	$17.73	$12.45
Third Quarter	$13.00	$4.57
Fourth Quarter	$7.75	$4.51
2016		
First Quarter (1)	$5.42	$2.60

(1) Through February 25, 2016

On February 25, 2016, the closing sale price of our common stock on the NYSE was $3.33 per share. As of February 25, 2016, there were 317 registered shareholders and approximately 13,500 beneficial shareholders of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See Management's Discussion and Analysis of Financial Condition and Results of Operations "— Liquidity and Capital Resources."

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2010 to the cumulative total shareholder return for (i) the stocks of 500 large-cap corporations maintained by Standard & Poor's ("S&P 500"), assuming the reinvestment of dividends; (ii) the Philadelphia Oil Service Sector index (the "OSX"), a price-weighted index of leading oil service companies, assuming the reinvestment of dividends; and (iii) a peer group selected by us (the "Peer Group") consisting of the following companies: Atwood Oceanics, Inc., Diamond Offshore Drilling, Inc., FMC Technologies, Inc., Forum Energy Technologies, Inc., GulfMark Offshore, Inc., Hercules Offshore, Inc., Hornbeck Offshore Services, Inc., Oceaneering International, Inc., Oil States International, Inc., Rowan Companies plc, TETRA Technologies, Inc., and Tidewater Inc. The returns of each member of the Peer Group have been weighted according to each individual company's equity market capitalization as of December 31, 2015 and have been adjusted for the reinvestment of any dividends. We believe that the members of the Peer Group provide services and products more comparable to us than those companies included in the OSX. The graph assumes $100 was invested on December 31, 2010 in our common stock at the closing price on that date price and on December 31, 2010 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented are as follows: our stock — (56.7)%; the Peer Group — (55.9)%; the OSX — (35.6)%; and S&P 500 — 80.8%. These results are not necessarily indicative of future performance.

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Comparison of Five Year Cumulative Total Return among Helix, S&P 500, OSX and Peer Group

	As of December 31,					
	2010	2011	2012	2013	2014	2015
Helix	$100.0	$130.2	$170.0	$190.9	$178.8	$43.3
Peer Group Index	$100.0	$100.8	$99.5	$112.4	$78.8	$44.1
Oil Service Index	$100.0	$88.2	$89.8	$114.7	$86.0	$64.4
S&P 500	$100.0	$102.1	$118.5	$156.8	$178.3	$180.8

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum number of shares that may yet be purchased under the program (2) (3)
October 1 to October 31, 2015	—	$—	—	707,874
November 1 to November 30, 2015	—	—	—	707,874
December 1 to December 31, 2015	11,277	5.78	—	878,328
	11,277	$5.78	—	

(1) Includes shares forfeited by certain members of our Board of Directors in satisfaction of minimum withholding taxes upon vesting of restricted shares.

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(2) Under the terms of our stock repurchase program, the issuance of shares to members of our Board of Directors and to certain employees, including shares issued to our employees under the Employee Stock Purchase Plan (the "ESPP") (Note 12), increases the number of shares available for repurchase. For additional information regarding our stock repurchase program, see Note 10.

(3) In January 2016, we issued approximately 1.2 million shares of restricted stock to our executive officers, select management employees and certain members of our Board of Directors who have elected to take their quarterly fees in stock in lieu of cash. We also issued approximately 0.1 million shares of our common stock to our employees under the ESPP. These issuances will increase the number of shares available for repurchase by a corresponding amount (Note 10).

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2015 should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included elsewhere in this Annual Report. In February 2013, we sold ERT and as a result, the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment are presented as discontinued operations in this Annual Report.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share amounts)				
Statement of Operations Data:					
Net revenues	$695,802	$1,107,156	$876,561	$846,109	$702,000
Gross profit (loss) [1]	(233,774)	344,036	260,685	49,915	149,683
Income (loss) from operations [2]	(307,360)	261,756	179,034	(68,483)	63,040
Net income (loss) from continuing operations [3]	(376,980)	195,550	111,976	(66,840)	37,816
Income from discontinued operations, net of tax [4]	—	—	1,073	23,684	95,221
Net income (loss), including noncontrolling interests	(376,980)	195,550	113,049	(43,156)	133,037
Net income applicable to noncontrolling interests	—	(503)	(3,127)	(3,178)	(3,098)
Net income (loss) applicable to common shareholders	(376,980)	195,047	109,922	(46,334)	129,939
Adjusted EBITDA from continuing operations [5]	172,736	378,010	268,311	233,612	178,953
Basic earnings (loss) per share of common stock:					
Continuing operations	$(3.58)	$1.85	$1.03	$(0.67)	$0.33
Discontinued operations	—	—	0.01	0.23	0.90
Net income (loss) per common share	$(3.58)	$1.85	$1.04	$(0.44)	$1.23
Diluted earnings (loss) per share of common stock:					
Continuing operations	$(3.58)	$1.85	$1.03	$(0.67)	$0.33
Discontinued operations	—	—	0.01	0.23	0.90
Net income (loss) per common share	$(3.58)	$1.85	$1.04	$(0.44)	$1.23
Weighted average common shares outstanding:					
Basic	105,416	105,029	105,032	104,449	104,528
Diluted	105,416	105,045	105,184	104,449	104,953

(1) Amount in 2015 includes impairment charges of $205.2 million for the Helix 534, $133.4 million for the HP I and $6.3 million for certain capitalized vessel project costs (Note 4). Amount in 2012 includes impairment charges of approximately $177.1 million, including $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former well intervention business in Australia. Amount in 2011 includes a $6.6 million impairment charge related to our well intervention equipment in Australia.

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(2) Amount in 2015 includes a $16.4 million impairment charge on goodwill related to our U.K. well intervention reporting unit (Notes 2 and 6)

(3) Amount in 2015 includes losses totaling $124.3 million related to our investments in Deepwater Gateway and Independence Hub (Note 5). Amount in 2015 also includes unrealized losses totaling $18.3 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels (Note 18). Amount in 2011 includes $10.6 million of other than temporary loss on the investment in our former Australian joint venture.

(4) Oil and gas property impairment charges and asset retirement obligation overruns totaled $144.3 million in 2012 (including a $138.6 million charge to reduce the value of ERT's properties to their estimated fair value in connection with the announcement in December 2012 of the sale of ERT) and $112.6 million in 2011.

(5) This is a non-GAAP financial measure. See "Non-GAAP Financial Measures" below for an explanation of the definition and use of such measure as well as a reconciliation of these amounts to each year's respective reported net income (loss) from continuing operations.

	December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Balance Sheet Data:					
Working capital	$473,123	$468,660	$553,427	$351,061	$548,066
Total assets (1)	2,411,952	2,700,698	2,544,280	3,386,580	3,582,347
Total debt	761,328	551,372	566,152	1,019,228	1,155,321
Total controlling interest shareholders' equity	1,278,963	1,653,474	1,499,051	1,393,385	1,421,403
Noncontrolling interests	—	—	25,059	26,029	28,138
Total shareholders' equity	1,278,963	1,653,474	1,524,110	1,419,414	1,449,541

(1) Amounts at December 31, 2012 and 2011 include assets of discontinued oil and gas operations totaling $900.2 million and $1.0 billion, respectively.

Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as a numerical measure of a company's historical or future performance, financial position, or cash flows that includes or excludes amounts from the most directly comparable measure under U.S. generally accepted accounting principles ("GAAP"). Non-GAAP financial measures should be viewed in addition to, and not as an alternative to, our reported results prepared in accordance with GAAP. Users of this financial information should consider the types of events and transactions that are excluded from these measures.

We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required by our debt covenants. We believe that our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA from continuing operations as net income (loss) from continuing operations before income taxes, net interest expense, net other income or expense, and depreciation and amortization expense. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Because these impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non-cash goodwill impairment and losses on equity investments are also added back if applicable. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense and thus is added back to net income (loss) from continuing operations.

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In the following reconciliation, we provide amounts as reflected in our accompanying consolidated financial statements unless otherwise footnoted. This means that these amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA from continuing operations, when applicable, we exclude the noncontrolling interests related to the adjustment components of EBITDA. Our measure of Adjusted EBITDA also excludes the gain or loss on disposition of assets from continuing operations and the unrealized loss on our commodity derivative contracts. In addition, we include realized losses from the cash settlements of our ineffective foreign currency exchange contracts, which are excluded from EBITDA from continuing operations as a component of net other income or expense.

Other companies may calculate their measures of EBITDA and Adjusted EBITDA differently than we do, which may limit their usefulness as comparative measures. Because EBITDA and Adjusted EBITDA are not financial measures calculated in accordance with GAAP, they should not be considered in isolation or as a substitute for, but instead are supplemental to, income from operations, net income or other income data prepared in accordance with GAAP. The reconciliation of our net income (loss) from continuing operations to EBITDA from continuing operations and Adjusted EBITDA from continuing operations is as follows:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net income (loss) from continuing operations	$(376,980)	$195,550	$111,976	$(66,840)	$37,816
Adjustments:					
Income tax provision (benefit)	(101,190)	66,971	31,612	(59,158)	(36,806)
Net interest expense	26,914	17,859	32,898	48,160	70,181
Other (income) expense, net (1)	24,310	(814)	(6)	662	1,147
Depreciation and amortization	120,401	109,345	98,535	97,201	91,188
Asset impairments (2)	345,010	—	—	177,135	6,564
Goodwill impairment (3)	16,399	—	—	—	—
Losses on equity investments (4)	122,765	—	—	—	10,563
Loss on early extinguishment of long-term debt	—	—	12,100	17,127	2,354
EBITDA from continuing operations	177,629	388,911	287,115	214,287	183,007
Adjustments:					
Noncontrolling interests	—	(661)	(4,077)	(4,128)	(4,060)
(Gain) loss on disposition of assets, net	(92)	(10,240)	(14,727)	13,476	6
Unrealized loss on commodity derivative contracts	—	—	—	9,977	—
Realized losses from cash settlements of ineffective foreign currency exchange contracts	(4,801)	—	—	—	—
ADJUSTED EBITDA from continuing operations	$172,736	$378,010	$268,311	$233,612	$178,953

(1) Amount in 2015 includes unrealized losses totaling $18.3 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels (Note 18).

(2) Amount in 2015 reflects asset impairment charges for the Helix 534, the HP I and certain capitalized vessel project costs (Note 4). Amount in 2012 includes impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former well intervention business in Australia. Amount in 2011 reflects an impairment charge related to our well intervention equipment in Australia.

(3) Amount in 2015 reflects a goodwill impairment charge related to our U.K. well intervention reporting unit (Notes 2 and 6).

(4) Amount in 2015 primarily reflects losses from our share of impairment charges that Deepwater Gateway and Independence Hub recorded in December 2015 and the write-offs of the remaining capitalized interest related to these equity investments (Note 5). Amount in 2011 reflects loss on our former equity investment in an Australian joint venture.

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

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements located in Item 8. Financial Statements and Supplementary Data of this Annual Report. Any reference to Notes in the following management's discussion and analysis refers to the Notes to Consolidated Financial Statements located in Item 8. Financial Statements and Supplementary Data of this Annual Report. The results of operations reported and summarized below are not necessarily indicative of future operating results. This discussion also contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth under Item 1A. Risk Factors and located earlier in this Annual Report.

EXECUTIVE SUMMARY

Our Strategy

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We believe that focusing on these services will deliver favorable long-term financial returns. From time to time, we make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention capacity expanded when we took delivery of the Q5000 in April 2015. Our well intervention fleet is expected to further expand following the construction of the Q7000, a newbuild semi-submersible vessel, and its delivery in late 2017 or in 2018, and the delivery in 2016 of the Siem Helix I and Siem Helix II vessels, which we will charter in connection with the well intervention agreements that we entered into with Petrobras. With respect to our robotics business, we took delivery of the Grand Canyon II in April 2015 and we expect to take delivery of the Grand Canyon III in May 2016. In order to accommodate the addition of these two chartered vessels to our robotics fleet, and as a response to the decline in industry market conditions, we returned the Olympic Canyon, a chartered vessel, to its owner early in November 2015, and intend to return a second chartered vessel, the Rem Installer, to its owner when the charter ends in July 2016.

In January 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. entered into a Strategic Alliance Agreement and related agreements for the parties' strategic alliance to design, develop, manufacture, promote, market and sell on a global basis integrated equipment and services for subsea well intervention. The alliance is expected to leverage the parties' capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies. In April 2015, we and OneSubsea jointly ordered a 15,000 working p.s.i. IRS, which is expected to be completed by July 2017 for a total cost of approximately $27.5 million (approximately $13.8 million for our 50% interest).

Economic Outlook and Industry Influences

Demand for our services is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by domestic and global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including:

- worldwide economic activity, including available access to global capital and capital markets;
- supply and demand for oil and natural gas, especially in the United States, Europe, China and India;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by OPEC;

- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of onshore shale oil and natural gas;

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- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the level of excess production capacity;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- potential acceleration of the development of alternative fuels;
- shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- weather conditions and natural disasters;
- environmental and other governmental regulations; and
- domestic and international tax laws, regulations and policies.

Oil prices have fallen almost 75% since mid-year 2014. The decline in oil prices reflects expectations of a sustained increase in production by competing oil exporters such as OPEC amid continued global supply of oil in excess of demand. Lower oil prices have had a significant adverse impact on investments in oil and gas exploration and production. In addition, the pickup in oil consumption by oil importers has been weaker than expected, in part reflecting the slowdown in overall growth in China, the world's largest oil importer.

In light of the sharp decline in oil prices, many oil and gas companies have terminated or not renewed contracts for more than half of their contracted rigs and have drastically cut investments in exploration and production. We expect these challenging industry conditions to continue into 2016 and beyond if oil and gas prices fail to increase to a level conducive to increased activity levels. Increased competition for limited offshore oil and gas projects has driven down rates that drilling rig contractors are charging for their services, which affects all offshore oil and gas services contractors, including us. Increased competition is also expected to affect utilization of our assets, and increasingly for 2016, our robotics assets. In addition, the current volatile and uncertain macroeconomic conditions in some countries around the world, such as Brazil, may have a direct and/or indirect impact on existing contracts and contracting opportunities.

Many oil and gas companies are increasingly focusing on optimizing production of their existing subsea wells. We believe that we have a competitive advantage in terms of performing well intervention services efficiently. Furthermore, we believe that when oil and gas companies begin to increase overall spending levels, it will likely be for production activities rather than for exploration projects. Our well intervention and robotics operations are intended to service the life span of an oil and gas field as well as to provide abandonment services at the end of the life of a field as required by governmental regulations. Thus over the longer term, we believe that fundamentals for our business remain favorable as the need for prolongation of well life in oil and gas production is the primary driver of demand for our services.

Our strategy is to be positioned for future recovery while coping with a sustained period of weak activity. This strategy is based on the following factors: (1) the need to extend the life of subsea wells is significant to the commerciality of the wells as plug and abandonment costs are considered; (2) our services offer commercially viable alternatives for reducing the finding and development costs of reserves as compared to new drilling; and (3) in past cycles, well intervention and workover have been one of the first activities to recover, and in a prolonged market downturn are important to the commercial viability of deepwater wells.

At December 31, 2015, we had cash on hand of $494.2 million and $249.4 million available for borrowing under our Revolving Credit Facility. Our capital expenditures for 2016 are currently anticipated to total approximately $240 million. We believe that we have sufficient liquidity without incurring additional indebtedness beyond the availability under the Revolving Credit Facility (Note 7) in 2016.

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Business Activity Summary

We have enhanced our financial position and strengthened our balance sheet with proceeds from the sale of certain non-core business assets, which, together with liquidity under our Revolving Credit Facility, have allowed us to strategically focus on our core well intervention and robotics businesses. Since 2009, we have generated approximately $1.5 billion in pre-tax proceeds from asset sale transactions. These dispositions primarily include approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in Cal Dive International Inc., $25 million from the sale of our former reservoir consulting business, approximately $238 million from the sale of our two remaining pipelay vessels, the Caesar and the Express, and $624 million from the sale of ERT.

In April 2015, we took delivery of the Q5000, a newbuild semi-submersible well intervention vessel. The vessel then transited from the construction shipyard in Singapore to the Gulf of Mexico where it completed its sea trials after the topside equipment was installed. The Q5000 commenced operations in the Gulf of Mexico during the fourth quarter of 2015. The vessel is expected to commence services in April 2016 under our five-year contract with BP.

Also in April 2015, we took delivery of the Grand Canyon II, a chartered newbuild vessel with more capabilities than some of our older chartered ROV support vessels. The Grand Canyon II is currently in the Gulf of Mexico where it is expected to provide ROV support services during 2016.

In 2015, the Seawell was out of service until September 2015 undergoing dry dock and major capital upgrades that extended its estimated useful economic life by approximately 15 years. The vessel has been warm stacked thereafter as a result of weak demand for our services.

RESULTS OF OPERATIONS

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. Our Subsea Construction results diminished following the sale in 2013 and early 2014 of essentially all of our assets related to this previously reported business segment. Previously, we had another reported business segment, Oil and Gas. In February 2013, we completed the sale of ERT (Note 1). Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Annual Report.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our services cover the lifecycle of an offshore oil or gas field. We operate primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. In addition to servicing the oil and gas market, our Robotics operations are contracted for the development of renewable energy projects (wind farms). As of December 31, 2015, our consolidated backlog that is supported by written agreements or contracts totaled $1.8 billion, of which $388.4 million is expected to be performed in 2016. The substantial majority of our backlog is associated with our Well Intervention business segment. As of December 31, 2015, our well intervention backlog was $1.6 billion, including $278.8 million expected to be performed in 2016. Our five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel and our four-year agreements with Petrobras to provide well intervention services offshore Brazil with the Siem Helix I and Siem Helix II chartered vessels, represent approximately 82% of our total backlog. At December 31, 2014, the total backlog associated with our operations was $2.3 billion. Backlog contracts are cancelable sometimes without penalty. In addition, if there are cancellation fees, the amount of those fees can be substantially less than the rates we would have generated had we performed the contract. Accordingly, backlog is not necessarily a reliable indicator of total annual revenues for our services as contracts may be added, renegotiated, deferred, canceled and in many cases modified while in progress.

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Comparison of Years Ended December 31, 2015 and 2014

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31, 2015	2014	Increase/ (Decrease)
Net revenues —			
Well Intervention	$373,301	$667,849	$(294,548)
Robotics	301,026	420,224	(119,198)
Production Facilities	75,948	93,175	(17,227)
Other	—	358	(358)
Intercompany elimination	(54,473)	(74,450)	19,977
	$695,802	$1,107,156	$(411,354)
Gross profit —			
Well Intervention [1]	$(165,049)	$219,554	$(384,603)
Robotics	41,446	86,419	(44,973)
Production Facilities [1]	(106,112)	41,762	(147,874)
Corporate and other	(3,961)	(2,778)	(1,183)
Intercompany elimination	(98)	(921)	823
	$(233,774)	$344,036	$(577,810)
Gross margin —			
Well Intervention	(44)%	33%	
Robotics	14%	21%	
Production Facilities	(140)%	45%	
Total company	(34)%	31%	
Number of vessels or robotics assets [2] / Utilization [3]			
Well Intervention vessels	6/58%	5/88%	
Robotics assets	59/57%	57/78%	
Chartered robotics vessels	4/78%	4/85%	

(1) 2015 amounts included asset impairment charges (see discussions below).

(2) Represents number of vessels or robotics assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. The Seawell was excluded for the first eight months of 2015 as it was out of service undergoing major capital upgrades.

(3) Represents average utilization rate, which is calculated by dividing the total number of days the vessels or robotics assets generated revenues by the total number of calendar days in the applicable period.

Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Year Ended December 31, 2015	2014	Increase/ (Decrease)
Well Intervention	$22,855	$29,875	$(7,020)
Robotics	31,618	44,575	(12,957)
	$54,473	$74,450	$(19,977)

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In reviewing the discussion below of our results of operations, please refer to the tables above and Note 13 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics and Production Facilities segments. The results of our previously reported Subsea Construction segment are immaterial and thus no longer meet the threshold to be separately reported as a business segment. These results are now aggregated within “Other” for the periods presented.

Net Revenues. Our total net revenues decreased by 37% in 2015 as compared to 2014. In general, decreased revenues for 2015 reflect both the reduced opportunities for work and the acceptance of work at reduced rates for some of our assets following the industry-wide reaction to the substantial decline in oil prices.

Our Well Intervention revenues decreased by 44% in 2015 as compared to 2014 primarily reflecting decreased utilization of our available well intervention vessels due to lack of work, idle days associated with the dry docks for the Q4000 and the Helix 534, and the Seawell being out of service in 2015 undergoing certain capital upgrades to extend its estimated useful life and being warm stacked after those life extension activities were completed in September 2015. In the North Sea, the Skandi Constructor was 56% utilized during 2015. The vessel was idle for the majority of the first four months of 2015 and has been warm stacked since November 2015 at reduced charter rates. The vessel was 88% utilized during 2014, including the 29 idle days associated with the vessel being in regulatory dry dock during the fourth quarter of 2014. The Well Enhancer was 89% utilized during 2015 as compared to 87% utilized during 2014, including the 24 idle days associated with the vessel being in regulatory dry dock in January 2014. In the Gulf of Mexico, we attempted to arrange replacement projects to fill the 150-day void in the Helix 534’s schedule caused by a contract cancellation (for which we received a termination fee of $11.6 million). We were successful in filling all but 26 days in the first quarter of 2015 but were only able to secure 50 days of utilization for the vessel in the second quarter of 2015. The Helix 534 commenced its regularly scheduled regulatory dry dock in September 2015. The vessel completed its dry dock in November 2015 and we currently plan to cold stack the vessel in 2016 due to low levels of activity. The Helix 534 was 83% utilized during 2014 with 53 idle days during the fourth quarter of 2014, including 14 days for required annual inspections and 39 days following the cancellation of a contract. The Q4000 was 71% utilized during 2015 as compared to being 91% utilized during 2014. Idle time for the Q4000 included 64 days in the second quarter of 2015 for its regularly scheduled regulatory dry dock. The Q5000 joined our well intervention fleet in the Gulf of Mexico in October 2015 following completion of certain modifications and upgrades necessary for its operations for BP in the Gulf of Mexico. The Q5000 was utilized for 58 days during the fourth quarter of 2015.

Our Robotics revenues decreased by 28% in 2015 as compared to 2014. The decrease primarily reflects lower utilization of our Robotics assets, accepting work at generally reduced rates, and 442 fewer days of spot vessel utilization. Some of our ROV units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas industry downturn. Utilization of our chartered ROV support vessels decreased primarily in the fourth quarter of 2015 reflecting the end of a long-term project offshore India and a reduction in near term work opportunities as a result of further market deterioration in the offshore energy industry.

Our Production Facilities revenues decreased by 18% in 2015 as compared to 2014, which reflects the decrease in our variable throughput fee as a result of both the decline in oil prices and lower production volumes. The decrease in production volumes reflects natural declines in subsea reservoirs and the Phoenix field being shut in for the majority of March 2015 for some development activities within the field and during which time the HP I underwent required maintenance.

Gross Profit. Excluding the impact of impairment charges related to our Helix 534 and HP I vessels and certain capitalized vessel project costs (Note 4), our gross profit decreased by 68% as compared to 2014. Excluding the $211.6 million impairment charges related to the Helix 534 and certain capitalized vessel project costs, the gross profit related to our Well Intervention segment decreased by 79% in 2015 as compared to 2014 reflecting reduced revenues as a result of the Q4000, the Seawell and the Helix 534 being idle while undergoing their respective regulatory dry dock inspections and repairs during 2015, and our vessels operating under reduced rates or being idle for considerable periods of time during 2015 due to lack of available projects as a result of the ongoing industry downturn.

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The gross profit associated with our Robotics segment decreased by 52% in 2015 as compared to 2014 primarily reflecting decreased utilization for our Robotics assets, less spot work in 2015 and reduced profit margins on any newly awarded work.

Excluding the $133.4 million impairment charge for the HP I, the gross profit related to our Production Facilities segment decreased by 35% in 2015 as compared to 2014. The decrease primarily reflects the decrease in revenues associated with our variable throughput fee, which was adversely affected by the decrease in oil prices and lower production volumes from the Phoenix field.

Goodwill Impairment. The $16.4 million impairment charge in 2015 reflects the write-off of the entire goodwill balance associated with our U.K. well intervention reporting unit (Notes 2 and 6).

Gain on Disposition of Assets, Net. The $10.2 million net gain on disposition of assets in 2014 primarily reflects a $10.5 million gain associated with the sale of our Ingleside spoolbase in January 2014 (Note 4).

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $35.2 million in 2015 as compared to 2014. The decrease was primarily attributable to a reduction in payroll-related costs including costs associated with our variable performance-based incentive compensation programs (Note 12) and overhead cost saving measures including headcount reductions. Our selling, general and administrative expenses as a percentage of net revenues remained consistent in the comparable year-over-year periods.

Equity in Earnings (Losses) of Investments. Equity in earnings (losses) of investments was $(124.3) million in 2015 and $0.9 million in 2014. The losses in 2015 primarily reflect our share of impairment charges that Deepwater Gateway and Independence Hub recorded in December 2015 (Note 5).

Net Interest Expense. Our net interest expense totaled $26.9 million in 2015 as compared to $17.9 million in 2014 primarily reflecting an increase in interest expense and a decrease in interest income, partially offset by an increase in capitalized interest. The increase in interest expense was associated with the Nordea Q5000 Loan, which was funded in April 2015 (Note 7). Interest income totaled $2.1 million for 2015 as compared to $4.8 million for 2014. The amount of interest income for 2014 includes $2.1 million from a U.S. Internal Revenue Service income tax refund (Note 8). Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $11.0 million for 2015 as compared to $10.4 million for 2014.

Other Income (Expense), Net. We reported other expense, net, of $24.3 million for 2015 as compared to other income, net, of $0.8 million in 2014. Net other expense for 2015 primarily reflects losses associated with our foreign currency exchange contracts, including $18.0 million upon de-designation of our Grand Canyon II and Grand Canyon III hedges and $5.1 million related to our hedge ineffectiveness (Note 18). Net other income for 2014 included losses of $1.7 million related to our hedge ineffectiveness. Also included in other income (expense), net, were foreign currency transaction gains (losses) of $(1.2) million and $2.5 million, respectively, in the comparable year-over-year periods. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies.

Other Income – Oil and Gas. Our other income - oil and gas decreased by $12.2 million in 2015 as compared to 2014. The decrease was primarily attributable to a $7.2 million insurance reimbursement in the first quarter of 2014 related to asset retirement work previously performed as well as the decrease in our overriding royalty interests. The reduction in our overriding royalty income reflects the decline in oil prices and lower production volumes as previously discussed.

Income Tax Provision (Benefit). Income taxes reflected a benefit of $101.2 million in 2015 as compared to a provision of $67.0 million in 2014. The variance primarily reflects decreased profitability in the current year period.

The effective tax rate was 21.2% for 2015 as compared to 25.5% for 2014. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

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Comparison of Years Ended December 31, 2014 and 2013

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31,		Increase/
	2014	2013	(Decrease)
Net revenues —			
Well Intervention	$667,849	$452,452	$215,397
Robotics	420,224	333,246	86,978
Production Facilities	93,175	88,149	5,026
Subsea Construction	358	71,321	(70,963)
Intercompany elimination	(74,450)	(68,607)	(5,843)
	$1,107,156	$876,561	$230,595
Gross profit —			
Well Intervention	$219,554	$142,762	$76,792
Robotics	86,419	57,035	29,384
Production Facilities	41,762	50,619	(8,857)
Subsea Construction	461	18,302	(17,841)
Corporate and other	(3,239)	(4,673)	1,434
Intercompany elimination	(921)	(3,360)	2,439
	$344,036	$260,685	$83,351
Gross margin —			
Well Intervention	33%	32%	
Robotics	21%	17%	
Production Facilities	45%	57%	
Total company	31%	30%	
Number of vessels or robotics assets (1) / Utilization (2)			
Well Intervention vessels	5/88%	4/92%	
Robotics assets	57/78%	57/63%	
Chartered robotics vessels	4/85%	5/88%	

(1) Represents number of vessels or robotics assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(2) Represents average utilization rate, which is calculated by dividing the total number of days the vessels or robotics assets generated revenues by the total number of calendar days in the applicable period.

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Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Year Ended December 31,		Increase/
	2014	2013	(Decrease)
Well Intervention	$29,875	$22,448	$7,427
Robotics	44,575	41,169	3,406
Production Facilities	—	4,673	(4,673)
Subsea Construction	—	317	(317)
	$74,450	$68,607	$5,843

Net Revenues. Our total net revenues increased by 26% in 2014 as compared to 2013. Net revenues for our business segments increased year over year, reflecting the addition of vessels in our Well Intervention business (see below), the increased asset utilization within our Robotics segment, and the slightly higher revenues for the HP I reflecting the variable production component of the fee arrangement in the Phoenix field. Our Subsea Construction revenues decreased reflecting the sale of our pipelay vessels in mid-year 2013 (Note 4).

Our Well Intervention revenues increased by 48% in 2014 as compared to 2013 primarily reflecting the addition of two vessels, the chartered Skandi Constructor in April 2013 and the Helix 534 in February 2014, as well as higher demand for our services. Our vessels had high utilization (88%) during 2014 despite three vessels being in regulatory dry dock in 2014: the Well Enhancer (24 days), the Skandi Constructor (29 days) and the commencement of the life extension activities on the Seawell (25 days) which were completed in September 2015. Separately, a supply boat collided into the Q4000 in November 2014, which caused some damage to the vessel. The Q4000 was on reduced rates for 17 days during collision inspection and repairs. In addition, the Helix 534 was idle for 53 days during the fourth quarter of 2014, including 14 days for required annual inspections and 39 days following the cancellation of a contract.

Our Robotics revenues increased by 26% in 2014 as compared to 2013. The increase primarily reflects the higher utilization of our ROVs and trenchers, and 259 additional days of spot vessel utilization. Our trenching activities, primarily conducted in the North Sea region, significantly increased during 2014 as compared to the unusually weak market that was experienced in 2013.

Our Production Facilities revenues increased by 6% in 2014 as compared to 2013 reflecting an increase in our total revenues under our fee arrangement for the HP I, including the variable portion of the fee for throughput processed by the HP I. The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements.

Gross Profit. Our gross profit increased by 32% in 2014 as compared to 2013. The gross profit related to our Well Intervention segment increased by 54% in 2014 as compared to 2013 reflecting the addition of two vessels to our fleet since March 31, 2013.

The gross profit associated with our Robotics segment increased by 52% in 2014 as compared to 2013 reflecting increased utilization for our ROVs and trenching assets and related support vessels. Utilization for our trenching assets increased significantly reflecting the resumption of trenching projects in the North Sea region following an unusually weak year for that work in 2013.

The gross profit related to our Production Facilities segment decreased by 17% in 2014 as compared to 2013. The decrease primarily reflects the amortization of the HP I's initial regulatory dry dock costs that were incurred during the fourth quarter of 2013.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 18). The $14.1 million loss on commodity derivative contracts reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts.

Gain on Disposition of Assets, Net. The $10.2 million net gain on disposition of assets in 2014 primarily reflects a $10.5 million gain associated with the sale of our Ingleside spoolbase in January 2014 (Note 4). The $14.7 million gain on disposition of assets in 2013 primarily reflects a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $10.3 million in 2014 as compared to 2013. The increase primarily reflects $5.3 million of charges associated with the provision for uncertain collection of a portion of our then existing trade receivables (Note 16), certain costs associated with start-up activities in Brazil, and costs to support the growth of both our well intervention and robotics businesses. However, our selling, general and administrative expenses as a percentage of net revenues decreased from 9.4% in 2013 to 8.4% in 2014.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $2.1 million in 2014 as compared to 2013. The decrease primarily reflects lower revenues for both Deepwater Gateway and Independence Hub due to lower production at the fields being processed at each facility. Additionally, Deepwater Gateway's operations were affected by a fire at the facility in early May 2014 that shut in production at the platform for most of the second quarter. Production was restored to the facility in July 2014.

Net Interest Expense. Our net interest expense totaled $17.9 million in 2014 as compared to $32.9 million in 2013. The decrease consists of both a reduction in interest expense and an increase in interest income. The decrease in interest expense reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT and our redemption in July 2013 of the remaining $275 million of our Senior Unsecured Notes then outstanding. Interest income totaled $4.8 million for 2014 as compared to $1.2 million for 2013. The amount of interest income for 2014 includes $2.1 million related to an income tax refund (Note 8) and $1.8 million on the promissory note held in connection with the sale of our Ingleside spoolbase (Note 4). Capitalized interest remained consistent year over year.

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in 2013 included the $8.6 million loss in connection with our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes then outstanding and the acceleration of the remaining $3.5 million of deferred financing fees related to the term loan component of our former credit agreement following the repayment of that indebtedness.

Other Income, Net. We reported other income, net, of $0.8 million for 2014 primarily reflecting foreign exchange fluctuations in our non-U.S. dollar functional currencies. Included in this amount was $1.7 million of losses related to ineffectiveness associated with our foreign currency hedge with respect to the Grand Canyon II charter payments (Note 18).

Other Income – Oil and Gas. The $16.9 million income for 2014 included a $7.2 million insurance reimbursement related to asset retirement work previously performed. The majority of the remaining oil and gas income is associated with our overriding royalty interests in ERT's Wang well, which commenced production in April 2013. The $6.6 million income for 2013 primarily represents cash payments related to services we provided to ERT following its sale to a third party and the initial proceeds associated with our overriding royalty interests in ERT's Wang well.

Income Tax Provision. Income taxes reflected expenses of $67.0 million in 2014 as compared to $31.6 million in 2013. The variance primarily reflects increased profitability in 2014. The effective tax rate of 25.5% for 2014 was higher than the 22.0% effective tax rate for 2013 as a result of increased profitability in certain jurisdictions with higher tax rates.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity (in thousands):

	December 31, 2015	2014
Net working capital	$473,123	$468,660
Long-term debt [1]	$689,688	$523,228
Liquidity [2]	$743,577	$1,060,092

(1) Long-term debt does not include the current maturities portion of our long-term debt as that amount is included in net working capital. It is also net of the unamortized debt discount on the 2032 Notes. See Note 7 for information relating to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by letters of credit drawn against the facility. Our liquidity at December 31, 2015 included cash and cash equivalents of $494.2 million and $249.4 million of available borrowing capacity under our Revolving Credit Facility (Note 7). Our liquidity at December 31, 2014 included cash and cash equivalents of $476.5 million and $583.6 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our long-term debt, including current maturities, is as follows (in thousands):

	December 31, 2015	2014
Term Loan (matures June 2018)	$255,000	$277,500
Nordea Q5000 Loan (matures April 2020)	232,143	—
MARAD Debt (matures February 2027)	89,148	94,792
2032 Notes (mature March 2032) [1]	185,037	179,080
Total debt	$761,328	$551,372

(1) These amounts are net of the unamortized debt discount of $15.0 million and $20.9 million, respectively. The 2032 Notes will increase to their $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the first date on which the holders of the notes may require us to repurchase the notes.

The following table provides summary data from our consolidated statements of cash flows (in thousands):

	Year Ended December 31, 2015	2014	2013
Cash provided by (used in):			
Operating activities	$110,805	$359,485	$104,861
Investing activities	$(295,719)	$(335,512)	$(126,077)
Financing activities	$204,625	$(30,071)	$(487,421)
Discontinued operations [1]	$—	$—	$552,462

(1) Represents total cash flows associated with the operations of ERT which was sold in February 2013. Proceeds from the sale of ERT totaled $614.8 million, net of transaction costs. Other cash flows in the table above reflect our continuing operations.

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Our current requirements for cash primarily reflect the need to fund capital expenditures for our current lines of business and to service our debt. Historically, we have funded our capital program with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

As a further response to the industry-wide spending reductions, we remain even more focused on maintaining a strong balance sheet and adequate liquidity. Over the near term, we may seek to reduce, defer or cancel certain planned capital expenditures. We believe that our cash on hand, internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next 12 months.

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and a consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD Debt and our Nordea Credit Agreement indebtedness) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Our Credit Agreement also permits our Unrestricted Subsidiaries (as defined in our Credit Agreement) to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of December 31, 2015 and 2014, we were in compliance with all of our debt covenants.

A prolonged period of weak industry activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Furthermore, during any period of sustained weak economic activity and reduced EBITDA, our ability to access the full available commitment under our Revolving Credit Facility may be impacted. In fact, at December 31, 2015, our available borrowing capacity under our Revolving Credit Facility, based on the leverage ratio covenant, was restricted to $249.4 million, net of $13.2 million of letters of credit issued. We anticipate that our borrowing capacity under the Revolving Credit Facility may continue to decrease. However, for the remainder of 2016, we have no current plans or forecasted requirements to borrow under our Revolving Credit Facility other than for issuances of letters of credit. Our ability to comply with these covenants and other restrictions is affected by industry and economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, that failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

Subject to the terms of the Credit Agreement, under our original Credit Agreement we may borrow and/or obtain letters of credit up to $600 million ($400 million pursuant to the February 2016 amendment to the Credit Agreement) under our Revolving Credit Facility. Subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. See Note 7 for additional information relating to our long-term debt, including more information regarding our Credit Agreement, including covenants and collateral.

The 2032 Notes can be converted to our common stock prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our consolidated balance sheet. No conversion triggers were met during the years ended December 31, 2015 and 2014.

Operating Cash Flows

Total cash flows from operating activities decreased by $248.7 million in 2015 as compared to 2014 primarily reflecting the significant reduction in our operating results as a result of the industry downturn and changes in our working capital. Our operating cash flows for 2014 included the receipt of $35.2 million income tax refund.

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Total cash flows from operating activities increased by $285.1 million in 2014 as compared to 2013 primarily reflecting increases in income from operations, changes in our working capital and a $35.2 million income tax refund. Operating cash flows for 2013 also included $30.5 million of net cash used in discontinued operations related to ERT, which we sold in February 2013.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamic positioning vessels, improvements and modifications to existing assets, and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2015, 2014 and 2013 are as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Capital expenditures:			
Well Intervention	$(307,879)	$(283,635)	$(283,132)
Robotics	(10,700)	(51,348)	(39,655)
Production Facilities	(1,867)	(869)	(1,252)
Other	135	(1,060)	(387)
Distributions from equity investments, net (1)	7,000	7,911	9,295
Proceeds from sale of assets (2)	17,592	13,574	189,054
Acquisition of noncontrolling interests (3)	—	(20,085)	—
Net cash used in investing activities – continuing operations	(295,719)	(335,512)	(126,077)
Oil and Gas capital expenditures	—	—	(31,855)
Proceeds from sale of ERT, net of transaction costs	—	—	614,820
Net cash provided by investing activities – discontinued operations	—	—	582,965
Net cash provided by (used in) investing activities	$(295,719)	$(335,512)	$456,888

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the years ended December 31, 2015, 2014 and 2013 were $7.0 million, $8.8 million and $12.3 million, respectively (Note 5).

(2) Amounts in 2015 and 2014 primarily reflect cash received from the sale of our Ingleside spoolbase. Amount in 2013 primarily reflects the sale of the Caesar and the Express.

(3) Relates to the acquisition in February 2014 of our former minority partner's noncontrolling interests in the entity that owns the HP I.

Capital expenditures associated with our business primarily have included payments associated with the construction of our Q5000 and Q7000 vessels (see below), payments in connection with the Seawell life extension activities in 2015, the upgrades and modifications of the Helix 534 in 2014, the investment in the topside well intervention equipment for the Siem Helix I and Siem Helix II vessels to be chartered to perform under our agreements with Petrobras (see below), and the acquisition of additional ROVs and trenchers for our robotics business.

In March 2012, we entered into a contract with a shipyard in Singapore for the construction of the Q5000. Pursuant to the terms of this contract, payments were made as a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2015, our total investment in the Q5000 was $494.9 million, including $386.5 million of scheduled payments made to the shipyard. The vessel was delivered in the second quarter of 2015 and it commenced well intervention services in the Gulf of Mexico during the fourth quarter of 2015. The vessel is expected to commence services in April 2016 under our five-year contract with BP. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects (Note 7). The $250 million Nordea Q5000 Loan was funded upon the delivery of the Q5000 in April 2015.

In September 2013, we executed a second contract with the same shipyard in Singapore that constructed the Q5000. This contract is for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is being built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the original terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% was to be paid upon the delivery of the vessel. In June 2015, we entered into an amendment with the shipyard to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017, and in connection with this extension, we agreed to pay the shipyard incremental costs of up to $14.5 million. In December 2015, we entered into a second amendment with the shipyard. Pursuant to this amendment, the remaining 80% will be paid in three installments, with 20% in June 2016, 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. We also agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. At December 31, 2015, our total investment in the Q7000 was $112.2 million, including $69.2 million paid to the shipyard upon signing the contract. In 2016, we plan to incur approximately $95 million of costs related to the construction of the Q7000, including the scheduled shipyard payment of $69.2 million.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, the Siem Helix I, which is expected to be in service for Petrobras in the second half of 2016, and the Siem Helix II, which is expected to be in service in 2017. Our total investment in the topside equipment for both vessels is expected to be approximately $260 million. We have invested $113.3 million as of December 31, 2015 and plan to invest approximately $95 million in the topside equipment in 2016.

Outlook

We anticipate that our capital expenditures for fiscal year 2016 will approximate $240 million. This estimate may change based on various economic factors. We may seek to further reduce the level of our planned future capital expenditures given a prolonged industry downturn. We believe that our cash on hand, internally generated cash flows and availability under our Revolving Credit Facility if necessary will provide the capital necessary to continue funding our 2016 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2015 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Term Loan	$255,000	$30,000	$225,000	$—	$—
Nordea Q5000 Loan	232,143	35,714	71,429	125,000	—
MARAD debt	89,148	5,926	12,754	14,058	56,410
2032 Notes (2)	200,000	—	—	—	200,000
Interest related to debt (3)	187,264	31,271	49,468	24,620	81,905
Property and equipment (4)	362,814	140,467	222,347	—	—
Operating leases (5)	900,275	149,362	296,351	237,989	216,573
Total cash obligations	$2,226,644	$392,740	$877,349	$401,667	$554,888

(1) Excludes unsecured letters of credit outstanding at December 31, 2015 totaling $13.2 million. These letters of credit support various obligations, such as contractual obligations, customs duties, contract bidding and insurance

activities.

(2) Notes mature in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of our common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of their issuance price on that 30th trading day (i.e., $32.53 per share). At December 31, 2015, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 7 for additional information.

(3) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at December 31, 2015 for variable rate debt.

(4) Primarily reflects our Q7000 semi-submersible vessel currently under construction and the topside equipment for the Siem Helix I and Siem Helix II chartered vessels (Note 14).

(5) Operating leases include vessel charters and facility leases. At December 31, 2015, our vessel charter commitments totaled approximately $860.8 million, including the yet to be delivered Grand Canyon III, Siem Helix I and Siem Helix II vessels. The less than one year amount includes approximately $3.4 million of additional commitments to extend the delivery of the Grand Canyon III until May 2016. The Rem Installer's charter will end in July 2016, at which time we intend to return the vessel to its owner.

Contingencies

We believe that there are currently no contingencies that would have a material adverse effect on our financial position, results of operations and cash flows. During 2015, we concluded that a potential contractual obligation to reimburse a third party for certain foreign taxes was no longer probable and thus we reversed a previous accrual in the amount of $5.2 million for this contingent liability as a reduction in our cost of sales.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our results of operations and financial condition, as reflected in the accompanying consolidated financial statements and related footnotes, are prepared in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe that the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data. See Note 2 for a detailed discussion on the application of our accounting policies.

Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term contracts are contracts that contain either lump-sum provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

The majority of our contracts contain provisions for specific time, material and equipment charges. Revenues generated from these contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Certain dayrate contracts with built-in rate changes require us to record revenues on a straight-line basis. We may receive revenues for mobilization of equipment and personnel under dayrate contracts. Revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, also are deferred and recognized using the same straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the contract period. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

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Property and Equipment

Property and equipment is recorded at cost. Depreciation expense is derived primarily using the straight-line method over the estimated useful life of an asset.

Assets used in operations are evaluated for impairment indicators whenever changes in facts and circumstances indicate that the carrying amount of the asset or asset group may not be recoverable and may exceed its fair value. Based on our evaluation at December 31, 2015, impairment on the Helix 534 was indicated based on the increasing probability of it being cold stacked in 2016. Impairment was also indicated on the HP I because of continuing decreases in throughput revenues, lower production volumes and increases in maintenance costs. As impairment indicators were identified, we conducted the recoverability assessment by comparing the expected future cash flows to the asset's carrying amount. The sum of undiscounted future cash flows expected to be generated by the Helix 534 or the HP I was less than their respective carrying amount and therefore these assets were impaired.

We impaired the Helix 534 and the HP I based on the difference between the carrying amount and the estimated fair value. The fair value of Helix 534 was based on its estimated salvage value according to current market pricing. We estimated the fair value of the HP I based on the present value of its expected future cash flows. We recognized impairment charges of $205.2 million for the Helix 534 and $133.4 million for the HP I. In addition, we recorded impairment charges of $6.3 million to write off capitalized costs associated with certain vessel projects that we no longer expect to materialize.

See Note 4 for additional information regarding our property and equipment.

Equity Investments

We periodically review our equity investments for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary.

In the event we incur losses in excess of the carrying amount of an equity investment and reduce our investment balance to zero, we would not record additional losses unless (i) we guaranteed obligations of the investee, (ii) we are otherwise committed to provide further financial support for the investee, or (iii) it is anticipated that the investee's return to profitability is imminent. If we provided a commitment to fund losses, we would continue to record losses resulting in a negative equity method investment, which is presented as a liability.

See Note 5 for additional information regarding our equity investments.

Goodwill and Other Intangible Assets

We have $45.1 million of goodwill recorded as of December 31, 2015. We are required to perform an impairment analysis of goodwill at least annually or more frequently whenever events or circumstances occur indicating that it might be impaired. We have elected November 1 to be our annual impairment assessment date for goodwill.

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Under the first step of the goodwill impairment test, the fair value of each reporting unit is compared to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, goodwill impairment is indicated and a second step is performed to measure the amount of impairment loss. At November 1, 2015, we had two reporting units with goodwill, our U.K. well intervention reporting unit and our robotics reporting unit. We used both the income approach (discounted cash flow method) and the market approach to estimate the fair value of our reporting units. The fair value of our robotics reporting unit exceeded its carrying amount by approximately 3% and no impairment of goodwill was recorded. We performed sensitivity analyses regarding material assumptions used in assessing the recoverability of goodwill. We also performed a market capitalization reconciliation by comparing the fair value of equity (fair value of total invested capital less fair value of total debt) to market capitalization. These analyses validated the results of the first step of our goodwill impairment analysis; however, we acknowledge that our robotics reporting unit is at risk of failing the first step of the goodwill impairment analysis if industry market conditions and the expected operating performance of this reporting unit continue to deteriorate for a prolonged period of time. We will continue to monitor our robotics reporting unit for goodwill impairment.

Based on the results of the first step, we performed the second step of the impairment test for our U.K. well intervention reporting unit. There was no implied fair value of goodwill after we allocated the fair value of the reporting unit to all the assets and liabilities as if the reporting unit were acquired in a business combination. We therefore concluded that goodwill of our U.K. well intervention reporting unit was fully impaired and recorded an impairment charge of $16.4 million.

See Note 6 for additional information regarding our goodwill.

Income Taxes

Deferred income taxes are based on the differences between the financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We consider the undistributed earnings of our non-U.S. subsidiaries without operations in the U.S. to be permanently reinvested. We have not provided deferred U.S. income tax on the accumulated earnings and profits from our non-U.S. subsidiaries without operations in the U.S. as we consider them permanently reinvested.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management’s assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See Note 8 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by us.

Derivative Instruments and Hedging Activities

Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, including interest rate swaps and foreign currency exchange contracts. All derivative contracts are reflected in our balance sheet at fair value. Changes in the assumptions used could impact whether the fair value change in the hedged instrument is charged to earnings or accumulated other comprehensive income (loss) (a component of shareholders' equity).

See Note 18 for additional information regarding our derivative contracts.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As of December 31, 2015, we were exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2015, $487.1 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, thereby increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013 we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally, in June 2015 we entered into various interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Q5000 Loan debt. These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. The impact of interest rate risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $2.0 million in interest expense for the year ended December 31, 2015.

Foreign Currency Exchange Rate Risk. Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to our North Sea operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies. In addition, a substantial portion of our contracts provide for collections from customers in U.S. dollars.

Assets and liabilities of our subsidiaries that do not have the U.S. dollar as their functional currency are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in "Accumulated other comprehensive loss" ("Accumulated OCI") in the shareholders' equity section of our consolidated balance sheets. At December 31, 2015, approximately 17% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded foreign currency translation unrealized gains (losses) of $(12.8) million, $(19.5) million and $5.0 million to Accumulated OCI for the years ended December 31, 2015, 2014 and 2013, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries without operations in the U.S. to be permanently reinvested.

We also have other foreign subsidiaries with a majority of their operations in U.S. dollars, which is their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the consolidated statements of operations as a component of "Other income (expense), net." For the years ended December 31, 2015, 2014 and 2013, these amounts resulted in gains (losses) of $(1.2) million, $2.5 million and $0.7 million, respectively.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our business and cash flows. As a result, we entered into various foreign currency exchange contracts to stabilize expected cash outflows related to certain vessel charters denominated in Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. At December 31, 2015 and 2014, the aggregate fair value of these foreign currency exchange contracts was a net liability of $61.4 million and $50.4 million, respectively. Upon the de-designation of the Grand Canyon II and Grand Canyon III hedges in December 2015, $18.0 million of the $61.4 million liability was no longer treated under hedge accounting (Note 18) and was recognized as a component of "Other income (expense), net" in the consolidated statement of operations. For the years ended December 31, 2015 and 2014, we recorded losses totaling $5.1 million and $1.7 million, respectively, in other income (expense), net, related to foreign currency hedge ineffectiveness. For the year ended December 31, 2013, the losses resulting from changes in the fair value of our foreign exchange contracts that were not designated for hedge accounting (Note 18) totaled $0.6 million.

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Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and subsidiaries

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Deepwater Gateway, L.L.C. (a limited liability company in which the Company has a 50% interest) and Independence Hub, LLC (a limited liability company in which the Company has a 20% interest) for the year ended December 31, 2015. In the consolidated financial statements, the Company's investment in Deepwater Gateway, L.L.C. is stated at approximately $26 million and the Company's obligation associated with its investment in Independence Hub, LLC is stated at approximately $8 million as of December 31, 2015. The Company's equity in the net losses of Deepwater Gateway, L.L.C. and Independence Hub, LLC is stated at approximately $124 million for the year ended December 31, 2015. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Deepwater Gateway, L.L.C. and Independence Hub, LLC, as of and for the year ended December 31, 2015, is based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helix Energy Solutions Group, Inc. and subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 29, 2016

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and subsidiaries

We have audited Helix Energy Solutions Group, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Helix Energy Solutions Group, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Helix Energy Solutions Group, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015, and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 29, 2016

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Report of Independent Registered Public Accounting Firm

To the Management Committee of
Deepwater Gateway, L.L.C.
Houston, Texas

We have audited the accompanying balance sheet of Deepwater Gateway, L.L.C. (the “Company”) as of December 31, 2015, and the related statements of operations, cash flows, and members’ equity for the year ended December 31, 2015. 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit 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, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Deepwater Gateway, L.L.C. as of December 31, 2015 and the results of its operations and its cash flows for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 12, 2016

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Report of Independent Registered Public Accounting Firm

To the Management Committee of
Independence Hub, LLC
Houston, Texas

We have audited the accompanying balance sheet of Independence Hub, LLC (the “Company”) as of December 31, 2015, and the related statements of operations, cash flows, and members’ equity for the year ended December 31, 2015. 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit 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, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

The financial statements include considerations of the Members’ having guaranteed their commitment to the Company to provide the necessary level of financial support to enable the Company to pay its obligations as they become due.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Independence Hub, LLC as of December 31, 2015 and the results of its operations and its cash flows for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 12, 2016

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$494,192	$476,492
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $350 and $4,735, respectively	76,287	104,724
Unbilled revenue	20,434	28,542
Costs in excess of billing	31	2,034
Current deferred tax assets	53,573	31,180
Other current assets	39,518	51,301
Total current assets	684,035	694,273
Property and equipment	2,544,857	2,241,444
Less accumulated depreciation	(941,848)	(506,060)
Property and equipment, net	1,603,009	1,735,384
Other assets:		
Equity investments	26,200	149,623
Goodwill	45,107	62,146
Other assets, net	53,601	59,272
Total assets	$2,411,952	$2,700,698
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$65,370	$83,403
Accrued liabilities	71,641	104,923
Income tax payable	2,261	9,143
Current maturities of long-term debt	71,640	28,144
Total current liabilities	210,912	225,613
Long-term debt	689,688	523,228
Deferred tax liabilities	180,974	260,275
Other non-current liabilities	51,415	38,108
Total liabilities	1,132,989	1,047,224
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 106,289 and 105,586 shares issued, respectively	945,565	934,447
Retained earnings	404,299	781,279
Accumulated other comprehensive loss	(70,901)	(62,252)
Total shareholders' equity	1,278,963	1,653,474
Total liabilities and shareholders' equity	$2,411,952	$2,700,698

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2015	2014	2013
Net revenues	$695,802	$1,107,156	$876,561
Cost of sales:			
Cost of sales	584,566	763,120	615,876
Asset impairments	345,010	—	—
Total cost of sales	929,576	763,120	615,876
Gross profit (loss)	(233,774)	344,036	260,685
Goodwill impairment	(16,399)	—	—
Loss on commodity derivative contracts	—	—	(14,113)
Gain on disposition of assets, net	92	10,240	14,727
Selling, general and administrative expenses	(57,279)	(92,520)	(82,265)
Income (loss) from operations	(307,360)	261,756	179,034
Equity in earnings (losses) of investments	(124,345)	879	2,965
Net interest expense	(26,914)	(17,859)	(32,898)
Loss on early extinguishment of long-term debt	—	—	(12,100)
Other income (expense), net	(24,310)	814	6
Other income – oil and gas	4,759	16,931	6,581
Income (loss) before income taxes	(478,170)	262,521	143,588
Income tax provision (benefit)	(101,190)	66,971	31,612
Net income (loss) from continuing operations	(376,980)	195,550	111,976
Income from discontinued operations, net of tax	—	—	1,073
Net income (loss), including noncontrolling interests	(376,980)	195,550	113,049
Less net income applicable to noncontrolling interests	—	(503)	(3,127)
Net income (loss) applicable to common shareholders	$(376,980)	$195,047	$109,922
Basic earnings (loss) per share of common stock:			
Continuing operations	$(3.58)	$1.85	$1.03
Discontinued operations	—	—	0.01
Net income (loss) per common share	$(3.58)	$1.85	$1.04
Diluted earnings (loss) per share of common stock:			
Continuing operations	$(3.58)	$1.85	$1.03
Discontinued operations	—	—	0.01
Net income (loss) per common share	$(3.58)	$1.85	$1.04
Weighted average common shares outstanding:			
Basic	105,416	105,029	105,032
Diluted	105,416	105,045	105,184

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Net income (loss), including noncontrolling interests	$(376,980)	$195,550	$113,049
Other comprehensive loss, net of tax:			
Unrealized loss on hedges arising during the period	(25,259)	(37,364)	(16,847)
Reclassification adjustments for loss included in net income (loss)	13,659	3,365	1,476
Reclassification adjustments for loss from derivatives de-designated as cash flow hedges included in net income	18,014	—	—
Income taxes on unrealized loss on hedges	(2,214)	11,899	5,380
Unrealized gain (loss) on hedges, net of tax	4,200	(22,100)	(9,991)
Foreign currency translation gain (loss)	(12,849)	(19,464)	4,970
Other comprehensive loss, net of tax	(8,649)	(41,564)	(5,021)
Comprehensive income (loss)	(385,629)	153,986	108,028
Less comprehensive income applicable to noncontrolling interests	—	(503)	(3,127)
Comprehensive income (loss) applicable to common shareholders	$(385,629)	$153,483	$104,901

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Helix Energy Solutions Group, Inc. Shareholders' Equity						
	Common Stock						
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Controlling Interest Shareholders' Equity	Non-controlling Interests	Total Equity
Balance, December 31, 2012	105,763	$932,742	$476,310	$ (15,667)	$1,393,385	$26,029	$1,419,414
Net income	—	—	109,922	—	109,922	3,127	113,049
Foreign currency translation adjustments	—	—	—	4,970	4,970	—	4,970
Unrealized loss on hedges, net	—	—	—	(9,991)	(9,991)	—	(9,991)
Distributions to noncontrolling interests	—	—	—	—	—	(4,097)	(4,097)
Equity component of debt discount on Convertible Senior Notes due 2032	—	49	—	—	49	—	49
Stock compensation expense	—	7,510	—	—	7,510	—	7,510
Stock repurchases	(390)	(8,855)	—	—	(8,855)	—	(8,855)
Activity in company stock plans, net and other	267	1,842	—	—	1,842	—	1,842
Excess tax from stock-based compensation	—	219	—	—	219	—	219
Balance, December 31, 2013	105,640	$933,507	$586,232	$ (20,688)	$1,499,051	$25,059	$1,524,110
Net income	—	—	195,047	—	195,047	503	195,550
Foreign currency translation adjustments	—	—	—	(19,464)	(19,464)	—	(19,464)
Unrealized loss on hedges, net	—	—	—	(22,100)	(22,100)	—	(22,100)
Distributions to noncontrolling interests	—	—	—	—	—	(1,018)	(1,018)
Acquisition of noncontrolling interests	—	2,898	—	—	2,898	(24,544)	(21,646)
Stock compensation expense	—	2,176	—	—	2,176	—	2,176
Stock repurchases	(321)	(7,698)	—	—	(7,698)	—	(7,698)
Activity in company stock plans, net and other	267	3,496	—	—	3,496	—	3,496
Excess tax from stock-based compensation	—	68	—	—	68	—	68
Balance, December 31, 2014	105,586	$934,447	$781,279	$ (62,252)	$1,653,474	$—	$1,653,474
Net loss	—	—	(376,980)	—	(376,980)	—	(376,980)
Foreign currency translation adjustments	—	—	—	(12,849)	(12,849)	—	(12,849)
Unrealized gain on hedges, net	—	—	—	4,200	4,200	—	4,200
Stock compensation expense	—	5,463	—	—	5,463	—	5,463

Cumulative stock compensation expense in excess of fair value of modified liability awards	—	2,915	—	—	2,915	—	2,915
Activity in company stock plans, net and other	703	3,443	—	—	3,443	—	3,443
Excess tax from stock-based compensation	—	(703)	—	—	(703)	—	(703)
Balance, December 31, 2015	106,289	$945,565	$404,299	$ (70,901)	$1,278,963	$—	$1,278,963

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$(376,980)	$195,550	$113,049
Adjustments to reconcile net income (loss), including noncontrolling interests, to net cash provided by operating activities:			
Income from discontinued operations, net of tax	—	—	(1,073)
Depreciation and amortization	120,401	109,345	98,535
Non-cash impairment charges	361,409	—	—
Amortization of deferred financing costs	5,664	4,870	5,187
Stock-based compensation expense	6,543	3,133	8,307
Amortization of debt discount	5,957	5,596	5,172
Deferred income taxes	(103,022)	23,154	(24,937)
Excess tax benefit from stock-based compensation	—	(68)	(219)
Equity in losses of investments	124,345	—	—
Gain on disposition of assets, net	(92)	(10,240)	(14,727)
Loss on early extinguishment of debt	—	—	12,100
Unrealized losses and ineffectiveness on derivative contracts, net	18,281	1,320	77
Changes in operating assets and liabilities:			
Accounts receivable, net	36,354	43,963	(3,320)
Other current assets	7,956	(6,461)	14,277
Income tax payable	(7,464)	9,088	(56,164)
Accounts payable and accrued liabilities	(63,817)	12,841	(32,045)
Oil and gas asset retirement costs	—	(1,024)	(10,334)
Other non-current, net	(24,730)	(31,582)	(9,024)
Net cash provided by operating activities	110,805	359,485	104,861
Net cash used in discontinued operations	—	—	(30,503)
Net cash provided by operating activities	110,805	359,485	74,358
Cash flows from investing activities:			
Capital expenditures	(320,311)	(336,912)	(324,426)
Distributions from equity investments, net of earnings	7,000	7,911	9,295
Proceeds from sale of assets	17,592	13,574	189,054
Acquisition of noncontrolling interests	—	(20,085)	—
Net cash used in investing activities	(295,719)	(335,512)	(126,077)
Net cash provided by discontinued operations	—	—	582,965
Net cash provided by (used in) investing activities	(295,719)	(335,512)	456,888
Cash flows from financing activities:			
Early extinguishment of Senior Unsecured Notes	—	—	(281,490)
Borrowings under revolving credit facility	—	—	47,617
Repayment of revolving credit facility	—	—	(147,617)
Repurchase of Convertible Senior Notes due 2025	—	—	(3,487)
Proceeds from Nordea Q5000 Loan	250,000	—	—
Repayment of Nordea Q5000 Loan	(17,857)	—	—
Proceeds from Term Loan	—	—	300,000

Repayment of term loans	(22,500)	(15,000)	(374,681)
Repayment of MARAD borrowings	(5,644)	(5,376)	(5,120)
Deferred financing costs	(1,737)	(3,586)	(10,954)
Distributions to noncontrolling interests	—	(1,018)	(4,097)
Repurchases of common stock	(1,121)	(8,382)	(11,256)
Excess tax benefit from stock-based compensation	—	68	219
Exercise of stock options, net and other	—	—	734
Proceeds from issuance of ESPP shares	3,484	3,223	2,711
Net cash provided by (used in) financing activities	204,625	(30,071)	(487,421)
Effect of exchange rate changes on cash and cash equivalents	(2,011)	4,390	(2,725)
Net increase (decrease) in cash and cash equivalents	17,700	(1,708)	41,100
Cash and cash equivalents:			
Balance, beginning of year	476,492	478,200	437,100
Balance, end of year	$494,192	$476,492	$478,200

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 — Organization

Unless the context indicates otherwise, the terms "we," "us" and "our" in this Annual Report refer collectively to Helix Energy Solutions Group, Inc. and its subsidiaries ("Helix" or the "Company"). We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We provide services primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil.

Our Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities (Note 13). Our Subsea Construction results diminished following the sale in 2013 and early 2014 of essentially all of our assets related to this previously reported business segment.

Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our Well Intervention segment also includes intervention riser systems ("IRSs"), some of which we rent out on a stand-alone basis, and subsea intervention lubricators ("SILs"). Our well intervention vessels include the Q4000, the Q5000, the Well Enhancer, the Seawell, the Helix 534 and the Skandi Constructor, which is a chartered vessel. The Q5000, a newbuild semi-submersible well intervention vessel, commenced operations in the Gulf of Mexico during the fourth quarter of 2015. We currently have under construction another semi-submersible well intervention vessel, the Q7000. We have also contracted to charter the Siem Helix I and the Siem Helix II, two newbuild monohull vessels to be used in connection with our contracts to provide well intervention services offshore Brazil.

Our Robotics segment includes remotely operated vehicles ("ROVs"), trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates four chartered ROV support vessels including the Grand Canyon II, which was delivered to us in April 2015.

Our Production Facilities segment includes the Helix Producer I (the "HP I"), a ship-shaped dynamic positioning floating production unit vessel, and the Helix Fast Response System (the "HFRS"), which provides certain operators access to our Q4000 and HP I vessels in the event of a well control incident in the Gulf of Mexico. The Production Facilities segment also includes our ownership interest in Independence Hub, LLC ("Independence Hub"). We previously had an ownership interest in Deepwater Gateway, L.L.C. ("Deepwater Gateway"), which we sold for $25 million in February 2016 (Note 5).

Discontinued Operations

In February 2013, we sold Energy Resource Technology GOM, Inc. ("ERT"), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico, for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects. As a result, we have presented the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. Results for 2013 reflect the operating results from January 1, 2013 through February 6, 2013 when ERT was sold. There were no material results of operations for our former oil and gas segment subsequent to the sale of ERT.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority owned subsidiaries. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We account for our former ownership interest in Deepwater Gateway and our ownership interest in Independence Hub under the equity method of accounting. Noncontrolling interests represent the minority shareholders' proportionate share of the equity in Kommandor LLC, a Delaware limited liability company formed for the purpose of converting a ferry vessel into the HP I. In February 2014, we acquired our former minority partner's noncontrolling interests (approximately 19%) in Kommandor LLC for $20.1 million. The consolidated results of Kommandor LLC are included in our Production Facilities segment. All material intercompany accounts and transactions have been eliminated.

Basis of Presentation

Our consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("U.S. GAAP"). Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format. We have made all adjustments (which were normal recurring adjustments) that we believe are necessary for a fair presentation of our consolidated financial statements, as applicable.

Use of Estimates

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

Cash and Cash Equivalents

Cash and cash equivalents are highly liquid financial instruments with original maturities of three months or less. They are carried at cost plus accrued interest, which approximates fair value.

Accounts and Notes Receivable and Allowance for Uncollectible Accounts

Accounts and notes receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The amount of our net accounts receivable and our note receivable approximates fair value. We establish an allowance for uncollectible accounts based on historical experience as well as any specific collection issues that we have identified. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will definitively not be collected (Note 16).

Property and Equipment

Property and equipment is recorded at cost. Property and equipment is depreciated on a straight line basis over the estimated useful life of each asset. The cost of improvements is capitalized while the cost of repairs and maintenance is charged to expense as incurred. For the years ended December 31, 2015, 2014 and 2013, repair and maintenance expense totaled $32.8 million, $44.6 million and $31.5 million, respectively.

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying amount of an asset or asset group may not be recoverable because such carrying amount may exceed the asset's or asset group's fair value. If, upon review, the sum of undiscounted future cash flows expected to be generated by the asset or asset group is less than its carrying amount, an impairment is recorded. The amount of the impairment recorded is calculated as the difference between the carrying amount of the asset or asset group and its estimated fair value. Individual assets are grouped for impairment purposes at the lowest level where there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The expected future cash flows used for impairment reviews and related fair value calculations are based on assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. The fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. These fair value measurements fall within Level 3 of the fair value hierarchy.

Assets are classified as held for sale when a formal plan to dispose of the assets exists and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when we commit to a plan to sell and thereafter while those assets are held for sale. Losses are measured as the difference between an asset's fair value less costs to sell and the asset's carrying amount. Estimates of anticipated sales prices are judgmental and subject to revision in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data.

Capitalized Interest

Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful life of the asset in the same manner as the underlying asset. Capitalized interest is a component of our net interest expense (Note 7).

Equity Investments

We periodically review our equity investments for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever the fair value of an equity investment is determined to be below its carrying amount and the reduction is considered to be other than temporary. In judging "other than temporary," we consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term operating and financial prospects of the entity and our longer-term intent of retaining our investment in the entity.

In the event we incur losses in excess of the carrying amount of an equity investment and reduce our investment balance to zero, we would not record additional losses unless (i) we guaranteed obligations of the investee, (ii) we are otherwise committed to provide further financial support for the investee, or (iii) it is anticipated that the investee's return to profitability is imminent. If we provided a commitment to fund losses, we would continue to record losses resulting in a negative equity method investment, which is presented as a liability.

Goodwill

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. At the time of our annual assessment of goodwill on November 1, 2015, we had two reporting units with goodwill.

We first assess qualitative factors in order to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. Some of the qualitative factors evaluated include, among other things, the results of the most recent impairment analysis, the most recent operating results of the reporting unit, the current outlook for the reporting unit, and the current conditions of the market in which the reporting unit operates. If the qualitative assessment indicates a potential impairment, we perform the first step of the goodwill impairment analysis as described below. Our policy is to bypass the qualitative assessment at least once every three years and perform the first step of the goodwill impairment analysis, which was planned for November 1, 2016. However, we elected to perform the first step of the goodwill impairment analysis on November 1, 2015 given the current oil and gas industry downturn and the sharp decline in our stock price.

The goodwill impairment analysis is a two-step process. The first step is to identify whether a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment analysis is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit were acquired in a business combination).

We use both the income approach and the market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment analysis. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the upcoming fiscal year's forecasted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same economic risks. We also perform a market capitalization reconciliation by comparing the fair value of equity (fair value of total invested capital less fair value of total debt) to market capitalization and evaluate the reasonableness of the implied equity premium.

Our goodwill at December 31, 2015, 2014 and 2013 was associated with our Well Intervention and Robotics segments. As a result of our 2015 goodwill impairment analysis, we recorded an impairment charge of $16.4 million to write off the goodwill associated with our U.K. well intervention reporting unit. The fair value of our robotics reporting unit exceeded the carrying amount of goodwill based on the first step of the impairment analysis and no impairment was recorded. In 2014, we performed the qualitative assessment as described above and concluded that there was no indication of goodwill impairment. In our 2013 goodwill impairment analysis, the fair values of both of our reporting units with goodwill exceeded their respective carrying amounts based on the first step of the impairment analysis. We did not record any amount of goodwill impairment in 2014 or 2013.

Recertification Costs and Deferred Dry Dock Charges

Our vessels are required by regulation to be periodically recertified. Recertification costs are incurred while a vessel is in dry dock. In addition, routine repairs and maintenance are performed and at times, major replacements and improvements are performed. We expense routine repairs and maintenance costs as they are incurred. We defer and amortize dry dock and related recertification costs over the length of time for which we expect to receive benefits from the dry dock and related recertification, which is generally 30 months but can be as long as 60 months if the appropriate permitting is obtained. A dry dock and related recertification process typically lasts one to two months, a period during which the vessel is idle and generally not available to earn revenue. Major replacements and improvements that extend the vessel's economic useful life or functional operating capability are capitalized and depreciated over the vessel's remaining economic useful life.

As of December 31, 2015 and 2014, capitalized deferred dry dock charges included within "Other assets, net" in the accompanying consolidated balance sheets (Note 3) totaled $19.6 million and $11.6 million (net of accumulated amortization of $18.3 million and $7.5 million), respectively. During the years ended December 31, 2015, 2014 and 2013, dry dock amortization expense was $10.8 million, $14.1 million and $14.8 million, respectively.

Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term services contracts are contracts that contain either lump-sum provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue are expected to be billed and collected within one year. However, we also monitor the collectability of our outstanding trade receivables on a continual basis in connection with our evaluation of allowance for doubtful accounts.

Dayrate Contracts. Revenues generated from specific time, material and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Certain dayrate contracts with built-in rate changes require us to record revenues on a straight-line basis. We may receive revenues for mobilization of equipment and personnel under dayrate contracts. Revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, also are deferred and recognized using the same straight line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the contract period. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Lump Sum Contracts. Revenue on significant lump sum contracts is recognized under the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. In determining whether a contract should be accounted for using the percentage-of-completion method, we consider whether:

- the customer provides specifications for the provision of services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions for enforceable rights regarding the goods or services to be provided, consideration to be received, and the manner and terms of payment;
- the customer can be expected to satisfy its obligations under the contract; and
- we can be expected to perform our contractual obligations.

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, weather and other external factors outside of our control may affect the progress and estimated cost of a project's completion, and therefore the timing of revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Revenue from Royalty Interests

Revenues from royalty interests are recognized according to monthly oil and gas production on an entitlement basis. Revenues for royalty interests are reflected in "Other income - oil and gas" in the accompanying consolidated statements of operations.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We consider the undistributed earnings of our non-U.S. subsidiaries without operations in the U.S. to be permanently reinvested.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2015, we believe that we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Stock-Based Compensation

Stock-based compensation cost is measured at the grant date based on the estimated fair value of the award. Stock-based compensation based solely on service conditions is recognized on a straight-line basis over the vesting period of the related shares. Tax deduction benefits for a stock-based award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow.

Compensation cost for restricted stock is the product of grant date fair value of each share and the number of shares granted and is recognized over the respective vesting periods on a straight-line basis.

The estimated fair value of performance share units ("PSUs") is determined using a Monte Carlo simulation model. Compensation cost for PSUs that are accounted for as equity awards is measured based on the estimated grant date fair value and recognized over the vesting period on a straight-line basis. Unvested PSUs that are accounted for as liability awards are measured based on the estimated fair value at the balance sheet date and changes in fair value of the awards are recognized in earnings. Cumulative compensation cost for vested PSUs equals the actual cash payout amount upon vesting. To the extent the recognized fair value of the modified liability awards is less than the compensation cost associated with the grant date fair value of the original equity awards at the end of a reporting period, the higher amount is recorded as stock-based compensation expense. The amount of cumulative compensation expense recognized in excess of the fair value of the modified liability awards is recorded in equity.

Foreign Currency

Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to our North Sea operations). Results of operations for our non-U.S. subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2015 and 2014 and the resulting translation adjustments, which were unrealized losses of $12.8 million and $19.5 million, respectively, are included in "Accumulated other comprehensive loss" ("Accumulated OCI"), a component of shareholders' equity.

For the years ended December 31, 2015, 2014 and 2013, our foreign currency transaction gains (losses) totaled $(1.2) million, $2.5 million and $0.7 million, respectively. These realized amounts are exclusive of any gains or losses from our foreign currency exchange derivative contracts. All foreign currency transaction gains and losses are recognized currently in the consolidated statements of operations.

Derivative Instruments and Hedging Activities

Our business is exposed to market risks associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we enter into certain derivative contracts, including interest rate swaps and foreign currency exchange contracts. All derivatives are reflected in the accompanying consolidated balance sheets at fair value.

We formally document all relationships between hedging instruments and the related hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are designated as hedges are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued because it is probable the hedged transaction will not occur, deferred gains or losses on the hedging instruments are recognized in earnings immediately. If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in Accumulated OCI are amortized to earnings over the remaining period of the original forecasted transaction.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. The fair value of our interest rate swaps is calculated as the discounted cash flows of the difference between the rate fixed by the hedge instrument and the LIBOR forward curve over the remaining term of the hedge instrument. The fair value of our foreign currency exchange contracts is calculated as the discounted cash flows of the difference between the fixed payment specified by the hedge instrument and the expected cash inflow of the forecasted transaction using a foreign currency forward curve. Changes in the fair value of derivatives that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of Accumulated OCI until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

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Interest Rate Risk

From time to time, we enter into interest rate swaps to stabilize cash flows related to our long-term variable interest rate debt. Changes in the fair value of interest rate swaps are deferred to the extent the swaps are effective. These changes are recorded as a component of Accumulated OCI until the anticipated interest is recognized as interest expense. The ineffective portion of the interest rate swaps, if any, is recognized immediately in earnings within the line titled “Net interest expense.” The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

Foreign Currency Exchange Rate Risk

Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar. We enter into foreign currency exchange contracts from time to time to stabilize expected cash outflows related to our vessel charters that are denominated in foreign currencies.

See Note 18 for more information regarding our derivative contracts including our oil and gas commodity contracts associated with ERT.

Earnings Per Share

The presentation of basic earnings per share (“EPS”) amounts on the face of the accompanying consolidated statements of operations is computed by dividing the net income applicable to our common shareholders by the weighted average shares of our outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. We have shares of restricted stock issued and outstanding, which currently are unvested. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding unrestricted common stock and the shares of restricted stock are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute EPS amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss, we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas and renewable industries. Oil and gas companies spend capital on exploration, drilling and production operations, the amount of which is generally dependent on the prevailing view of future oil and gas prices which are subject to many external factors that may contribute to significant volatility. Our customers consist primarily of major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue from major customers (those representing 10% or more of our consolidated revenues) is as follows: 2015 — Shell (16%) and Talos (11%), 2014 — Anadarko (13%) and 2013 — Shell (14%). Most of the concentration of revenues was generated by our Well Intervention business.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

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Assets and liabilities measured at fair value are based on one or more of three valuation techniques as described in Note 17.

Asset Retirement Obligations

Pursuant to the terms of the ERT sale transaction, we retained the reclamation obligations associated with one property located in the Gulf of Mexico. During 2013, we paid $5.2 million for our pro-rata share of the costs to complete the reclamation of this property. For the year ended December 31, 2014, we recorded a $7.2 million insurance reimbursement related to asset retirement work previously performed on this property.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (the “FASB”) issued Accounting Standards Update (“ASU”) No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” This ASU provides a single five-step approach to account for revenue arising from contracts with customers. The ASU requires an entity to recognize revenue in a way that depicts 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. This revenue standard was originally effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. In August 2015, the FASB issued ASU No. 2015-14 to defer the effective date of ASU No. 2014-09 by one year to annual reporting periods beginning after December 15, 2017. Adoption as of the original effective date is permitted. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption through a cumulative adjustment. We are currently evaluating our existing revenue recognition policies to determine which types of contracts are within the scope of this guidance and what impact the adoption of this standard may have on our consolidated financial statements. We have not yet determined if we will apply the full retrospective or the modified retrospective method.

In April 2015, the FASB issued ASU No. 2015-03, “Simplifying the Presentation of Debt Issuance Costs.” This ASU requires that debt issuance costs related to a recognized debt liability be reported on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The guidance is effective retrospectively beginning in the first quarter of fiscal 2017 and early adoption is permitted. In August 2015, the FASB issued ASU No. 2015-15, “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.” This ASU includes an SEC staff announcement that the SEC staff will not object to an entity presenting the cost of securing a revolving line of credit as an asset, regardless of whether a balance is outstanding. The subject of this ASU was not previously addressed by ASU No. 2015-03. We do not expect these two ASUs to materially affect our balance sheets as amounts will be reclassified from long-term assets to partial offsets to long-term debt. The guidance will not affect our statements of operations or statements of cash flows.

In July 2015, the FASB issued ASU No. 2015-11, “Simplifying the Measurement of Inventory.” This ASU requires inventory that is measured using first-in, first-out or average cost method to be recorded at the lower of cost and net realizable value. The guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. We do not expect this guidance to materially affect our consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, “Balance Sheet Classification of Deferred Taxes.” This ASU requires companies to classify all deferred tax assets and liabilities as non-current on the balance sheet instead of separating deferred taxes into current and non-current amounts. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by this guidance. The guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. We do not expect this guidance to materially affect our consolidated financial statements.

We do not expect any other recent accounting standards to have a material impact on our financial position, results of operations or cash flows.

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Note 3 — Details of Certain Accounts

Other current assets consist of the following (in thousands):

	December 31, 2015	2014
Note receivable (Note 4)	$10,000	$17,500
Other receivables	426	423
Prepaid insurance	5,433	6,582
Other prepaids	10,751	15,541
Spare parts inventory	4,985	1,857
Value added tax receivable	7,842	9,326
Other	81	72
Total other current assets	$39,518	$51,301

Other assets, net consist of the following (in thousands):

	December 31, 2015	2014
Note receivable (Note 4)	$—	$10,000
Deferred dry dock expenses, net (Note 2)	19,615	11,631
Deferred financing costs, net (Note 7)	19,856	23,399
Intangible assets with finite lives, net	781	696
Charter fee deposit (Note 14)	12,544	12,544
Other	805	1,002
Total other assets, net	$53,601	$59,272

Accrued liabilities consisted of the following (in thousands):

	December 31, 2015	2014
Accrued payroll and related benefits	$14,775	$61,246
Current asset retirement obligations	553	575
Unearned revenue	12,841	11,461
Accrued interest	4,854	4,221
Derivative liability (Note 18)	23,192	13,222
Taxes payable excluding income tax payable	8,136	6,236
Other	7,290	7,962
Total accrued liabilities	$71,641	$104,923

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Other non-current liabilities consisted of the following (in thousands):

	December 31, 2015	2014
Loss in excess of equity investment (Note 5)	$8,308	$—
Derivative liability (Note 18)	39,709	37,767
Other	3,398	341
Total other non-current liabilities	$51,415	$38,108

Note 4 — Property and Equipment

The following is a summary of the gross components of property and equipment (dollars in thousands):

	Estimated Useful Life	December 31, 2015	2014
Vessels	15 to 30 years	$1,944,753	$1,657,448
ROVs, trenchers and ROVDrills	10 years	311,971	310,841
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	288,133	273,155
Total property and equipment		$2,544,857	$2,241,444

In 2012, we entered into an agreement to sell our two remaining subsea construction pipelay vessels, the Caesar and the Express, and related pipelay equipment. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million and recorded a loss on disposal of $1.1 million. In July 2013, we completed the sale of the Express for $100 million, which resulted in a gain on disposal of $15.6 million.

In January 2014, we sold our spoolbase located in Ingleside, Texas for $45 million. In connection with this sale, we received $15 million in cash and a $30 million secured promissory note. Interest on the note is payable quarterly at a rate of 6% per annum. We received $2.5 million, $7.5 million and $10 million of principal payments on this note in December 2014, January 2015 and December 2015, respectively. Under the terms of the note, the remaining $10 million principal balance is required to be paid on December 31, 2016.

Our assessment at December 31, 2015 indicated impairment on the Helix 534 and the HP I. We impaired these assets based on the difference between the carrying amount and the estimated fair value. The fair value of the Helix 534 was based on its estimated salvage value according to current market pricing. We recorded an impairment charge of $205.2 million to reduce the carrying amount of the Helix 534 to its estimated fair value of $1.0 million and to write off deferred dry dock costs of $9.0 million associated with the Helix 534. We estimated the fair value of the HP I based on the present value of its expected future cash flows. We recorded an impairment charge of $133.4 million to reduce the carrying amount of the HP I to its estimated fair value of $124.3 million. In addition, we recorded impairment charges of $6.3 million to write off capitalized costs associated with certain vessel projects that we no longer expect to materialize.

In January 2016, we sold our office and warehouse property located in Aberdeen, Scotland for approximately $11 million. At the same time, we entered into a separate agreement to lease back the facility for 15 years with two five-year options to extend the lease.

Note 5 — Equity Investments

As of December 31, 2015, we had ownership interests in Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of

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Mexico. Our investment in Deepwater Gateway totaled $26.2 million and $80.9 million as of December 31, 2015 and 2014, respectively (including net capitalized interest of $1.2 million as of December 31, 2014). For the year ended December 31, 2015, we recorded losses totaling $49.4 million to account for our 50% share of losses from Deepwater Gateway and to write off the remaining capitalized interest of $1.2 million. These losses included our share of an impairment charge that Deepwater Gateway recorded in December 2015 (see below).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. In connection with the acquisition, we paid a $1.0 million participation fee. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. As of December 31, 2014, our investment in Independence Hub was $68.8 million (including net capitalized interest of $3.9 million). As of December 31, 2015, our share of the losses reported by Independence Hub exceeded the carrying amount of our investment by $8.3 million. This liability is reflected in "Other non-current liabilities" in the accompanying consolidated balance sheet. For the year ended December 31, 2015, we recorded losses totaling $74.9 million to account for our 20% share of losses from Independence Hub and to write off the $1.0 million participation fee and the remaining capitalized interest of $3.6 million. These losses included our share of an impairment charge that Independence Hub recorded in December 2015 (see below).

In July 2015, Enterprise sold its offshore Gulf of Mexico pipelines and services business to Genesis Energy, L.P. ("Genesis") for approximately $1.5 billion. Enterprise's ownership interests in both Deepwater Gateway and Independence Hub were included in the sale. In December 2015, we were notified by Genesis that the operator of the facility no longer forecasted utilization of the "Independence Hub" platform and planned to turn over the platform for decommissioning. In December 2015, Independence Hub recorded an impairment charge of $343.3 million to reduce the carrying amount of the platform assets to their estimated fair value of zero. Independence Hub's estimated asset retirement obligations as of December 31, 2015 amounted to $42.1 million reflecting the estimated costs to decommission the platform. Since we are committed to providing the necessary level of financial support to enable Independence Hub to pay its obligations as they become due, we recorded a liability of $8.3 million for our share of the estimated obligations, net of remaining working capital. Additionally in December 2015, Deepwater Gateway recorded an impairment charge of $96.7 million to reduce the carrying amount of its long-lived assets to their estimated fair value of $70.8 million. Deepwater Gateway's estimated asset retirement obligations as of December 31, 2015 amounted to $20.8 million. In February 2016, we received a cash distribution of $1.2 million and sold our ownership interest in Deepwater Gateway to a subsidiary of Genesis for $25 million.

We received the following distributions from our equity method investments (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Deepwater Gateway	$5,200	$6,150	$7,600
Independence Hub	1,800	2,640	4,660
Total	$7,000	$8,790	$12,260

The summarized aggregated financial information related to our equity method investments is as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Revenues	$14,791	$23,284	$32,943
Operating income (loss)	(448,138)	411	10,058
Net income (loss)	(448,138)	411	10,058

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	December 31, 2015	2014
Current assets	$3,181	$7,898
Non-current assets	70,812	475,789
Current liabilities	180	50
Non-current liabilities	62,951	5,237

Note 6 — Goodwill

The changes in the carrying amount of goodwill are as follows (in thousands):

	Well Intervention	Robotics	Total
Balance at December 31, 2013	$18,123	$45,107	$63,230
Other adjustments (1)	(1,084)	—	(1,084)
Balance at December 31, 2014	17,039	45,107	62,146
Impairment loss	(16,399)	—	(16,399)
Other adjustments (1)	(640)	—	(640)
Balance at December 31, 2015	$—	$45,107	$45,107

(1) Reflects foreign currency adjustment related to the goodwill of our U.K. well intervention reporting unit.

Note 7 — Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31, 2015	2014
Term Loan (matures June 2018)	$255,000	$277,500
2032 Notes (mature March 2032)	200,000	200,000
MARAD Debt (matures February 2027)	89,148	94,792
Nordea Q5000 Loan (matures April 2020)	232,143	—
Unamortized debt discount	(14,963)	(20,920)
Total debt	761,328	551,372
Less current maturities	(71,640)	(28,144)
Long-term debt	$689,688	$523,228

Credit Agreement

In June 2013, we entered into a credit agreement (the "Credit Agreement") with a group of lenders pursuant to which we borrowed $300 million under the Credit Agreement's term loan (the "Term Loan") and, subject to the terms of the Credit Agreement, may borrow additional amounts (the "Revolving Loans") and/or obtain letters of credit under a revolving credit facility (the "Revolving Credit Facility") up to $600 million. Subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. As of December 31, 2015, we had no borrowings under the Revolving Credit Facility and our available borrowing capacity under that facility, based on the leverage ratio covenant, totaled $249.4 million, net of $13.2 million of letters of credit issued.

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The Term Loan and the Revolving Loans (together, the “Loans”) bear interest, at our election, in relation to either the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans.

The Loans or portions thereof bearing interest at the base rate currently bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 3.00%. The Loans or portions thereof bearing interest at a LIBOR rate currently bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 4.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We currently also pay a fixed commitment fee of 0.50% on the unused portion of our Revolving Credit Facility. The Term Loan currently bears interest at the one-month LIBOR rate plus 2.75%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $148.1 million of our borrowings under the Term Loan (Note 18). The fixed LIBOR rates are between 74 and 75 basis points.

The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the “Loan Documents”) include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries’ ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement). In January 2016, we amended the Credit Agreement to permit the sale and lease back of certain office and warehouse property located in Aberdeen, Scotland as well as the disposition of that property.

In May 2015 and in February 2016, we amended the Credit Agreement to revise the maximum permitted Consolidated Leverage Ratio as follows:

	Maximum Consolidated Leverage Ratio			
Four Fiscal Quarters Ending	May 2015 Amendment		February 2016 Amendment	
June 30, 2015	4.00	to 1.00	—	
September 30, 2015 through and including March 31, 2016	4.50	to 1.00	5.50	to 1.00
June 30, 2016	4.50	to 1.00	5.25	to 1.00
September 30, 2016 through and including December 31, 2016	4.50	to 1.00	5.00	to 1.00
March 31, 2017	4.00	to 1.00	4.75	to 1.00
June 30, 2017	3.50	to 1.00	4.25	to 1.00
September 30, 2017	3.50	to 1.00	3.75	to 1.00
December 31, 2017 and each fiscal quarter thereafter	3.50	to 1.00	3.50	to 1.00

Also pursuant to the February 2016 amendment to the Credit Agreement,

(a)

The revolving credit facility commitment under the Credit Agreement decreased from $600 million to $400 million.

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(b) The minimum permitted Consolidated Interest Coverage Ratio was revised as follows:

Four Fiscal Quarters Ending	Minimum Consolidated Interest Coverage Ratio	
March 31, 2016 through and including September 30, 2016	2.50	to 1.00
December 31, 2016 through and including March 31, 2017	2.75	to 1.00
June 30, 2017 and each fiscal quarter thereafter	3.00	to 1.00

(c) We are required to maintain minimum cash balances based on Consolidated Leverage Ratio as follows:

Consolidated Leverage Ratio	Minimum Cash
Greater than or equal to 4.50x	$150,000,000.00
Greater than or equal to 4.00x but less than 4.50x	$100,000,000.00
Greater than or equal to 3.50x but less than 4.00x	$50,000,000.00
Less than 3.50x	$0.00

We have designated five of our foreign subsidiaries, and may designate any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the "Unrestricted Subsidiaries"), provided we meet certain liquidity requirements, in which case EBITDA (net of cash distributions to the parent) of the Unrestricted Subsidiaries is not included in the calculations with respect to our financial covenants. Our obligations under the Credit Agreement are guaranteed by our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited, a wholly owned Scottish subsidiary. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets of the parent and our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited, plus pledges of up to two-thirds of the shares of certain foreign subsidiaries.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of $200 million in aggregate principal amount of Convertible Senior Notes due 2032 (the "2032 Notes"). The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes mature on March 15, 2032 unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes. We have the right and the intention to settle any such future conversions in cash.

Prior to March 20, 2018, the 2032 Notes are not redeemable. On or after March 20, 2018, we, at our option, may redeem some or all of the 2032 Notes in cash, at any time upon at least 30 days' notice, at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. In addition, the holders of the 2032 Notes may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the Indenture governing the 2032 Notes).

In connection with the issuance of the 2032 Notes, we recorded a debt discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6 years. In selecting the expected life, we selected the earliest date the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception. We recorded $22.5 million related to the carrying amount of the equity component of the 2032 Notes. The remaining unamortized amount of the debt discount of the 2032 Notes was $15.0 million and $20.9 million at December 31, 2015 and 2014, respectively.

MARAD Debt

This U.S. government guaranteed financing (the “MARAD Debt”) is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As required by the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date.

Nordea Credit Agreement

In September 2014, a wholly owned subsidiary incorporated in Luxembourg, Helix Q5000 Holdings S.à r.l. (“Q5000 Holdings”), entered into a credit agreement (the “Nordea Credit Agreement”) with a syndicated bank lending group for a term loan (the “Nordea Q5000 Loan”) in an amount of up to $250 million. The Nordea Q5000 Loan was funded in the amount of $250 million in April 2015 at the time the Q5000 vessel was delivered. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., also a wholly owned Luxembourg subsidiary, guaranteed the Nordea Q5000 Loan. The loan is secured by the Q5000 and its charter earnings as well as by a pledge of the shares of Q5000 Holdings. This indebtedness is non-recourse to Helix.

The Nordea Q5000 Loan bears interest at a LIBOR rate plus a margin of 2.5%, with an undrawn fee of 0.875% prior to funding on April 30, 2015. The Nordea Q5000 Loan matures on April 30, 2020 and is repayable in scheduled principal installments of $8.9 million, payable quarterly, with a balloon payment of $80.4 million at maturity. Q5000 Holdings may elect to prepay amounts outstanding under the Nordea Q5000 Loan without premium or penalty, but may not reborrow any amounts prepaid. Installment amounts are subject to adjustment for any prepayments on this debt. In certain circumstances, Q5000 Holdings will be required to prepay the loan. In June 2015, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $187.5 million of our borrowings under the Nordea Q5000 Loan (Note 18). The fixed LIBOR rates are between 149 and 152 basis points.

The Nordea Credit Agreement and related loan documents include terms and conditions, including covenants, that are considered customary for this type of transaction. The covenants include restrictions on Q5000 Holdings’s ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, and pay dividends. In addition, the Nordea Credit Agreement obligates Q5000 Holdings to meet certain minimum financial requirements, including liquidity, consolidated debt service coverage and collateral maintenance. As of December 31, 2015, Q5000 Holdings was in compliance with these covenants.

Other

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and a consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2015, we were in compliance with these covenants.

In 2013, we fully repaid the remaining indebtedness outstanding under our former credit facility. In connection with the repayments of this debt, we recorded charges totaling $3.5 million to accelerate a pro rata portion of deferred financing costs associated with the term loan component of the credit facility. This charge is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations. Also in 2013, we fully redeemed our former Senior Unsecured Notes. Our 2013 results of operations include a loss on early extinguishment of debt totaling $8.6 million, which reflects a $6.5 million call premium and a $2.1 million charge to accelerate the remaining deferred financing costs associated with the original issuance of the Senior Unsecured Notes.

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We paid financing costs associated with our debt totaling $1.7 million in 2015 and $3.6 million in 2014. Unamortized deferred financing costs are included in "Other assets, net" in the accompanying consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs (in thousands):

	December 31, 2015			December 31, 2014		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loan (matures June 2018)	$3,638	$(1,819)	$1,819	$3,638	$(1,091)	$2,547
Revolving Credit Facility (matures June 2018)	14,787	(6,924)	7,863	13,275	(3,982)	9,293
2032 Notes (mature March 2032)	3,759	(2,377)	1,382	3,759	(1,763)	1,996
MARAD Debt (matures February 2027)	12,200	(6,711)	5,489	12,200	(6,223)	5,977
Nordea Q5000 Loan (matures April 2020)	3,811	(508)	3,303	3,586	—	3,586
Total deferred financing costs	$38,195	$(18,339)	$19,856	$36,458	$(13,059)	$23,399

Scheduled maturities of long-term debt outstanding as of December 31, 2015 are as follows (in thousands):

	Term Loan	2032 Notes (1)	MARAD Debt	Nordea Q5000 Loan	Total
Less than one year	$30,000	$—	$5,926	$35,714	$71,640
One to two years	30,000	—	6,222	35,715	71,937
Two to three years	195,000	—	6,532	35,714	237,246
Three to four years	—	—	6,858	35,714	42,572
Four to five years	—	—	7,200	89,286	96,486
Over five years	—	200,000	56,410	—	256,410
Total debt	255,000	200,000	89,148	232,143	776,291
Current maturities	(30,000)	—	(5,926)	(35,714)	(71,640)
Long-term debt, less current maturities	225,000	200,000	83,222	196,429	704,651
Unamortized debt discount (2)	—	(14,963)	—	—	(14,963)
Long-term debt	$225,000	$185,037	$83,222	$196,429	$689,688

(1) Beginning in March 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our option elect to repurchase these notes. The notes will mature in March 2032.

(2) The 2032 Notes will increase to their face amount through accretion of non-cash interest charges through March 2018.

The following table details the components of our net interest expense (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Interest expense (1)	$40,024	$33,064	$44,484
Interest income	(2,068)	(4,786)	(1,167)
Capitalized interest	(11,042)	(10,419)	(10,419)
Net interest expense	$26,914	$17,859	$32,898

(1) Interest expense of $2.8 million was allocated to ERT during the year ended December 31, 2013 and is included in discontinued operations. Following the sale of ERT in February 2013, we ceased allocating interest expense to

ERT, which then constituted a discontinued operation.

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Note 8 — Income Taxes

We and our subsidiaries file a consolidated U.S. federal income tax return. We believe that our recorded assets and liabilities are reasonable. However, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Components of income tax provision (benefit) on continuing operations reflected in the consolidated statements of operations consist of the following (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Current	$1,832	$43,817	$57,128
Deferred	(103,022)	23,154	(25,516)
	$(101,190)	$66,971	$31,612
Domestic	$(102,978)	$29,613	$11,615
Foreign	1,788	37,358	19,997
	$(101,190)	$66,971	$31,612

Components of income (loss) before income taxes are as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Domestic	$(485,760)	$73,700	$36,176
Foreign	7,590	188,821	107,412
	$(478,170)	$262,521	$143,588

Income taxes are provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items that are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the U.S. statutory rate and our effective rate from continuing operations are as follows:

	Year Ended December 31,		
	2015	2014	2013
Statutory rate	35.0%	35.0%	35.0%
Foreign provision	(13.7)	(9.1)	(11.6)
Other	(0.1)	(0.4)	(1.4)
Effective rate	21.2%	25.5%	22.0%

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Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each are as follows (in thousands):

	December 31, 2015	2014
Deferred tax liabilities:		
Depreciation	$173,863	$211,903
Original Issue Discount on 2032 Notes	17,957	16,269
Equity investments in production facilities	8,029	50,685
Prepaid and other	1,883	4,211
Total deferred tax liabilities	$201,732	$283,068
Deferred tax assets:		
Net operating losses	$(23,595)	$(23,076)
Reserves, accrued liabilities and other	(52,672)	(53,973)
Total deferred tax assets	(76,267)	(77,049)
Valuation allowance	1,936	23,076
Net deferred tax liabilities	$127,401	$229,095
Deferred income tax is presented as:		
Current deferred tax assets	(53,573)	(31,180)
Non-current deferred tax liabilities	180,974	260,275
Net deferred tax liabilities	$127,401	$229,095

At December 31, 2015, our U.S. net operating losses available for carryforward or carryback totaled $47.2 million and our foreign tax credits available for carryforward or carryback totaled $7.9 million. The net operating loss carryforward would expire in 2035 if unused, while the foreign tax credit carryforward would expire in 2025 if unused. We anticipate fully utilizing the net operating loss and $4.6 million of the foreign tax credits via carryback claims. At December 31, 2015, the U.K. net operating losses of our well intervention company available for carryforward or carryback totaled $13.7 million. We anticipate fully utilizing the net operating loss via a carryback claim. At December 31, 2015, we had a $1.9 million valuation allowance related to certain non-U.S. deferred tax assets, primarily net operating losses generated from our oil and gas operations in the U.K., as management believes it is more likely than not that we will not be able to utilize the tax benefit. Additional valuation allowances may be made in the future if in management’s opinion it is more likely than not that the tax benefit will not be utilized.

We consider the undistributed earnings of our non-U.S. subsidiaries without operations in the U.S. to be permanently reinvested. At December 31, 2015 and 2014, our non-U.S. subsidiaries without operations in the U.S. had accumulated earnings and profits of approximately $304.0 million and $338.0 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits from our non-U.S. subsidiaries without operations in the U.S. as we consider them permanently reinvested.

We had no uncertain tax positions as of December 31, 2015. In 2014, we recognized a $3.4 million tax benefit as a result of the completion of examination procedures for the 2006 through 2010 audit period by the U.S. Internal Revenue Service (see below). We account for tax-related interest in interest expense and tax penalties in selling, general and administrative expenses. We charged $0.2 million to income tax expense for interest and penalties accrued in 2013, which brought our total liabilities for interest and penalties to $1.3 million at December 31, 2013. In 2014, in connection with the recognition of the $3.4 million tax benefit from the completion of examination procedures by the Internal Revenue Service, we reversed approximately $1.3 million of accrued interest and penalties.

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A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	2014	2013
Balance at January 1,	$4,723	$4,506
Additions for tax positions of prior years	—	217
Reductions for tax positions of prior years	(4,723)	—
Balance at December 31,	$—	$4,723

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. In June 2014, the Internal Revenue Service and the Joint Committee on Taxation completed the examination procedures including all appeals and administrative reviews that the taxing authorities are required and expected to perform for the 2006 through 2010 audit period, and in September 2014, we received an income tax refund in the amount of $35.2 million. The refund was primarily attributable to the utilization of a net operating loss carryback from 2010. The tax periods from 2012 through 2015 remain open to review and examination by the Internal Revenue Service. In non-U.S. jurisdictions, the open tax periods include 2009 through 2015.

Note 9 — Shareholders' Equity

Our amended and restated Articles of Incorporation provide for authorized Common Stock of 240,000,000 shares with no stated par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share issuable in one or more series.

The components of Accumulated OCI are as follows (in thousands):

	December 31, 2015	2014
Cumulative foreign currency translation adjustment	$(43,010)	$(30,161)
Unrealized loss on hedges, net [1]	(27,891)	(32,091)
Accumulated other comprehensive loss	$(70,901)	$(62,252)

(1) Amounts relate to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III charters as well as interest rate swap contracts for the Term Loan and the Nordea Q5000 Loan, and are net of deferred income taxes totaling $15.1 million and $17.3 million as of December 31, 2015 and 2014, respectively (Note 18).

Note 10 — Stock Buyback Program

Our Board of Directors has granted us the authority to repurchase shares of our common stock in an amount equal to any equity issued to our employees, officers and directors under our stock-based compensation plans, including share-based awards issued under our existing long-term incentive plans and shares issued to our employees under our employee stock purchase plans (Note 12). We may continue to make repurchases pursuant to this authority from time to time as additional equity is issued under our stock based plans depending on prevailing market conditions and other factors. As described in an announced plan, all repurchases may be commenced or suspended at any time as determined by management. During 2015, we did not purchase any shares as then available under this program. As of December 31, 2015, we had repurchased a total of 3,589,425 shares of our common stock for $53.5 million or an average of $14.90 per share. We had 878,328 shares of our common stock available for repurchase under the program at December 31, 2015.

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Note 11 — Earnings Per Share

The computations of the numerator (income) and denominator (shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying consolidated statements of operations are as follows (in thousands):

	Year Ended December 31,					
	2015		2014		2013	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Continuing operations:						
Net income (loss) applicable to common shareholders	$(376,980)		$195,047		$109,922	
Less: Income from discontinued operations, net of tax	—		—		(1,073)	
Net income (loss) from continuing operations	(376,980)		195,047		108,849	
Less: Undistributed income allocable to participating securities – continuing operations	—		(1,018)		(801)	
Net income (loss) applicable to common shareholders – continuing operations	$(376,980)	105,416	$194,029	105,029	$108,048	105,032
Discontinued operations:						
Income from discontinued operations, net of tax	$—		$—		$1,073	
Less: Undistributed income allocable to participating securities – discontinued operations	—		—		(8)	
Net income applicable to common shareholders – discontinued operations	$—	105,416	$—	105,029	$1,065	105,032
Diluted:						
Continuing operations:						
Net income (loss) applicable to common shareholders – continuing operations	$(376,980)	105,416	$194,029	105,029	$108,048	105,032
Effect of dilutive securities:						
Share-based awards other than participating securities	—	—	—	16	—	152
Undistributed income reallocated to participating securities	—	—	—	—	1	—
Net income (loss) applicable to common shareholders – continuing operations	$(376,980)	105,416	$194,029	105,045	$108,049	105,184
Discontinued operations:						
Income from discontinued operations, net of tax	$—	105,416	$—	105,045	$1,073	105,184

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We had net losses from continuing operations for the year ended December 31, 2015. Accordingly, our diluted EPS calculation for 2015 was equivalent to our basic EPS calculation because it excluded any assumed exercise or conversion of common stock equivalents because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in those respective years. Shares that otherwise would have been included in the diluted per share calculations for the year ended December 31, 2015, assuming we had earnings from continuing operations, are as follows (in thousands):

	2015
Diluted shares (as reported)	105,416
Share-based awards	59
Total	105,475

In addition, approximately 8.0 million of potentially dilutive shares related to our Convertible Senior Notes Due 2032 (the “2032 Notes”) were excluded from the diluted EPS calculation for the years ended December 31, 2014 and 2013 because we have the right and the intention to settle any such future conversions in cash (Note 7).

Note 12 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our discretionary contributions are in the form of cash and, prior to 2014, consisted of a 50% match of each employee’s contribution up to 5% of the employee’s salary. Beginning in 2014, our matching contributions increased to 75% of the first 5% of the employee’s salary. At their meetings in February 2016 the Compensation Committee of our Board of Directors and our Board of Directors resolved to suspend Helix’s discretionary matching contributions for an indefinite period. For the years ended December 31, 2015, 2014 and 2013, our costs related to the 401(k) plan totaled $2.8 million, $2.2 million and $1.7 million, respectively.

Employee Stock Purchase Plan

We have an employee stock purchase plan (the “ESPP”). The ESPP has 1.5 million shares authorized for issuance, of which 0.9 million shares were available for issuance as of December 31, 2015. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors and Section 423 of the Internal Revenue Code. The per share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. For the years ended December 31, 2015, 2014 and 2013, share-based compensation expense with respect to the ESPP was $1.1 million, $1.0 million and $0.8 million, respectively. At their meetings in February 2016 the Compensation Committee of our Board of Directors and our Board of Directors amended the ESPP to give the Board or the Compensation Committee the authority to suspend purchases under the ESPP at any time, and to give Helix management the authority to limit the number of shares our employees can purchase during each ESPP purchase period.

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Long-Term Incentive Stock-Based Plan

We currently have one active long-term incentive stock-based plan, the 2005 Long-Term Incentive Plan, as amended and restated effective May 9, 2012 (the “2005 Incentive Plan”). In May 2012, the shareholders approved an amendment to and restatement of the 2005 Incentive Plan to: (i) authorize 4.3 million additional shares for issuance pursuant to our equity incentive compensation programs, (ii) authorize incentive stock options, stock appreciation rights, cash awards and performance awards to be made pursuant to the 2005 Incentive Plan, and (iii) include performance criteria for awards that may be made contingent upon the achievement of one or more performance measures, as well as limits on individual awards, in accordance with the requirements for performance-based compensation under Section 162(m) of the Internal Revenue Code. As of December 31, 2015, there were 6.0 million shares available for issuance under the 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options.

The 2005 Incentive Plan is administered by the Compensation Committee of our Board of Directors. The Compensation Committee also determines the type of award to be made to each participant and, as set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The Compensation Committee may grant stock options, restricted stock, restricted stock units (“RSUs”), PSUs and cash awards. Prior to 2012, awards granted to employees under the incentive plans vested 20% per year over a five year period. Commencing in 2012, awards granted under the 2005 Incentive Plan have a vesting period of three years (or 33% per year).

The following grants of share-based awards were made in 2015 under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2015 (1)	289,163	$21.70	33% per year over three years
January 2, 2015 (2)	289,163	$25.06	100% on January 1, 2018
January 5, 2015 (3)	3,946	$21.66	100% on January 1, 2017
January 12, 2015 (1)	3,866	$19.40	33% per year over three years
January 12, 2015 (2)	3,866	$25.06	100% on January 11, 2018
February 1, 2015 (1)	2,664	$18.77	33% per year over three years
February 1, 2015 (2)	2,664	$25.06	100% on January 31, 2018
April 1, 2015 (3)	6,476	$14.96	100% on January 1, 2017
July 1, 2015 (3)	6,631	$12.63	100% on January 1, 2017
October 1, 2015 (3)	17,876	$4.79	100% on January 1, 2017
December 3, 2015 (4)	170,454	$6.16	33% per year over three years

(1) Reflects the grant of restricted stock to our executive officers and select management employees.
(2) Reflects the grant of PSUs to our executive officers and select management employees.
(3) Reflects the grant of restricted stock to certain independent members of our Board of Directors who have made an election to take their quarterly fees in stock in lieu of cash.
(4) Reflects annual equity grants to each independent member of our Board of Directors.

In January 2016, we granted our executive officers and select management employees 1,143,062 shares of restricted stock under the 2005 Incentive Plan. The market value of the restricted shares was $5.26 per share or $6.0 million and the shares vest 33% per year for a three-year period. Separately, we issued our executive officers and select management employees 1,143,062 PSUs under the 2005 Incentive Plan.

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Restricted Stock

We grant restricted stock to members of our Board of Directors, executive officers and select management employees. The following table summarizes information about our restricted stock:

	Year Ended December 31,					
	2015		2014		2013	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Awards outstanding at beginning of year	554,960	$17.54	771,942	$13.62	1,191,402	$14.14
Granted	501,076	15.57	139,455	23.22	168,468	21.63
Vested (2) (3)	(332,223)	16.44	(356,437)	11.27	(502,022)	17.50
Forfeited	(62,689)	20.93	—	—	(85,906)	13.79
Awards outstanding at end of year (3)	661,124	$16.28	554,960	$17.54	771,942	$13.62

(1) Represents the weighted average grant date fair value, which is based on the quoted closing market price of our common stock on the trading day prior to the date of grant.

(2) Total fair value of restricted stock and RSUs that vested during the years ended December 31, 2015, 2014 and 2013 was $5.1 million, $8.2 million and $11.0 million, respectively.

(3) The vested and year-end amounts in 2014 each include 33,760 shares of RSUs with the grant date fair value of $15.80 per share. In December 2013, management elected to pay out the January 2014 vesting of these RSUs in cash. As a result, we recorded a $1.3 million liability associated with these RSUs at December 31, 2013 and an additional liability of $0.2 million during 2014. We paid $0.8 million of this liability in January 2014 and $0.7 million in January 2015.

For the years ended December 31, 2015, 2014 and 2013, $5.5 million, $5.0 million and $6.6 million, respectively, were recognized as stock-based compensation expense related to restricted stock and RSUs. Forfeitures on restricted stock totaled approximately 6% based on our most recent five-year average of historical forfeiture rates. Future compensation expense associated with unvested restricted stock at December 31, 2015 totaled approximately $6.5 million. The weighted average vesting period related to unvested restricted stock at December 31, 2015 was approximately 1.8 years.

Performance Stock Units

Since 2012, we have issued PSUs to our executive officers. We also have issued PSUs to select management employees since 2015. The PSUs provide for an award based on the performance of our common stock over a three-year period compared to the performance of other companies in a peer group selected by the Compensation Committee of our Board of Directors with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The PSUs vest 100% on the three-year anniversary date of the grant. The vested PSUs may be settled in either cash or shares of our common stock at the discretion of the Compensation Committee of our Board of Directors.

We issued 295,693 PSUs in 2015 with a grant date fair value of $25.06 per unit, 73,609 PSUs in 2014 with a grant date fair value of $26.79 per unit and 89,329 PSUs in 2013 with a grant date fair value of $27.50 per unit. Until December 2014, the PSUs were being treated as equity awards. In January 2015, in connection with the vesting of the 2012 PSU awards, the decision was made by the Compensation Committee of our Board of Directors to settle these PSUs with a cash payment of $4.5 million (rather than an equivalent number of shares of our common stock, which was the default payment method for the PSU awards). Accordingly, PSUs are accounted for as liability awards. For the years ended December 31, 2015, 2014 and 2013, $0.2 million, $5.4 million and $2.2 million, respectively, were recognized as stock-based compensation expense related to PSUs. For the year ended December 31, 2015, $2.9 million was recorded in equity reflecting the cumulative compensation expense recognized in excess of the estimated fair value of the modified liability PSU awards at December 31, 2015. The liability balance for unvested PSUs was $0.7 million and $7.9 million at December 31, 2015 and 2014, respectively. We paid $4.5 million to cash settle the 2012 grant of PSUs when they vested in January 2015. We paid $0.2 million to cash settle the 2013 grant of PSUs when they vested in January 2016.

Stock Options

There have been no stock options granted since 2004. All of the remaining 52,800 stock options were exercised in 2013 at a weighted average price of $13.91 per share. The aggregate intrinsic value of the stock options exercised during the year ended December 31, 2013 was approximately $0.5 million.

Long-Term Incentive Cash Plans

We also have certain long-term incentive cash plans (the "LTI Cash Plans") that provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). Payment amounts under these awards are calculated based on the ratio of the average stock price during the applicable measurement period over the original base price determined by the Compensation Committee of our Board of Directors at the time of the award. The maximum amount payable under these share-based cash awards is twice the original amount of the award and if the average price during the measurement period is less than 75% of the base price, no payout will be made at the applicable vesting date. Cash payments under these awards are made each year during the vesting period on the anniversary date of the award. Cash awards granted since 2012 have a vesting period of three years while those granted prior to 2012 have a vesting period of five years. The LTI Cash Plans are considered liability plans and as such are re-measured to fair value each reporting period with corresponding changes in the liability amount being reflected in our results of operations.

The cash awards granted under the LTI Cash Plans to our executive officers and select management employees totaled $8.9 million in 2014 and $8.4 million in 2013. No long-term incentive cash awards were granted in 2015. For the year ended December 31, 2015, we recorded reductions of $3.7 million ($2.1 million related to our executive officers) of previously recognized compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans, reflecting the effect the decrease in our stock price since December 31, 2014 had on the value of our liability plan. For the years ended December 31, 2014 and 2013, total compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans was $7.2 million ($3.6 million related to our executive officers) and $9.1 million ($5.3 million related to our executive officers), respectively. The liability balance for the cash awards issued under the LTI Cash Plans was less than $0.1 million at December 31, 2015 and $12.8 million ($7.9 million related to our executive officers) at December 31, 2014. During 2015, 2014 and 2013, we paid $8.9 million, $9.2 million and $7.1 million of the liability associated with the LTI Cash Plans. No long-term incentive cash awards were paid or granted in January 2016.

Note 13 — Business Segment Information

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. Our U.S., U.K. and Brazil well intervention operating segments are aggregated into the Well Intervention business segment for financial reporting purposes. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Q5000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our well intervention segment also includes IRSs, some of which we rent out on a stand-alone basis, and SILs. Our Robotics segment includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates four chartered ROV support vessels. The Production Facilities segment includes the HP I as well as our investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. Our Subsea Construction results diminished following the sale in 2013 and early 2014 of essentially all of our assets related to this previously reported business segment. All material intercompany transactions between the segments have been eliminated. We sold ERT in February 2013, and as a result, the historical operating results of our former Oil and Gas segment are presented as discontinued operations in the accompanying consolidated financial statements. See Note 1 for additional information regarding our discontinued operations.

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We evaluate our performance based on operating income and income before income taxes of each reportable segment. Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments. Certain financial data by reportable segment are summarized as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Net revenues —			
Well Intervention	$373,301	$667,849	$452,452
Robotics	301,026	420,224	333,246
Production Facilities	75,948	93,175	88,149
Subsea Construction	—	358	71,321
Intercompany elimination	(54,473)	(74,450)	(68,607)
Total	$695,802	$1,107,156	$876,561
Income (loss) from operations —			
Well Intervention (1)	$(194,381)	$204,810	$131,840
Robotics	27,832	68,329	44,132
Production Facilities (2)	(106,847)	41,138	49,778
Subsea Construction (3)	(52)	10,923	33,685
Corporate and other	(33,814)	(62,523)	(77,041)
Intercompany elimination	(98)	(921)	(3,360)
Total	$(307,360)	$261,756	$179,034
Net interest expense —			
Well Intervention	$(102)	$(252)	$(128)
Robotics	29	(5)	19
Production Facilities	385	384	380
Corporate and eliminations (4)	26,602	17,732	32,627
Total	$26,914	$17,859	$32,898
Equity in earnings (losses) of investments	$(124,345)	$879	$2,965
Income (loss) before income taxes —			
Well Intervention (1)	$(193,572)	$211,725	$132,057
Robotics (5)	2,454	61,025	44,342
Production Facilities (2)	(231,577)	41,633	52,363
Subsea Construction (3)	53	11,201	33,205
Corporate and eliminations	(55,528)	(63,063)	(118,379)
Total	$(478,170)	$262,521	$143,588
Income tax provision (benefit) —			
Well Intervention	$(1,230)	$50,102	$26,718
Robotics	515	21,612	15,530
Production Facilities	(81,052)	14,395	17,233
Subsea Construction	26	3,881	11,655
Corporate and eliminations	(19,449)	(23,019)	(39,524)
Total	$(101,190)	$66,971	$31,612

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	Year Ended December 31,		
	2015	2014	2013
Identifiable assets —			
Well Intervention	$1,492,901	$1,470,349	$1,245,229
Robotics	274,926	299,701	282,373
Production Facilities	182,007	459,427	495,829
Subsea Construction	10,027	27,547	38,054
Corporate and other	452,091	443,674	482,795
Total	$2,411,952	$2,700,698	$2,544,280
Capital expenditures —			
Well Intervention	$307,879	$283,635	$283,132
Robotics	10,700	51,348	39,655
Production Facilities	1,867	869	1,252
Corporate and other	(135)	1,060	387
Total	$320,311	$336,912	$324,426
Depreciation and amortization —			
Well Intervention	$66,095	$57,570	$44,619
Robotics	26,724	24,478	22,263
Production Facilities	21,340	21,278	17,193
Subsea Construction	—	—	8,651
Corporate and eliminations	6,242	6,019	5,809
Total	$120,401	$109,345	$98,535

(1) Amount in 2015 includes impairment charges of $205.2 million for the Helix 534 and $6.3 million for certain capitalized vessel project costs and a $16.4 million impairment charge on goodwill related to our U.K. well intervention reporting unit.

(2) Amount in 2015 includes a $133.4 million impairment charge for the HP I.

(3) Amount in 2014 includes the $10.5 million gain on the sale of our Ingleside spoolbase in January 2014. Amount in 2013 includes the $1.1 million loss on the sale of the Caesar in June 2013 and the $15.6 million gain on the sale of the Express in July 2013.

(4) Amount in 2014 includes $16.9 million of income with $7.2 million from an insurance reimbursement related to asset retirement work previously performed and the remaining income associated with our overriding royalty interests in ERT’s Wang well, which commenced production in April 2013. Amount in 2013 includes the $12.1 million loss on early extinguishment of debt.

(5) Amount in 2015 includes unrealized losses totaling $18.3 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels.

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Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Well Intervention	$22,855	$29,875	$22,448
Robotics	31,618	44,575	41,169
Production Facilities	—	—	4,673
Subsea Construction	—	—	317
Total	$54,473	$74,450	$68,607

Revenues by individually significant region are as follows (in thousands):

	Year Ended December 31,		
	2015	2014	2013
United States	$298,391	$403,994	$345,525
North Sea (1)	263,438	504,016	403,816
Other	133,973	199,146	127,220
Total	$695,802	$1,107,156	$876,561

(1) Includes revenues of $187.7 million, $362.7 million and $327.1 million, respectively, which were from the U.K.

Our assets related to operations, primarily our vessels, operate throughout the year in various regions around the world such as the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa. The following table provides our property and equipment, net of accumulated depreciation, by individually significant geographic location of our assets (in thousands):

	December 31,	
	2015	2014
United States	$1,024,691	$893,106
United Kingdom	352,740	355,996
Singapore (1)	112,313	434,319
Other	113,265	51,963
Total	$1,603,009	$1,735,384

(1) Primarily includes vessels under construction.

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Note 14 — Commitments and Contingencies and Other Matters

Commitments

Commitments Related to Our Fleet

In February 2013, we contracted to charter the Grand Canyon II and the Grand Canyon III for use in our robotics operations. The terms of the charters are for five years from their respective delivery dates. We took delivery of the Grand Canyon II in April 2015 and received a $4.7 million non-refundable payment from the shipyard that constructed the vessel related to the delayed delivery of the vessel. This payment is amortized as a reduction in our cost of sales over the five-year charter for the vessel. The delivery of the Grand Canyon III has been deferred until May 2016.

In September 2013, we executed a contract with the same shipyard in Singapore that constructed the Q5000. This contract is for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is being built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the original terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% was to be paid upon the delivery of the vessel. Pursuant to the first amendment, we agreed to pay the shipyard incremental costs of up to $14.5 million to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017. We paid $7.3 million of these costs in July 2015 and the remaining costs will be paid upon the delivery of the vessel. Pursuant to the second amendment we entered into in December 2015, the remaining 80% will be paid in three installments, with 20% in June 2016, 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. We agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. Incremental costs are capitalized as they are incurred during the construction of the vessel. At December 31, 2015, our total investment in the Q7000 was $112.2 million, including the $69.2 million paid to the shipyard upon signing the contract.
In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, the Siem Helix I, which is expected to be in service for Petrobras in the second half of 2016, and the Siem Helix II, which is expected to be in service in 2017. At December 31, 2015, our total investment in the topside equipment for the two vessels was $113.3 million. In November 2014, we paid a charter fee deposit of $12.5 million, which will be used to reduce our future charter payments.

Lease Commitments

We lease facilities and charter vessels under non-cancelable operating leases and vessel charters expiring at various dates through 2025. Future minimum rentals at December 31, 2015 are as follows (in thousands):

	Vessels	Facilities and Other	Total
2016	$144,389	$4,973	$149,362
2017	160,215	4,805	165,020
2018	126,890	4,441	131,331
2019	122,004	4,460	126,464
2020	107,484	4,041	111,525
Thereafter	199,867	16,706	216,573
Total lease commitments	$860,849	$39,426	$900,275

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For the years ended December 31, 2015, 2014 and 2013, total rental expense was approximately $134.3 million, $147.2 million and $102.1 million, respectively.

We sublease some of our facilities under non-cancelable sublease agreements. For the years ended December 31, 2015, 2014 and 2013, total rental income was $1.4 million, $0.8 million and $0.4 million, respectively. As of December 31, 2015, the minimum rentals to be received in the future totaled $1.6 million.

In January 2016, we entered into an agreement to lease back our former office and warehouse property located in Aberdeen, Scotland for 15 years with two five-year options to extend the lease. The annual minimum lease payment is approximately $0.9 million.

Contingencies and Claims

We believe that there are currently no contingencies that would have a material adverse effect on our financial position, results of operations and cash flows. During 2015, we concluded that a potential contractual obligation to reimburse a third party for certain foreign taxes was no longer probable and thus we reversed a previous accrual in the amount of $5.2 million for this contingent liability as a reduction in our cost of sales.

Litigation

On July 31, 2015, a purported stockholder, Parviz Izadjoo, filed a class action lawsuit styled Parviz Izadjoo v. Owen Kratz and Helix Energy Solutions Group, Inc. against the Company and Owen Kratz, our President and Chief Executive Officer, in the United States District Court for the Southern District of Texas on behalf of a putative class of all purchasers of shares of our common stock between October 21, 2014, and July 21, 2015, inclusive. The lawsuit asserts violations of Section 10(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and SEC Rule 10b-5 as to both us and Mr. Kratz, and Section 20(a) of the Exchange Act against Mr. Kratz based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding projections for 2015 dry docks of two of our vessels working in the Gulf of Mexico that allegedly caused the price at which putative class members bought stock during the proposed class period to be artificially inflated. The deadline to apply for appointment as lead plaintiff was September 29, 2015. On January 28, 2016, the judge approved a motion for the appointment of lead plaintiff and lead counsel, and the plaintiff has until March 14, 2016 to amend the complaint. We believe this lawsuit to be without merit and intend to vigorously defend against it.

We are involved in various legal proceedings, some involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Note 15 — Statement of Cash Flow Information

The following table provides supplemental cash flow information (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Interest paid, net of interest capitalized	$14,555	$11,628	$39,040
Income taxes paid	$16,905	$70,509	$113,331

Our non-cash investing activities include accruals for property and equipment capital expenditures. As of December 31, 2015 and 2014, these non-cash investing accruals totaled $18.7 million and $14.1 million, respectively. Additionally, our non-cash investing activities for the year ended December 31, 2014 included a $27.5 million non-cash transaction related to the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014 (Note 4).

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Note 16 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2015 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance at December 31, 2012	$5,152	$16,391
Additions (1)	2,236	—
Adjustments (2) (3)	(5,154)	6,469
Balance at December 31, 2013	2,234	22,860
Additions (1)	5,331	—
Deductions (4)	(2,830)	—
Adjustments	—	216
Balance at December 31, 2014	4,735	23,076
Additions (1)	3,275	—
Deductions (4)	(7,660)	—
Adjustments (5)	—	(21,140)
Balance at December 31, 2015	$350	$1,936

(1) The increase in allowance for uncollectible accounts primarily reflects charges associated with the provision for uncertain collection of a portion of our existing trade receivables related to our Robotics segment.

(2) The decrease in allowance for uncollectible accounts primarily reflects the reversal of a $4.0 million allowance against our trade receivables for work performed offshore India in 2007 as we collected the previously adjusted receivable balance pursuant to a settlement agreement.

(3) The increase in valuation allowance includes $6.5 million related to our net operating losses generated in Australia.

(4) The decrease in allowance for uncollectible accounts reflects the write-offs of trade receivables that are either settled or deemed uncollectible.

(5) The decrease in valuation allowance primarily reflects a $20.6 million reduction related to the loss of deferred tax assets for net operating losses within our Australian subsidiaries.

See Note 2 for a detailed discussion regarding our accounting policy on accounts receivable and allowance for uncollectible accounts and Note 8 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 17 — Fair Value Measurements

Assets and liabilities measured at fair value are based on one or more of three valuation techniques as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).

(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the short-term nature of these instruments. The following tables provide additional information relating to other financial instruments measured at fair value on a recurring basis (in thousands):

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	Fair Value Measurements at December 31, 2015 Using				Valuation Technique
	Level 1	Level 2 (1)	Level 3	Total	
Assets:					
Interest rate swaps	$—	$413	$—	$413	(c)
Liabilities:					
Foreign exchange contracts	—	61,427	—	61,427	(c)
Interest rate swaps	—	1,473	—	1,473	(c)
Total net liability	$—	$62,487	$—	$62,487	

	Fair Value Measurements at December 31, 2014 Using				Valuation Technique
	Level 1	Level 2 (1)	Level 3	Total	
Assets:					
Interest rate swaps	—	369	—	369	(c)
Liabilities:					
Foreign exchange contracts	—	50,428	—	50,428	(c)
Interest rate swaps	—	561	—	561	(c)
Total net liability	$—	$50,620	$—	$50,620	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. See Note 18 for further discussion on fair value of our derivative instruments.

The carrying values and estimated fair values of our long-term debt are as follows (in thousands):

	December 31, 2015		2014	
	Carrying Value	Fair Value (2)	Carrying Value	Fair Value (2)
Term Loan (matures June 2018)	$255,000	$248,467	$277,500	$270,563
Nordea Q5000 Loan (matures April 2020)	232,143	221,553	—	—
MARAD Debt (matures February 2027)	89,148	104,897	94,792	104,830
2032 Notes (mature March 2032) (1)	200,000	150,250	200,000	222,900
Total debt	$776,291	$725,167	$572,292	$598,293

(1) Carrying amount excludes the related unamortized debt discount of $15.0 million and $20.9 million at December 31, 2015 and 2014, respectively.

(2) The estimated fair value of the 2032 Notes was determined using Level 1 inputs under the market approach. The fair value of the Term Loan, the Nordea Q5000 Loan and the MARAD Debt was estimated using Level 2 fair value inputs under the market approach. The fair value of the Term Loan, the Nordea Q5000 Loan and the MARAD Debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the indebtedness as compared to other obligations in the marketplace with similar terms.

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Note 18 — Derivative Instruments and Hedging Activities

The following table presents the fair value and balance sheet classification of our derivative instruments that were designated as hedging instruments (in thousands):

	December 31, 2015		2014	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$413	Other assets, net	$369
		$413		$369
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$14,955	Accrued liabilities	$12,661
Interest rate swaps	Accrued liabilities	1,473	Accrued liabilities	561
Foreign exchange contracts	Other non-current liabilities	28,458	Other non-current liabilities	37,767
		$44,886		$50,989

The following table presents the fair value and balance sheet classification of our derivative instruments that were not designated as hedging instruments (in thousands):

	December 31, 2015		2014	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$6,763	Accrued liabilities	$—
Foreign exchange contracts	Other non-current liabilities	11,251	Other non-current liabilities	—
		$18,014		$—

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our then remaining oil and gas derivative contracts and our then existing interest rate swaps as hedging instruments. In February 2013, we cash settled all of these commodity derivative contracts and interest rate swap contracts.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively.

During renegotiations on the Grand Canyon, the Grand Canyon II and the Grand Canyon III charters, it became apparent in December 2015 that a portion of previously forecasted charter payments in NOK would no longer be made. We concluded that the foreign currency exchange contracts associated with the charter payments for the Grand Canyon II and the Grand Canyon III vessels no longer qualified for hedge accounting treatment. As a result, we de-designated these hedges and re-designated the hedging relationship between a portion of our foreign currency exchange contracts and our forecasted Grand Canyon II and Grand Canyon III charter payments of NOK434.1 million and NOK185.2 million, respectively, that were expected to remain highly probable of occurring. We recognized unrealized losses of $18.0 million related to the foreign currency exchange contracts associated with the portion of previously forecasted charter payments that would no longer be made. These unrealized losses are reflected in “Other income (expense), net” in the accompanying consolidated statement of operations. As of December 31, 2015, our Accumulated OCI (net of tax) included unrealized losses of $19.8 million associated with the re-designated foreign currency exchange contracts that qualify for hedge accounting treatment.

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Hedge ineffectiveness is reflected in “Other income (expense), net” in the accompanying consolidated statement of operations. For the year ended December 31, 2015, we recorded realized losses of $3.6 million related to the Grand Canyon II and Grand Canyon III hedge ineffectiveness and unrealized losses of $1.5 million related to the Grand Canyon hedge ineffectiveness. For the year ended December 31, 2014, we recorded realized losses of $0.5 million and unrealized losses of $1.2 million related to the Grand Canyon II hedge ineffectiveness. Ineffectiveness associated with our cash flow hedges was immaterial for the year ended December 31, 2013.

In September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan borrowings (Note 7). These contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally, in June 2015 we entered into various interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Q5000 Loan borrowings (Note 7). These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. Our interest rate swap contracts qualify for cash flow hedge accounting treatment.

The following tables present the impact that derivative instruments designated as cash flow hedges had on our Accumulated OCI (net of tax) and our consolidated statements of operations (in thousands). We estimate that as of December 31, 2015, $9.6 million of losses in Accumulated OCI associated with our derivatives is expected to be reclassified into earnings within the next 12 months.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax (Effective Portion) Year Ended December 31,		
	2015	2014	2013
Foreign exchange contracts	$4,734	$(22,170)	$(9,796)
Interest rate swaps	(534)	70	(195)
	$4,200	$(22,100)	$(9,991)

	Location of Loss Reclassified from Accumulated OCI into Earnings	Loss Reclassified from Accumulated OCI into Earnings (Effective Portion) Year Ended December 31,		
		2015	2014	2013
Foreign exchange contracts	Cost of sales	$(11,516)	$(2,507)	$(1,324)
Interest rate swaps	Net interest expense	(2,143)	(858)	(152)
		$(13,659)	$(3,365)	$(1,476)

The following table presents the impact that derivative instruments not designated as hedges had on our consolidated statement of operations (in thousands):

	Location of Gain (Loss) Recognized in Earnings on Derivatives	Gain (Loss) Recognized in Earnings on Derivatives Year Ended December 31,		
		2015	2014	2013
Oil and gas commodity contracts	Loss on commodity derivative contracts	$—	$—	$(14,113)
Interest rate swaps	Other income (expense), net	—	—	(86)
Foreign exchange contracts	Other income (expense), net	(18,014)	7	(630)

$(18,014)	$7	$(14,829)

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Note 19 — Quarterly Financial Information (Unaudited)

Offshore marine construction activities may fluctuate as a result of weather conditions as well as the timing of capital expenditures by oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2015				
Net revenues	$189,641	$166,016	$182,462	$157,683
Gross profit (loss) [1]	$34,947	$24,208	$31,969	$(324,898)
Net income (loss) applicable to common shareholders [2]	$19,642	$(2,635)	$9,880	$(403,867)
Basic earnings (loss) per common share	$0.19	$(0.03)	$0.09	$(3.83)
Diluted earnings (loss) per common share	$0.19	$(0.03)	$0.09	$(3.83)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2014				
Net revenues	$253,572	$305,587	$340,837	$207,160
Gross profit	75,846	109,138	126,247	32,805
Net income applicable to common shareholders	$53,719	$57,782	$75,586	$7,960
Basic earnings per common share	$0.51	$0.55	$0.72	$0.08
Diluted earnings per common share	$0.51	$0.55	$0.71	$0.08

(1) Amount in the fourth quarter of 2015 includes impairment charges of $205.2 million for the Helix 534 and $133.4 million for the HP I and $6.3 million for certain capitalized vessel project costs (Note 4).

(2) Amount in the fourth quarter of 2015 includes a $16.4 million impairment charge on goodwill related to our U.K. well intervention reporting unit (Notes 2 and 6), losses totaling $123.8 million related to our equity investments in Deepwater Gateway and Independence Hub (Note 5), and unrealized losses totaling $19.0 million on our foreign currency exchange contracts associated with the Grand Canyon, Grand Canyon II and Grand Canyon III chartered vessels (Note 18).

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

None.

Item 9A. Controls and Procedures

(a) Disclosure Controls and Procedures. We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2015 to provide reasonable assurance that information required to be disclosed in our reports under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and (ii) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

(b) Management's Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. This process includes policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of our internal control over financial reporting at December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013 framework). Based on this assessment, management concluded that, as of December 31, 2015, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in its report which appears in Item 8 of this Annual Report on Form 10-K.

(c) Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the fourth quarter of fiscal 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2016 Annual Meeting of Shareholders to be held on May 12, 2016. See also "Executive Officers of the Company" appearing in Part I of this Annual Report.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at our Website www.helixesg.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

Helix Energy Solutions Group, Inc.
ATTN: Corporate Secretary
3505 W. Sam Houston Parkway N., Suite 400
Houston, Texas 77043

Item 11. Executive Compensation

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2016 Annual Meeting of Shareholders to be held on May 12, 2016.

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

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2016 Annual Meeting of Shareholders to be held on May 12, 2016.

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

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2016 Annual Meeting of Shareholders to be held on May 12, 2016.

Item 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2016 Annual Meeting of Shareholders to be held on May 12, 2016.

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PART IV
Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The following financial statements included on pages 48 through 90 in this Annual Report are for the fiscal year ended December 31, 2015.

- Report of Independent Registered Public Accounting Firm
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm — Deepwater Gateway
- Report of Independent Registered Public Accounting Firm — Independence Hub
- Consolidated Balance Sheets as of December 31, 2015 and 2014
- Consolidated Statements of Operations for the Years Ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013
- Notes to Consolidated Financial Statements

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.
(2) Exhibits

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries. Reference is made to Exhibit listing beginning on page 95 hereof.

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SIGNATURES

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

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ ANTHONY TRIPODO
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

February 29, 2016

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

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 29, 2016
/s/ ANTHONY TRIPODO Anthony Tripodo	Executive Vice President, Chief Financial Officer and Director (principal financial officer)	February 29, 2016
/s/ ERIK STAFFELDT Erik Staffeldt	Vice President — Finance and Accounting (principal accounting officer)	February 29, 2016
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 29, 2016
/s/ T. WILLIAM PORTER T. William Porter	Director	February 29, 2016
/s/ NANCY K. QUINN Nancy K. Quinn	Director	February 29, 2016
/s/ JAN A. RASK Jan A. Rask	Director	February 29, 2016
/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 29, 2016
/s/ JAMES A. WATT James A. Watt	Director	February 29, 2016

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INDEX TO EXHIBITS

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Form of Common Stock certificate.	Exhibit 4.7 to the Form 8-A filed on June 30, 2006 (001-32936)
4.2	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000.	Exhibit 4.4 to the 2001 Form 10-K filed on March 28, 2002 (000-22739)
4.3	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002.	Exhibit 4.9 to the 2002 Form 10-K/A filed on April 8, 2003 (000-22739)
4.4	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002.	Exhibit 4.4 to the Form S-3 filed on February 26, 2003 (333-103451)
4.5	Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003.	Exhibit 4.12 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.6	Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004.	Exhibit 4.13 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.7	Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers.	Exhibit 4.3 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.8	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.9	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.2 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.10	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.3 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.11	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.4 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.12		

	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.13	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027.	Exhibit A to Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.14	Form of Third Amended and Restated Promissory Note to United States of America.	Exhibit 4.6 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.15	Indenture dated as of March 12, 2012 between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 12, 2012 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
4.16	Credit Agreement dated June 19, 2013 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, and other lender parties named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on June 19, 2013 (001-32936)
4.17	Amendment No. 1 to the Credit Agreement, dated as of May 13, 2015, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on May 14, 2015 (001-32936)
4.18	Amendment No. 2 to the Credit Agreement, dated as of January 19, 2016, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on January 25, 2016 (001-32936)
4.19	Amendment No. 3 to the Credit Agreement, dated as of February 9, 2016, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on February 10, 2016 (001-32936)
4.20	Credit Agreement dated September 26, 2014, by and among Helix Q5000 Holdings S.à r.l., Helix Vessel Finance S.à r.l. and Nordea Bank Finland PLC, London Branch as administrative agent and collateral agent, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on September 30, 2014 (001-32936)
10.1 *	1995 Long Term Incentive Plan, as amended.	Exhibit 10.3 to the Form S-1 filed on September 4, 1996 (333-11399)
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.2 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.3 *	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.4 *	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan.	Exhibit 10.2 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.5 *	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 12, 2005 (000-22739)
10.6 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.10 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.7 *	Amended and Restated 2005 Long-Term Incentive Plan of Helix Energy Solutions Group, Inc. dated May 9,	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 25, 2012

	2012.	(001-32936)
10.8 *	Form of Cash Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.9 *	Form of Performance Share Unit Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 10, 2014 (001-32936)
10.10 *	Form of Restricted Stock Award Agreement.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.11 *	Employee Stock Purchase Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.12 *	Amendment to the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan.	Filed herewith
10.13 *	Employment Agreement between Owen Kratz and the Company dated February 28, 1999.	Exhibit 10.5 to the 1998 Form 10-K filed on March 31, 1999 (000-22739)
10.14 *	Employment Agreement between Owen Kratz and the Company dated November 17, 2008.	Exhibit 10.1 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.15 *	Employment Agreement between Alisa B. Johnson and the Company dated November 17, 2008.	Exhibit 10.3 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.16 *	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008.	Exhibit 10.2 to the Current Report on Form 8-K filed on June 30, 2008 (001-32936)
10.17 *	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008.	Exhibit 10.5 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.18 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Clifford Chamblee dated May 11, 2011.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 27, 2011 (001-32936)
10.19 *	Separation and Release Agreement dated April 24, 2013 between Helix Energy Solutions Group, Inc. and Lloyd A. Hajdik.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on April 24, 2013 (001-32936)
10.20	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.21	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.22	Equity Purchase Agreement dated December 12, 2012, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.23	Form of Indemnification Agreement, by and among Talos Production LLC, Energy Resource Technology GOM, LLC, CKB Petroleum, LLC, and Helix Energy Solutions Group, Inc.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.24	Amendment No. 1 to Equity Purchase Agreement dated January 27, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 28, 2013 (001-32936)
10.25	Amendment No. 2 to Equity Purchase Agreement dated February 6, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 12, 2013 (001-32936)

10.26	Construction contract dated as of March 12, 2012 between Helix Energy Solution Group, Inc. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on March 16, 2012 (001-32936)
10.27	Construction Contract dated as of September 11, 2013 between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on September 13, 2013 (001-32936)
10.28	Amendment No. 1, dated as of June 8, 2015, to Construction Contract between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on June 11, 2015 (001-32936)
10.29	Amendment No. 2, dated December 2, 2015, to Construction Contract between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 7, 2015 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.30	Strategic Alliance Agreement dated January 5, 2015 among Helix Energy Solutions Group, Inc., OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V., and Schlumberger Oilfield Holdings Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2015 (001-32936)
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers.	Exhibit 14.1 to the Registrant's Current Report on Form 8-K filed on December 8, 2009 (001-32936)
21.1	List of Subsidiaries of the Company.	Filed herewith
23.1	Consent of Ernst & Young LLP.	Filed herewith
23.2	Consent of Deloitte & Touche LLP. (Deepwater Gateway L.L.C.).	Filed herewith
23.3	Consent of Deloitte & Touche LLP. (Independence Hub LLC).	Filed herewith
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith

* Management contracts or compensatory plans or arrangements