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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from to

Commission File Number 001-34579

Cobalt International Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**27-0821169**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
(Address of principal executive offices, including zip code)

(713) 579-9100
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, $0.01 par value	The New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 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). 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 ☒ 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 Securities Act). Yes ☐ No ☒

As of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates was approximately $5.8 billion.

As of December 31, 2014, the registrant had 411,296,254 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement relating to the 2015 Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Annual Report on Form 10-K.

Cobalt International Energy, Inc.

PART I

Cautionary Note Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains estimates and forward-looking statements, principally in "Business," "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations." Our estimates and forward-looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in this Annual Report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this Annual Report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect.

Our estimates and forward-looking statements may be influenced by the following factors, among others:

- our ability to successfully and efficiently execute our project appraisal, development and exploration activities;
- our liquidity and ability to finance our exploration, appraisal, development, and acquisition activities;
- oil and gas prices;
- lack or delay of partner, government and regulatory approvals related to our operations;
- projected and targeted capital expenditures and other costs and commitments;
- uncertainties inherent in making estimates of our oil and natural gas data;
- our dependence on our key management personnel and our ability to attract and retain qualified personnel;
- current and future government regulation of the oil and gas industry and our operations;
- changes in environmental, safety and health laws and regulations or the implementation or interpretation of those laws and regulations;
- our and our partners' ability to obtain permits and licenses and drill and develop our prospects and discoveries in the U.S. Gulf of Mexico and offshore West Africa;
- termination of or intervention in concessions, licenses, permits, rights or authorizations granted by the United States, Angolan and Gabonese governments to us;
- competition;
- our ability to find, acquire or gain access to new prospects and renew our exploration portfolio;
- the availability, cost and reliability of drilling rigs, containment resources, production equipment and facilities, supplies, personnel and oilfield services;
- the ability of the containment resources we have under contract to perform as designed or contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons;
- the availability and cost of developing appropriate infrastructure around and transportation to our prospects, discoveries and appraisal and development projects;
- military operations, civil unrest, disease, piracy, terrorist acts, wars or embargoes;

- our vulnerability to severe weather events, especially tropical storms and hurricanes in the U.S. Gulf of Mexico;
- the cost and availability of adequate insurance coverage;
- the results or outcome of any legal proceedings or investigations we may be subject to;
- our ability to meet our obligations under the agreements governing our indebtedness; and
- other risk factors discussed in the "Risk Factors" section of this Annual Report on Form 10-K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words are intended to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this Annual Report on Form 10-K might not occur and our future results and our performance may differ materially from those expressed in these forward-looking statements due to, including, but not limited to, the factors mentioned above. Because of these uncertainties, you should not place undue reliance on these forward-looking statements.

Item 1. *Business*

OVERVIEW

We are an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. Since our founding in 2005, our oil-focused, below-salt exploration efforts have been successful in each of our three operating areas, resulting in ten discoveries out of the seventeen exploration prospects drilled. These ten discoveries consist of North Platte, Heidelberg, Shenandoah and Anchor in the U.S. Gulf of Mexico; Cameia, Lontra, Mavinga, Bicuar and Orca offshore Angola; and Diaman offshore Gabon. In addition, we have an interest in the Yucatan discovery in the U.S. Gulf of Mexico.

With these discoveries, our primary focus areas are:

1. **Project Appraisal and Development**—to progress our discoveries, which are currently in various stages of appraisal and development, toward project sanction and into proved reserves, production, and cash flow;
2. **Continued Exploration**—to simultaneously maintain an ongoing exploration program on our current acreage; and
3. **New Ventures**—to seek the renewal of our worldwide exploration portfolio in locations applicable to our deepwater and below-salt exploration strength.

Since inception, we have focused primarily on drilling exploration wells on our extensive below-salt exploration portfolio, which has resulted in the ten discoveries referenced above. With these discoveries in hand, our focus has now shifted towards selectively developing these discoveries and establishing production from them. Thus, our current strategy is to direct the majority of our capital expenditures toward project appraisal and development activities with the aim to increase our proved reserves and establish production and cash flow while continuing exploration on our existing acreage and seeking new venture opportunities for long-term growth.

Each of our focus areas is discussed below by geographic region, followed by background information regarding the geology, plans for appraisal and development, licenses and leaseholds, drilling rigs and drilling results applicable to our geographic regions.

Project Appraisal and Development

U.S. Gulf of Mexico

We and our partners are moving forward on our Heidelberg, North Platte and Shenandoah appraisal and development projects and evaluating our Anchor discovery as described below:

Heidelberg Project. Our Heidelberg project was formally sanctioned in mid-2013, and Anadarko Petroleum Corporation ("Anadarko"), as operator, currently estimates first production from Heidelberg in the first half of 2016. On February 2, 2009, we announced that the Heidelberg #1 exploration well had encountered more than 200 feet of net pay thickness in Miocene horizons. Located in approximately 5,200 feet of water in Green Canyon Block 859 within the Miocene trend, this well was drilled to approximately 30,000 feet. An appraisal well was spud on the Heidelberg field in late 2011 in Green Canyon Block 903. On February 16, 2012, Anadarko announced the successful results of the appraisal well, which encountered approximately 250 feet of net pay thickness in high-quality Miocene sands. The appraisal well was drilled to a total depth of 31,030 feet in approximately 5,000 feet of water, about 1.5 miles south and 550 feet structurally up-dip from the Heidelberg #1 exploration well. Log and pressure data from the Heidelberg #1 exploration well and the Heidelberg appraisal well indicate excellent quality, continuous and pressure-connected reservoirs with high-quality oil. On April 19, 2012, Anadarko announced that a sidetrack well performed on the Heidelberg appraisal well successfully confirmed an extension of the Heidelberg field of up to 1,500 acres by encountering an oil/water contact that was approximately 700 feet down structure.

The Heidelberg production facility is designed to produce up to 80,000 barrels of oil per day ("BOPD") and 80 million cubic feet per day ("MMCFD") of gas. Anadarko, as operator, drilled the first field development well in 2014 and two additional development wells have recently reached total depth. Development drilling continues and is on schedule, with two drilling rigs currently operating in the field. The hull has arrived in the U.S. Gulf of Mexico, and the topsides are more than 70% complete. The subsea infrastructure remains on schedule to be fabricated and installed on time to support initial production in 2016. As of December 31, 2014, we had 8.4 million barrels ("MMBbls") of oil and 3.7 billion cubic feet ("Bcf") of gas of net proved undeveloped reserves attributed to the Heidelberg project. For more information regarding our proved undeveloped reserves, please see "—Summary of Oil and Gas Reserves." We own a 9.375% working interest in the Heidelberg project.

North Platte Project. On December 5, 2012, we announced a significant oil discovery at our North Platte prospect on Garden Banks Block 959 in the deepwater U.S. Gulf of Mexico. The North Platte #1 exploration well represents the first discovery in our deepwater U.S. Gulf of Mexico Alliance with TOTAL E&P USA INC. ("Total"). Based on extensive wireline evaluation, the discovery well encountered over 550 net feet of oil pay in multiple high-quality Inboard Lower Tertiary reservoirs. The North Platte oil discovery is particularly important because it provides evidence to support our geologic model of the Inboard Lower Tertiary trend where we hold a substantial acreage position with several potential follow-on exploration prospects, such as South Platte, Baffin Bay, Fraser, and Williams Fork. We conducted bypass coring on the North Platte #1 exploration well, which provided additional information we will use as we continue our evaluation of the North Platte oil discovery and plans for appraisal and development. The North Platte #1 exploration well is located in approximately 4,400 feet of water and was drilled to a total depth of approximately 34,500 feet.

In early 2015, we took delivery of the Rowan Reliance, a new-build, ultra-deepwater dynamically positioned drillship, which we plan to use for our operated U.S. Gulf of Mexico drilling campaign. We spud the North Platte #2 appraisal well with the Rowan Reliance in early February 2015. The results from the North Platte #2 appraisal well will help us as we continue to evaluate the commerciality and potential development options for North Platte. In addition, we continue to analyze the data obtained from a 5,200 square mile full azimuth 3-D seismic survey over the greater North Platte area, of which we have licensed data covering approximately 1,350 square miles. This 3-D seismic survey is designed to further improve the sub-salt imaging of the North Platte field as well as several other Inboard Lower Tertiary exploration prospects in which we have working interests. We are using this 3-D seismic data to optimize potential appraisal and development well locations on North Platte. We are also conducting reservoir fluids analyses and subsea studies to support our appraisal and development efforts there. Reservoir characterization and certain geologic modeling studies are ongoing in order to better understand reservoir continuity, productivity and recovery characteristics of the field. The North Platte project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of North Platte and own a 60% working interest.

Shenandoah Project. On February 4, 2009, we announced that Anadarko, as operator, had drilled the Shenandoah #1 exploration well into Inboard Lower Tertiary horizons and encountered net oil pay approaching 300 feet. This well, located in approximately 5,750 feet of water in Walker Ridge Block 52, was drilled to approximately 30,000 feet. The Shenandoah #2 appraisal well was spud in the third quarter of 2012 in approximately 5,800 feet of water, about 1.3 miles southwest of the Shenandoah #1 exploration well and was drilled to a total depth of 31,405 feet. On March 19, 2013, we announced that the Shenandoah #2 appraisal well encountered more than 1,000 net feet of oil pay in multiple high quality Inboard Lower Tertiary reservoirs. The Shenandoah #3 appraisal well was spud in the second quarter of 2014 and evaluated the same well-developed reservoir sands 1,500 feet down-dip and 2.3 miles east of the first appraisal well. This well found an expanded geologic reservoir section, confirmed excellent reservoir qualities and delineated the potential oil-water contacts of the field. Planning is currently underway for another appraisal well, which we expect will be spud in the second quarter of 2015. The Shenandoah project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis prior to the preparation of a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Shenandoah project.

Yucatan Project. In the first quarter of 2014, we acquired a 5.34% non-operated working interest in the Yucatan discovery, which is an Inboard Lower Tertiary discovery located approximately three miles south of our Shenandoah discovery. Following this acquisition, we participated as a non-operator in the Yucatan #3 appraisal well, which reached total depth of 33,838 feet in the third quarter 2014 and encountered approximately 57 gross feet of pay in Lower Tertiary oil bearing sands down-dip of the initial discovery. The well results and data acquired are currently being evaluated and Shell, as operator, has transitioned the project over to its appraisal team. The Yucatan project is in the early stages of the project development life cycle and will require substantial additional evaluation and analysis, which may include additional appraisal drilling, prior to preparing a development plan and seeking potential formal project sanction. Given its proximity to the Shenandoah discovery, it is possible that any future development of Yucatan would tie-back to production facilities at Shenandoah.

Anchor Discovery. On January 6, 2015, we announced that the initial exploration well on our Anchor prospect had been drilled to a total depth of 33,749 feet and encountered significant high quality oil pay in multiple Inboard Lower Tertiary horizons. The Anchor discovery is located approximately 140 miles from the Louisiana coast in 5,183 feet of water. Chevron, as operator, expects to conduct additional appraisal drilling at Anchor in 2015. The Anchor discovery will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Anchor discovery unit.

West Africa

We and our partners are moving forward on our development projects and evaluating our additional discoveries offshore West Africa as described below:

Cameia Project (Block 21). On February 9, 2012, we announced that the Cameia #1 exploration well was drilled in 5,518 feet (1,682 meters) of water to a total depth of 16,030 feet (4,886 meters), at which point an extensive wire-line evaluation program was conducted. The results of this wire-line evaluation program confirmed the presence of a 1,180 foot (360 meter) gross continuous hydrocarbon column with over a 75% net to gross pay estimate. No gas/oil or oil/water contact was evident on the wire-line logs. An extended Drill Stem Test ("DST") was performed on the Cameia #1 exploration well to provide additional information. The DST flowed at an un-stimulated sustained rate of 5,010 barrels per day of 44-degree API gravity oil and 14.3 million cubic feet per day of associated gas (approximately 7,400 barrels of oil equivalent per day ("BOEPD")) with minimal bottom-hole pressure drawdown. Upon shut-in, the bottom-hole pressure reverted to its initial state in less than one minute. The well bore used in the DST had a perforated interval of less than one-third of the reservoir section. The flow rate, which was restricted by surface equipment, facility and safety precautions, confirmed the presence of a very thick, high quality reservoir. We believe the well, without such restrictions, would have the potential to produce in excess of 20,000 BOPD. On March 2, 2012, we submitted a declaration of commercial well to Sociedade National de Combustíveis de Angola—Empresa Pública ("Sonangol") with respect to the Cameia #1 exploration well. During 2012, we drilled the Cameia #2 appraisal well, which was located approximately 2.2 miles (3.5 kilometers) south of the Cameia #1 exploration well and was successful in demonstrating lateral continuity within the reservoir originally encountered by the Cameia #1 exploration well. The results from the Cameia #2 appraisal well were also important as the well discovered a lower hydrocarbon-bearing zone at least 440 feet (134 meters) deeper than that which was observed in the Cameia #1 exploration well.

On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia discovery. In mid-April 2014, we spud the Cameia #3 appraisal well, which we expect to utilize as a production well in the Cameia field development. The results of the Cameia #3 appraisal well were successful and consistent with pre-drill expectations. A successful DST was also conducted on the Cameia #3 appraisal well. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Given the current commodity price environment, we believe an opportunity exists to review the project design concept and projected capital expenditures in order to optimize the cost and scale of the Cameia development and production facilities prior to formal project sanction. During 2015, we intend to pursue project cost reductions in light of the current weakness in the market for goods and services utilized in major offshore development projects. We remain committed to progressing the Cameia development towards project sanction and production, and, to that end, we plan to spud the Cameia #4 well in the first quarter of 2015, which we intend to utilize as a production well. Following drilling operations on Cameia #4, during 2015 we anticipate drilling a water injection well, returning to Cameia #3 to re-complete it as a production well, and also drilling another production well and a gas injection well, all for the Cameia development. We expect to achieve formal project sanction of Cameia by year-end 2015, and first production from Cameia will likely occur in 2018. The occurrence and timing of project sanction and first production from Cameia are subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum. We are the operator of and hold a 40% working interest in the Cameia project. Our partner in the Cameia project is Sonangol Pesquisa e Produção, S.A. ("Sonangol P&P"), with a 60% working interest.

Greater Orca Lontra Development (GOLD) Project (Block 20). In the first quarter of 2014, we drilled the successful Orca #1 exploration well on Block 20 offshore Angola to a measured depth of 12,703 feet (3,872 meters) and encountered approximately 250 feet (75 meters) of net oil pay in the sag and syn-rift reservoirs. A DST was conducted on the Orca #1 exploration well, and the well was successfully tested at a facility-constrained rate of 3,700 barrels of oil per day and 16.3 million cubic feet of gas per day with minimal drawdown (approximately 1%) in the upper sag section of the discovery. The results of this DST confirm that the Orca #1 exploration well is capable of substantial sustained oil production rates. On April 28, 2014, we submitted a declaration of commercial well to Sonangol regarding the Orca #1 exploration well. In late 2014, we spud the Orca #2 appraisal well, and operations on this well are ongoing.

On December 1, 2013, we announced that our Lontra #1 exploration well had been drilled to a total depth of 13,763 feet (4,195 meters) and encountered approximately 250 feet (75 meters) of net pay in a very high quality reservoir section. The Lontra #1 exploration well encountered both a high liquids content gas interval and an oil interval. A DST was performed on the high liquids content gas interval and successfully produced a sustained flow rate of 2,500 barrels per day of condensate and 39 million cubic feet per day of gas. The DST did not test the oil interval. On December 20, 2013, we submitted a declaration of commercial well to Sonangol regarding the Lontra #1 exploration well.

Given the geographical proximity of the Lontra discovery and the Orca discovery, both on Block 20 offshore Angola, our initial development concept is to tie-back the Lontra field to the Orca field as part of a hub development and to proceed with the development of the oil and condensate from the Orca and Lontra fields. The Greater Orca Lontra Development (GOLD) project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including additional appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of the GOLD project with a 40% working interest. Our partners in the GOLD project include BP Exploration Angola (Kwanza Benguela) Limited ("BP") and Sonangol P&P, with each partner holding a 30% working interest.

Bicuar Discovery (Block 21). On January 22, 2014, we announced that the Bicuar #1A exploration well was successfully drilled to a total depth of 18,829 feet (5,739 meters) and encountered approximately 180 feet (56 meters) of net pay from multiple pre-salt intervals. Results of an extensive logging, coring and fluid acquisition program confirmed the existence of both oil and condensate in multiple intervals. No free gas zones or water contacts were observed. The results from the Bicuar #1A exploration well are significant because they confirm the first discovery of mobile hydrocarbons tested in the pre-salt syn-rift geologic interval offshore Angola. On February 13, 2014, we submitted a declaration of commercial well to Sonangol regarding the Bicuar #1A exploration well. The Bicuar discovery is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of and have a 40% working interest in the Bicuar discovery. Our partner in Bicuar is Sonangol P&P, with a 60% working interest.

Mavinga Discovery (Block 21). On October 29, 2013, we announced that the Mavinga #1 exploration well had reached total depth and encountered approximately 100 feet (30 meters) of net oil pay. This discovery was confirmed by the successful production of oil from mini DSTs, direct pressure and permeability measurements and log and core analysis. Efforts to establish a sustained flow rate from a full DST were not successful. We believe that operational issues associated with the DST prevented the production from the oil reservoir during the production test. We estimate a gross oil column of up to 650 feet (200 meters) at the crest of the Mavinga structure updip of the Mavinga #1 exploration well. Additional drilling will be required to confirm the ultimate gross thickness of the crest of the Mavinga structure and Mavinga's reservoir quality. On November 12, 2013, we submitted a declaration of commercial well to Sonangol regarding the Mavinga #1 exploration well. The Mavinga discovery is in the very early stages of the development life-cycle and will require substantial additional evaluation and analysis, potentially including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. Given the results of the Mavinga #1 exploration well and its proximity to the location of our Cameia project, our initial development concept for the Mavinga discovery is to eventually tie back the Mavinga field to our Cameia project. Although we estimate formal sanction of the Cameia project by year-end 2015 and first production from the Cameia project in 2018 (subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum) those estimates and timelines do not include any potential tie-back development to or production from our Mavinga discovery. We are currently unable to estimate when the Mavinga discovery might be sanctioned or when we might achieve first production. We are the operator of and have a 40% working interest in the Mavinga discovery. Our partner in Mavinga is Sonangol P&P, with a 60% working interest.

Diaman Discovery (Diaba Block). On August 19, 2013, we announced that the Diaman #1B exploration well was drilled to a total depth of 18,323 feet (5,585 meters), and encountered approximately 160 to 180 feet (50 to 55 meters) of net hydrocarbons in the objective pre-salt formations on the Diaba Block offshore Gabon. The Diaman #1B exploration well successfully confirmed the existence of a working petroleum system, a salt seal, and high-quality sandstone reservoirs. We and our partners are continuing to analyze additional 3-D seismic data we acquired over the Diaba block in 2014. The operator currently expects to resume exploration drilling on the Diaba block offshore Gabon in 2016. Diaman is in the very early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to proceeding with any development plan. We have a 21.25% non-operated working interest in the Diaman discovery. Our partners in the Diaman discovery include Total Gabon, as operator (42.5% working interest), Marathon Petroleum Corporation (21.25% working interest), and the Republic of Gabon (15% working interest).

Continued Exploration

U.S. Gulf of Mexico

We currently have several below-salt exploration prospects in the deepwater U.S. Gulf of Mexico. Although we plan to utilize the Rowan Reliance, our only operated rig in the U.S. Gulf of Mexico, primarily for appraisal and development work, we will continue to mature our operated below-salt prospect inventory through seismic acquisition and evaluation and well permitting activities for future exploration drilling. We plan to drill one to two exploration wells per year in the U.S. Gulf of Mexico, although the order and timing of our exploration drilling is dependent on several factors and may vary over time. Specifically, we plan to focus on maturing our Rocky Mountain Miocene prospect as well as our South Platte, Baffin Bay, Fraser, and Williams Fork prospects, which are Inboard Lower Tertiary prospects in close proximity to our North Platte #1 discovery. Furthermore, we may elect to participate as a non-operator in the Goodfellow #1 exploration well, which will target Inboard Lower Tertiary horizons. Currently we have a 21.2% working interest in the Goodfellow prospect and our partners include ENI U.S. Operating Co. Inc. (25.7%), Samson Offshore, LLC (25.7%), and Total (27.4%). Prior to spudding the Goodfellow #1 exploration well, the composition and working interests of the Goodfellow partnership may change. See "Risk Factors—Risks Relating to Our Business—Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing."

West Africa

We also currently have several pre-salt exploration prospects offshore West Africa. Although we plan to utilize the SSV Petroserv Catarina, our only operated rig offshore West Africa, primarily on the appraisal and development of our existing discoveries, we plan to continue maturing up to 20 follow-on oil-focused exploration prospects on Blocks 20 and 21 offshore Angola. We plan to continue our exploration efforts offshore West Africa, although the order and timing of any exploration drilling is dependent on several factors and may vary over time. See "Risk Factors—Risks Relating to Our

Business—Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing."

New Ventures

In addition to our existing assets in the U.S. Gulf of Mexico and offshore West Africa and in furtherance of our strategy of renewing our world-wide exploration portfolio, our New Ventures group is actively evaluating additional exploration opportunities. Consistent with our core strengths, our New Ventures strategy is centered on pursuing high-value, deepwater oil-focused exploration opportunities in frontier and under-explored basins. Our New Ventures strategy continues to focus on the Atlantic Basin, specifically opportunities in Mexico and the Canadian East Coast.

Exploration Prospect Maturation Process

The process of maturing an exploration prospect from initial identification to drill-ready status begins with analyzing regional data, including industry well results, to understand a given trend's specific geology and defining those areas, or "prospects," that offer the highest potential for substantial hydrocarbon deposits while minimizing geologic risks. After these prospects are identified, we further mature our prospects by acquiring and reprocessing high resolution seismic data available in the potential prospect's direct vicinity. This includes advanced imaging information, such as wide-azimuth studies, to further our understanding of a particular prospect's characteristics, including both trapping mechanics and fluid migration patterns. Reprocessing is accomplished through a series of model building steps that incorporate the geometry of the salt and below salt geology to optimize the final image. In addition, we gather publicly available information, such as well logs, which we use to evaluate industry results and activities in order to understand the relationships between industry-drilled prospects and our portfolio of undrilled prospects. As part of the maturation of a prospect to drill-ready status, we also perform substantial drilling-related engineering work, such as generating a proposed well design, including the well evaluation and completion design, and the preparation of pore pressure prediction analysis and reports, site survey reports, and shallow hazard reports. The purpose of this work is to minimize the drilling and operational risk associated with drilling a well on a particular prospect. There are also numerous regulatory filings we must prepare and submit in order to obtain the required permits, authorizations and approvals needed to drill an exploration well on a prospect.

We may decide during any of the foregoing steps of prospect maturation that drilling an exploration well on a particular prospect may not be warranted given the geologic, drilling and economic risk profile that was developed during the prospect maturation process. Once the foregoing items, as applicable, are complete and we have determined that a prospect is ready and desirable for exploration drilling, and the geologic, economic and drilling risks associated with such prospect have been optimally mitigated, such prospect would be considered "mature."

General Information—U.S. Gulf of Mexico

Our U.S. Gulf of Mexico operations target oil-focused prospects in the subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico.

Geologic Overview

The subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico are characterized by well-defined hydrocarbon systems, comprised primarily of high-quality source rock and crude oil, and contain several of the most significant hydrocarbon discoveries in the deepwater U.S. Gulf of Mexico in recent years.

Miocene. The subsalt Miocene trend is an established play in the deepwater U.S. Gulf of Mexico. Discoveries in this trend include Heidelberg, Thunder Horse, Atlantis, Tahiti, Mad Dog, and Stampede.

This trend is characterized by high quality reservoirs and fluid properties, resulting in high production well rates.

Inboard Lower Tertiary. The Lower Tertiary horizon is an older formation than the Miocene, and, as such, is generally deeper, with greater geologic complexity. The industry has been successful in terms of locating and drilling large hydrocarbon-bearing structures in this interval. The reservoir quality of the Lower Tertiary has proven to be highly variable. Some regions, including those areas in which many of the historical Lower Tertiary discoveries have been made, exhibit lower permeability and generally lower natural gas content compared to the Miocene horizon.

However, a sub-region in the Lower Tertiary that has exhibited reservoir characteristics more similar to that of existing Miocene discoveries is the Inboard Lower Tertiary trend, which includes our oil discoveries at North Platte, Shenandoah and Anchor. The Inboard Lower Tertiary is a trend located to the north of existing Outboard Lower Tertiary fields such as St. Malo, Jack and Cascade, which are all on production from the Lower Tertiary. We were an early mover in the Inboard Lower Tertiary trend, targeting specific lease blocks as early as 2006. We believe our Inboard Lower Tertiary prospects are characterized by large, well-defined structures of a similar size to historic Outboard Lower Tertiary discoveries, but are differentiated by what we believe to be better reservoir quality and energy based upon data from wells drilled at our North Platte, Shenandoah and Anchor discoveries. We believe we hold a significant leasehold position in the Inboard Lower Tertiary and, to date, have had an exploration success rate of 60% in the Inboard Lower Tertiary.

Plans for Appraisal and Development

In general, the life-cycle of our major project developments begins with a thorough evaluation and analysis of well logs (including offset analog wells), reservoir core samples, fluid samples and, in some cases, the results of production tests from the initial exploration well that encountered what we believe may be commercial hydrocarbons. This information, along with relevant seismic data, is used to generate locations and plans for appraisal and development wells. Depending upon the project, we may choose to drill one or more appraisal wells prior to project sanction and development, each of which will undergo thorough analysis and evaluation. The information we obtain from exploration and appraisal wells is then used to create a development plan, which will include economic assumptions on the costs of drilling and completing development wells, the front-end engineering and design of offshore production and processing facilities, including subsea, umbilical, riser and flowline systems and other related transportation infrastructure. The project will become formally sanctioned when the relevant working interest partners have approved the development plan. Typically, following formal project sanction, we will commence the construction of offshore production facilities, and proceed with development drilling and the installation of subsea architecture in order to advance the project towards initial production.

A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a project development will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation and analysis, such as the steps described above, will need to be performed prior to official project sanction and development. In addition, substantial amounts of capital are required to progress a project through the project development life-cycle. At any time during the project development life-cycle, we may determine that the project would be uneconomic and abandon the project, despite the fact that the initial exploration well, or subsequent appraisal wells, discovered hydrocarbons. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

Leasehold Acreage

As of December 31, 2014, we owned interests in 266 blocks within the deepwater U.S. Gulf of Mexico, representing approximately 1.5 million gross (0.8 million net) acres. We are the designated operator of 238 of these blocks, or approximately 89% of our U.S. Gulf of Mexico leasehold acreage. The following schedule shows the developed and undeveloped acres in which we held interests as of December 31, 2014 in the U.S. Gulf of Mexico.

	Developed Lease Acres(1)		Undeveloped Lease Acres(2)	
	Gross	Net	Gross	Net
U.S. Gulf of Mexico	17,280	1,620	1,494,470	764,308

(1) Our developed lease positions of 17,280 gross (1,620 net) acres are entirely related to our Heidelberg project. The Heidelberg project was sanctioned for development in mid-2013 and all of the leasehold acreage associated with the Heidelberg project is held by a Suspension of Production, which was granted by the U.S. Department of the Interior for the federally-approved Heidelberg Unit. Anadarko, as operator, estimates first oil production from Heidelberg in the first half of 2016.

(2) Our Shenandoah, Anchor and North Platte projects are not yet sanctioned for development and therefore the acreage associated with these projects remains classified as undeveloped. We estimate that the North Platte project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 34,560 gross (20,736 net) acres; the Shenandoah project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 14,400 gross (2,880 net) acres; and the Anchor project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 20,160 gross (4,032 net) acres. If development projects related to North Platte, Anchor and Shenandoah are sanctioned, we will evaluate which acreage associated with these projects could then be classified as developed acreage.

The royalties on our lease blocks range from 12.5% to 18.75% with an average of 16.34%.

Most of our U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2024. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary lease term, our leases would extend beyond the primary term, generally for the life of production. Our leasehold interest in the U.S. Gulf of Mexico increased by 113,760 gross (65,804 net) acres in 2014. This increase was due to the acquisition of 53 blocks through the Central Gulf of Mexico lease sale 231 and certain trades with other industry participants, which were offset by the relinquishment of 30 blocks as a result of lease expiration, trade and sale.

The table below summarizes our undeveloped acreage scheduled to expire in the next five years in the U.S. Gulf of Mexico.

	Undeveloped Lease Acres Expiry									
	2015(1)(3)		2016(1)(2)(3)		2017(3)		2018(1)(3)		2019 and thereafter(1)(2)(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S. Gulf of Mexico	57,600	16,783	362,880	203,109	92,160	46,388	595,910	287,131	368,640	207,441

(1) The gross and net acreage numbers reflected in these columns include portions of the estimated 14,400 gross (2,880 net) acres covering U.S. Gulf of Mexico blocks associated with our Shenandoah project, upon which exploration and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Shenandoah

project is now part of the Shenandoah Unit, federally approved in 2014. We expect that the operator of the Shenandoah Unit will conduct additional appraisal drilling operations in 2015 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Shenandoah Unit.

(2) The gross and net acreage numbers reflected in these columns include portions of the estimated 34,560 gross (20,736 net) acres covering U.S. Gulf of Mexico blocks associated with our North Platte project, upon which an exploration well has discovered hydrocarbons, but a development project has not yet been sanctioned. We plan to perpetuate this acreage by an eventual unitization and sanctioned development plan and by applying for approval of a Suspension of Production.

(3) The gross and net acreage number reflected in these columns include portions of the estimated 20,160 gross (4,032 net) acres covering U.S. Gulf of Mexico blocks associated with our Anchor project, upon which an exploration well has discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Anchor project is now part of the Anchor Unit, federally approved in 2014. We expect that the operator of the Anchor Unit will conduct additional appraisal drilling operations in 2015 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Anchor Unit.

The acreage numbers in the table above do not reflect (i) 5,760 gross (1,152 net) acres covering leases associated with our Shenandoah project whose primary term expired in 2014 but are being held by continuous operations on the Shenandoah project, or (ii) 11,520 gross (2,304 net) acres covering leases associated with our Anchor project whose primary term expired in 2014 but are being held by continuous operations on the Anchor project. We expect that the operators of both Shenandoah and Anchor will continue to conduct operations on these projects during 2015 and eventually file for approval of a Suspension of Production in order to perpetuate this acreage. See “Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas.”

Drilling Rigs

On August 5, 2013, we executed a drilling contract with Rowan Reliance Limited, an affiliate of Rowan Companies plc, for the Rowan Reliance, a new-build, ultra-deepwater dynamically positioned drillship that is currently drilling our North Platte #2 appraisal well. The Rowan Reliance drillship is capable of operating in water depths of up to 12,000 feet and drilling to measured depths of up to 40,000 feet. The drilling contract provides for a firm three-year commitment, which began in February 2015, at a day rate of approximately $602,000 (inclusive of mobilization fees) and two one-year extension options at day rates to be mutually agreed.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled in the deepwater U.S. Gulf of Mexico during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	U.S. Gulf of Mexico(1)					
	2014(2)		2013(3)		2012(4)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Productive	1	0.2	1	0.2	2	0.69375
Dry	2	0.2534	2	1.02	1	0.45
Development						
Productive	1	0.09375	—	—	—	—
Dry	—	—	—	—	—	—
Total	4	0.54715	3	1.22	3	1.14375

(1) We did not drill any development wells in the U.S. Gulf of Mexico during the fiscal years ended December 31, 2013 and 2012, respectively.

(2) The wells noted include our Anchor #1 exploration well (productive), Shenandoah #3 appraisal well (dry), Yucatan #3 appraisal well (dry) and a Heidelberg development well (productive). The number of development wells does not include two Heidelberg development wells that were drilling as of December 31, 2014, one of which reached total depth in January 2015 and the other reached total depth in February 2015.

(3) The wells noted include our Shenandoah #2R appraisal well (productive), and our Ardennes #1 (dry) and Aegean #1 (dry) exploration wells.

(4) The wells noted include our North Platte #1 (productive) and Ligurian #2 (dry) exploration wells and our Heidelberg #3 appraisal well (productive).

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling in the U.S. Gulf of Mexico (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

U.S. Gulf of Mexico	
Gross(1)	**Net(1)**
1	0.6

(1) The well noted is the North Platte #2 appraisal well (60% working interest).

Strategic Relationship with Total

On April 6, 2009, we announced a long-term alliance with Total in which, through a series of transactions, we combined our respective U.S. Gulf of Mexico exploration lease inventory (which excludes our Heidelberg project, our Shenandoah project, and all developed or producing properties held by Total in the U.S. Gulf of Mexico) through the exchange of a 40% interest in our leases for a 60% interest in Total's leases, resulting in a current combined alliance portfolio covering 239 blocks. The initial mandatory five-well program and Total's obligation to carry a substantial share of our costs associated with those wells concluded at the end of drilling operations on our Aegean #1 exploration well. Pursuant to the alliance, Total remains obligated to pay 40% of the general and administrative costs relating to our operations in the deepwater U.S. Gulf of Mexico during the 10-year alliance term. Total also remains obligated to pay up to $75 million to carry up to two-thirds of (i) our costs for drilling or other operations (including seismic) conducted prior to the development phase on our North Platte project, and (ii) our costs for any additional exploration or appraisal wells apart from our North Platte project. We act as operator on behalf of the alliance through the exploration and appraisal phases of development. Upon completion of appraisal operations, operatorship will be determined by Total and ourselves, with the greatest importance being placed on majority (or largest) working interest ownership and the respective experience of each party in developments which have required the design, construction and ownership of a permanently anchored host facility to collect and transport oil or natural gas from such development.

General Information—West Africa

Our West Africa operations include appraisal and development activities on our discoveries as well as the exploration of oil-focused prospects targeting pre-salt geologic horizons in the Kwanza basin offshore Angola and the South Gabon Coastal basin offshore Gabon.

Geologic Overview

Offshore Angola and Gabon are characterized by the presence of salt formations and oil-bearing sediments located in pre-salt and above salt (Albian) horizons. Given the rifting that occurred when plate tectonics separated the South American and African continents, we believe the geology offshore Angola (Kwanza Basin) and Gabon (South Gabon Coastal Basin) is an analog to the geology offshore Brazil where several pre-salt discoveries are located. The basis for this hypothesis is that 150 million years ago, current day South America and Africa were part of a larger continent that broke apart. As these land masses slowly drifted away from each other, rift basins formed. These basins were filled with organic rich material and sediments, which in time became hydrocarbon source rocks and reservoirs. A thick salt layer was subsequently deposited, forming a seal over the reservoirs. Finally the continents continued to drift apart, forming two symmetric geologic areas separated by the Atlantic Ocean. This symmetry in geology is particularly notable in the deepwater areas offshore Gabon, Angola and the Campos Basin offshore Brazil. From an exploration perspective, we believe this similarity is very meaningful, particularly in the context of pre-salt Brazilian discoveries and our recent pre-salt discoveries at Cameia, Lontra, Mavinga, Bicuar, Orca and Diaman.

Plans for Appraisal and Development

In general, the life-cycle of our major project developments begins with a thorough evaluation and analysis of well logs, reservoir core samples, fluid samples and, in some cases, the results of production tests from the initial exploration well that encountered what we believe may be commercial hydrocarbons. This information, along with relevant seismic data, is used to generate locations and plans for appraisal and development wells. In Angola, there are also important regulatory approvals we must obtain from Sonangol throughout the project development life-cycle. For example, under the terms of our applicable licenses in Angola, following a successful exploration well we are required to file a declaration of commercial well with Sonangol, which we have done with respect to our Cameia #1, Mavinga #1, Lontra #1, Bicuar #1A, and Orca #1 exploration wells. Under the terms of our applicable licenses in Angola, we have two years from our declaration of commercial well to declare a commercial discovery, unless otherwise agreed by Sonangol. On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia project. Depending upon the project, we may choose to drill one or more appraisal wells, each of which will undergo thorough analysis and evaluation. Once we file a declaration of commercial discovery with Sonangol, we have three months to file a development plan with Sonangol for approval. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. The development plan will include economic assumptions on the costs and timeline for drilling and completing development wells, the front-end engineering design, procurement, installation and commissioning of offshore production and processing facilities such as FPSO vessels, and also includes engineering design, procurement, installation and commissioning of subsea, umbilical, riser and flowline systems and other related transportation infrastructure. The project will become formally sanctioned when the relevant working interest partners have approved the development plan, including Sonangol and the Angola Ministry of Petroleum. Typically, following formal project sanction, we will commence the construction of offshore production facilities, proceed with development drilling and installation of subsea architecture in order to advance the project towards initial production. With respect to our Cameia development, we plan to conduct certain development drilling prior to formal project sanction.

A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a project development will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation and analysis, such as the steps described above, will need to be performed prior to official project sanction and development, including important regulatory approvals. At any time during the project development life-cycle, we may determine that the project would be uneconomic and abandon the project, despite the fact that the initial exploration well, or subsequent appraisal or development wells, discovered hydrocarbons. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

Licenses

Block 9 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 9 offshore Angola by executing a Risk Services Agreement ("Block 9 RSA") with Sonangol. The Block 9 RSA governs our 40% working interest in and operatorship of Block 9 offshore Angola and forms the basis of our exploration, development and production operations on this block. The Block 9 RSA provides for an initial exploration period of four years. On April 3, 2014, the Angola Ministry of Petroleum published Executive Decree 95/14, which granted us a two-year extension of the initial exploration phase on Block 9 offshore Angola, which is now scheduled to expire on March 1, 2016, and an optional exploration period of an additional three years. We do not have contractual rights to sell natural gas on Block 9, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 9. Block 9 is approximately 1 million acres (4,000 square kilometers) in size or approximately 167 U.S. Gulf of Mexico blocks and is located immediately offshore in the southeastern-most portion of the Kwanza Basin. Water depth ranges from zero to more than 3,200 feet (1,000 meters). Sonangol P&P is our partner on Block 9 and holds a 60% working interest. For more information regarding our Block 9 license, please see "—Material Agreements—Risk Services Agreements for Blocks 9 and 21 Offshore Angola."

Block 21 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 21 offshore Angola by executing a Risk Services Agreement ("Block 21 RSA") with Sonangol. The Block 21 RSA governs our 40% working interest in and operatorship of Block 21 offshore Angola and forms the basis of our exploration, development and production operations on this block. The Block 21 RSA provides for an initial exploration period of five years, which is scheduled to expire on March 1, 2015. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We do not have contractual rights to sell natural gas on Block 21, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21. Block 21 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately

200 U.S. Gulf of Mexico blocks. The block is 30 to 90 miles (50 to 140 kilometers) offshore in water depths of 1,300 to 5,900 feet (400 to 1,800 meters) in the central portion of the Kwanza Basin. Sonangol P&P is our partner on Block 21 and holds a 60% working interest. For more information regarding our Block 21 license, please see "—Material Agreements—Risk Services Agreements for Blocks 9 and 21 Offshore Angola."

On August 26, 2014, we received documentation confirming that Nazaki Oil and Gaz ("Nazaki") and Alper Oil Limitada ("Alper") are no longer members of the contractor group of Blocks 9 and 21 offshore Angola. Pursuant to a series of Executive Decrees passed by the Republic of Angola, the working interests previously held by Nazaki and Alper in Blocks 9 and 21 have been transferred to and are now held by Sonangol P&P. As a result, we no longer have any relationship with Nazaki or Alper. The contractor groups for Blocks 9 and 21 offshore Angola now consist only of Sonangol P&P (60% working interest) and the Company (40% working interest). Our obligation to carry and pay for Alper's 10% working interest terminated immediately with the transfer of Alper's interest to Sonangol P&P pursuant to the terms of our 2010 agreements with Alper. As a result, our paying interest in these blocks has been reduced from 62.5% to 52.5% during the initial exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. In addition, all historical costs of our carry of Alper will be recouped by us from Sonangol P&P's share of production revenues from these blocks. We are the operator of Blocks 9 and 21.

Block 20 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 20 offshore Angola by executing a Production Sharing Contract (the "Block 20 PSC") with Sonangol. The Block 20 PSC governs our 40% working interest in and operatorship of Block 20 offshore Angola and forms the basis of our exploration, development and production operations on Block 20 offshore Angola. Sonangol P&P and BP are the other holders of working interests under the Block 20 PSC. The Block 20 PSC provides for an initial exploration period of five years, which is scheduled to expire on January 1, 2017, and an optional exploration period of an additional three years. We do not have contractual rights to sell natural gas on Block 20 offshore Angola, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20. Block 20 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately 200 U.S. Gulf of Mexico blocks and is centered approximately 75 miles west of Luanda in the deepwater Kwanza Basin. It is immediately to the north of Block 21. For more information regarding our Block 20 license, please see "—Material Agreements—Production Sharing Contract for Block 20 Offshore Angola."

Diaba Block offshore Gabon. We acquired our non-operated 21.25% working interest in the Diaba Block offshore Gabon by entering into an assignment agreement with Total Gabon. Through the assignment we became a party to the Production Sharing Agreement ("PSA") between the operator Total Gabon and the Republic of Gabon. The PSA gives us the right to recover costs incurred and receive a share of the remaining profit from any commercial discoveries made on the block. We have contractual rights to any form of hydrocarbons, including natural gas, discovered on our Gabon license area. The Diaba Block is approximately 2.2 million acres (9,100 square kilometers) in size or approximately 370 U.S. Gulf of Mexico blocks. The block is 40 to 120 miles (60 to 200 kilometers) offshore in water depths of 300 to 10,500 feet (100 to 3,200 meters) in the central portion of the offshore South Gabon Coastal basin.

As of December 31, 2014, our working interests in Blocks 9, 20 and 21 offshore Angola and the Diaba Block offshore Gabon comprised an aggregate 5,652,687 gross (1,840,581 net) undeveloped acres. We do not currently own any working interests in developed acreage offshore Angola, although exploration wells have discovered hydrocarbons at Cameia, Mavinga and Bicuar on Block 21 offshore Angola and at Lontra and Orca on Block 20 offshore Angola. We have filed a declaration of commercial well with respect to each of those exploration wells pursuant to the terms of the Block 21 RSA and the Block 20 PSC. On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia project. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Upon the approval of a development area by the applicable Angolan government authorities, we will be in a position to specify the acreage assigned to the Cameia project. Likewise, upon approval of development areas by the applicable Angolan government authorities with respect to each of our Mavinga, Bicuar, Lontra and Orca discoveries, we will be in a position to specify the acreage assigned to each respective discovery. In addition, the Diaman #1B exploration well on the Diaba Block offshore Gabon was also successful in discovering hydrocarbons, however, the Diaman discovery remains in the early phases of the development project life-cycle. After the approval of a development plan, the delineation of a development area and the completion of certain other steps, we will evaluate which acreage associated with these discoveries could then be classified as developed acreage. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

The table below summarizes our undeveloped acreage scheduled to expire in the next five years offshore West Africa.

	Undeveloped Acres Expiring									
	2015		2016		2017		2018		2019 and thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Offshore West Africa										
Angola:										
Block 9(1)	—	—	988,668	395,467	—	—	—	—	—	—
Block 20(2)	—	—	—	—	1,210,569	484,228	—	—	—	—
Block 21(3)	1,210,816	484,326	—	—	—	—	—	—	—	—
Gabon:										
Diaba(4)	—	—	2,242,634	476,560	—	—	—	—	—	—

(1) Pursuant to the Block 9 RSA and Executive Decree 95/14, which granted us a two-year extension of the initial exploration phase on Block 9 offshore Angola, our Block 9 acreage is now scheduled to expire as of March 1, 2016.

(2) Pursuant to the Block 20 PSC, our license to exploration acreage on Block 20 will expire as of January 1, 2017, subject to certain extensions. This expiration date may be extended by three years if we notify Sonangol in writing of such extension at least thirty days before January 1, 2017, provided we have otherwise fulfilled our obligations under the agreement and agree to drill additional wells pursuant to the Block 20 PSC. The undeveloped acreage numbers listed in this row include acreage associated with our Lontra and Orca discoveries upon which exploration wells have discovered hydrocarbons, but a formal declaration of commercial discovery has not yet been filed with the applicable Angolan government authorities and therefore an associated development area has not yet been approved.

(3) Pursuant to the Block 21 RSA, our license to exploration acreage on Block 21 will expire as of March 1, 2015, subject to certain extensions. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue to pursue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. The undeveloped acreage numbers listed in this row include acreage associated with our Cameia, Mavinga and Bicuar projects upon which exploration wells have discovered hydrocarbons and we have filed declarations of commercial wells, but associated development areas have not yet been approved. See "Risk Factors—Risks Relating to Our Business—Under the

terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

(4) Pursuant to the PSA governing the Diaba Block, our license to acreage not defined by an approved development area will expire as of December 31, 2016, subject to certain extensions.

Drilling Rigs

We currently have the Petroserv SSV Catarina under contract for use in our offshore Angolan pre-salt drilling campaign. The drilling contract for the SSV Catarina, a new-build, sixth-generation semi-submersible drilling rig commenced in April 2013 and provides for a firm three-year commitment at a day rate of approximately $600,000 and two one-year extension options at day rates to be mutually agreed. Such rates are subject to standard reimbursement and escalation contractual provisions. We plan to utilize the Petroserv SSV Catarina for exploration, appraisal and development activities offshore Angola.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled offshore West Africa during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Offshore West Africa					
	2014(2)		2013(3)		2012(4)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration(1)						
Productive	3	1.2	3	1.0125	2	0.8
Dry	2	0.8	—	—	—	—
Total	5	2.0	3	1.0125	2	0.8

(1) We did not drill any development wells offshore West Africa during the fiscal years ended December 31, 2014, 2013, and 2012, respectively, although we expect that the Cameia #3 appraisal well which was drilled in 2014 will be used as a field development well.

(2) The wells noted include our Orca #1 exploration well (productive), Bicuar #1A exploration well (productive), Cameia #3 appraisal well (productive), Loengo #1 exploration well (dry), and Mupa #1 exploration well (dry).

(3) The wells noted include our Mavinga #1, Lontra #1, and Diaman #1B exploration wells (all productive).

(4) The wells noted include our Cameia #1 exploration well and Cameia #2 appraisal well (all productive).

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling offshore West Africa (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

West Africa	
Gross(1)	Net(1)
1	0.40

(1) The well noted is the Orca #2 appraisal well.

Summary of Oil and Gas Reserves

The summary data with respect to our estimated proved reserves and future cash flows has been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm, in accordance with the definitions and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities and adjusted for imbalances. The December 31, 2014 reserve report was completed on January 22, 2015, and a copy is included as an exhibit to this report.

Proved Reserves

As of December 31, 2014, our estimated net proved undeveloped reserves totaled 8.4 MMBbls of oil and 3.7 Bcf of natural gas. All of our proved reserves are attributable to our interest in the Heidelberg field in the U.S. Gulf of Mexico.

	Estimated Net Proved Reserves as of December 31, 2014		
	Oil (MMBbls)	Natural Gas (Bcf)	Total (MMBOE)
Proved Developed	0	0	0
Proved Undeveloped	8.4	3.7	9.0

All estimated future net cash flows are attributable to projected production from the Heidelberg Field in the U.S. Gulf of Mexico. The table below provides information regarding estimated future net cash flows (excluding derivative contracts) and the benchmark prices used.

	Estimated Future Net Cash Flows (in millions, except $ per Bbl/Mcf)
Estimated Future Net Cash Flows	$557.0
Standardized Measure	$365.3
PV-10	$365.3
Benchmark oil price ($/Bbl)	$95.24
Benchmark natural gas price ($/Mcf)	$ 4.77

Standardized Measure of Discounted Net Future Cash Flows

The standardized measure of discounted net future cash flows ("Standardized Measure") is the present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows. As of December 31, 2014, the Standardized Measure was approximately $365.0 million.

SEC reporting rules require companies to prepare reserve estimates using reserve definitions and pricing based on 12-month historical un-weighted first-day-of-the-month average prices, rather than year-end prices. Our estimated net proved reserves, future net cash flows, PV-10 and Standardized Measure were determined using index prices for oil and gas and were held constant throughout the life of the assets. For oil volumes, the average Light Louisiana Sweet spot price of $98.48 per barrel was used and was adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $4.35 per MMBtu was used and was adjusted for energy content, transportation fees, and a regional price differential. For the proved reserves, the average spot prices are adjusted by energy content and weighted by production over the remaining lives of the properties to determine the benchmark prices used. Such benchmark prices are $95.24 per barrel of oil and $4.77 per Mcf of gas.

PV-10

Present value of future net pre-tax cash flows attributable to our estimated net proved reserves (after deducting future development and production costs), discounted at 10% per annum (“PV-10”) is a non-GAAP financial measure and is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the relative monetary significance of our properties regardless of tax structure. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our proved reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV-10 is not a substitute for the Standardized Measure. Our PV-10 and the Standardized Measure do not purport to present the fair value of our proved reserves. PV-10 is equal to the Standardized Measure as of December 31, 2014 as the tax basis in our interests in the Heidelberg Field and related net operating loss exceeds the future net cash flows (after deducting future development and production costs) and accordingly there is no tax effect on future cash flows as of December 31, 2014.

Independent Qualified Estimator

We use an Independent Qualified Estimator (“IQE”) to generate and update our proved reserves. The IQE is a qualified, industry recognized, external consulting firm with extensive experience in the evaluation and estimation of reserves and resources. This approach provides us with an objective, independent assessment of the reserves which comprise our portfolio.

For the year ended December 31, 2014, we engaged NSAI to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our proved reserves and related future net cash flows.

NSAI, our independent reserve engineers, was established in 1961. Over the past 50 years, NSAI has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, acquisition and divestiture evaluations, simulation studies, exploration resources assessments, equity determinations, and management and advisory services. NSAI professionals subscribe to a code of professional conduct and NSAI is a Registered Engineering Firm in the State of Texas. NSAI is independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists and does not own an interest in our properties and is not employed on a contingent fee basis.

Internal controls over reserves estimation process

Our Reserve Evaluation Policy outlines the process and standards by which reserves are estimated, classified and reported for all our proved reserves, whether they are operated by us or operated by others. Our Chief Operating Officer Van P. Whitfield is accountable for the Reserve Evaluation Policy. Mr. Whitfield has over 39 years of experience leading oil and gas exploration and production operations activities globally. He has a Bachelor of Science Degree in Petroleum Engineering from Louisiana State University.

The Reserve Estimation Policy is administered by the Reserves Process Chair (“RPC”). The RPC is accountable for the completion of the annual and any in-year reserve estimates conducted by the

IQE. Our Executive Vice President, Execution and Appraisal, James H. Painter acts in the role of RPC. Mr. Painter has over 34 years of experience in the oil and gas industry. Mr. Painter has a Bachelor of Science Degree in Geology from Louisiana State University.

For each reserve evaluation, a qualified technical team is established to provide data to NSAI to enable NSAI to prepare its estimate of the extent and value of the proved reserves of certain of our oil and gas properties. Our qualified technical team works with NSAI to ensure the integrity, accuracy and timeliness of data we furnish to NSAI for purposes of their reserve estimation process. Our qualified technical team has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team at a minimum holds a Bachelor of Science degree in petroleum engineering, geology or other relevant degree.

Our geotechnical, engineering and commercial inputs and interpretations required to calculate the reserves for our portfolio are compiled by our staff. This information is shared with the IQE in an open and collaborative manner, and the IQE is provided full access to complete and accurate information pertaining to the assets and to all applicable personnel. Any differences between reserve estimates internally generated by us and the IQE that exceed established threshold limits are reviewed to ensure the accuracy of the quantifiable data being used in the assessment; available data has been shared and discussed; and that methodologies and assumptions used in the estimations are clearly understood.

The NSAI technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Ruurdjan (Rudi) de Zoeten. Mr. Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (No. 73709) and has over 30 years of practical experience in petroleum engineering. He graduated from University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. de Zoeten has been practicing consulting petroleum geology at NSAI since 2008. Mr. de Zoeten is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 3179) and has over 25 years of practical experience in petroleum geosciences. He graduated from the University of Wisconsin, Madison, in 1986 with a Bachelor of Science Degree in Geology and from University of Texas at Austin in 1988 with a Master of Arts Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our Audit Committee reviews the processes utilized in the development of our Reserve Evaluation Policy and the Reserve Report prepared by the IQE annually.

Technology used to establish proved reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI uses technical and economic data including, but not limited to, well logs, geologic maps, seismic data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating of and Auditing of Oil & Gas Reserves information promulgated by the Society of Petroleum Engineers (SPE Standards). They used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy and reservoir modeling that are considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. All of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions necessarily represent only informed professional judgment. See "Risk Factors—Risks Relating to Our Business—Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated."

MATERIAL AGREEMENTS

Production Sharing Contract for Block 20 Offshore Angola

On December 15, 2011, the Council of Ministers of Angola published Decree Law No. 303/11 which granted the mining rights for the prospecting, research, development and production of hydrocarbons on Block 20 offshore Angola to Sonangol, as the national concessionaire, and appointed us as the operator of Block 20. On December 20, 2011, CIE Angola Block 20 Ltd., our wholly-owned subsidiary, executed the PSC. The PSC forms the basis of our exploration, development and production operations on Block 20 offshore Angola. We are the operator of and own a 40% working interest in Block 20 offshore Angola. Currently, our paying interest on Block 20 is 57.14%, which is applicable during the exploration period. Under the PSC, we are required to drill four exploration wells (with at least one of these wells having a pre-salt objective) and acquire approximately 579 square miles (1,500 square kilometers) of 3-D seismic data all within five years of the signing of the PSC, subject to certain extensions. After this initial five year period ends, subject to any extensions, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. We have the right to a 30-year production period.

In order to guarantee these exploration work obligations under the PSC, we and BP are required to post a financial guarantee of $360 million. Our share of this financial guarantee is 57.14%, or approximately $206 million. We have delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the PSC, the amount of this letter of credit will be reduced accordingly. We acquired approximately 1,500 square kilometers of 3-D seismic data in 2012, and, accordingly, our letter of credit was reduced by approximately $17.1 million on August 16, 2012. As a result of completing drilling activities on the Lontra #1 and Orca #1 exploration wells in 2013 and 2014, respectively, our letter of credit was reduced by approximately $108.57 million on June 3, 2014. In addition, pursuant to the PSC, we and BP are required to make certain contributions for bonus, scholarships and for social projects such as the Sonangol Research and Technology Center aggregating $607.5 million, comprised of $242.5 million in the first year after the signing of the PSC, $85 million on each of the first, second and third anniversaries of the signing of the PSC, and $110 million on the fourth anniversary of the signing of the PSC. We are obligated to pay 57.14% of the foregoing costs, less $10 million previously paid, or approximately $337 million. We shall recover all exploration, development, production, administration and services expenditures incurred under the PSC by taking up to a maximum amount of 50% of all liquid hydrocarbons produced from Block 20. In addition, proportionate with our working interest in Block 20, we will receive 40% of a variable revenue stream that the Contractor Group (as defined in the PSC) will be allocated from Sonangol based on the Contractor Group's rate of return, reduced by applicable Angolan taxes, calculated on a quarterly basis. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 10% to 70%, and is inversely related to the applicable rate of return. Pursuant to the PSC, we do not have contractual rights to sell natural gas from Block 20, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20.

Risk Services Agreements for Blocks 9 and 21 Offshore Angola

On June 11, 2009, the Council of Ministers of Angola published Decree Law No. 15/09 and Decree Law No. 14/09 which granted the mining rights for the prospecting, exploration, development and production of hydrocarbons on Blocks 9 and 21 offshore Angola, respectively, to Sonangol, as the national concessionaire, and appointed us as the operator of Blocks 9 and 21, respectively. On December 16, 2009, the Council of Ministers of Angola approved the terms of the finalized RSAs. On February 24, 2010, we executed RSAs for Blocks 9 and 21 offshore Angola with Sonangol, Sonangol P&P, Nazaki and Alper. Nazaki and Alper have each assigned their working interests in Blocks 9 and 21 to Sonangol P&P. The "Contractor Group" under the RSAs is currently comprised of us and Sonangol P&P. The RSAs govern our 40% working interest in and operatorship of Blocks 9 and 21 offshore Angola and form the basis of our exploration, development and production operations on these blocks.

- Under the RSA for Block 9, we are required to drill three wells, as well as acquire approximately 386 square miles (1,000 square kilometers) of seismic data within four years of its signing. This four year period may be extended by one extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the four year period and if we have otherwise fulfilled our obligations under the agreement. After this initial four or seven year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. After this initial four or seven year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. During 2014, we received a two-year extension of the initial exploration phase on Block 9 offshore Angola, and our Block 9 acreage is now scheduled to expire as of March 1, 2016. We have the right to a 20 year production period, commencing on the date of the declaration of commercial discovery for each respective development area. In order to guarantee our exploration work obligations under the RSA for Block 9, we were required to post a financial guarantee in the amount of approximately $54.7 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the RSA, the amount of this letter of credit will be reduced accordingly. We acquired approximately 2,500 square kilometers of 3-D seismic data on Block 9 in 2011, and, accordingly, our letter of credit was reduced by approximately $9.375 million on April 25, 2011. As a result of completing drilling operations on the Loengo #1 exploration well in 2014, we submitted a request to Sonangol on October 27, 2014 to approve the reduction of our letter of credit by approximately $23.44 million. This request was approved by Sonangol on February 2, 2015 and the letter of credit was reduced accordingly on February 4, 2015. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the RSA and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 9, with Sonangol P&P holding a 60% working interest in the block and sharing in the exploration, development and production costs associated with such block, subject to our obligation to carry a portion of Sonangol P&P's expenses through the exploration phase. Currently, our paying interest in Block 9 is 52.5%, which is applicable during the exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. Proportionate with our working interest in Block 9, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from liquid hydrocarbon production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 72% to 95%, and is inversely related to the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 55% to 95% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid). Pursuant to the RSA, we do not have contractual rights to sell natural gas from Block 9, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 9. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

- Under the RSA for Block 21, we are required to drill four wells within five years of its signing. This five year period may be extended by one extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the five year period and if we have otherwise fulfilled our obligations under the agreement. After this initial five or eight year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. After this initial five or eight year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We have the right to a 25 year production period, commencing on the date of the declaration of commercial discovery for each respective development area. In order to guarantee these exploration work obligations under the Risk Services Agreement for Block 21, we were required to post a financial guarantee in the amount of approximately $92.2 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we completed our work obligations under the RSA, the amount of this letter of credit has been reduced accordingly. As a result of completing drilling operations on our Cameia #1 exploration well in 2012, our letter of credit was reduced by approximately $31.25 million on May 25, 2012. As a result of completing drilling activities on the Mavinga #1 and Bicuar #1A exploration wells in 2013, our letter of credit was reduced by approximately $40.63 million on March 12, 2014. During 2014, we completed drilling operations on our Mupa #1 exploration well, the fourth and final exploration well obligation on Block 21. We submitted a request to Sonangol on December 17, 2014 to approve the reduction of our letter of credit by approximately $20.3 million, thereby reducing the letter of credit balance to zero and allowing for cancellation. This request was approved by Sonangol on January 27, 2015 and the letter of credit was reduced to zero and cancelled effective February 10, 2015. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the RSA and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 21, with Sonangol P&P holding a 60% working interest in the block and sharing in the exploration, development and production costs associated with such block, subject to our obligation to carry a portion of Sonangol P&P's expenses through the exploration phase. Currently, our paying interest in Block 21 is 52.5%, which is applicable during the exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. Proportionate with our working interest in Block 21, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from liquid hydrocarbon production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 60% to 96%, and is inversely related to the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 35% to 90% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid). Pursuant to the RSA, we do not have contractual rights to sell natural gas from Block 21, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

COMPETITION

The oil and gas industry is highly competitive. We encounter strong competition from other independent, major and national oil and gas companies in acquiring properties and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and gas properties, or to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of significant declines in oil and gas prices, unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position.

Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily when attempting to make future acquisitions.

TITLE TO PROPERTY

We believe that we have satisfactory title to our prospect interests in accordance with standards generally accepted in the oil and gas industry. We currently have federal oil and gas leases in 266 blocks within the deepwater U.S. Gulf of Mexico covering approximately 1.5 million gross acres (0.8 million net acres). In West Africa, we currently have a license on the Diaba Block offshore Gabon, and licenses for Blocks 9, 20 and 21 offshore Angola covering a total of approximately 5,652,687 gross (1,840,581 net) acres. We do not have contractual rights to sell natural gas on our Angola blocks, but we have the right to use the natural gas during lease and production operations. We do, however, have contractual rights to any natural gas from our Gabon license area and all of our U.S. Gulf of Mexico leases. Our prospect interests are subject to applicable customary royalty and other interests, liens under operating agreements, liens for current taxes, and other burdens, easements, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of or affect our carrying value of the prospect interests.

CONTAINMENT RESOURCES

We are a member of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico, including the Helix Well Containment Group (“HWCG”), Clean Gulf Associates (“CGA”), the Marine Preservation Association (“MPA”), and National Response Corporation (“NRC”).

We are a member of HWCG Holdings, LLC, which in turn wholly owns HWCG, LLC. HWCG, LLC serves as the operating entity for the members of HWCG by carrying out day-to-day business activities and serving as a contracting party for various oil spill and well containment equipment and services on behalf of the HWCG members. Our relationship with HWCG provides us access to the Helix Producer 1, a production handling vessel, and the Helix Q4000, a multi-purpose field intervention and construction vessel. Together with various elements of relevant hardware such as hoses, connectors, risers, and similar equipment, the Helix Producer and the Helix Q4000 form the “Helix Fast Response System”. The Helix Fast Response System is currently capable of facilitating control and containment of spills in water depths up to 10,000 feet and has two capping stacks, a 15,000 psig capping stack and a 10,000 psig capping stack. The 10,000 psig capping stack is designed to have capturing and processing capabilities of 130,000 barrels of oil per day and 180 million cubic feet of gas per day. The 15,000 psig capping stack is designed to have capturing and processing capabilities of 55,000 barrels of oil per day and 100 million cubic feet of gas per day. The capping stacks are designed to handle deep, higher-pressure wells and would be used in the event a blowout preventer is ineffective. In addition to us, members of HWCG include operators such as Marathon Oil Company and Noble Energy, Inc., among others.

As a member of CGA, we have access to a large inventory of fast response oil spill recovery vessels for offshore response scenarios with remote sensing technology for locating oil slicks. In addition, the CGA fleet includes significant shoreline protection equipment and near-shore oil skimming vessels.

As a member of MPA, we have access to the resources of the Marine Spill Response Corporation (“MSRC”). MSRC provides a wide variety of surface spill equipment, including a deepwater response fleet, aerial dispersant fleet, and approximately 75% of the existing dispersant material in the U.S. Gulf of Mexico region. NRC is an umbrella response corporation that provides us access to a wide variety of surface spill response equipment as well as a wide group of surface response contractors that can address a surface response as well as play a support role in addressing a subsea well containment event. In addition, we have existing contracts with a number of contractors which have equipment that could assist in well containment efforts as well as with the surface effects of a subsea blowout or in addressing a concurrent surface spill. Examples of such equipment include, but are not limited to, anchor and supply vessels, subsea transponders and communication equipment, subsea cutting equipment, debris removal equipment, air and water monitoring and scientific support vessels, remote-operated vehicles, storage and shuttle vessels, and subsea dispersant equipment.

For our operations offshore West Africa, we have contracts in place with Wild Well Control which provide for subsea well control planning, response management, and access to a 15,000 psig capping stack system, subsea debris removal equipment package, and subsea dispersant application equipment in air freight configuration for mobilization to Angola. We also have contracts in place for the provision of oil spill management, equipment and response services. Specifically, we have contracted with (i) Braemer-Howells, a U.K.-based company with staff in Angola, which provides us access to oil spill response management, equipment and services, (ii) the West and Central African Aerial Surveillance and Dispersant Service, a non-profit organization which provides aerial surveillance and chemical dispersant services offshore Angola utilizing aircraft based in Ghana, and (iii) Oil Spill Response Limited, a U.K.-based company which is wholly owned by exploration and production companies and provides us access to personnel and equipment for oil spill events. We have also developed an Oil Spill Response Plan to address any potential spill, and we have access to equipment which is pre-staged in Angola, including containment boom, skimming systems, chemical dispersant systems, and temporary oil storage systems.

Furthermore, we also have contracts in place with Witt-O'Brien's, The Response Group and J. Connor Consulting for the provision of additional emergency response management services to help us address an incident in either the U.S. Gulf of Mexico or West Africa.

We are also members of the Oil Spill Response, Ltd. Global Dispersant Stockpile. This membership provides us access to a supply of over 1 million gallons of dispersant for use in a subsea well control event. This stockpile is stored in six locations around the world in portable containers ready for air freight transport.

In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors—Risks Relating to Our Business—We are subject to drilling and other operational hazards."

INSURANCE COVERAGE

For our U.S. Gulf of Mexico operations, we purchase insurance limits including a $650 million policy for operator's extra expense, which includes coverage for well control losses, re-drill and pollution clean-up expenses, $450 million of aggregated limits for third-party liability losses including coverage for bodily injury or death and property damage as well as seepage and clean-up of pollution on a sudden and accidental basis, and a $45 million policy for pollution damages as defined under the Oil Pollution Act of 1990 ("OPA"). In addition, we have identified certain of our unencumbered assets in the U.S. Gulf of Mexico to demonstrate $105 million of Oil Spill Financial Responsibility ("OSFR") through self-insurance to the Bureau of Ocean Energy Management ("BOEM") as permitted under the OPA. Towards the end of 2013, we also purchased insurance coverage for our working interest related to construction for our only U.S. Gulf of Mexico sanctioned development project, the Anadarko operated Heidelberg field development.

For our West Africa operations, we purchase operator's extra expense insurance with limits per well of the greater of three times the amount of our nominal dry-hole authorization-for-expenditure for each well or approximately $350 to $400 million. In addition, we also purchase $50 million of third-party liability insurance coverage specifically for liabilities arising out of our Angolan operations. Upon anticipated sanction of our operated Cameia field development project, we plan to purchase insurance coverage associated with those construction risks.

In general, our current insurance policies cover physical damage to our oil and gas assets. The coverage is designed to repair or replace assets damaged by insurable events. Certain of our stated insurance limits scale down to our working interest in the prospect being drilled, including coverage for well control losses, re-drill and pollution clean-up expenses and certain excess third-party liability coverage. All insurance recovery is subject to various deductibles or retentions as well as specific terms, conditions and exclusions associated with each individual policy. We believe that our coverage limits are sufficient and are consistent with what is held by our peers operating in the deepwater U.S. Gulf of Mexico and West Africa. However, there is no assurance that such coverage will adequately protect us against liability and loss from all potential consequences and damages associated with losses, should they occur. In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors—Risks Relating to Our Business—We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage" and "Risk Factors—Risks Relating to Our Business—We are subject to drilling and other operational hazards."

ENVIRONMENTAL MATTERS AND REGULATION

General

We are, and our future operations will be, subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use, transportation and disposal of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- enjoin some or all of the operations of facilities deemed not in compliance with such laws and regulations or permits issued thereunder;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas exploration, drilling, production and transportation activities;
- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate or address pollution from our operations.

These laws, regulations and permits may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws, regulations and permits can be costly; the regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Moreover, particularly in light of the Deepwater Horizon incident in the U.S. Gulf of Mexico, public interest in the protection of the environment and human health has increased. Offshore drilling in some areas has been opposed by environmental groups and, in other areas, has been restricted. Our operations could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that result in increased costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal, cleanup requirements or financial responsibility and assurance requirements.

Accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result, including costs relating to claims arising from damage to natural resources, property and persons. Moreover, environmental laws and regulations are complex, change frequently and have tended to become more stringent over time.

Accordingly, we cannot assure you that we have been or will be at all times in compliance with such laws and regulations, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the existing laws or regulatory issues to which we and our business operations are or may be subject to in the future.

Impact of the 2010 U.S. Gulf of Mexico Oil Spill

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the U.S. Department of the Interior ("DOI") and two of its agencies, the BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE"), which together formerly comprised the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), responded to this incident by imposing moratoria on drilling operations. These agencies adopted numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico that are applicable to us and with which our new applications for exploration plans and drilling permits must prove compliant. These regulations include (i) the Increased Safety Measures for Energy Development on the Outer Continental Shelf—Final Rule, which sets forth increased safety measures for offshore energy development and requires, among other things, that all offshore operators submit written certifications as to compliance with the rules and regulations for operations occurring in the Outer Continental Shelf including the submission of independent third party written certifications as to the capabilities of certain safety devices, such as blowout preventers and their components, (ii) the Workplace Safety Rule, which requires operators to develop and implement a comprehensive Safety and Environmental Management System, or SEMS, for oil and gas operations and codifies and makes mandatory the American Petroleum Institute's Recommended Practice 75, (iii) NTL No 2010-N06, which sets forth requirements for exploration plans, development and production plans and development operations coordination documents to include a blowout scenario, the assumptions and calculations that are used to determine the volume of the worst case discharge scenario, and proposed measures to prevent and mitigate a blowout and (iv) NTL No. 2010-N10, which requires that each operator submit adequate information demonstrating that it has access to and can deploy containment resources that would be adequate to promptly respond to a blowout or other loss of well control, adds additional requirements to oil spill response plans and requires that operators submit written certifications stating that the operator will conduct all authorized activities in compliance with all applicable regulations. While we conducted our own internal SEMS assessment and conducted a third party SEMS audit in 2013 to ensure we are in compliance with all applicable regulations related to our SEMS, effective June 4, 2013, the so-called SEMS II Rule amended the Work Place Safety rule to include additional safety requirements. Operators, including us, are now required to comply with the SEMS II Rule, and have an independent audit completed by June 4, 2015. In addition, the BSEE has proposed revisions to 30 CFR 250, subpart H on Oil and Gas Production Safety Systems to address recent technological advances in production safety systems and equipment used to collect and treat oil and gas from Outer Continental Shelf leases. This includes among other things, certain standards concerning the use of best available and safest technology, more rigorous design and testing requirements for boarding shut down valves, and an increase in approved leakage rates for certain safety valves. When finalized, these and any additional new regulations may result in delays in the permitting process.

Compliance with new and existing regulations and the interpretations of them may materially increase the cost of and time required to obtain drilling permits or conduct our drilling operations in the U.S. Gulf of Mexico, which may adversely affect our business, financial position or future results of operations.

Oil Pollution Act of 1990

The OPA and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters or in the exclusive economic zone of the U.S. Liability under the OPA is strict, joint and several and potentially unlimited. A "responsible party" under the OPA includes the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility to cover potential liabilities related to an oil spill for which such person would be statutorily responsible in an amount that depends on the risk represented by the quantity or quality of oil handled by such facility. The BSEE has promulgated regulations that implement the financial responsibility requirements of the OPA. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil, administrative and/or criminal enforcement actions. There has also been a call from public interest groups, certain governmental officials and, in 2011, the National Commission on the BP Deepwater Horizon Spill and Offshore Drilling for, among other things, increased government oversight of the offshore oil and gas industry, to require more comprehensive financial assurance requirements, to raise or eliminate the economic damages liability cap under OPA, significantly raise daily penalties for OPA infractions and make the environmental review process more stringent. If adopted, certain of these proposals have the potential to adversely affect our operations by restricting areas in which we may carry out exploration or development activities and/or causing us to incur increased operating expenses or liabilities. To satisfy OPA's requirement that we demonstrate at least $150 million of Oil Spill Financial Responsibility, we have (i) identified certain unencumbered assets in the U.S. Gulf of Mexico to the BOEM to demonstrate $105 million of Oil Spill Financial Responsibility through self-insurance, and (ii) procured the remaining $45 million of Oil Spill Financial Responsibility through third party insurance coverage.

Clean Water Act

The U.S. Federal Water Pollution Control Act of 1972, or Clean Water Act, as amended ("CWA"), imposes restrictions and controls on the discharge of pollutants, produced waters and other oil and natural gas wastes into waters of the U.S. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Under the CWA, permits must be obtained to discharge pollutants into regulated waters. In addition, certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up related damage and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

Marine Protected Areas

Executive Order 13158, issued in 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the U.S. and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the U.S. Environmental Protection Agency ("EPA") to propose regulations under the CWA to ensure appropriate levels of protection for the marine environment. This order and related CWA regulations have the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Consideration of Environmental Issues in Connection with Governmental Approvals

Our operations frequently require licenses, permits and other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act (“OCSLA”), the National Environmental Policy Act (“NEPA”), and the Coastal Zone Management Act (“CZMA”) require federal agencies to evaluate environmental issues in connection with granting such approvals or taking other major agency actions. OCSLA, for instance, requires the DOI to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment, and gives the DOI authority to refuse to issue, suspend or revoke permits and licenses allowing such activities in certain circumstances, including when there is a threat of serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency must prepare an environmental assessment and, potentially, an environmental impact statement. If such NEPA documents are required, the preparation of such could significantly delay the permitting process and involve increased costs. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we will have to certify that we will conduct our activities in a manner consistent with any applicable CZMA program. Violation of these foregoing requirements may result in civil, administrative or criminal penalties.

Naturally Occurring Radioactive Materials

Wastes containing naturally occurring radioactive materials (“NORM”) may also be generated in connection with our operations. Certain oil and natural gas exploration and production activities may enhance the radioactivity, or the concentration, of NORM. In the U.S., NORM is subject to regulation primarily under individual state radiation control regulations. In addition, NORM handling and management activities are governed by regulations promulgated by the Occupational Safety and Health Administration. These regulations impose certain requirements concerning worker protection; the treatment, storage and disposal of NORM waste; the management of waste piles, containers and tanks containing NORM; and restrictions on the uses of land with NORM contamination.

Resource Conservation and Recovery Act

The U.S. Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently exempt from RCRA’s requirements pertaining to hazardous waste and are regulated under RCRA’s non-hazardous waste and other regulatory provisions. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Accordingly, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we expect to generate some amounts of ordinary industrial wastes, such as waste solvents and waste oils, which may be regulated as hazardous wastes.

Air Pollution Control

The U.S. Clean Air Act, as amended (“CAA”) and state air pollution laws adopted to fulfill its mandates provide a framework for national, state, regional and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to the CAA and other pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA or other air pollution laws and regulations, including the suspension or termination of permits and monetary fines. Recently, the EPA also proposed new air regulations for oil and gas exploration, production, transmission and storage. These include new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and air toxics standards issued in April 2012 and updated VOC performance standards for storage tanks used in crude oil and natural gas production and transmission issued in August 2013. These regulations could require us to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements.

Superfund

The U.S. Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (“CERCLA”), also known as “Superfund,” imposes joint and several liability for response costs at certain contaminated properties and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or past owner or operator of the site where the release occurred and anyone who transported, disposed or arranged for the disposal of a hazardous substance at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur and seek natural resource damages.

Protected Species and Habitats

The U.S. federal Endangered Species Act, the federal Marine Mammal Protection Act, and similar federal and state wildlife protection laws prohibit or restrict activities that could adversely impact protected plant and animal species or habitats. Oil and natural gas exploration and production activities could be prohibited or delayed in areas where protected species or habitats may be located, or expensive mitigation may be required to accommodate such activities.

Climate Change

Our operations and the combustion of petroleum and natural gas-based products results in the emission of greenhouse gases (“GHG”) that could contribute to global climate change. Climate change regulation has gained momentum in recent years internationally and domestically at the federal, regional, state and local levels. Various U.S. regions and states have already adopted binding climate change legislation. In addition, the U.S. Congress has at times considered the passage of laws to limit the emission of GHGs. It is possible that federal legislation related to GHG emissions will be considered by Congress in the future.

The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Pursuant to the EPA's "Mandatory Reporting of Greenhouse Gases" final rule ("GHG Reporting Rule"), operators of stationary sources emitting more than established annual thresholds of carbon dioxide equivalent GHGs, as well as certain oil and natural gas facilities, including certain producers and offshore exploration and production operations, must inventory and report their GHG emissions annually. The EPA also regulates GHG emissions from certain stationary sources under regulations formerly known as the Tailoring Rule. In June 2013, the Obama Administration released its Climate Action Plan ("CAP") that, among other things, calls upon the EPA to promulgate greenhouse gas regulations for new and existing power plants. In 2014, the EPA issued these proposals which are expected to be finalized by summer 2015. The EPA is also required pursuant to a settlement agreement to issue GHG emissions standards for oil refineries, but no such standards have been proposed to date. In addition, the CAP calls upon EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. On January 14, 2015, the White House unveiled these plans which, among other things directs the EPA to propose rules to regulate methane emissions from the oil and gas industry from new and modified sources by summer 2015, with a finalized rule in 2016. The EPA is also directed to expand the GHG Reporting Rule to cover all segments of the oil and gas industry. Additionally, in April 2010 and August 2012, the EPA and the National Highway Traffic Safety Administration finalized GHG emissions standards for light duty vehicles for model years 2012 through 2016 and 2017 through 2025, respectively. In August 2011, these two agencies also announced national efficiency and emissions standards for medium and heavy duty engines and vehicles. Each of these pending, proposed and future laws, regulations and initiatives could adversely affect us directly as well as indirectly, as they could decrease the demand for oil and natural gas.

On the international level, various nations, including Angola and Gabon, have committed to reducing their GHG emissions pursuant to the Kyoto Protocol. The Kyoto Protocol was set to expire in 2012. In late 2011, an international climate change conference in Durban, South Africa resulted in, among other things, an agreement to negotiate a new climate change regime by 2015 that would aim to cover all major greenhouse gas emitters worldwide, including the U.S., and take effect by 2020. In November and December 2012, at an international meeting held in Doha, Qatar, the Kyoto Protocol was extended by amendment until 2020. In addition, the Durban agreement to develop the protocol's successor by 2015 and implement it by 2020 was reinforced at a November 2013 international climate change conference in Warsaw, Poland. The next international meeting is scheduled for December 2015 in Paris, France. U.S. federal climate change legislation or regulation or climate change legislation or regulation in other regions in which we conduct business could have an adverse effect on our results of operations, financial condition and demand for oil and natural gas.

Health and Safety

Our operations are subject to the requirements of the federal U.S. Occupational Safety and Health Act ("OSH Act") and comparable foreign and state statutes. These laws and their implementing regulations strictly govern the protection of the health and safety of employees. In particular, the OSH Act hazard communication standard, EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act of 1986 and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require us to ensure our workplaces meet minimum safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase our cost of doing business by increasing the future cost of transporting our production to market, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Homeland Security Regulations

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and natural gas facilities that are deemed to present "high levels of security risk." The DHS is currently in the process of adopting regulations that will determine whether our operations may in the future be subject to DHS-mandated security requirements. Presently, it is not possible to accurately estimate the costs we could incur, directly or indirectly, to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and Production

Development and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. U.S. laws under which we operate may also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

Regulation of Transportation and Sale of Natural Gas

The availability, terms and cost of transportation significantly affect sales of natural gas. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. The FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. Upon us reaching the production stage of our business model, such regulations will be applicable to us.

Although gas prices are currently unregulated, Congress historically has been active in the area of gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

U.S. Coast Guard and the U.S. Customs Service

The transportation of drilling rigs to the sites of our prospects in the U.S. Gulf of Mexico and our operation of such drilling rigs is subject to the rules and regulations of the U.S. Coast Guard and the U.S. Customs Service. Such regulation sets safety standards, authorizes investigations into vessel operations and accidents and governs the passage of vessels into U.S. territory. We are required by these agencies to obtain various permits, licenses and certificates with respect to our operations.

Laws and Regulations of Angola and Gabon

Our exploration and production activities offshore Angola and Gabon are subject to Angolan and Gabonese regulations, respectively. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following are summaries of certain applicable regulatory frameworks in Angola and Gabon.

Angola

In Angola, petroleum exploration and development activities are governed by the Petroleum Activities Law (the "Angola PAL"). Pursuant to the Angola PAL, all hydrocarbons located underground are property of the State of Angola, and exploitation rights can only be granted by the President of the Republic to Sonangol, as the national concessionaire. Foreign companies may only engage in petroleum activities in Angola in association with Sonangol through a commercial company or consortium, and generally upon entering a production sharing contract or a risk services agreement.

The Angolan PAL and the regulations thereunder extensively regulate the activities of oil and gas companies operating in Angola, including financial and insurance requirements, local content and involvement requirements, exploration and development processes, and operational matters. Local content regulations stipulate which goods or services relating to the oil and gas industry must be provided by Angolan companies (being companies which are beneficially owned in their majority by Angolan citizens), whether on a sole basis or in association with foreign contractors, and which goods or services may be provided by foreign companies. Goods or services which may be provided by foreign companies are generally subject to a local preference rule, whereby Angolan companies are granted preference in tendering for such activities or services, provided that the price difference in such tender does not exceed 10% of the total tendered amount. The power to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, is vested with Sonangol.

The petroleum agreements entered with Sonangol set forth the main provisions for exploration and production activities, including fiscal terms, mandatory State participation, obligations to meet domestic supply requirements, local training and spending obligations, and ownership of assets used in petroleum operations. Angolan law and these agreements also contain important limitations on assignment of interests in such licenses, including in most cases the need to obtain the consent of Angolan authorities.

Certain industry-specific and general application statutes and regulations govern health, safety and environmental matters under Angolan law. Prior to commencing petroleum operations in Angola, contractors must, among other things, prepare an environmental impact assessment and establish and implement a health and safety plan. Such environmental laws govern the disposal of by-products from petroleum operations and required oil spill preparedness capabilities. Failure to comply with these laws may result in civil and criminal liability, including, without limitation, fines or penalties.

Angola enacted the Foreign Exchange Law for the Petroleum Sector in 2012, Law N° 2/12, of January 13, 2012, which requires, among other things, that all foreign exchange operations be carried out through Angolan banks, that oil and gas companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. As a consequence, foreign currency proceeds obtained by oil and gas companies from the sale of their share of production cannot be retained in full outside Angola, as a portion of the proceeds required to settle tax liabilities and pay for local petroleum operations-related expenses must be deposited in and paid through Angolan banks. Furthermore, oil and gas companies are required to convert funds into local currency and deposit such funds in local bank accounts in order to pay for local petroleum operations-related expenses. The Foreign Exchange Law for the Petroleum Sector was further supplemented by Banco Nacional de Angola's Order 20/2012, of April 25, 2012, which details the procedures and mechanisms that must be adopted by oil and gas companies and sets forth a schedule for their phased implementation. Under this statute, since October 1, 2012, oil companies (including operators) are required to make all payments for goods and services supplied by foreign exchange residents (as defined in the Foreign Exchange Law) out of bank accounts domiciled in Angola, whether in national or foreign currency. As of July 1, 2013, oil and gas exploration and production companies (including operators) are now required to make all payments for goods and services provided by foreign exchange residents in local currency. From October 1, 2013 onwards, operators are required to make all payments for goods and services related to Angolan operations provided by non-residents out of bank accounts domiciled in Angola. Banco Nacional de Angola (BNA) has recently issued Order 7/14, of October 8, 2014 which determines that oil companies shall sell to BNA the foreign currency required to pay taxes and other tax dues before the State. The operators shall also sell to BNA the foreign currency necessary to pay foreign exchange residents.

On October 8, 2013, Angola enacted Executive Decree 333/13 ("ED 333/13") which enforces a consumption tax on oil companies. ED 333/13 requires companies that provide taxable services to oil companies to assess the applicable consumption tax, and oil companies, as beneficiary of those services, must pay the net value of the service to the service provider and remit the consumption tax to the Angolan government. The services that are subject to the consumption tax include, but are not limited to, consultancy services, supply of energy, water and telecommunications, leasing of machines and other equipment, private security services and travel services. The applicable consumption tax rates are 5% or 10% of the value of the services depending on the nature of the service rendered.

On October 21, 2014, Angola published Presidential Legislative Decree no. 3-A/14 which repealed ED 333/13. This new statute provides that there will be no consumption tax applicable to the petroleum companies which are in the exploration and development phases and until first oil, subject to certain exceptions. Subject to the approval of the Ministry of Finance and Sonangol, petroleum companies may also benefit from the consumption tax exemption during the production phase should those companies demonstrate that the consumption tax causes imbalances which render the petroleum projects not economically viable.

Executive Decree no. 224/12 of 16 July approved the Operational Discharge Management Regulations. This statute applies to all operational discharges generated during petroleum operations, both onshore and offshore. It sets the zero discharge prohibition establishing that all operational discharges resulting from onshore activities into the ground, inland waters and coastal waters are prohibited, except where duly justified for safety reasons. Discharges of (i) drill cuttings contaminated with non-water based drilling muds; (ii) non-water based drilling fluids; and (iii) sands produced resulting from operations in the maritime zone are prohibited and must be brought to shore and be treated as hazardous waste. This statute requires operators such as ourselves to prepare an Operational Discharge Management Plan for all facilities or groups of facilities under its responsibility. The statute also establishes that the direct discharge of chemical products into the sea and the use of compounds where the content in aromatics is greater than 1% (one percent) as a base for the manufacture of drilling fluids are prohibited. On April 8, 2014, Executive Decree no. 97/14 was published in the Angolan official gazette. This statute approved a moratorium on the implementation of the above mentioned regulations. Petroleum companies operating existing deep and ultra-deep water facilities now have until July 8, 2015 to implement these regulations.

See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

Gabon

In 2014, a new Hydrocarbons Law entered into force to regulate oil and gas activities in Gabon. It has repealed some prior laws relating to oil activities as well as all contradictory regulations contained in the remaining non-repealed laws of the oil and gas sector.

Pursuant to the Hydrocarbons Law, petroleum resources in Gabon are the property of the State of Gabon and petroleum companies undertake operations on behalf of the Government of Gabon. In order to conduct petroleum operations, oil and gas companies must enter into a hydrocarbons agreement, typically an exploration and production sharing contract ("EPSC"), with the Minister of Hydrocarbons and the Minister of Economy. Such agreement is subject to enactment by Presidential Decree, and its provisions must conform to the Hydrocarbons Law, subject to being null and void.

Furthermore, all oil companies, even those carrying out operations under the previous legal framework, must make payment of two financial contributions set forth in the new Hydrocarbons Law, namely the Investment Diversification Fund (payment of 1% of the Contractor's turnover during the production phase), and the Hydrocarbons Investment Fund (payment of 2% of the Contractor's turnover during the production phase), within two years of the entry into force thereof. Oil companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities ("*Fonds RES*") at the *Banque des Etats de l'Afrique Centrale* or at a Gabonese banking or financial institution.

The Hydrocarbons Law provides for a detailed legal framework in terms of organization of the sector, contents and terms and conditions of hydrocarbons agreements, liability, local content, safety and environment, domestic supply requirements, fiscal terms such as production sharing, royalty, bonuses and other charges, corporate income tax, customs, and local training obligations.

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—*Société Nationale des Hydrocarbures du Gabon*—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to the Hydrocarbons Law, the State may acquire an equity stake of up to 20%, at market value, within any companies applying for or already holding an exclusive production authorization. The contractor must carry the State in its 20% participating interest in the hydrocarbons agreements during the exploration phase. The parties are free to agree on a higher stake at market value. Further, the national oil company may also acquire participating interests of up to 15%, at market value.

In addition to general local content regulations which require a 90/10 ratio of Gabon national to foreign expatriate workers involved in petroleum activities, pursuant to the Hydrocarbons Law, subcontracting activities are awarded in priority to Gabonese companies in which more than 80% of the workforce consists of Gabonese nationals. In this respect, only technically qualified license holders may be hired as subcontractors.

Assignment of interests is subject to the Ministry of Hydrocarbons' consent. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within 2 years of entry into force of the Hydrocarbons Law.

With respect to gas, the State shall enjoy exclusive marketing rights for non-associated gas while any non-commercial share of associated gas remains the property of the State.

Hydrocarbons agreements entered into prior to the Hydrocarbon Law's publication remain in force and should continue to be governed by their own provisions. Our understanding is that the Hydrocarbons Law applies to any issues not expressly dealt with in these contracts' provisions.

Our EPSC governing our license to the Diaba block offshore Gabon was entered into before the publication of the Hydrocarbon Law. The Diaba EPSC contains a stabilization clause, which provides for the stability of the legal, tax, economic and financial conditions in force at the signing of the EPSC. Pursuant to the Diaba EPSC, these conditions may not be adversely altered during the term of the agreement, however, we can make no assurance that the Hydrocarbon Law will not adversely affect our operations or assets in Gabon. See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

EMPLOYEES

As of December 31, 2014, we had 205 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory. In addition, as of December 31, 2014, we had 150 contractors, consultants and secondees working in our offices and field locations.

CORPORATE INFORMATION

We were incorporated pursuant to the laws of the State of Delaware as Cobalt International Energy, Inc. in August 2009 to become a holding company for Cobalt International Energy, L.P. Cobalt International Energy, L.P. was formed as a limited partnership on November 10, 2005 pursuant to the laws of the State of Delaware. Pursuant to the terms of a corporate reorganization that we completed in connection with our initial public offering, all of the interests in Cobalt International Energy, L.P. were exchanged for common stock of Cobalt International Energy, Inc. and, as a result, Cobalt International Energy, L.P. is wholly-owned by Cobalt International Energy, Inc.

AVAILABLE INFORMATION

We make certain filings with the SEC, including our Annual Report on Form 10-K, proxy statements, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.cobaltintl.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 between the hours of 10 a.m. and 3 p.m. on official business days or by calling 1-800-SEC-0330 for further information on the operation of the Public Reference Room. Also, these filings are available on the internet at http://www.sec.gov. Our press releases and recent analyst presentations are also available on our website. The information on our website does not constitute a part of this Annual Report on Form 10-K and shall not be deemed to be a part hereof or incorporated into this or any our filings with the SEC.

EXECUTIVE OFFICERS

The following table sets forth certain information concerning our executive officers as of the date of this Annual Report.

Name	Age	Position
Joseph H. Bryant	59	Chairman of the Board of Directors and Chief Executive Officer
Van P. Whitfield	63	Chief Operating Officer and Executive Vice President
John P. Wilkirson	57	Chief Financial Officer and Executive Vice President
James H. Painter	57	Executive Vice President
James W. Farnsworth	59	Chief Exploration Officer and Executive Vice President
Shashank V. Karve	59	Executive Vice President, Projects
Jeffrey A. Starzec	38	Executive Vice President and General Counsel
Richard A. Smith	55	Senior Vice President
Lynne L. Hackedorn	56	Vice President, Government and Public Affairs

Biographical Information

Joseph H. Bryant has served as Chief Executive Officer and Chairman of our Board of Directors since our inception in November 2005. Mr. Bryant has 36 years of experience in the oil and gas industry. Prior to joining Cobalt, from September 2004 to September 2005, he was President and Chief Operating Officer of Unocal Corporation, an oil and gas exploration and production company. From May 2000 to August 2004, Mr. Bryant was President of BP Exploration (Angola) Limited, from January 1997 to May 2000, Mr. Bryant was President of BP Canada Energy Company (including serving as President of Amoco Canada Petroleum Co. between January 1997 and May 2000, prior to its merger with BP Canada), and from 1993 to 1996, Mr. Bryant served as President of a joint venture between Amoco Orient Petroleum Company and the China National Offshore Oil Corporation focused on developing the offshore Liuhua fields. Prior to 1993, Mr. Bryant held executive leadership positions in Amoco Production Company's business units in The Netherlands and the Gulf of Mexico, serving in many executive capacities and in numerous engineering, financial and operational roles throughout the continental United States. Mr. Bryant served on the board of directors of Berry Petroleum Company from October 2005 until May 2011. Mr. Bryant currently also serves on the board of directors of the American Petroleum Institute. Mr. Bryant holds a Bachelor of Science in Mechanical Engineering from the University of Nebraska.

Van P. Whitfield has served as Chief Operating Officer and Executive Vice President since September 2011. Mr. Whitfield served as our Executive Vice President, Operations and Development from May 2006 until September 2011. Mr. Whitfield has over 39 years of experience leading oil and gas production operations and marketing activities in North America, the United Kingdom and Europe, the Middle East and Asia. Prior to joining Cobalt, from May 2003 to May 2005, Mr. Whitfield served as Senior Vice President, Western Operations of CDX Gas LLC, an independent oil and gas company. From October 2002 to April 2003 he served as Production Unit Leader for the Angola Liquid Natural Gas Project, BP Exploration (Angola) Limited and from June 2001 to October 2002, he held the position of Vice President, Power and Water of ExxonMobil Saudi Arabia (Southern Ghawar) Ltd, an exploration and production company. Mr. Whitfield has also held the positions of Senior Vice President of BP Global Power, President and General Manager of Amoco Netherlands BV and Production Manager of Amoco (U.K.) Exploration Company, both exploration and production companies. In addition, he has held numerous operational and technical leadership positions in various Amoco Production Company locations, including: the position of Production Manager, West Texas and Engineering Manager, Worldwide. Mr. Whitfield has a Bachelor of Science Degree—Petroleum Engineering from Louisiana State University and is a graduate of the Executive Program at Stanford University.

John P. Wilkirson has served as Executive Vice President and Chief Financial Officer since June 2010. From 2007 until June 2010, Mr. Wilkirson served as our Vice President, Strategic Planning and Investor Relations. Mr. Wilkirson has 33 years of experience in the energy industry. Prior to joining Cobalt, from 1998 to 2005, Mr. Wilkirson was Vice President, Strategic Planning and Economics of Unocal Corporation, where his primary responsibilities included identifying and addressing major strategic issues, managing the global asset and investment portfolio, leading the economic analysis and evaluations function and overseeing performance management. He played an instrumental role as the integration executive for Unocal Corporation's merger into Chevron Corporation. Prior to Unocal Corporation, from 1992 to 1997, Mr. Wilkirson was an Engagement Manager at McKinsey & Company, Inc., a management consulting firm, serving energy clients on strategy and performance improvement engagements. Additional industry experience includes positions at Exxon Company USA from 1980 to 1984 and Sohio Petroleum Company and BP from 1984 to 1991, in petroleum engineering and commercial assignments. Mr. Wilkirson has a Bachelor of Science with Highest Honors in Petroleum Engineering and a Master of Business Administration from the University of Texas at Austin.

James H. Painter has served as Executive Vice President since April 2013. Mr. Painter previously served as our Executive Vice President, Gulf of Mexico from our inception in November 2005 until April 2013. Mr. Painter has more than 34 years of experience in the oil and gas industry. Prior to joining Cobalt, from February 2004 to September 2005, Mr. Painter was the Senior Vice President of Exploration and Technology at Unocal Corporation. Prior to his position at Unocal Corporation (following the merger between Ocean Energy Inc. and Devon Energy Corporation), from April 2003 to October 2003, Mr. Painter served as the Vice President of Exploration at Devon Energy Corporation, an oil and gas exploration and production company. From January 1995 to April 2003, Mr. Painter served in various manager and executive positions at Ocean Energy Inc. (and its predecessor Flores and Rucks, Inc.) with his final position as Senior Vice President of Gulf of Mexico and International Exploration. Additional industry experience includes positions at Forest Oil Corporation, an independent oil and gas exploration and production company, Mobil Oil Corporation and Superior Oil Company, Inc. Mr. Painter holds a Bachelor of Science in Geology from Louisiana State University.

James W. Farnsworth has served as our Chief Exploration Officer and Executive Vice President since April 2013. Mr. Farnsworth previously served as Chief Exploration Officer from our inception in November 2005 until April 2013. Mr. Farnsworth has had more than 33 years of experience in the oil and gas industry. From 2003 to 2005, Mr. Farnsworth held the position of Vice President of World-Wide Exploration and Technology, at BP p.l.c., a global energy company, responsible for BP p.l.c.'s global exploration business inclusive of North America, West Africa, North Africa, South America, Russia and the Far East. His prior positions at BP p.l.c., from 1983 to 2003, include: Vice President of North America Exploration; Vice President of Gulf of Mexico Exploration; Exploration Manager for Alaska; Deepwater Gulf of Mexico Production Manager for non-operated fields. Mr. Farnsworth has a Bachelor of Science Degree in Geology from Indiana University and a Masters of Science Degree in Geophysics from Western Michigan University.

Shashank V. Karve joined Cobalt in December 2014 and currently serves as our Executive Vice President, Projects. Mr. Karve has over 30 years of experience managing and executing large scale offshore oil and gas developments. Prior to joining Cobalt, from September 2011 to December 2014, Mr. Karve was President and CEO of Seanergis Management Services, a company he co-founded to offer area wide upstream and midstream infrastructure to the oil and gas industry. From 2009 until May 2011, Mr. Karve held the positions of Managing Director and Chief Operating Officer of MODEC, Inc. and Chairman and CEO of MODEC International Inc., a global provider of floating production, storage, and offloading (FPSO) vessels and other offshore oil and gas infrastructure. During this time, Mr. Karve was responsible for the on-time delivery of the first FPSOs on the pre-salt Lula field offshore Brazil and the Jubilee field offshore Ghana. From 2001 to 2008, Mr. Karve served as President and CEO of MODEC International LLC, where he oversaw MODEC's entry into the Brazilian and Angolan FPSO markets. Prior to that, Mr. Karve held several senior managerial positions with MODEC International LLC, including serving as Chief Operating Officer from 1997 to 2001. Mr. Karve received a graduate degree in Ocean Engineering from the Massachusetts Institute of Technology and a bachelor's degree in Naval Architecture and Marine Engineering from the Indian Institute of Technology.

Jeffrey A. Starzec has served as Executive Vice President and General Counsel since February 2015. Mr. Starzec also serves as our Corporate Secretary. Mr. Starzec served as our Senior Vice President and General Counsel from January 2012 to February 2015. From June 2009 until December 2011, Mr. Starzec served as our Associate General Counsel and Corporate Secretary. Prior to joining Cobalt, Mr. Starzec practiced corporate and securities law at Vinson & Elkins LLP from July 2006 until June 2009, where he represented a variety of energy companies, including Cobalt in connection with its strategic alliance with Total in the U.S. Gulf of Mexico. Mr. Starzec began his legal career at Baker Botts LLP and holds a Bachelor of Science in Economics from Duke University and a J.D. from Harvard Law School.

Richard A. Smith has served as Senior Vice President since September 2014. Prior to holding this position, Mr. Smith served as Senior Vice President and President of Cobalt Angola from November 2013 to September 2014. Mr. Smith served as Vice President, Investor Relations, Compliance and Risk Management from December 2012 until November 2013. Before that, Mr. Smith served as Vice President, Investor Relations and Planning from October 2011 until December 2012. Mr. Smith served as Vice President, International Business Development, Commercial and Finance from September 2010 until October 2011. From October 2007 until September 2010, Mr. Smith served as our Vice President. Mr. Smith has over 32 years of oil and gas industry experience in North American and international markets. Prior to joining Cobalt, from September 2005 to September 2007, Mr. Smith was Vice President, Joint Venture Development Corporate Affairs for the BP Russia Offshore Strategic Performance Unit, an oil and gas exploration and production unit of BP. From February 2002 to August 2005, he held the position of Vice President and then Executive Director for BP Exploration (Angola) Limited, an oil and gas exploration and production company operating in Angola. Mr. Smith's additional industry experience includes leadership positions at various companies in the oil and gas industry operating in Azerbaijan, Georgia, Turkey, the United Kingdom, the United States and Canada. Mr. Smith holds a Bachelor of Commerce from the University of Calgary.

Lynne L. Hackedorn has served as Vice President, Government and Public Affairs since October 2011. Ms. Hackedorn served as our Vice President, Government, Public Affairs and Land from September 2010 until October 2011. From April 2006 until September 2010, Ms. Hackedorn served as our Vice President, Land. Ms. Hackedorn has over 29 years of experience in the oil and gas industry. Prior to joining Cobalt, from 2001 to 2006, Ms. Hackedorn served as Senior Landman at Hydro Gulf of Mexico, L.L.C., formerly Spinnaker Exploration Company, L.L.C., an oil and gas exploration and production company, handling a variety of land functions within both the shelf and deepwater areas of the Gulf of Mexico. From 1998 to 2001, Ms. Hackedorn held management positions within the offshore Gulf of Mexico regions of Sonat Exploration GOM, Inc. and El Paso Production GOM, Inc., both oil and gas exploration and production companies. From 1994 to 1998, Ms. Hackedorn was a Landman with Zilkha Energy Company, also an oil and gas exploration and production company. Ms. Hackedorn began her career as a Landman in 1984 at ARCO Oil and Gas Company, where she worked in the onshore South Texas region from 1984 until 1990, and then in the offshore Gulf of Mexico region from 1990 until 1994. Ms. Hackedorn currently also serves on the Executive Committee and Board of Directors of National Ocean Industries Association. Ms. Hackedorn earned her Bachelor of Science in Petroleum Land Management from the University of Houston, graduating Magna Cum Laude.

Item 1A. *Risk Factors*

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K, including the consolidated financial statements and the related notes appearing at the end of this Annual Report on Form 10-K. If any of the following risks actually occurs, our business, business prospects, stock price, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Annual Report on Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below.

Risks Relating to Our Business

Failure to effectively execute our appraisal and development projects could result in significant delays and/or cost over-runs, including the delay of any future production, which could negatively impact our operating results, liquidity and financial position.

We currently have an extensive inventory of appraisal and development projects, all of which are in the early stages of the project development life-cycle, except for our Heidelberg project. Our development projects and discoveries will require substantial additional evaluation and analysis, including appraisal drilling and the expenditure of substantial amounts of capital, prior to preparing a development plan and seeking formal project sanction. First production from these development projects and discoveries is not expected for several years, with the exception of our Heidelberg project. All of our development projects and discoveries are located in challenging deepwater environments and, given the magnitude and scale of the initial discoveries, will entail significant technical and financial challenges, including extensive subsea tiebacks to an FPSO or production platform, pressure maintenance systems, gas re-injection systems, and other specialized infrastructure. This may include the advancement of technology and equipment necessary to withstand the higher pressures associated with producing oil and gas from Inboard Lower Tertiary horizons.

This level of development activity and complexity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. In addition, we have increased dependency on third-party technology and service providers and other supply chain participants for these complex projects. We may not be able to fully execute these projects due to:

- inability to obtain sufficient and timely financing;
- inability to attract and/or retain sufficient quantity of personnel with the skills required to bring these complex projects to production on schedule and on budget;
- significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure could adversely affect project development;
- inability to advance certain technologies;
- lack of partner or government approval for projects;
- civil disturbances, anti-development activities, legal challenges or other interruptions which could prevent access; and
- drilling hazards or accidents or natural disasters.

We may not be able to compensate for, or fully mitigate, these risks.

Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, which may in turn limit our ability to execute our development projects and achieve production, conduct exploration activities or renew our exploration portfolio.

We do not currently generate any revenue from operations. We expect our capital outlays and operating expenditures to increase substantially over at least the next several years as we expand our operations. Developing major offshore oil and gas projects, especially in complex and challenging environments, continuing exploration activities and obtaining additional leases or concessional licenses and seismic data are very expensive, and we expect that we will need to raise substantial additional capital, through future private or public equity offerings, asset sales, strategic alliances or debt or project financing, before we generate any revenue from operations. The recent significant decline in oil and natural gas prices may make it more difficult for us to obtain additional financing.

Our future capital requirements will depend on many factors, including:

- the scope, rate of progress and cost of our project appraisal and development activities;
- the scope, rate of progress and cost of our exploration activities;
- the success of our exploration activities;
- the extent to which we invest in additional oil leases or concessional licenses;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- our ability to attract and retain adequate personnel;
- our ability to meet the timelines for development set forth in our license agreements;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the timing of partner and governmental approvals and/or concessions; and
- the effects of competition by other companies operating in the oil and gas industry.

While we believe our operations will be adequately funded at current working interests through at least 2016, we do not currently have any commitments for future external funding and we do not expect to generate any revenue from production for several years. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing stockholders could be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our leases or licenses, we would dilute our ownership interest subject to the farm-out and any potential value resulting therefrom, and we may lose operating control over such prospects.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary license term, our licenses over the developed areas of a prospect could extend beyond the primary term, generally for the life of production. However, unless we make and declare discoveries within certain time periods specified in the documents governing our licenses, our interests in either the undeveloped parts of our license areas (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) may be forfeited, we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses. The costs to maintain licenses may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. If we are not successful in raising additional capital, we may be unable to execute our development projects, continue our exploration activities or successfully exploit our properties, and we may lose the rights to develop these properties upon the expiration of our licenses.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations.

The price that we will receive for our oil and natural gas production will significantly affect our revenue, profitability, access to capital and future growth rate. The market price of oil and natural gas affects the valuation of our business and price of our common stock despite the fact that we currently do not produce or sell oil or natural gas. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil and natural gas prices depend on numerous factors. These factors include, but are not limited to, the following:

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- speculation as to the future price of oil and the speculative trading of oil futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories and oil and natural gas refining capacities;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price and availability of alternative fuels.

Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance our capital expenditures and results of operations;
- reducing the amount of oil and natural gas that we can produce economically;
- causing us to delay, postpone or terminate our exploration, appraisal and development activities;
- reducing any future revenues, operating income and cash flows;
- reducing the carrying value of our crude oil and natural gas properties; or

• limiting our access to sources of capital, such as equity and long-term debt.

Oil and natural gas prices have recently declined dramatically and will likely continue to be volatile in the future. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, and the market price of our common stock, results of operations, liquidity or ability to finance planned capital expenditures.

We have limited proved reserves and areas that we decide to drill may not yield hydrocarbons in commercial quantities or quality, or at all.

We have limited proved reserves and our exploration portfolio consists of identified yet unproven exploration prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. The exploration, appraisal and development wells we drill may not yield hydrocarbons in commercial quantities or quality, or at all. In addition, while our exploration efforts are oil-focused, any well we drill may discover gas or other hydrocarbons, which we may not have rights to develop or produce. Our current appraisal and development projects and exploration prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Exploration wells have been drilled on a limited number of our exploration prospects. In addition, we have drilled a limited number of appraisal wells on our discoveries. Undue reliance should not be placed on our limited drilling results or any estimates of the characteristics of our projects or prospects, including any derived calculations of our potential resources or reserves based on these limited results and estimates. Additional appraisal wells, other testing and production data from completed wells will be required to fully appraise our discoveries, to better estimate their characteristics and potential resources and reserves and to ultimately understand their commerciality and economic viability. Accordingly, we do not know how many of our development projects, discoveries or exploration prospects will contain hydrocarbons in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if hydrocarbons are found on our exploration prospects in commercial quantities, construction costs of oil pipelines, production platforms, facilities or subsea infrastructure or FPSO vessels, as applicable, and transportation costs may prevent such prospects from being economically viable development projects. We will require various regulatory approvals in order to develop and produce from any of our discoveries, which may not be forthcoming or may be delayed.

Additionally, the analogies drawn by us from available data from other wells, more fully explored prospects or producing fields may not prove valid in respect of our drilling prospects. We may terminate our drilling program for a prospect if data, information, studies and previous reports indicate that the possible development of our prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

To date, there has been limited exploration, appraisal and development drilling which has targeted the pre-salt horizon in the deepwater offshore West Africa and the Inboard Lower Tertiary trend in the deepwater U.S. Gulf of Mexico, areas in which we intend to focus a substantial amount of our exploration and development efforts.

Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production.

Our use of the term "development project" in this Annual Report on Form 10-K in relation to our appraisal and development activities refers to our Heidelberg, Shenandoah, North Platte, Orca and Cameia projects. Our use of the term "discoveries" in this Annual Report on Form 10-K in relation to our exploration efforts refers to our existing discoveries: North Platte, Heidelberg, Shenandoah, Anchor, Yucatan, Cameia, Mavinga, Lontra, Bicuar, Orca and Diaman and is not intended to refer to (i) our exploration portfolio as a whole, (ii) prospects where drilling activities have not discovered hydrocarbons or (iii) our undrilled exploration prospects. A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a development project will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation, analysis, expenditure of capital and partner and regulatory approvals will need to be performed and obtained prior to official project sanction and development, which may include (i) the drilling of appraisal wells, (ii) the evaluation and analysis of well logs, reservoir core samples, fluid samples and the results of production tests from both exploration and appraisal wells, and (iii) the preparation of a development plan which includes economic assumptions on future oil and gas prices, the costs of drilling development wells, and the construction or leasing of offshore production facilities and transportation infrastructure. Regulatory approvals are also required to proceed with certain development plans. Relatively more testing and evaluation of our exploration, appraisal and development wells will be required for our projects and discoveries offshore West Africa than our projects in the U.S. Gulf of Mexico given the limited amount of drilling that has taken place in pre-salt horizons offshore West Africa. There is currently no oil or gas production in the pre-salt Kwanza Basin offshore Angola, an area in which we intend to devote a substantial amount of our appraisal and development activities.

Any of the foregoing steps of evaluation and analysis may render a particular development project uneconomic, and we may ultimately decide to abandon the project, despite the fact that the initial exploration well, or subsequent appraisal or development wells, discovered hydrocarbons. We may also decide to abandon a project based on forecasted oil and gas prices or the inability to obtain sufficient financing. We may not be successful in obtaining partner or regulatory approvals to develop a particular discovery, which could prevent us from proceeding with development and ultimately producing hydrocarbons from such discovery, even if we believe a development would be economically successful.

We do not currently generate any revenue from operations and our future performance is uncertain.

We do not currently generate any revenue from production and the commencement of production from our oil and gas properties will depend upon our ability to execute the appraisal and development of our projects and progress our projects through the project appraisal and development life-cycle, including the approval of development plans, obtaining formal project sanction, achieving successful appraisal and development drilling results and constructing or leasing production facilities and related subsea infrastructure. Our ability to commence production will also depend upon us being able to obtain substantial additional capital funding on a timely basis and attract and retain adequate personnel. We do not expect to commence production for at least another year, and therefore we do not expect to generate any revenue from production in the near future. Companies in their initial stages of development face substantial business and financial risks and may suffer significant losses. We have generated substantial net losses and negative cash flows from operating activities since our inception and expect to continue to incur substantial net losses as we continue our project appraisal and development activities, our exploration drilling program and our new venture activities. We face challenges and uncertainties in financial and commercial planning as a result of the complex nature of our business, the unavailability of historical data (particularly offshore West Africa) and uncertainties regarding the nature, scope and results of our future activities and financial commitments. In the event that our appraisal, development or exploration drilling schedules are not completed, or are delayed, modified or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this Annual Report on Form 10-K. As a result of industry factors or factors relating specifically to us, we may have to change our methods of conducting business, which may cause a material adverse effect on our results of operations and financial condition.

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing oil reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating exploration, appraisal and development wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploration wells bear a much greater risk of financial loss than development wells. In the past we have experienced unsuccessful drilling efforts. Moreover, the successful drilling of an oil well does not necessarily result in a profit on investment. A variety of factors, both geological and market-related, can cause a well or an entire development project to become uneconomic or only marginally economic. Our initial drilling sites, and any potential additional sites that may be developed, require significant additional exploration and appraisal, regulatory approval and commitments of resources prior to commercial development. We face additional risks in the Inboard Lower Tertiary Trend in the U.S. Gulf of Mexico and in the Kwanza basin offshore Angola and offshore Gabon due to a general lack of infrastructure and, in the case of offshore Angola and Gabon, underdeveloped oil and gas industries and increased transportation expenses due to geographic remoteness. Thus, this may require either a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

We contract with third parties to conduct drilling and related services on our development projects and exploration prospects for us. Such third parties may not perform the services they provide us on schedule or within budget. The recent decline in oil and gas prices may have an adverse impact on certain third parties from which we contract drilling, development and related oilfield services, which in turn could affect such companies' ability to perform such services for us and result in delays to our exploration, appraisal and development activities. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by the third parties we contract with is highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or equipment malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices; therefore, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from an area compared with production from similar producing areas;

- assumed effects of regulation by governmental agencies and court rulings;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures; and
- estimates of future severance and excise taxes, workover costs, and remedial costs.

For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, because our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with a number of major development projects on which we are moving forward. We must successfully execute our development projects, including development drilling, in order to generate future production and cash flow. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development projects available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. Therefore, a development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. Projects in frontier areas may require the development of special technology for development drilling or well completion and we may not have the knowledge or expertise in applying new technology. All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of hydrocarbon reserves. This puts a property at higher risk for future impairment if commodity prices decrease or operating or development costs increase.

Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing.

Our drilling and development plans on our acreage are scheduled our over a multi-year period. Our drilling and development plans depend on a number of factors, including the availability of capital and equipment, qualified personnel, seasonal and weather conditions, regulatory and block partner approvals, civil and political conditions, oil prices, costs and drilling results. The final determination on whether to drill any exploration, appraisal, or development well, including the exact drilling location as well as the successful development of any discovery, will be dependent upon the factors described elsewhere in this Annual Report on Form 10-K as well as, to some degree, the results of our drilling activities. Because of these uncertainties, we do not know if the drilling locations we have identified or targeted will be drilled in the location we currently anticipate, within our expected timeframe or at all or if we will be able to economically produce oil or gas from these or any other potential drilling locations. As such, our actual drilling and development plans and locations may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

We are not, and may not be in the future, the operator on all of our acreage, and do not, and may not in the future, hold all of the working interests in our acreage. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets.

Currently, we are not the operator on approximately 11% of our deepwater U.S. Gulf of Mexico blocks, and we are not the operator on the Diaba Block offshore Gabon. As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future prospects that result in a greater proportion of our prospects being operated by others. In addition, the terms of our current or future licenses or leases may require at least the majority of working interests to approve certain actions. As a result, we may have limited ability to exercise influence over the operations of the prospects operated by our partners or which are not wholly-owned by us, as the case may be. Dependence on the operator or our partners could prevent us from realizing our target returns for those prospects. Further, it may be difficult for us to minimize the cycle time between discovery and initial production with respect to prospects for which we do not operate or wholly-own. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- partner, government and regulatory approvals;
- selection of technology; and
- the rate of production of reserves, if any.

Furthermore, even though we are the operator of Blocks 9, 20 and 21 offshore Angola, we are required to obtain the prior approval of Sonangol for most of our operational activities. This limited ability to exercise control over the operations of some of our prospects may cause a material adverse effect on our results of operations and financial condition.

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or lease partners. As a result of our exploration success, we have a large inventory of development projects which will require significant capital expenditures and have long development cycle times. Our partners, both in the U.S. Gulf of Mexico and West Africa, must be able to fund their share of investment costs through the lengthy development cycle, through cash flow from operations, external credit facilities, or other sources, including project financing arrangements. Our partners may not be successful in obtaining such financing, which could negatively impact the progress and timeline for development. In addition to project development costs, our partners must also be able to fund their share of exploration and other operating expenses. If any of our partners in the blocks or leases in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In response to the recent decline in oil and gas prices, certain of our partners have announced capital expenditure reductions, which may cause such partners to elect not to participate in the drilling of a particular exploration or appraisal well with us. This could increase our share of the costs of such operation and may cause us to cancel or delay certain exploration or appraisal drilling programs.

In addition, if any of the service providers we contract with to conduct development or exploration activities file for bankruptcy or are otherwise unable to fulfill their obligations to us, we may face increased costs and delays in locating replacement vendors. The recent decline in oil and gas prices may have an adverse impact on certain third parties from which we contract drilling, development and related oilfield services, which in turn could affect such companies' ability to perform such services for us and result in delays to our exploration, appraisal and development activities. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our business, results of operations or financial condition.

We are dependent on certain members of our management and technical team and our inability to retain or recruit qualified personnel may impair our ability to grow our business.

Our investors must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, discovering and developing oil reserves and progressing our development projects toward first production. Our performance and success are dependent, in part, upon key members of our management and technical team, and their loss or departure could be detrimental to our future success. You must be willing to rely to a significant extent on our management's discretion and judgment. In addition, a significant portion of our employee base is at or near retirement age. Furthermore, we utilize the services of a number of individual consultants for contractually fixed periods of time. Our inability to retain or recruit qualified personnel may impair our ability to grow our business and develop our discoveries, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various license agreements and leases, our interests in the undeveloped parts of our license (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) areas may lapse and we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses. For example, pursuant to the terms of the Block 21 RSA, the initial exploration period with respect to Block 21 offshore Angola will terminate on March 1, 2015 and, on such date we will lose our exploration rights on Block 21. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We can make no assurances that we will receive an extension of the initial exploration period on Block 21 or what the terms of the extension might be. Under the Block 20 PSC, in order to preserve our rights in the block, we will be required to drill four exploration wells within five years of the signing of the Block 20 PSC, or January 1, 2017, subject to certain extensions. Currently, we have drilled two exploration wells on Block 20.

Furthermore, as required by our license agreements, within thirty days following a successful exploration well, we are required to submit a declaration of commercial well to Sonangol. Within two years after the date of the declaration of commercial well, we must submit to Sonangol a formal declaration of commercial discovery. Within three months from the declaration of commercial discovery, we are required to submit a development plan to Sonangol and the Angola Ministry of Petroleum for review and approval. Within forty-two months after the formal declaration of commercial discovery, we are required to commence first production from such discovery. Given our exploration success, we now have five complex appraisal and development projects offshore Angola, including Cameia, Mavinga, Lontra, Orca and Bicuar, each of which we must progress through the project development life-cycle in order to comply with the deadlines outlined above. Our failure or inability to meet these deadlines could jeopardize our production rights or result in forfeiture of our production rights with respect to these projects, which would have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

In addition, most of our deepwater U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2024. Generally, we are required to commence exploration activities or successfully exploit our properties during the primary lease term in order for these leases to extend beyond the primary lease term. A portion of the leases covering our Shenandoah and Anchor discoveries are beyond their primary term, and the operator must conduct continuous operations or obtain a Suspension of Production in order to maintain such leases. Accordingly, we and our partners may not be able to drill all of the prospects identified on our leases or licenses prior to the expiration of their respective terms and we can make no assurances that the operator of the discoveries in which we hold a non-operated interest will be able to successfully perpetuate leases through continuous operations or obtaining a Suspension of Production. Should the prospects we have identified under the licenses or leases currently in place yield discoveries, we cannot assure you that we will not face delays in drilling these prospects or otherwise have to relinquish these prospects. The costs to maintain licenses over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business. For each of our blocks and license areas, we cannot assure you that any renewals or extensions will be granted or whether any new agreements or leases will be available on commercially reasonable terms, or, in some cases, at all.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental, safety, health and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental, safety, and health liabilities and could acquire assets on an "as is" basis. Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploration prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of environmental, safety and health or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve many risks that a combination of experience, knowledge and careful evaluation may not be able to overcome. Our future success will depend on the success of our exploration and production activities and on the future existence of the infrastructure and technology that will allow us to take advantage of our findings. Additionally, our properties are located in deepwater, which generally increases the capital and operating costs, technical challenges and risks associated with exploration and production activities. As a result, our exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected production from our prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of oil and gas prices, proximity, capacity and availability of pipelines, the availability of processing facilities, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of hydrocarbons, environmental, safety, health and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

We are subject to drilling and other operational hazards.

The exploration and production business involves a variety of operating risks, including, but not limited to:

- blowouts, cratering and explosions;
- mechanical and equipment problems;
- uncontrolled flows or leaks of oil or well fluids, natural gas or other pollution;
- fires and gas flaring operations;
- marine hazards with respect to offshore operations;

- formations with abnormal pressures;
- pollution, other environmental risks and geological problems; and
- weather conditions and natural disasters.

These risks are particularly acute in deepwater drilling and exploration for natural resources. Any of these events could result in loss of human life, significant damage to property, environmental damage, impairment of our operations, delays in our drilling operations, increased costs and substantial losses. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

We are members of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico and offshore West Africa. Through these industry groups, as described under "Business—Containment Resources", we have contractual rights to access certain oil spill and well containment resources. We can make no assurance that these resources will perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons. Furthermore, our contracts for the use of oil spill and well containment resources contain strict indemnity provisions that generally require us to indemnify the contractor for all losses incurred as a result of assisting us in our oil spill and well containment efforts, subject to certain exceptions and limitations. In the event we experience a subsea blowout, explosion, fire, uncontrolled flow of hydrocarbons or any of the other operational risks identified above, the oil spill and well containment resources which we have contractual rights to will not prevent us from incurring losses or shield us from liability, which could be substantial and have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

The high cost or unavailability of drilling rigs, equipment, transportation, personnel, oil field services and infrastructure could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, transportation, supplies or qualified personnel, often during periods of higher oil prices or in emerging areas of exploration. During these periods and within these areas, the costs of drilling rigs, equipment, transportation, supplies and personnel are substantially greater and their availability may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, transportation, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our ability to produce hydrocarbons will depend substantially on the availability and capacity of gathering systems, pipelines, processing facilities and tanker transportation owned and operated by third parties. Additionally, such infrastructure may not be available on commercially reasonable terms. We may be required to shut in oil wells because of the absence of a market or because access to pipelines, gathering systems, processing facilities or tanker transportation may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could have a material adverse effect on our business, financial condition or results of operations.

Our operations will involve special risks that could adversely affect operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions.

These conditions can cause substantial damage to facilities and interrupt our operations. As a result, we could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Deepwater exploration generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Such risks are particularly applicable to our deepwater exploration efforts in the Inboard Lower Tertiary trend and pre-salt offshore Angola and Gabon. In addition, there may be production risks of which we are currently unaware. Whether we use existing pipeline infrastructure, participate in the development of new subsea infrastructure or use floating production systems to transport oil from producing wells, if any, these operations may require substantial time for installation, or encounter mechanical difficulties and equipment failures that could result in significant cost overruns and delays. Furthermore, deepwater operations generally, and operations in the Inboard Lower Tertiary and offshore West Africa trends in particular, lack the physical and oilfield service infrastructure present on the shelf. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated hydrocarbons, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of this infrastructure, oil and gas discoveries we make in the deepwater, if any, may never be economically producible.

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

Our operations in the U.S. Gulf of Mexico may be adversely impacted by tropical storms and hurricanes.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations in the U.S. Gulf of Mexico as well as operations within the path and the projected path of the tropical storms or hurricanes. In the future, during a shutdown period, we may be unable to access wellsites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to offshore drilling rigs and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which may have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

The geographic concentration of our properties in the U.S. Gulf of Mexico and offshore Angola and Gabon subjects us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting the U.S. Gulf of Mexico and offshore Angola and Gabon.

Our properties are concentrated in three countries: the U.S. Gulf of Mexico and offshore Angola and Gabon. Some or all of these properties could be affected should such regions experience:

- severe weather or natural disasters;
- moratoria on drilling or permitting delays;
- delays in or the inability to obtain regulatory approvals;
- delays or decreases in production;
- delays or decreases in the availability of drilling rigs and related equipment, facilities, personnel or services;

- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- changes in the regulatory, political and fiscal environment.

For example, in response to the Deepwater Horizon incident in 2010, the U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI and the BOEM and the BSEE, imposed moratoria on drilling operations, required operators to reapply for exploration plans and drilling permits and adopted extensive new regulations, which effectively had halted drilling operations in the deepwater U.S. Gulf of Mexico for a period of time. Additionally, oil and gas properties and facilities located in the U.S. Gulf of Mexico were significantly damaged by Hurricanes Katrina and Rita in 2005, which required our competitors to spend a significant amount of time and capital on inspections, repairs, debris removal, and the drilling of replacement wells. We maintain insurance coverage for only a portion of these risks. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss. We do not carry business interruption insurance.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

Regulations enacted as a result of the Deepwater Horizon drilling rig accident and resulting oil spill may have significantly increased certain of the risks we face and increased the cost of operations in the U.S. Gulf of Mexico.

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI, the BOEM and the BSEE, responded to this incident by imposing moratoria on drilling operations and adopting numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico. Compliance with these new regulations and interpretations has increased the cost of our drilling operations in the U.S. Gulf of Mexico.

The successful execution of our U.S. Gulf of Mexico business plan depends on our ability to continue our exploration and appraisal efforts. A prolonged suspension of or delay in our drilling operations would adversely affect our business, financial position or future results of operations.

Furthermore, the Deepwater Horizon incident has increased and may further increase certain of the risks we face, including, without limitation, the following:

- increased governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and inspections and training requirements;
- increased difficulty in obtaining leases and permits to drill offshore wells, including as a result of any bans or moratoria placed on offshore drilling;
- potential legal challenges to the issuance of permits and the conducting of our operations;
- higher drilling and operating costs;
- higher royalty rates and fees on leases acquired in the future;
- higher insurance costs and increased potential liability thresholds under proposed legislation and regulations;

- decreased partner participation in wells we operate;
- higher capital costs as a result of any increase to the risks we or our industry face; and
- less favorable investor perception of the risk-adjusted benefits of deepwater offshore drilling.

The occurrence of any of these factors, or their continuation, could have a material adverse effect on our business, financial position or future results of operations.

We face various risks associated with increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations such as offshore drilling and development. For example, environmental activists have recently challenged lease sales and decisions to grant air-quality permits in the U.S. Gulf of Mexico for offshore drilling.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering, processing or production facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased regulation;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act, and any determination that we violated the U.S. Foreign Corrupt Practices Act could have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

In connection with entering into our RSAs for Blocks 9 and 21 offshore Angola, two Angolan-based E&P companies were assigned as part of the contractor group by the Angolan government. We had not worked with either of these companies in the past, and, therefore, our familiarity with these companies was limited. In the fall of 2010, we were made aware of allegations of a connection between senior Angolan government officials and one of these companies, Nazaki Oil and Gáz, S.A. ("Nazaki"), which was a full paying member of the contractor group but is no longer a member of such group. In March 2011, the SEC commenced an informal inquiry into these allegations. To avoid non-overlapping information requests, we voluntarily contacted the U.S. Department of Justice ("DOJ") with respect to the SEC's informal request and offered to respond to any requests the DOJ may have. Since such time, we have complied with all requests from the SEC and DOJ with respect to their inquiry. In November 2011, a formal order of investigation was issued by the SEC related to our operations in Angola. In August 2014, we received a Wells Notice from the SEC related to this investigation. In January 2015, we received a termination letter from the SEC advising us that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. We continue to cooperate with the DOJ with regard to its ongoing parallel investigation. We have conducted an extensive investigation into these allegations and believe that our activities in Angola have complied with all laws, including the FCPA. We are unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue, or otherwise provide any assurance regarding the duration, scope, developments in, results of or consequences of its investigation.

In the future, we may be partnered with other companies with whom we are unfamiliar. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the government may seek to hold us liable for successor liability FCPA violations committed by companies in which we invest or that we acquire.

A change in U.S. energy policy could have a significant impact on our operations and profitability.

U.S. energy policy and laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential rules and regulations that could impact the sources and uses of energy in the United States. For example, new CAFE standards enacted in 2012 will result in a significant increase in the fuel economy of cars and light trucks and will reduce the future demand for crude oil for road transport use. GHG emissions regulations may increase the demand for natural gas as fuel for power generation.

We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are impacted in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in U.S. energy policy.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business.

We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business. See "Legal Proceedings." We are vigorously defending against the current lawsuits and do not believe it will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

Because we maintain a diversified portfolio of assets that includes both U.S. and international projects, the complexity and types of legal proceedings with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our oil and gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Angola and Gabon.

Our operations are exposed to risks of war, local economic conditions, political disruption, civil disturbance and governmental policies that may:

- disrupt our operations;
- restrict the movement of funds or limit repatriation of profits;
- in the case of our non-U.S. operations, lead to U.S. government or international sanctions; and
- limit access to markets for periods of time.

Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our financial condition and results of operations. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the U.S. or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the U.S., which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Angola, Gabon, the United States, the Cayman Islands and other jurisdictions, in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof, could have a material adverse effect on our results of operations and financial position, as well as on the market price of our common stock.

Outbreaks of disease in the geographies in which we operate may adversely affect our business operations and financial condition.

Many of our operations are currently, and will likely remain in the near future, in developing countries which are susceptible to outbreaks of disease and may lack the resources to effectively contain such an outbreak quickly. Such outbreaks may impact our ability to explore for oil and gas, develop or produce our license areas by limiting access to qualified personnel, increasing costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and oil and gas production to and from our areas of operation and diverting the time, attention and resources of government agencies which are necessary to conduct our operations. In addition, any losses we experience as a result of such outbreaks of disease which impact sales or delay production may not be covered by our insurance policies.

An epidemic of the Ebola virus disease is currently ongoing in parts of West Africa. A substantial number of deaths have been reported by the World Health Organization ("WHO") in West Africa, and the WHO has declared it a global health emergency. It is impossible to predict the effect and potential spread of the Ebola virus in West Africa and surrounding areas. Should the Ebola virus continue to spread, including to the countries in which we operate, or not be satisfactorily contained, our exploration, development and production plans for our operations could be delayed, or interrupted after commencement. Any changes to these operations could significantly increase costs of operations. Our operations require contractors and personnel to travel to and from Africa as well as the unhindered transportation of equipment and oil and gas production (in the case of our producing fields). Such operations also rely on infrastructure, contractors and personnel in Africa. If travel bans are implemented or extended to the countries in which we operate, including Angola or Gabon, or contractors or personnel refuse to travel there, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow.

The oil and gas industry, including the acquisition of exploration acreage worldwide, is intensely competitive.

The international oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of oil and gas. We operate in a highly competitive environment for acquiring exploration acreage and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be able to pay more for productive or prospective properties and prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry- wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. Our ability to acquire additional exploration prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to extensive local, state, federal and international regulations. We may be required to make large expenditures to comply with governmental regulations, particularly in respect of the following matters:

- licenses and leases for drilling operations;
- foreign exchange and banking;
- royalty increases, including retroactive claims;
- drilling and development bonds and social payment obligations;
- reports concerning operations;
- the spacing of wells;
- unitization of oil accumulations;
- environmental remediation or investigation; and
- taxation.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages for which we may not maintain, or otherwise be protected by, insurance coverage. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

For example, Angola has enacted a new Foreign Exchange Law for the Petroleum Sector, which requires, among other things, that all foreign exchange operations be carried out through Angolan banks, that oil and gas exploration and production companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas exploration and production companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. See "Business—Laws and Regulations of Angola and Gabon—Angola" for more information. These new rules require additional compliance efforts and costs on our and other industry participants' part, and may in some cases cause delay or other issues in connection with the acquisition of or payments for goods and services. Any of these consequences could have a material adverse effect on our results of operations.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas in increasingly difficult physical environments, such as below-salt deepwater, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. For example, in 2012, a wave of network attacks impacted Saudi Arabia's oil industry and breached financial institutions in the US. Certain countries, including China, Russia and Iran, are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

We and our operations are subject to numerous environmental, health and safety regulations which may result in material liabilities and costs.

We are, and our future operations will be, subject to various international, foreign, federal, state and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use and transportation of regulated materials and the health and safety of our employees. We are required to obtain various environmental permits from governmental authorities for our operations, including drilling permits for our wells. There is a risk that we have not been or will not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject. If we violate or fail to comply with these laws, regulations or permits, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain permits in a timely manner or at all (due to opposition from community or environmental interest groups, governmental delays, changes in laws or the interpretation thereof or any other reasons), such failure could impede our operations, which could have a material adverse effect on our results of operations and our financial condition.

We, as the named lessee or as the designated operator under our current and future oil leases and licenses, could be held liable for all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our third-party contractors. To the extent we do not address these costs and liabilities or if we are otherwise in breach of our lease or license requirements, our leases or licenses could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform the majority of the drilling and other services related to our operations. There is a risk that we may contract with third parties with unsatisfactory environmental, health and safety records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of the acts or omissions of our contractors, which could have a material adverse effect on our results of operations and financial condition.

As the designated operator of certain of our leases and licenses, we are required to maintain bonding or insurance coverage for certain risks relating to our operations, including environmental risks. We maintain insurance at levels that we believe are consistent with current industry practices, but we are not fully insured against all risks. Our insurance may not cover any or all environmental claims that might arise from our operations or those of our third-party contractors. If a significant accident or other event occurs and is not fully covered by our insurance, or our third-party contractors have not agreed to bear responsibility, such accident or event could have a material adverse effect on our results of operations and our financial condition. In addition, we may not be able to obtain required bonding or insurance coverage at all or in time to meet our anticipated startup schedule for each well, and if we fail to obtain this bonding or coverage, such failure could have a material adverse effect on our results of operations and financial condition.

Releases to deepwater of regulated substances are common, and under certain environmental laws, we could be held responsible for all of the costs relating to any contamination caused by us or our contractors, at our facilities and at any third party waste disposal sites used by us or on our behalf. These costs could be material. In addition, offshore oil exploration and production involves various hazards, including human exposure to regulated substances, including naturally occurring radioactive materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or other damage resulting from the release of regulated substances to the environment, endangered species, property or to natural resources.

Particularly since the Deepwater Horizon event in the U.S. Gulf of Mexico in 2010, there has been an increased interest in making regulation of deepwater oil and gas exploration and production more stringent in the U.S. If adopted, certain proposals such as a significant increase or elimination of financial liability caps for economic damages, could significantly raise daily penalties for infractions and require significantly more comprehensive financial assurance requirements under OPA which could affect our results of operations and our financial condition.

In addition, we expect continued attention to climate change issues. Various countries and U.S. states and regions have agreed to regulate emissions of greenhouse gases (“GHG”), including methane (a primary component of natural gas) and carbon dioxide, a byproduct of oil and natural gas combustion. Additionally, the U.S. Congress has in the past and may in the future consider legislation requiring reductions in GHG emissions. The EPA began regulating GHG emissions from certain stationary sources in January 2011 and has enacted GHG emissions standards for certain classes of vehicles. The EPA has adopted rules requiring the reporting of GHG emissions, including from certain offshore oil and natural gas production facilities on an annual basis. In addition, in accordance with the Obama Administration’s June 2013 Climate Action Plan (“CAP”), the EPA published proposed rules in January 2014 and June 2014 to regulate GHG emissions from new power plants and GHG emissions applicable to existing power plants, respectively. EPA announced it will finalize these proposals by summer 2015. The CAP also calls upon EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. On January 14, 2015, the White House unveiled these plans which, among other things directs the EPA to propose rules to regulate methane emissions from the oil and gas industry from new and modified sources by summer 2015, with a finalized rule in 2016. The EPA is also directed to expand the GHG Reporting Rule to cover all segments of the oil and gas industry. The regulation of GHGs and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future environmental, health and safety laws, and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and our financial condition. See “Business—Environmental Matters and Regulation.”

Non-U.S. holders of our common stock, in certain situations, could be subject to U.S. federal income tax upon the sale, exchange or other disposition of our common stock.

Our assets consist primarily of interests in U.S. oil and gas properties (which constitute U.S. real property interests for purposes of determining whether we are a U.S. real property holding corporation) and interests in non-U.S. oil and gas properties, the relative values of which at any time may be uncertain and may fluctuate significantly over time. Therefore, we may be, now or at any time while a non-U.S. investor owns our common stock, a U.S. real property holding corporation. As a result, under the Foreign Investment in Real Property Tax Act ("FIRPTA"), certain non-U.S. investors may be subject to U.S. federal income tax on gain from the disposition of shares of our common stock, in which case they would also be required to file U.S. tax returns with respect to such gain. Whether these FIRPTA provisions apply depends on the amount of our common stock that such non-U.S. investors hold and whether, at the time they dispose of their shares, our common stock is regularly traded on an established securities market (such as the New York Stock Exchange ("NYSE")) within the meaning of the applicable Treasury Regulations. So long as our common stock is listed on the NYSE, only a non-U.S. investor who has held, actually or constructively, more than 5% of our common stock may be subject to U.S. federal income tax on the disposition of our common stock under FIRPTA.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

Several external factors could arise which would significantly impact our ability to effectively insure our oil and natural gas exploration and development operations. Should legislation be passed to increase the minimum insurance limit of the OSFR policy required for future U.S. Gulf of Mexico oil and natural gas exploration, there is no assurance that we will be able to obtain this insurance. The insurance markets may not provide products to financially insure us against all operational risks. For instance, civil and criminal penalties for environmental pollution can be very severe and may not be insurable. For some risks, we may not obtain insurance if we believe the market price of available insurance is excessive or prohibitive relative to the risks presented. For instance, we do not purchase business interruption or wind insurance due to the market pricing.

Even when insurance is purchased, exclusions in coverage, unanticipated circumstances and potentially large indemnity obligations may have a material adverse effect on our operations and financial condition. Because third-party contractors and other service providers are used in our offshore operations, we may not realize the intended protections of worker's compensation laws in dealing with their employees. Generally, under our contracts with drilling and other oilfield service contractors, we are obligated, subject to certain exceptions and limitations, to indemnify such contractors for all claims arising out of damage to our property, injury or death to our employees and pollution emanating from the well-bore, including pollution resulting from blow-outs and uncontrolled flows of hydrocarbons.

Our level of indebtedness may increase and thereby reduce our financial flexibility.

We have issued $2.68 billion aggregate principal amount of convertible senior notes (the "notes"). The notes do not contain restrictive covenants, and we may incur significant additional indebtedness in the future in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets. Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows, if and when generated, could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;

- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing; and
- a high level of indebtedness may impair our ability to obtain additional financing in the future for our development projects, exploration drilling program, working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital.

The conditional conversion feature of our 3.125% senior convertibles notes due 2024, if triggered, may adversely affect our financial condition and operating results.

If the conditional conversion feature of our 3.125% senior convertibles notes due 2024 is triggered, holders of such notes will be entitled to convert these notes at any time during specified periods outlined in the indenture governing such notes, at their option. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of these notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

Conversions of the notes may adversely affect our financial condition and operating results.

Holders of notes will be entitled to convert the notes at their option at any time up until the maturity date, being December 1, 2019 for the 2.625% convertible senior notes due 2019 and May 15, 2024 for the 3.125% senior convertible notes due 2024. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of the notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

The accounting method for convertible debt securities that may be settled in cash, such as the notes, could have a material effect on our reported financial results.

Under Accounting Standards Codification 470-20, Debt with Conversion and Other Options, which we refer to as ASC 470-20, an entity must separately account for the liability and equity components of the convertible debt instruments (such as the notes) that may be settled entirely or partially in cash upon conversion in a manner that reflects the issuer's economic interest cost. The effect of ASC 470-20 on the accounting for the notes is that the equity component is required to be included in the additional paid-in capital section of stockholders' equity on our consolidated balance sheet, and the value of the equity component would be treated as original issue discount for purposes of accounting for the debt component of the notes. As a result, we will be required to record a greater amount of non-cash interest expense in current periods presented as a result of the amortization of the discounted carrying value of the notes to their face amount over the term of the notes. We will report lower net income in our financial results because ASC 470-20 will require interest to include both the current period's amortization of the debt discount and the instrument's coupon interest, which could adversely affect our reported or future financial results, the trading price of our common stock and the trading price of the notes.

We may account for the notes utilizing the treasury stock method. The effect of this method is that the shares issuable upon conversion of convertible securities are not included in the calculation of diluted earnings per share except to the extent that the conversion value of such securities exceeds their principal amount. Under the treasury stock method, for diluted earnings per share purposes, the notes would be accounted for as if the number of shares of common stock that would be necessary to settle such excess, if we elected to settle such excess in shares, are issued.

However, we cannot be sure that the accounting standards in the future will continue to permit the use of the treasury stock method. If we are unable to use the treasury stock method in accounting for the shares issuable upon conversion of the notes, for whatever reason, then we would have to apply the if-converted method, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings per share if the effect would be antidilutive. Under the if-converted method, for diluted earnings per share purposes, convertible debt is antidilutive whenever its interest, net of tax and nondiscretionary adjustments, per common share obtainable on conversion exceeds basic earnings per share. Dilutive securities that are issued during a period and dilutive convertible securities for which conversion options lapse, or for which related debt is extinguished during a period, will be included in the denominator of diluted earnings per share for the period that they were outstanding. Likewise, dilutive convertible securities converted during a period will be included in the denominator for the period prior to actual conversion. Moreover, interest charges applicable to the convertible debt will be added back to the numerator.

Risks Relating to our Common Stock

Our stock price may be volatile, and investors in our common stock could incur substantial losses.

Our stock price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common stock may be influenced by many factors, including, but not limited to:

- to what extent our exploration wells are successful;
- the price of oil and natural gas;
- the success of our development operations, and the marketing of any oil and gas we produce;
- regulatory developments in the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- increases in operating costs, including cost overruns associated with our exploration and development activities;

- analysts' reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- the issuance or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete and areas in which we operate; and
- general economic, political and market conditions.

A substantial portion of our total outstanding shares may be sold into the market at any time. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares sold in our public offerings are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all the remaining shares of common stock are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rules 144 or 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates, and other limitations under Rule 144. Additionally, we have registered all shares of our common stock that we may issue under our employee and director benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these stock awards have transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

Conversion of the notes may dilute the ownership interest of existing stockholders, including holders who have previously converted their notes.

The conversion of some or all of the notes may dilute the ownership interests of existing stockholders. Any sales in the public market of any shares of our common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the anticipated conversion of the notes into shares of our common stock or a combination of cash and shares of our common stock could depress the price of our common stock.

Holders of our common shares will be diluted if additional shares are issued.

We may issue additional shares of common stock, preferred stock, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We may issue additional shares of common stock in connection with complementary or strategic acquisitions of assets or businesses. We also issue restricted stock to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Ownership of our capital stock is concentrated among our largest stockholders and their affiliates.

A small number of stockholders hold a majority of our common stock. These stockholders have influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership may limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial. Furthermore, these stockholders may sell their shares of common stock at any time. Such sales could be substantial and adversely affect the market price of our common stock.

Provisions of our certificate of incorporation and by-laws could discourage potential acquisition proposals and could deter or prevent a change in control.

Some provisions in our certificate of incorporation and by-laws, as well as Delaware statutes, may have the effect of delaying, deferring or preventing a change in control. These provisions, including those providing for the possible issuance of shares of our preferred stock and the right of the board of directors to amend the by-laws, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire a substantial number of shares of our common stock or to launch other takeover attempts that a stockholder might consider to be in his or her best interest. These provisions could limit the price that some investors might be willing to pay in the future for shares of our common stock.

Provisions of the notes could discourage an acquisition of us by a third party.

Certain provisions of the notes could make it more difficult or more expensive for a third party to acquire us, or may even prevent a third party from acquiring us. For example, upon the occurrence of a fundamental change, holders of the notes will have the right, at their option, to require us to repurchase all of their notes or any portion of the principal amount of such notes in integral multiples of $1,000. In addition, the acquisition of us by a third party could require us, under certain circumstances, to increase the conversion rate for a holder who elects to convert its notes in connection with such acquisition. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common stock of an opportunity to sell their common stock at a premium over prevailing market prices.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Consequently, investors must rely on sales of their shares of common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Please refer to the information under the caption "Business" in this Annual Report on Form 10-K.

Item 3. ***Legal Proceedings***

We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business.

On November 30, 2014, two purported stockholders, St. Lucie County Fire District Firefighters' Pension Trust Fund and Fire and Police Retiree Health Care Fund, San Antonio, filed a class action lawsuit in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through November 4, 2014 (the "*St. Lucie* lawsuit"). The *St. Lucie* lawsuit, filed against us and certain officers, former and current members of the Board of Directors, underwriters, and investment firms and funds, asserts violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures, primarily regarding compliance with the U.S. Foreign Corrupt Practices Act ("FCPA") in our Angolan operations and the performance of certain wells offshore Angola. On December 4, 2014, Steven Neuman, a purported stockholder, filed a substantially similar lawsuit against us and certain of our officers in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through August 4, 2014 (the "*Neuman* lawsuit"). Like the *St. Lucie* lawsuit, the *Neuman* lawsuit asserts violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding our compliance with the FCPA in our Angolan operations. Among other remedies, both the *St. Lucie* and *Neuman* lawsuits seek damages in an unspecified amount, along with an award of attorney fees and other costs and expenses to the plaintiffs. Motions to consolidate the two actions are currently pending. The deadline to apply for appointment as lead plaintiff was February 2, 2015. The Court has set a scheduling conference on March 2, 2015 to consider all pending motions.

On January 16, 2015, Edward Ogden, a purported stockholder, filed a derivative action in the U.S. District Court for the Southern District of Texas against us, as a nominal defendant, and certain of our officers and former and current directors. The lawsuit alleges that the individual defendants breached their fiduciary duties, including in relation to compliance with the FCPA in our Angolan operations and regarding the performance of certain wells offshore Angola. The lawsuit further alleges that certain officers received performance-based compensation in excess of what they were entitled and that certain officers and directors engaged in unlawful trading. The lawsuit also alleges that the plaintiff was excused from making a demand on the basis of futility. The plaintiff asserts claims for breach of fiduciary duty, unjust enrichment, and corporate waste. The plaintiff seeks damages in an unspecified amount, disgorgement of profits, appropriate equitable relief, and an award of attorney fees and other costs and expenses. Based upon an agreement with the plaintiff, we are required to plead, answer, or otherwise respond to the lawsuit in March 2015.

We are vigorously defending against the current lawsuits and do not believe they will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations. For more information, see "Risk Factors—Risks Related to Our Business—We operate in a litigious environment."

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

Market Information

Our common stock is traded on the NYSE under the symbol "CIE." On January 30, 2015, the last reported sale price for our common stock on NYSE was $9.12 per share. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NYSE.

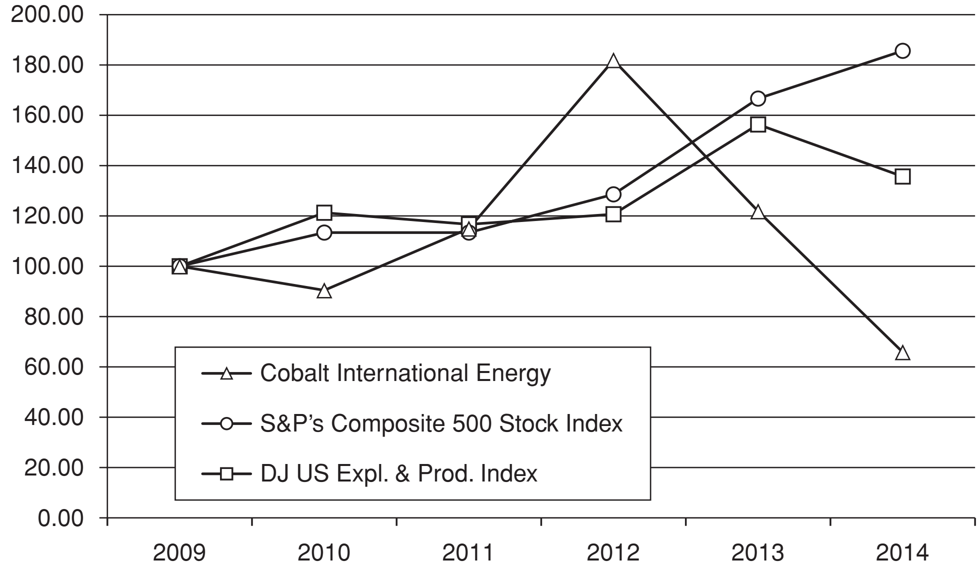
	High	Low
Year ending December 31, 2015		
First Quarter (through January 30, 2015)	$ 9.28	$ 7.77
Year ended December 31, 2014		
Fourth Quarter	$13.76	$ 7.40
Third Quarter	18.42	13.38
Second Quarter	19.77	16.90
First Quarter	19.90	15.36
Year ended December 31, 2013		
Fourth Quarter	$25.31	$13.75
Third Quarter	30.27	24.15
Second Quarter	29.34	24.65
First Quarter	28.56	22.25

Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that we specifically incorporate it by reference into such filing.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of our common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on our common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from

December 16, 2009, the date we commenced trading on the New York Stock Exchange, through December 31, 2014.



An investment of $100 is assumed to have been made in our common stock, in the S&P's Composite 500 Stock Index (with reinvestment of all dividends) and in the Dow Jones U.S. Exploration & Production Index on December 16, 2009, and its relative performance is tracked through December 31, 2014:

	As of December 16, 2009	Year Ended December 31, 2010	2011	2012	2013	2014
Cobalt International Energy, Inc.	$100.00	$ 90.44	$114.96	$181.93	$121.85	$ 65.85
S&P's Composite 500 Stock Index	100.00	113.38	113.38	128.58	166.64	185.62
Dow Jones U.S. Exploration & Production Index	100.00	121.27	116.66	120.68	156.35	135.67

Holders

As of December 31, 2014, there were approximately 192 holders of record of our common stock. The number of record holders does not include holders of shares in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

Dividend Policy

At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. The decision to pay dividends on our common stock is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant.

Equity Compensation Plan

For information on securities authorized under our equity compensation plans, see the section entitled "Executive Compensation—Equity Compensation Plan Information" in our definitive Proxy Statement for our annual meeting of stockholders to be held on April 30, 2015.

Item 6. *Selected Financial Data*

The selected historical financial information set forth below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with our financial statements and the notes to those financial statements included elsewhere in this Annual Report on Form 10-K. The consolidated statements of operations and cash flows information for the years ended December 31, 2014, 2013, 2012, 2011, and 2010 were derived from Cobalt International Energy, Inc.'s audited financial statements.

Consolidated Statement of Operations Information:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	($ in thousands except per share data)				
Oil and gas revenue	$ —	$ —	$ —	$ —	$ —
Operating costs and expenses					
Seismic and exploration	85,567	74,213	61,583	32,239	45,030
Dry hole expense and impairment	236,930	351,050	134,085	45,732	44,178
General and administrative	114,860	105,547	87,963	59,130	48,063
Depreciation and amortization	4,584	1,874	1,197	735	787
Total operating costs and expenses	441,941	532,684	284,828	137,836	138,058
Operating income (loss)	(441,941)	(532,684)	(284,828)	(137,836)	(138,058)
Other income (expense):					
Gain (loss) on sale of assets	(12)	2,993	—	—	—
Interest income	5,958	6,043	5,041	4,199	1,582
Interest expense	(74,768)	(65,376)	(3,212)	—	—
Total other income (expense)	(68,822)	(56,340)	1,829	4,199	1,582
Net income (loss) before income tax	(510,763)	(589,024)	(282,999)	(133,637)	(136,476)
Income tax expense (benefit)(1)	—	—	—	—	—
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)	$ (133,637)	$ (136,476)
Basic and diluted income (loss) per common share	$ (1.25)	$ (1.45)	$ (0.70)	$ (0.35)	$ (0.39)
Weighted average number of common shares—basic and diluted	407,116,144	406,839,997	403,356,174	376,603,520	349,342,050

(1) No income tax benefit has been reflected since a full valuation allowance has been established against the deferred tax asset that would have been generated as a result of the operating results.

Consolidated Balance Sheet Information:

	As of December 31,				
	2014	2013	2012	2011	2010
			($ in thousands)		
Cash and cash equivalents(1)	$ 258,721	$ 192,460	$1,425,815	$ 292,546	$ 302,720
Short-term restricted funds	45,062	200,339	90,440	69,009	—
Short-term investments(2)	1,530,206	1,319,380	789,668	858,293	534,933
Total current assets	2,003,134	1,967,443	2,456,742	1,335,094	889,632
Total property, plant and equipment(3)	1,932,361	1,476,275	1,099,756	863,326	463,769
Long-term restricted funds	105,051	104,496	395,652	270,235	338,515
Long-term investments	326,047	14,661	36,267	47,232	40,003
Total assets	4,450,863	3,633,673	4,011,459	2,527,944	1,746,443
Total current liabilities(4)	303,601	340,967	160,956	238,069	24,559
Total long term liabilities(5)	2,032,996	1,163,560	1,161,285	210,961	2,850
Total stockholders' equity	2,114,266	2,129,146	2,689,218	2,078,914	1,719,034
Total liabilities and stockholders' equity	4,450,863	3,633,673	4,011,459	2,527,944	1,746,443

(1) The decrease in cash and cash equivalents from December 31, 2012 to December 31, 2013 was primarily due to the investment in held-to-maturity securities from the proceeds we received upon the issuance of our 2.625% convertible senior notes due 2019 in December 2012. The increase in cash and cash equivalents from December 31, 2011 to December 31, 2012 was due to the proceeds that we received on December 17, 2012 from the issuance of our 2.625% convertible senior notes due 2019. These proceeds were temporarily held in money market funds as of December 31, 2012.

(2) The increase in short-term investments from December 31, 2013 to December 31, 2014 was attributable to the investment of the proceeds from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The increase in short-term investments from December 31, 2012 to December 31, 2013 was attributable to the investment of the proceeds from the issuance of our 2.625% convertible senior notes due 2019 in December 2012. The increase in investments from December 31, 2010 to December 31, 2011 was attributed to the investment of the proceeds from the equity offering of common stock during 2011.

(3) The increase from December 31, 2013 to December 31, 2014 reflects the capitalized costs for the Anchor #1 exploration well, the Orca #2 appraisal well, and the Heidelberg development costs. The increase from December 31, 2012 to December 31, 2013 primarily reflects the capitalized costs for the Mavinga #1, Lontra #1, Bicuar #1A, Orca #1 and Diaman #1B exploration wells. The increase from December 31, 2011 to 2012 reflects acquisition of unproved leases in the U.S. Gulf of Mexico and the capitalized costs for the Heidelberg #3 and Cameia #2 appraisal wells and the North Platte #1 exploration well. The increase from December 31, 2010 to December 31, 2011 reflects the acquisition costs of Block 20 offshore Angola.

(4) The increase in current liabilities at December 31, 2013 was due to year-end accruals for exploration costs primarily in West Africa and the short-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21. The decrease in current liabilities at December 31, 2012 was primarily attributed to the payment of certain bonus obligations for Block 20 during 2012. The increase in current liabilities at December 31, 2011 consists of year-end accruals for exploration costs in the U.S. Gulf of Mexico and West Africa and the short-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21.

(5) The significant increase in long-term liabilities from December 31, 2013 to December 31, 2014 reflects the issuance of $1.3 billion aggregate principal amount of the 3.125% convertible senior

notes due 2024 on May 13, 2014. The significant increase in long-term liabilities from December 31, 2011 to December 31, 2012 reflects the issuance of $1.38 billion aggregate principal amount of the 2.625% convertible senior notes due 2019 on December 17, 2012. The increase in long-term liabilities at December 31, 2011 reflects the long-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21.

Consolidated Statement of Cash Flows Information:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	($ in thousands)				
Net cash provided by (used in):					
Operating activities	$ (64,526)	$ (216,368)	$ (140,397)	$ (57,795)	$(133,264)
Investing activities	(1,138,393)	(1,015,995)	(564,761)	(430,391)	(758,372)
Financing activities	1,269,180	(992)	1,838,427	478,012	101,256

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

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements," and the other matters set forth in this Annual Report on Form 10-K. The following discussion of our financial condition and results of operations should be read in conjunction with our financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K, as well as the information presented under "Selected Financial Data." Due to the fact that we have not generated any revenues, we believe that the financial information contained in this Annual Report on Form 10-K is not indicative of, or comparable to, the financial profile that we expect to have once we begin to generate revenues. Except to the extent required by law, we undertake no obligation to update publicly any forward-looking statements for any reason, even if new information becomes available or other events occur in the future.

We are an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. Since our founding in 2005, our oil-focused, below-salt exploration efforts have been successful in each of our three operating areas, resulting in ten discoveries out of the seventeen exploration prospects drilled. These ten discoveries consist of North Platte, Heidelberg, Shenandoah and Anchor in the U.S. Gulf of Mexico; Cameia, Lontra, Mavinga, Bicuar and Orca offshore Angola; and Diaman offshore Gabon. In addition, we have an interest in the Yucatan discovery in the U.S. Gulf of Mexico.

Factors Affecting Comparability of Future Results

You should read this management's discussion and analysis of our financial condition and results of operations in conjunction with our historical financial statements included elsewhere in this Annual Report on Form 10-K. Below are the period-to-period comparisons of our historical results and the analysis of our financial condition. In addition to the impact of the matters discussed in "Risk Factors," our future results could differ materially from our historical results due to a variety of factors, including the following:

Success in the Discovery and Development of Oil and Gas Reserves. Because we have no operating history in the production of oil and gas, our future results of operations and financial condition will be directly affected by our ability to discover and develop reserves through our drilling activities. The calculation of our geological and petrophysical estimates is complex and imprecise, and it is possible that our future exploration will not result in additional discoveries, and, even if we are able to successfully make such discoveries, there is no certainty that the discoveries will be commercially viable to produce. Our results of operations will be adversely affected in the event that our estimated oil and gas asset base does not result in reserves that may eventually be commercially developed.

Oil and Gas Revenue. We have not yet commenced production activities. If and when we do commence production, we expect to generate revenue from such production. No oil and gas revenue is reflected in our historical financial statements.

Production Costs. We have not yet commenced production activities. If and when we do commence production, we will incur production costs. Production costs are the costs incurred in the operation of producing and processing our production and are primarily comprised of lease operating expense, workover costs and production and ad valorem taxes. No production costs are reflected in our historical financial statements.

General and Administrative Expenses. These costs include expenses associated with our staff costs, information technology, rent, travel, annual and quarterly reporting, investor relations, registrar and transfer agent fees, incremental insurance costs, and accounting and legal services.

Depreciation, Depletion and Amortization. We have not yet commenced production activities. If and when we do commence production, we will amortize the costs of successful exploration, appraisal, drilling and field development using the unit-of-production method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved and unproved leasehold properties and associated asset retirement costs will be amortized using the unit-of-production method based on total estimated proved developed and undeveloped reserves. No depletion of oil and gas properties is reflected in our historical financial statements.

Demand and Price. The demand for oil and gas is susceptible to volatility related to, among other factors, policy decisions by oil-producing nations, the level of global economic activity and may also fluctuate depending on the performance of specific industries. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for oil and gas we expect to produce. Since we have not generated revenues, these key factors will only affect our financial statements when we produce and sell hydrocarbons.

We expect to earn income from:

- domestic and international sales, which consist of sales of oil and natural gas;
- sales to international markets; and
- other sources, including services, investment income and foreign exchange gains.

We expect that our expenses will include:

- costs of sales (which are composed of production costs, insurance, and costs associated with the operation of our wells);
- maintenance and repair of property and equipment;
- costs of acquiring new leases or licenses;
- costs of acquiring seismic data;
- depreciation, amortization and impairment of fixed assets;
- depletion of oilfields;
- exploration costs;

- selling expenses (which include expenses relating to the transportation, marketing and distribution of our products) and general and administrative expenses; and
- interest expense and foreign exchange losses.

We expect that fluctuations in our financial condition and results of operations will be driven by a combination of factors, including:

- the volumes of oil and natural gas we produce and sell;
- changes in the domestic and international prices of oil and natural gas, which are denominated in U.S. dollars;
- fluctuations in the royalty rates on the leases that we hold;
- our success in future bidding rounds for licenses, leases and concessions;
- political and economic conditions in the countries in which we operate; and
- the amount of taxes and duties that we are required to pay with respect to our future operations, by virtue of our status as a U.S. company and our involvement in the oil and gas industry.

Results of Operations

We operate our business in two geographic segments: the U.S. Gulf of Mexico and West Africa. The discussion of the results of operations and the period-to-period comparisons presented below for each operating segment and our consolidated operations analyzes our historical results. The following discussion may not be indicative of future results.

Fiscal year ended December 31, 2014 as compared to year ended December 31, 2013

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase (Decrease)	Percentage Change
	($ in thousands)			
U.S. Gulf of Mexico Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	31,531	48,688	(17,157)	(35)%
Dry hole expense and impairment	133,223	207,039	(73,816)	(36)%
General and administrative	71,767	72,777	(1,010)	(1)%
Depreciation and amortization	1,693	1,328	365	27%
Total operating costs and expenses	**238,214**	**329,832**	**(91,618)**	**(28)%**
Operating income (loss)	**(238,214)**	**(329,832)**	**(91,618)**	**(28)%**
West Africa Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	54,036	25,525	28,511	112%
Dry hole expense and impairment	103,707	144,011	(40,304)	(28)%
General and administrative	43,093	32,770	10,323	32%
Depreciation and amortization	2,891	546	2,345	429%
Total operating costs and expenses	**203,727**	**202,852**	**875**	**0%**
Operating income (loss)	**(203,727)**	**(202,852)**	**875**	**0%**
Consolidated Operations:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	85,567	74,213	11,354	15%
Dry hole expense and impairment	236,930	351,050	(114,120)	(33)%
General and administrative	114,860	105,547	9,313	9%
Depreciation and amortization	4,584	1,874	2,710	145%
Total operating costs and expenses	**441,941**	**532,684**	**(90,743)**	**(17)%**
Operating income (loss)	**(441,941)**	**(532,684)**	**(90,743)**	**(17)%**
Other income (expense)				
Gain (loss) on sale of assets	(12)	2,993	(3,005)	(100)%
Interest income	5,958	6,043	(85)	(1)%
Interest expense	(74,768)	(65,376)	9,392	14%
Total other income (expense)	**(68,822)**	**(56,340)**	**12,482**	**22%**
Net income (loss) before income tax	**(510,763)**	**(589,024)**	**(78,261)**	**(13)%**
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$(510,763)**	**$(589,024)**	**$ (78,261)**	**(13)%**

U.S. Gulf of Mexico Segment:

Oil and gas revenue. We have not yet commenced production activities in the U.S. Gulf of Mexico. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2014 and 2013, respectively.

Operating costs and expenses. Our operating costs and expenses for our U.S. Gulf of Mexico operations consisted of the following during the years ended December 31, 2014 and 2013:

Seismic and exploration. Seismic and exploration costs decreased by approximately $17.2 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease was primarily due to a $20.2 million decrease in seismic costs offset by the increase of $0.7 million in delay rental and $2.3 million in exploration expenses attributed primarily to standby costs on the Ensco 8503 incurred during January 2014.

Dry hole expense and impairment. Dry hole expense and impairment decreased by $73.8 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease is due to impairment of unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2014	2013	Increase (Decrease)
	($ in thousands)		
Impairment of Unproved leasehold:			
Ardennes prospect	$ —	$ 29,122	$(29,122)
Aegean prospect	—	38,499	(38,499)
Other leasehold(1)	57,308	10,002	47,306
Amortization of leasehold with carrying value under $1 million	10,662	9,417	1,245
Dry Hole Expense:			
Ligurian #1 exploration well	46	631	(585)
Ardennes #1 exploration well	(133)	66,133	(66,266)
Aegean #1 exploration well	3,920	53,235	(49,315)
Anchor #1 exploration well	38,075	—	38,075
Yucatan #2 exploration well	17,313	—	17,313
Shenandoah by-pass #3 appraisal well	5,032	—	5,032
Other Impairments:			
Obsolete inventory	1,000	—	1,000
	$133,223	$207,039	$(73,816)

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs decreased by $1.0 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The decrease in general and administrative costs during this period was primarily attributed to a $10.2 million increase in staff related expenses which includes non-cash equity compensation and a $3.0 million increase in insurance and office support costs, offset by a decrease of $3.7 million in legal and consulting fees and an increase of $10.5 million in recoveries from partners associated with drilling activities.

Depreciation and amortization. Depreciation and amortization did not materially change during the year ended December 31, 2014 as compared to the year ended December 31, 2013.

West Africa Segment:

Oil and gas revenue. We have not yet commenced production activities in West Africa. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2014 and 2013.

Operating costs and expenses. Our operating costs and expenses for our West Africa operations consisted of the following during the years ended December 31, 2014 and 2013:

Seismic and exploration. Seismic and exploration costs increased by approximately $28.5 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The increase was primarily attributed to an increase of $37.6 million in exploration expenses, offset by a decrease of $9.1 million in seismic costs. During the year ended December 31, 2014, seismic and exploration expenses included $34.4 million in standby costs associated with the Ocean Confidence and SSV Catarina drilling rig, $5.6 million associated with the early contract termination of support vessels and helicopters, $1.4 million in custom fees and freight charges and $12.6 million in seismic costs. During the year ended December 31, 2013, seismic and exploration expenses included $3.8 million in standby costs associated with acceptance testing and drilling equipment issues with the Ocean Confidence drilling rig and $21.7 million in seismic costs.

Dry hole expense and impairment. Dry hole expense and impairment decreased by $40.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The decrease is due to dry hole expense during the years ended December 31, 2014 and 2013 as reflected in the following table:

	Year Ended December 31,		
	2014	2013	Increase (Decrease)
	($ in thousands)		
Impairment of Unproved Leasehold:			
Block 9 prospect	$ 2,500	$ —	$ 2,500
Dry Hole Expense(1):			
Cameia #2 drill stem test(2)	2,046	81,607	(79,561)
Diaman #1 exploration well	—	17,066	(17,066)
Mavinga #1 exploration well	—	12,520	(12,520)
Lontra #1 exploration well	—	32,247	(32,247)
Loengo #1 exploration well	52,672	—	52,672
Mupa #1 exploration well	46,489	—	46,489
Other Impairment:			
Obsolete inventory	—	571	(571)
	$103,707	$144,011	$(40,304)

(1) The amounts listed above and charged to dry hole expense for our Lontra #1 and Mavinga #1 exploration wells only relate to the costs associated with drilling the lowest intervals beneath the pay zones. The majority of the well costs associated with our Lontra #1 and Mavinga #1 exploration wells were capitalized as of December 31, 2013 and will remain suspended pending further evaluation of these wells. The amounts listed above for our Cameia #2 Drill Stem Test and Diaman #1, Loengo #1 and Mupa #1 exploration wells were abandoned and were charged to dry hole expense.

(2) The amounts listed above and charged to dry hole expense for the Cameia #2 drill stem test only relate to the costs associated with the testing of a geologic zone beneath the pay zone reservoirs encountered by the Cameia #1 and Cameia #2 wells.

General and administrative. General and administrative costs increased by $10.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in general and administrative costs during this period was primarily attributed to a $1.4 million increase in staff related expenses in Angola and $23.5 million in contractual charges from partners for overhead and technical charges, offset by a $13.2 million decrease in other office related expenses and a $1.4 million decrease for contractors and consulting services incurred in support of West Africa operations during the year ended December 31, 2014.

Depreciation and amortization. Depreciation and amortization increased by $2.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily attributed to the depreciation of $9.8 million of running tools and equipment over three years' estimated useful lives. We purchased the running tools and equipment for $3.5 million and $6.3 million during the years ended December 31, 2014 and 2013, respectively.

Consolidated:

Other income (expense). Other income (expense) increased by $12.5 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily due to a $9.4 million increase in interest expense associated with the issuance of the 3.125% convertible senior notes due 2024 on May 13, 2014 and a $3.1 million decrease in other income attributed to gain on sale of other assets during the year ended December 31, 2013.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $568.0 million and $461.6 million with a corresponding full valuation of $568.0 million and $461.6 million for the years ended December 31, 2014 and 2013, respectively.

Fiscal year ended December 31, 2013 as compared to year ended December 31, 2012

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase (Decrease)	Percentage Change
	($ in thousands)			
U.S. Gulf of Mexico Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	48,688	32,874	15,814	48%
Dry hole expense and impairment	207,039	134,085	72,954	54%
General and administrative	72,777	63,270	9,507	15%
Depreciation and amortization	1,328	967	361	37%
Total operating costs and expenses	**329,832**	**231,196**	**98,636**	43%
Operating income (loss)	**(329,832)**	**(231,196)**	**98,636**	43%
West Africa Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	25,525	28,709	(3,184)	(11)%
Dry hole expense and impairment	144,011	—	144,011	—%
General and administrative	32,770	24,693	8,077	33%
Depreciation and amortization	546	230	316	137%
Total operating costs and expenses	**202,852**	**53,632**	**149,220**	278%
Operating income (loss)	**(202,852)**	**(53,632)**	**149,220**	278%
Consolidated Operations:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	74,213	61,583	12,630	21%
Dry hole expense and impairment	351,050	134,085	216,965	162%
General and administrative	105,547	87,963	17,584	20%
Depreciation and amortization	1,874	1,197	677	57%
Total operating costs and expenses	**532,684**	**284,828**	**247,856**	87%
Operating income (loss)	**(532,684)**	**(284,828)**	**247,856**	87%
Other income (expense)				
Gain on sale of assets	2,993	—	2,993	—%
Interest income	6,043	5,041	1,002	20%
Interest expense	(65,376)	(3,212)	62,164	1935%
Total other income (expense)	**(56,340)**	**1,829**	**58,169**	3180%
Net income (loss) before income tax	**(589,024)**	**(282,999)**	**306,025**	108%
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$(589,024)**	**$(282,999)**	**$306,025**	108%

U.S. Gulf of Mexico Segment:

Oil and gas revenue. We have not yet commenced production activities in the U.S. Gulf of Mexico. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2013 and 2012.

Operating costs and expenses. Our operating costs and expenses for our U.S. Gulf of Mexico operations consisted of the following during the years ended December 31, 2013 and 2012:

Seismic and exploration. Seismic and exploration costs increased by approximately $15.8 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase was primarily due to a $16.6 million increase in seismic costs and a $0.3 million increase in delay rentals, offset by the decrease of $1.1 million in exploration expenses which were primarily attributable to standby and regulatory acceptance costs incurred for Ensco 8503 drilling rig during the year ended December 31, 2012. There were no standby costs incurred for the Ensco 8503 drilling rig during the year ended December 31, 2013.

Dry hole expense and impairment. Dry hole expense and impairment increased by $73.0 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase is due to impairment of unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2013	2012	Increase (Decrease)
	($ in thousands)		
Impairment of Unproved leasehold:			
Ligurian prospect	$ —	$ 41,861	$(41,861)
Ardennes prospect	29,122	—	29,122
Aegean prospect	38,499	—	38,499
Other leasehold(1)	10,002	8,298	1,704
Amortization of leasehold with carrying value under $1 million	9,417	10,007	(590)
Dry Hole Expense:			
Ligurian #1 exploration well	631	8,100	(7,469)
Ligurian #2 exploration well	—	48,994	(48,994)
Heidelberg #3 appraisal well side track	—	4,109	(4,109)
Shenandoah #2 appraisal well	—	12,716	(12,716)
Ardennes #1 exploration well	66,133	—	66,133
Aegean #1 exploration well	53,235	—	53,235
	$207,039	$134,085	$ 72,954

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs increased by $9.5 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in general and administrative costs during this period was primarily attributed to an $11.4 million increase in staff related expenses which includes non-cash equity compensation, a $12.9 million increase in legal and other consulting fees, an $8.0 million increase in insurance and office support costs, offset by an increase of $22.8 million in recoveries from partners due to the increase in drilling activities.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

West Africa Segment:

Oil and gas revenue. We have not yet commenced production activities in West Africa. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2013 and 2012.

Operating costs and expenses. Our operating costs and expenses for the West Africa operations consisted of the following during the years ended December 31, 2013 and 2012:

Seismic and exploration. Seismic and exploration costs decreased by approximately $3.2 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The decrease of $3.2 million was primarily attributed to an increase of $4.7 million in seismic costs, offset by a decrease of $7.9 million in other exploration costs. During the year ended December 31, 2012, approximately $11.7 million in standby costs were incurred associated with the drilling of the Cameia #2 appraisal well as compared to $3.6 million in standby costs incurred in early 2013 associated with drilling equipment issues with the Ocean Confidence drilling rig.

Dry hole expense and impairment. Dry hole expense and impairment increased by $144.0 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase is due to dry hole expense during the years ended December 31, 2013 as reflected in the following table:

	Year Ended December 31,		
	2013	2012	Increase (Decrease)
	($ in thousands)		
Dry Hole Expense(1):			
Cameia #2 drill stem test(2)	$ 81,607	$—	$ 81,607
Diaman #1 exploration well	17,066	—	17,066
Mavinga #1 exploration well	12,520	—	12,520
Lontra #1 exploration well	32,247	—	32,247
Other Impairment:			
Obsolete inventory	571	—	571
	$144,011	$—	$144,011

(1) The amounts listed above and charged to dry hole expense for our Lontra #1 and Mavinga #1 exploration wells only relate to the costs associated with drilling the lowest intervals beneath the pay zones. The majority of the well costs associated with our Lontra #1 and Mavinga #1 exploration wells have been capitalized as of December 31, 2013 and will remain suspended pending further evaluation of these wells. The amounts listed above for our Diaman #1 exploration well were charged to dry hole expense because this well encountered mechanical problems early in the drilling process and was re-spud as the Diaman #1B exploration well.

(2) The amounts listed above and charged to dry hole expense for the Cameia #2 drill stem test only relate to the costs associated with the testing of a geologic zone beneath the pay zone reservoirs encountered by the Cameia #1 and Cameia #2 wells.

General and administrative. General and administrative costs increased by $8.1 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in general and administrative costs during this period was primarily attributed to a $2.1 million increase in staff related expenses in Angola, a $4.5 million increase in other office related expenses and a $1.5 million increase for contractors and consulting services incurred in support of West Africa operations during the year ended December 31, 2013.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Consolidated:

Other income (expense). Other income (expense) increased by $58.2 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase was primarily due to the increase of $1.0 million from interest earned in investment securities and $3.0 million in gain on sale of other assets, offset by $62.2 million recognized for the interest expense associated with our 2.625% convertible senior notes due 2019 during the year ended December 31, 2012.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $568.0 million and $461.6 million with a corresponding full valuation of $568.0 million and $269.6 million for the years ended December 31, 2013 and 2012, respectively.

Liquidity and Capital Resources.

Our Heidelberg project was sanctioned in mid-2013, and the operator currently estimates first production from Heidelberg in the first half of 2016. We continue to advance our Cameia project through the project development life-cycle. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Given the current commodity price environment, we believe an opportunity exists to review the project design concept and projected capital expenditures in order to optimize the cost and scale of the Cameia development and production facilities prior to formal project sanction. During 2015, we intend to pursue project cost reductions in light of the current weakness in the market for goods and services utilized in major offshore development projects. We remain committed to progressing the Cameia development towards project sanction and production, and, to that end, we plan to spud the first of several planned Cameia development wells in the first quarter of 2015. We expect to achieve formal project sanction of Cameia by year-end 2015, and first production from Cameia will likely occur in 2018. The occurrence and timing of project sanction and first production from Cameia is subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum.

Until substantial production is achieved, our primary sources of liquidity are expected to be cash on hand, amounts paid pursuant to the terms of our Total alliance and funds from any future equity and debt financings, asset-based ventures and asset monetizations.

We expect to incur substantial expenditures and generate significant operating losses as we continue to:

- evaluate each of our discoveries through project appraisal and potential development towards first production and cash flow;
- continue our exploration activity on our existing acreage;
- seek the renewal of our worldwide exploration portfolio in locations applicable to our deepwater and below-salt exploration strength; and
- incur expenses related to operating as a public company and compliance with regulatory requirements.

Our future financial condition and liquidity will be impacted by, among other factors, our ability to obtain financing, oil and gas prices, the success of our project development and exploration efforts, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed with which we can bring such discoveries to production, whether and to what extent we invest in additional oil leases and concessional licenses, and the actual cost of exploration, appraisal and development of our prospects.

As of December 31, 2014, we had approximately $2.3 billion in liquidity, which includes cash and cash equivalents, short-term restricted cash, short-term investments, long-term restricted cash and long-term investments. This amount does not include amounts Total is obligated to pay us pursuant to the terms of our U.S. Gulf of Mexico alliance. We expect to expend approximately $800 to $900 million for our capital and operating expenditures in 2015. Given our exploration success, our focus has now shifted towards selectively developing our discoveries with the aim to turn them into production. Thus, we currently expect to allocate approximately 80% of our planned 2015 capital and operating expenditure budget toward project appraisal and development activities. Our capital and operating expenditures were approximately $829 million for the full-year ended December 31, 2014. Our capital and operating expenditures exclude interest payments, Angolan social contributions and items amortized in future years' operations. We expect to use approximately $200 million for these items in 2015. We expect that our existing cash on hand will be sufficient to fund our planned exploration and appraisal drilling program and development activities at current working interests through at least 2016.

On February 19, 2015 we executed a commitment letter with Société Générale and certain of its affiliates for a limited recourse $150 million senior secured reserve-based loan facility to fund the majority of our share of the remaining Heidelberg field development costs. It is anticipated that the facility will be further syndicated. The commitments are subject to the negotiation and execution of definitive loan documentation and other customary conditions.

We are currently pursuing certain asset-based ventures and monetizations to fund our long-term project appraisal, development and exploration activities. We may also seek additional funding through equity and debt financings. Additional funding, including funding through any asset-based venture or monetization, may not be available to us on acceptable terms or at all. In addition, the terms of any financing may adversely affect the holdings or the rights of our existing stockholders. For example, if we raise additional funds by issuing additional equity securities, further dilution to our existing stockholders will result. If we are unable to obtain funding on a timely basis or on acceptable terms, we may be required to significantly curtail our exploration, appraisal and development activities. Any asset-based venture or monetization may also require us to relinquish rights to some of our development projects or exploration prospects which we would otherwise develop on our own, or with a majority working interest.

Cash Flows

	Year Ended December 31.		
	2014	2013	2012
		($ in thousands)	
Net cash provided by (used in):			
Operating Activities	$ (64,526)	$ (216,368)	$ (140,397)
Investing Activities	(1,138,393)	(1,015,995)	(564,761)
Financing Activities	1,269,180	(992)	1,838,427

Operating activities. Net cash of $64.5 million, $216.4 million and $140.4 million used in operating activities during 2014, 2013 and 2012, respectively, were primarily related to cash payments for seismic expenses, exploration expenses and inventory incurred in the U.S. Gulf of Mexico and in West Africa

Investing activities. Net cash used in investing activities in 2014 was approximately $1.1 billion, compared with net cash used in investing activities of approximately $1.0 billion and $564.8 million in 2013 and 2012, respectively. The net cash used in 2014 primarily relates to capital expenditures incurred for the Shenandoah #3 appraisal well, Shenandoah #3 appraisal well by-pass, Anchor #1, Anchor #2 and Yucatan #2 exploration wells and the Heidelberg development project in the deepwater U.S. Gulf of Mexico and the Cameia #3 appraisal well, Loengo #1 and Mupa #1 exploration wells offshore Angola, and purchase of investment securities from the net proceeds of the 3.125% convertible senior notes due 2024. The net cash used in 2013 primarily relates to capital expenditures relating to the Ardennes #1 and Aegean #1 exploration wells in the deepwater U.S. Gulf of Mexico and the Mavinga #1, Lontra #1, Bicuar #1A and Diaman #1B exploration wells offshore Angola. The net cash used in 2012 primarily relates to capital expenditures for the North Platte #1 exploration well in the deepwater U.S. Gulf of Mexico and the Cameia #1 exploration well and Cameia #2 appraisal well offshore Angola.

Financing activities. Net cash provided by financing activities in 2014 was approximately $1.3 billion, compared with net cash used by financing activities of approximately $1.0 million and net cash provided by financing activities of $1.8 billion in 2013 and 2012, respectively. The $1.3 billion in net cash provided by financing activities in 2014 relates to net proceeds we received from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The $1.0 million net cash used in financing activities relates to the debt issuance costs paid during 2013. The $1.8 billion in net cash provided by financing activities in 2012 was attributed to the net proceeds we received from the issuance of our 2.625% convertible senior notes due 2019 in December 2012 and our public offering of common stock in February 2012.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2014:

	Payments Due By Year						
	2015	2016	2017	2018	2019	Thereafter	Total
	($ in thousands)						
Drilling Rig and Related Contracts	$544,559	$299,702	$208,104	$ 17,104	$ —	$ —	$1,069,469
Operating Leases	9,755	4,801	2,309	2,369	2,405	5,626	27,265
Lease Rentals(1)	7,353	5,460	5,007	2,282	1,973	7,223	29,298
Social and Work Program Payment Obligations(2)	55,999	84,729	5,714	5,714	—	—	152,156
Long-term Debt Obligations(3):							
Principal	—	—	—	—	1,380,000	1,300,000	2,680,000
Interest	76,850	76,850	76,850	76,850	76,850	177,596	561,846
Total	**$694,516**	**$471,542**	**$297,984**	**$104,319**	**$1,461,228**	**$1,490,445**	**$4,520,034**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to our U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

(2) Includes our contractual payment obligations for (i) social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that we were and are contractually obligated to pay in consideration for the Angolan government granting us the licenses to explore for and develop hydrocarbons offshore Angola and (ii) our remaining work program obligations on Block 9 offshore Angola. Pursuant to the terms of the RSAs for Blocks 9 and 21 and the PSC for Block 20, we are not required to pay annual rental payments to maintain the licenses from year to year.

(3) Represents principal amounts of our 2.625% convertible senior notes due 2019 and our 3.125% convertible senior notes due 2024 and interest payable semi-annually in arrears.

In the future, we may be party to additional contractual arrangements including but not limited to arrangements listed below, which will subject us to further contractual obligations:

- credit facilities and other debt instruments;
- contracts for the lease of additional drilling rigs;
- contracts for the provision of production facilities;
- infrastructure construction contracts; and
- long term oil and gas property lease arrangements.

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We plan to follow the "sales" (or cash) method of accounting for oil and gas revenues. Under this method, we will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the year ended December 31, 2014, no revenues have been recognized in our financial statements.

We recognize interest income on bank balances and deposits on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however we periodically assess the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believe that the credit risk is minimal.

Investments. We adopted a policy on accounting for our investments, which consist entirely of debt securities based on the accounting guidance relating to "*Accounting for Certain Investments in Debt and Equity Securities*." The debt securities are carried at amortized costs and classified as held-to-maturity as we have the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Money market funds and certificates of deposit are carried at face value.

We conduct a regular assessment of our debt securities with unrealized losses to determine whether securities have other-than-temporary impairment. This assessment considers, among other factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether we intend to sell or whether it is more likely than not that we will be required to sell the debt securities.

Property, Plant and Equipment. We use the "successful efforts" method of accounting for our oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes are capitalized and amortized over the proved developed reserves on a units-of-production basis. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed on an individual basis periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological, and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Inventory. Inventories consist of various tubular products that will be used in our drilling programs. The inventory is stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

Income Taxes. We applied the liability method of accounting for income taxes in accordance with accounting guidance relating to "*Income Taxes*" as clarified by *Accounting for Uncertainty in Income Taxes*. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since we are in development stage and there can be no assurance that we will generate any earnings or any specific level of earnings in future years, we will establish a valuation allowance for deferred tax assets (net of liabilities).

Use of Estimates. The preparation of our consolidated financial statements in conformity with United States generally accepted accounting principles requires us to make estimates and assumptions that impact our reported assets and liabilities, disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include: (i) accruals related to expenses, (ii) assumptions used in estimating fair value of equity-based awards and the fair value of the liability component of the convertible senior notes and (iii) assumptions used in impairment testing. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Estimates of Proved Oil & Natural Gas Reserves. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As of December 31, 2014, we have proved undeveloped reserves in the U.S. Gulf of Mexico. Estimated reserve quantities and future cash flows were estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. The accuracy of these reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating cost, severance taxes, development cost and workover cost, all of which may in fact vary considerably from actual results;
- the accuracy of various mandated economic assumptions (such as the future prices of oil and natural gas); and
- the judgments of the persons preparing the estimates.

Asset Retirement Obligations. We currently do not have any oil and natural gas production or any legal obligations to incur decommissioning costs. Should such production occur in the future, we expect to have significant obligations under our lease agreements and federal regulation to remove our equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations ("ARO") are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Pursuant to the accounting guidance relating to "*Asset Retirement Obligations,*" we are required to record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties representing asset retirement costs on our balance sheet. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, we will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the consolidated statement of operations.

Earnings (Loss) Per Share. Basic earnings (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings (loss) per share incorporate the potential dilutive impact of our 2.625% convertible senior notes due 2019, our 3.125% convertible senior notes due 2024, stock options, unvested restricted stock and restricted stock units outstanding during the periods presented, unless their effect is anti-dilutive. In addition, we apply the if-converted method to our convertible debt instruments, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings (loss) per share if the effect would be anti-dilutive.

Equity-Based Compensation. We account for stock-based compensation at fair value. We grant various types of stock-based awards including stock options, restricted stock and performance-based awards. The fair value of stock option awards is determined by using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of our common stock on the grant date. We record compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when we determine that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risks" refers to the risk of loss arising from changes in commodity prices, interest rates, foreign currency exchange rates, and other relevant market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments will be entered into for purposes of risk management and not for speculation.

Due to the historical volatility of commodity prices, if and when we commence production, we may enter into various derivative instruments to manage our exposure to volatility of commodity market prices. We may use options (including floors and collars) and fixed price swaps to mitigate the impact of downward swings in commodity prices to our cash flow. All contracts will be settled with cash and would not require the delivery of physical volumes to satisfy settlement. While in times of higher commodity prices this strategy may result in our having lower net cash inflows than we would otherwise have if we had not utilized these instruments, management believes the risk reduction benefits of such a strategy would outweigh the potential costs.

We may borrow under fixed rate and variable rate debt instruments that give rise to interest rate risk. Our objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing our costs of capital.

Item 8. ***Financial Statements and Supplementary Data***

The information required is included in this report as set forth in the "Index to Consolidated Financial Statements" on page F-1 to this Annual Report on Form 10-K.

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

None

Item 9A. ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2014, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and our Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Because of the inherent limitation in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2014.

Management's Report on Internal Control over Financial Reporting

The information required to be furnished pursuant to this item is set forth under the caption "Management's Report on Internal Control over Financial Reporting" in Item 8 of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The information required to be furnished pursuant to this item is set forth under the caption "Report of Independent Registered Public Accounting Firm" in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

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

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is set forth under the captions "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement (the "2015 Proxy Statement") for our annual meeting of stockholders to be held on April 30, 2015, which sections are incorporated herein by reference.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this Annual Report on Form 10-K.

Item 11. ***Executive Compensation***

The information required by this item is set forth in the sections entitled "Election of Directors—Director Compensation," "Executive Compensation" and "Corporate Governance" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

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

The information required by this item is set forth in the sections entitled "Security Ownership of Certain Beneficial Owners and Management" and "Executive Compensation—Equity Compensation Plan Information" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

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

The information required by this item is set forth in the section entitled "Corporate Governance" and "Certain Relationships and Related Transactions" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services***

The information required by this item is set forth in the section entitled "Ratification of Appointment of Independent Auditors" in the 2015 Proxy Statement, which section is incorporated herein by reference.

GLOSSARY OF SELECTED OIL AND GAS TERMS

"2-D seismic data"	Two-dimensional seismic data, being an interpretive data that allows a view of a vertical cross-section beneath a prospective area.
"3-D seismic data"	Three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic data.
"Angola PAL"	Angola Petroleum Activities Law.
"Appraisal well"	A well drilled after an exploration well to gain more information on the drilled reservoirs.
"Barrel"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"Bbl"	Barrel.
"Bcf"	Billion cubic feet.
"Below-salt"	A term encompassing both subsalt, as used in connection with the U.S. Gulf of Mexico, and pre-salt, as used in connection with offshore West Africa.
"Block 9 RSA"	Risk Service Agreement governing Block 9 offshore Angola.
"Block 21 RSA"	Risk Service Agreement governing Block 21 offshore Angola.
"Block 20 PSC"	Production Sharing Contract governing Block 20 offshore Angola.
"Blowouts"	Blowout is the uncontrolled release of a formation fluid, usually gas, from a well being drilled, typically for petroleum production.
"BOEPD"	Barrels of oil equivalent per day. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"BOPD"	Barrels of oil per day.
"Btu"	British thermal unit.
"Completion"	The procedure used in finishing and equipping an oil or natural gas well for production.

"Delay rental"	Payment made to the lessor under a non-producing oil and natural gas lease at the beginning or end of each year to continue the lease in force for another year during its primary term.
"Development"	The phase in which an oil field is brought into production by drilling development wells and installing appropriate production systems.
"Development well"	A well drilled to a known formation in a discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.
"Drilling and completion costs"	All costs, excluding operating costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all labor and other construction and installation costs incident thereto, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, costs of plugging back, deepening, rework operations, repairing or performing remedial work of any type, costs of plugging and abandoning any well participated in by us, and reimbursements and compensation to well operators.
"Dry hole"	An exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
"DST"	Drill stem test
"E&P"	Exploration and production.
"EPSC"	Exploration and Production Sharing Contract.
"Exploration well"	A well drilled either (a) in search of a new and as yet undiscovered pool of oil or natural gas or (b) with the hope of significantly extending the limits of a pool already developed.
"Farm-out"	An agreement whereby the owner of the leasehold or working interest agrees to assign a portion of his interest in certain acreage subject to the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farm-out, the owner of the leasehold or working interest may retain some interest such as an overriding royalty interest, an oil and natural gas payment, offset acreage or other type of interest.
"Field"	A geographical area under which an oil or natural gas reservoir lies in commercial quantities.
"FERC"	Federal Energy Regulatory Commission
"FPSO"	Floating Production, Storage and Offloading system.
"Gathering system"	Pipelines and other facilities that transport oil from wells and bring it by separate and individual lines to a central delivery point for delivery into a transmission line or mainline.
"Gross acre"	An acre in which a working interest is owned. The number of gross acres is the total number of acres in which an interest is owned.

"Horizon"	A zone of a particular formation; that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.
"IQE"	Independent Qualified Estimator.
"Leases"	Full or partial interests in oil or natural gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas upon payment of rental, bonus, royalty or any other payments.
"MBOE"	Thousand barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"MMBOE"	Million barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"Mcf"	Thousand cubic feet.
"MMBbls"	Million barrels.
"MMBtu"	Million British thermal units.
"MMCFD"	Million cubic feet per day.
"Natural gas"	Natural gas is a combination of light hydrocarbons that, in average pressure and temperature conditions, is found in a gaseous state. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.
"Net pay thickness"	The vertical extent of the effective hydrocarbon-bearing rock (expressed in feet). The net pay thickness encountered by an exploration well may differ from the mean net pay thickness of the prospect due to several factors, including the relative location of the exploration well on the structure, potential thickness variations that may occur across the prospect and the extent to which potential reservoir horizons are penetrated.
"NORM"	Naturally occurring radioactive materials.
"NSAI"	Netherland, Sewell & Associates, Inc.
"Oil and natural gas lease"	A legal instrument executed by a mineral owner granting the right to another to explore, drill, and produce subsurface oil and natural gas. An oil and natural gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee.
"OPEC"	Organization of the Petroleum Exporting Countries.
"Operator"	A party that has been designated as manager for exploration, drilling, and/or production on a lease. The operator is the party that is responsible for (a) initiating and supervising the drilling and completion of a well and/or (b) maintaining the producing well.

"Play"	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.
"Porosity"	Porosity is the percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be a relic of deposition (primary porosity, such as space between grains that were not compacted together completely) or can develop through alteration of the rock (secondary porosity, such as when feldspar grains or fossils are preferentially dissolved from sandstones).
"Productive well"	A well that has been drilled to the targeted depth and proves, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well.
"Prospect(s)"	Potential trap which may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of them fail neither oil nor natural gas will be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"PSA"	Production Sharing Agreement.
"PV-10"	Present value of future net pre-tax cash flows attributable to our estimated net proved reserves (after deducing future development and production costs), discounted at 10% per annum.
"Reservoir"	A subsurface body of rock having sufficient porosity and permeability to store and to allow for the mobility of fluids/ hydrocarbons included in its pores.
"Royalty"	A fractional undivided interest in the production of oil and natural gas wells, or the proceeds therefrom to be received free and clear of all costs of development, operations or maintenance.
"RPC"	Reserves Process Chair.
"SEC"	United States Securities and Exchange Commission.
"Shut in"	To close the valves on a well so that it stops producing.
"Spud"	The very beginning of drilling operations of a new well, occurring when the drilling bit penetrates the surface utilizing a drilling rig capable of drilling the well to the authorized total depth.

"Standardized Measure"	The present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows.
"Working interest"	An interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.
"Workover"	Operations on a producing well to restore or increase production.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

Cobalt International Energy, Inc.

(2) Financial Statement Schedule

Not applicable.

(3) Exhibits

The following exhibits are filed with this Annual Report on Form 10-K or incorporated by reference:

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.2	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.3	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))

Exhibit Number	Description of Document
10.4	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.5	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.6	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.7	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.8	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.10	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.11	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.12	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.13	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.14	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.15†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

Exhibit Number	Description of Document
10.17†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.18†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.19†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.20†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.21†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.22†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.23†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.24†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.25†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.26†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.28†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.29†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.30†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.31†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))

Exhibit Number	Description of Document
10.32†	Form of Restricted Stock Unit Award Notification under the Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.33†*	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield
10.34†*	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth
10.35†*	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter
10.36†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2015
10.37†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015
10.38†*	Form of Stock Appreciation Right Award Agreement under the Company's Long Term Incentive Plan
10.39†*	Form of Restricted Stock Unit Award Agreement under the Company's Long Term Incentive Plan
10.40†*	Form of Restricted Stock Award Agreement under the Company's Long Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

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.

Cobalt International Energy, Inc.

By: /s/ JOSEPH H. BRYANT

Name: Joseph H. Bryant
Title: *Chairman of the Board of Directors and Chief Executive Officer*

Dated: February 23, 2015

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

Signature	Title	Date
/s/ JOSEPH H. BRYANT Joseph H. Bryant	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 23, 2015
/s/ JOHN P. WILKIRSON John P. Wilkirson	Chief Financial Officer and Executive Vice President (Principal Financial Officer and Principal Accounting Officer)	February 23, 2015
/s/ JACK E. GOLDEN Jack E. Golden	Director	February 23, 2015
/s/ KAY BAILEY HUTCHISON Kay Bailey Hutchison	Director	February 23, 2015
/s/ JON A. MARSHALL Jon A. Marshall	Director	February 23, 2015
/s/ KENNETH W. MOORE Kenneth W. Moore	Director	February 23, 2015

Signature	Title	Date
/s/ MYLES W. SCOGGINS Myles W. Scoggins	Director	February 23, 2015
/s/ WILLIAM P. UTT William P. Utt	Director	February 23, 2015
/s/ D. JEFF VAN STEENBERGEN D. Jeff van Steenbergen	Director	February 23, 2015
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Director	February 23, 2015

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
COBALT INTERNATIONAL ENERGY, INC

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by Securities and Exchange Commission rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

There are inherent limitations to the effectiveness of internal control over financial reporting, however well designed, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that an internal control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2014. The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

/s/ JOSEPH H. BRYANT

Joseph H. Bryant
Chairman of the Board of Directors and Chief Executive Officer

/s/ JOHN P. WILKIRSON

John P. Wilkirson
Chief Financial Officer and Executive Vice President

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2014, 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). Cobalt International Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed 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, Cobalt International Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2014 consolidated financial statements of Cobalt International Energy, Inc. and our report dated February 23, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2015

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited the accompanying consolidated balance sheets of Cobalt International Energy, Inc. (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cobalt International Energy, Inc. at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, 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), Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2014, 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 23, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2015

Cobalt International Energy, Inc.

Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
	($ in thousands, except per share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 258,721	$ 192,460
Joint interest and other receivables	59,974	124,639
Prepaid expenses and other current assets	14,497	55,857
Inventory	94,674	74,768
Short-term restricted funds	45,062	200,339
Short-term investments	1,530,206	1,319,380
Total current assets	2,003,134	1,967,443
Property, plant, and equipment:		
Oil and gas properties, successful efforts method of accounting, net of accumulated depletion of $0	1,920,979	1,464,383
Other property and equipment, net of accumulated depreciation and amortization of $8,977 and $4,394, as of December 31, 2014 and 2013, respectively	11,382	11,892
Total property, plant, and equipment, net	1,932,361	1,476,275
Long-term restricted funds	105,051	104,496
Long-term investments	326,047	14,661
Deferred income taxes	30,334	17,061
Other assets	53,936	53,737
Total assets	$ 4,450,863	$ 3,633,673
Liabilities and Stockholders' Equity		
Current liabilities:		
Trade and other accounts payable	$ 8,010	$ 131,428
Accrued liabilities	214,972	143,459
Short-term contractual obligations	50,285	49,019
Deferred income taxes	30,334	17,061
Total current liabilities	303,601	340,967
Long-term debt	1,928,528	1,035,980
Long-term contractual obligations	101,945	124,901
Other long-term liabilities	2,523	2,679
Total long-term liabilities	2,032,996	1,163,560
Stockholders' equity:		
Common stock, $0.01 par value per share; 2,000,000,000 shares authorized 408,505,079 and 406,949,839 issued and outstanding as of December 31, 2014 and 2013, respectively	4,085	4,069
Additional paid-in capital	4,137,803	3,641,936
Accumulated deficit during the development stage	(2,027,622)	(1,516,859)
Total stockholders' equity	2,114,266	2,129,146
Total liabilities and stockholders' equity	$ 4,450,863	$ 3,633,673

See accompanying notes.

Cobalt International Energy, Inc.

Consolidated Statements of Operations

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands except per share data)		
Oil and gas revenue	$ —	$ —	$ —
Operating costs and expenses:			
Seismic and exploration	85,567	74,213	61,583
Dry hole expense and impairment	236,930	351,050	134,085
General and administrative	114,860	105,547	87,963
Depreciation and amortization	4,584	1,874	1,197
Total operating costs and expenses	441,941	532,684	284,828
Operating income (loss)	(441,941)	(532,684)	(284,828)
Other income (expense):			
Gain (loss) on sale of assets	(12)	2,993	—
Interest income	5,958	6,043	5,041
Interest expense	(74,768)	(65,376)	(3,212)
Total other income (expense)	(68,822)	(56,340)	1,829
Net income (loss) before income tax	(510,763)	(589,024)	(282,999)
Income tax expense	—	—	—
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)
Basic and diluted income (loss) per common share	$ (1.25)	$ (1.45)	$ (0.70)
Basic and diluted weighted average common shares outstanding	407,116,144	406,839,997	403,356,174

See accompanying notes.

Cobalt International Energy, Inc.

Consolidated Statements of Changes in Stockholders' Equity

	Common Stock	Additional Paid-in Capital	Accumulated Deficit During Development Stage	Total
	($ in thousands)			
Balance, December 31, 2011	$3,875	$2,719,875	$ (644,836)	$2,078,914
Common stock issued at public offering, net of costs	181	489,128	—	489,309
Common stock issued for restricted stock and restricted stock units	10	(10)	—	—
Equity based compensation	—	22,410	—	22,410
Exercise of stock options	—	338	—	338
Common stock withheld for taxes on equity based compensation	—	(170)	—	(170)
Conversion option relating to 2.625% convertible senior notes due 2019, net of allocated costs	—	381,416	—	381,416
Net income (loss)	—	—	(282,999)	(282,999)
Balance, December 31, 2012	$4,066	$3,612,987	$ (927,835)	$2,689,218
Common stock issued for restricted stock and stock options	3	(3)	—	—
Equity based compensation	—	28,754	—	28,754
Exercise of stock options	—	198	—	198
Net income (loss)	—	—	(589,024)	(589,024)
Balance, December 31, 2013	$4,069	$3,641,936	$(1,516,859)	$2,129,146
Common stock issued for restricted stock and stock options	16	(16)	—	—
Equity based compensation	—	31,742	—	31,742
Exercise of stock options	—	33	—	33
Common stock withheld for taxes on equity based compensation	—	(630)	—	(630)
Conversion option relating to 3.125% convertible senior notes due 2024, net of allocated costs	—	464,738	—	464,738
Net income (loss)	—	—	(510,763)	(510,763)
Balance, December 31, 2014	$4,085	$4,137,803	$(2,027,622)	$2,114,266

See accompanying notes.

Cobalt International Energy, Inc.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2014	2013	2012
		($ in thousands)	
Cash flows provided from operating activities			
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation and amortization	4,584	1,874	1,197
Dry hole expense and impairment	236,930	351,050	134,085
Gain on sale of assets	—	(2,993)	—
Equity based compensation	31,742	28,754	22,410
Amortization of premium (accretion of discount) on investments	18,159	21,955	15,091
Amortization of debt discount	71,330	46,847	—
Changes in operating assets and liabilities:			
Joint interest and other receivables	64,679	(62,967)	(1,518)
Inventory	(20,906)	(10,052)	(29,237)
Prepaid expense and other current assets	41,359	(31,915)	(1,726)
Deferred charges	15,980	(32,753)	(10,985)
Trade and other accounts payable	(64,369)	63,552	(3,309)
Accrued liabilities and other	46,749	(696)	16,594
Net cash provided by (used in) operating activities	(64,526)	(216,368)	(140,397)
Cash flows from investing activities			
Capital expenditures for oil and gas properties	(70,639)	(80,439)	(142,841)
Capital expenditures for other property and equipment	(4,074)	(8,483)	(5,139)
Exploration wells drilling in process	(678,017)	(581,194)	(329,534)
Proceeds from sale of oil and gas properties	—	3,006	—
Change in restricted funds	43,667	180,729	29,573
Proceeds from maturity of investment securities	1,700,123	1,366,977	1,082,876
Purchase of investment securities	(2,129,453)	(1,896,591)	(1,199,696)
Net cash provided by (used in) investing activities	(1,138,393)	(1,015,995)	(564,761)
Cash flows from financing activities			
Proceeds from public offering, net of costs	—	—	489,309
Proceeds from debt offering, net of costs	1,269,778	(1,190)	1,348,950
Proceed from exercise of stock options	33	198	338
Payments for common stock withheld for taxes on equity based compensation	(631)	—	(170)
Net cash provided by (used in) financing activities	1,269,180	(992)	1,838,427
Net increase (decrease) in cash and cash equivalents	66,261	(1,233,355)	1,133,269
Cash and cash equivalents, beginning of period	192,460	1,425,815	292,546
Cash and cash equivalents, end of period	$ 258,721	$ 192,460	$ 1,425,815
Cash paid for interest	$ 56,764	$ 34,615	$ —
Non-Cash Disclosures			
Change in accrued capital expenditures	$ (56,129)	$ 58,769	$ (105,802)
Transfer of investment securities to and from restricted funds	$ 112,434	$ 26	$ 178,830

See accompanying notes.

1. Summary of Significant Accounting Policies

Description of Operations

Cobalt International Energy, Inc. (the "Company") is an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa.

Effective January 1, 2015, Cobalt International Energy, L.P. (the "Partnership"), an indirect wholly-owned subsidiary of the Company, assigned its ownership interest in the oil and gas leases, wells, production facilities and other assets and agreements associated with the Company's Heidelberg development to Cobalt GOM #1 LLC, an indirect wholly-owned subsidiary of the Company.

The terms "Company," "Cobalt," "we," "us," "our," "ours," and similar terms refer to Cobalt International Energy, Inc. unless the context indicates otherwise.

Basis of Presentation

At December 31, 2014, the accompanying consolidated financial statements include the accounts of the Company and the Partnership. Prior to the effective date of a corporate reorganization, both entities were under common control arising from common direct or indirect ownership of each. The transfer of the Partnership interests to the Company represented a reorganization of entities under common control and was accounted for at historical cost.

Recently Issued Accounting Standards

In June 2014, the Financial Accounting Standards Board (the "FASB") amended Accounting Standard Codification Topic No. 915, *Development Stage Entities* (the "ASC Topic 915"), to remove the definition of a development stage entity from the Master Glossary of the ASC, thereby removing the financial reporting distinction between development stage entities and other reporting entities. The amendments eliminate the requirements for development stage entities to (1) present inception-to-date information in the statements of income, cash flows, and shareholder equity, (2) label the financial statements as those of a development stage entity, (3) disclose a description of the development stage activities in which the entity is engaged, and (4) disclose in the first year in which the entity is no longer a development stage entity that in prior years it had been in the development stage.

These amendments and the other remaining disclosure requirements of the ASC Topic 915 should be applied retrospectively. For public business entities, ASC Topic 915 is effective for annual reporting periods beginning after December 15, 2014, and interim periods therein. Early application of ASC Topic 915 is permitted for any annual reporting period or interim period for which the entity's financial statements have not yet been issued or made for issuance. Upon adoption, entities will no longer present or disclose any information required by the ASC Topic 915. The Company elected to apply ASC Topic 915 early effective in the Form 10-Q for the quarter ended June 30, 2014 and other reports thereafter.

Use of Estimates

The preparation of financial statements in conformity with United States generally accepted accounting principles ("GAAP") requires the Company to make estimates and assumptions that affect the reported amounts of assets including proved reserves and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and

1. Summary of Significant Accounting Policies (Continued)

expenses during the reporting period. Significant estimates the Company makes include (a) accruals related to expenses, (b) assumptions used in estimating fair value of equity based awards and the fair value of the liability component of the convertible senior notes and (c) assumptions used in impairment testing. Although the Company believes these estimates are reasonable, actual results could differ from these estimates.

Fair Value Measurements

The fair values of the Company's cash and cash equivalents, joint interest and other receivables, restricted funds and investments approximate their carrying amounts due to their short-term duration. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. The Company categorizes each of its fair value measurements as applicable to one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. The levels are:

Level 1—Quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities. This category includes the Company's cash and money market funds.

Level 2—Quoted prices in non-active markets or in active markets for similar assets or liabilities, and inputs other than quoted prices that are observable, for the asset or liability, either directly or indirectly for substantially the full contractual term of the asset or liability being measured. This category includes the Company's U.S. Treasury bills, U.S. Treasury notes, U.S. Government agency securities, commercial paper, corporate bonds and certificates of deposits.

Level 3—Inputs that are generally unobservable and typically reflect management's estimate of assumptions that market participants would use in pricing the asset or liability. The Company does not currently have any financial instruments categorized as Level 3.

Revenue Recognition

The Company will follow the "sales" (or cash) method of accounting for oil and gas revenues. Under this method, the Company will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which the Company is entitled based on its ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the years ended December 31, 2014, 2013 and 2012, no revenues have been recognized in these consolidated financial statements.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and funds invested in highly liquid instruments with maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however, the Company periodically assesses the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believes that the credit risk is minimal.

Restricted Funds

Restricted funds consist of collateral for letters of credit relating to our operations offshore Angola.

1. Summary of Significant Accounting Policies (Continued)

Investments

The Company's policy on accounting for its investments, which consist entirely of debt securities, is based on the accounting guidance relating to "*Accounting for Certain Investments in Debt and Equity Securities*." The Company considers all highly liquid interest-earning investments with a maturity of three months or less at the date of purchase to be cash equivalents. Investments with original maturities of greater than three months and remaining maturities of less than one year are classified as short-term investments. Investments with maturities beyond one year are classified as long-term investments. The debt securities are carried at amortized costs and classified as held-to-maturity securities as the Company has the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Held-to-maturity securities are stated at amortized cost, which approximates fair market value as of December 31, 2014 and 2013. Income related to these securities is reported as a component of interest income in the Company's consolidated statement of operations. *See Note 6—Investments.*

Investments are considered to be impaired when a decline in fair value is determined to be other-than-temporary. The Company conducts a regular assessment of its debt securities with unrealized losses to determine whether securities have other-than-temporary impairment ("OTTI"). This assessment considers, among other factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether the Company intends to sell or whether it is more likely than not that the Company will be required to sell the debt securities. As of December 31, 2014 and 2013, the Company has no OTTI in its debt securities.

Capitalized Interest

For exploration and development projects that have not commenced production, interest is capitalized as part of the historical cost of developing and constructing assets. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. *See Note 8—Property, Plant, and Equipment and Note 10—Long-term Debt*.

Joint Interest and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These receivables are usually settled within 30 days of the invoice date.

Property, Plant, and Equipment

The Company uses the "successful efforts" method of accounting for its oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes

1. Summary of Significant Accounting Policies (Continued)

are capitalized and amortized over the proved developed reserves on a units-of-production basis. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Asset Retirement Obligations

The Company currently does not have any oil and natural gas production or any legal obligations to incur decommissioning costs. Should such production occur in the future, the Company expects to have significant obligations under its lease agreements and federal regulation to remove its equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires the Company to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Pursuant to the accounting guidance relating to "*Asset Retirement Obligations*", the Company is required to record a separate liability for the estimated fair value of its asset retirement obligations, with an offsetting increase to the related oil and natural gas properties representing asset retirement costs on its balance sheet. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The estimated fair value of asset retirement obligations is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, the Company will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the consolidated statements of operations.

Inventory

Inventories consist of various tubular products that are used in the Company's drilling programs. The products are stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

1. Summary of Significant Accounting Policies (Continued)

Income Taxes

The Company applied the liability method of accounting for income taxes in accordance with accounting guidance related to "*Income Taxes*" as clarified by "*Accounting for Uncertainty in Income Taxes*." Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since the Company currently has no production activities and there can be no assurance that the Company will generate any earnings or any specific level of earnings in future years, the Company has established a valuation allowance that equals its net deferred tax assets. *See Note 16.*

Equity-Based Compensation

The Company accounts for stock-based compensation at fair value. The Company grants various types of stock-based awards including stock options, restricted stock and performance-based awards. The fair value of stock option awards is determined using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date. *See Note 14.*

Earnings (Loss) Per Share

Basic income (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. The calculation of diluted income (loss) per share should include the potential dilutive impact of non-vested restricted shares, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, during the period, unless their effect is anti-dilutive. For the year ended December 31, 2014, 5,997,374 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2013, 6,735,046 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options and the 2.625% convertible senior notes due 2019 were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2012, 5,617,697 shares of non-vested restricted stock, non-vested restricted stock units and outstanding stock options were excluded from the diluted income (loss) per share because they are anti-dilutive.

Operating Costs and Expenses

Expenses consist primarily of the costs of acquiring and processing of geological and geophysical data, exploration, and appraisal drilling expenses, consultants, telecommunications, payroll and benefit costs, information system and legal costs, office rent, contract costs, and bookkeeping and audit fees.

2. Cash and Cash Equivalents

As of December 31, 2014 and 2013, cash and cash equivalents consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cash at banks	$ 57,750	$ 82,428
Money market funds	122,218	75,039
Held-to-maturity securities(1)	78,753	34,993
	$258,721	$192,460

(1) These securities mature three months or less from date of purchase.

3. Restricted Funds

Restricted funds consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Short-term:		
Collateral on letters of credit for Angola	$ 45,062	$200,339
	$ 45,062	$200,339
Long-term:		
Collateral on letters of credit for Angola	$105,051	$104,496
	$105,051	$104,496
Total restricted funds(1)	$150,113	$304,835

(1) As of December 31, 2014 and 2013, $150.1 million and $304.8 million, respectively, was held in a collateral account established to secure letters of credit issued in support of the Company's contractually agreed work program obligations on Blocks 9, 20 and 21 offshore Angola. During the year ended December 31, 2014, restricted funds of $155.0 million were released to the Company in connection with completion of a portion of the agreed work program obligations on Block 20 and 21 offshore Angola. As of December 31, 2014, $45.1 million was reclassified from long-term restricted funds to short-term restricted funds in connection with the completion of a portion of the Company's agreed work program obligations on Block 9 and 21 offshore Angola. On February 5, 2015, restricted funds totaling $45.1 million were released to the Company in connection with completion of a portion of the work program obligations on Block 9 and completion of the remaining work program obligations on Block 21. The Block 21 letter of credit was therefore reduced to zero and cancelled effective February 10, 2015. As of December 31, 2014 and 2013, the collateral in this account was invested in U.S. Treasury bills and Treasury notes purchased at discounts and at premiums, respectively, resulting in a net carrying value of $150.1 million and $304.8 million, respectively. The contractual maturities of these securities are within one year.

4. Joint Interests and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These are usually settled within 30 days of the invoice date. As of December 31, 2014 and 2013, the balance in joint interest and other receivables consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Partners in the U.S. Gulf of Mexico	$ 3,274	$ 68,664
Partners in West Africa	46,312	46,897
Accrued interest on investment securities	7,663	5,632
Other	2,725	3,446
	$59,974	$124,639

5. Prepaid Expenses and Other Current Assets

As of December 31, 2014 and 2013, prepaid expenses and other current assets consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Prepaid expenses:		
Prepaid expenses(1)	$ 6,273	$37,796
Other current assets:		
Cash advance to joint venture partner(2)	—	9,685
Rig mobilization, regulatory and other related costs(3)	8,224	8,376
	$14,497	$55,857

(1) As of December 31, 2014, prepaid expenses include $6.3 million of the prepaid and unamortized portion of payments made for software licenses, related maintenance fees and insurance. As of December 31, 2013, prepaid expenses include $11.5 million of the prepaid and unamortized portion of payments made for software licenses, related maintenance fees, insurance and $26.3 million of prepaid costs associated with the Ensco drilling rig contract. The drilling rig contract terminated in January 2014 and upon receipt and application of prepaid amounts against the final invoice from Ensco, any remaining balance of the prepayment was refunded to the Company.

(2) As of December 31, 2013, the $9.7 million in other current assets relates to payment of cash calls made to our joint interest partner, Total Gabon, for operating costs to drill the Diaman #1B exploration well. This prepayment was applied against the joint interest bills upon receipt from Total Gabon as of December 31, 2014.

(3) As of December 31, 2014 and 2013, the $8.2 million and $8.4 million, respectively, in other current assets relates to the short-term portion of the mobilization and regulatory acceptance testing costs associated with the SSV Catarina drilling rig and the Rowan Reliance drilling rig.

6. Investments

The Company's investments in held-to-maturity securities which are recorded at amortized cost and approximate fair market value were as follows as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	($ in thousands)	
U.S. Treasury bills	$ 46,064	$ 304,834
U.S. Treasury notes	104,049	—
Corporate securities	1,321,261	856,002
Commercial paper	483,534	408,033
U.S. Agency securities	24,996	—
Certificates of deposit	105,215	105,000
Total	$2,085,119	$1,673,869

The Company's consolidated balance sheet included the following held-to-maturity securities:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cash and cash equivalents	$ 78,753	$ 34,993
Short-term investments	1,530,206	1,319,380
Short-term restricted funds	45,062	200,339
Long-term restricted funds	105,051	104,496
Long-term investments	326,047	14,661
	$2,085,119	$1,673,869

The contractual maturities of these held-to-maturity securities as of December 31, 2014 and 2013 were as follows:

	December 31, 2014		December 31, 2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	($ in thousands)			
Within 1 year	$1,759,072	$1,759,072	$1,659,208	$1,659,208
After 1 year	326,047	326,047	14,661	14,661
	$2,085,119	$2,085,119	$1,673,869	$1,673,869

7. Fair Value Measurements

The following tables summarize the Company's significant financial instruments as categorized by the fair value measurement hierarchy:

	Level 1		Level 2		Balance as of
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	December 31, 2014
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 57,750	$ 57,750	$ —	$ —	$ 57,750
Money market funds	122,218	122,218			122,218
Commercial paper	—	—	70,524	70,524	70,524
Corporate bonds	—	—	8,229	8,229	8,229
Subtotal	179,968	179,968	78,753	78,753	258,721
Short-term restricted funds:					
U.S. Treasury bills	—	—	45,062	45,062	45,062
Subtotal	—	—	45,062	45,062	45,062
Short-term investments:					
U.S. Agency securities	—	—	24,996	24,996	24,996
Corporate bonds	—	—	986,985	986,985	986,985
Commercial paper	—	—	413,010	413,010	413,010
Certificates of deposits	—	—	105,215	105,215	105,215
Subtotal	—	—	1,530,206	1,530,206	1,530,206
Long-term restricted funds:					
U.S. Treasury bills	—	—	1,002	1,002	1,002
U.S. Treasury notes	—	—	104,049	104,049	104,049
Subtotal	—	—	105,051	105,051	105,051
Long-term investments:					
Corporate bonds	—	—	326,047	326,047	326,047
Subtotal	—	—	326,047	326,047	326,047
Total	$179,968	$179,968	$2,085,119	$2,085,119	$2,265,087

7. Fair Value Measurements (Continued)

	Level 1		Level 2		Balance as of December 31, 2013
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 82,428	$ 82,428	$ —	$ —	$ 82,428
Money market funds	75,039	75,039	—	—	75,039
Commercial paper	—	—	9,993	9,993	9,993
Certificate of deposits	—	—	25,000	25,000	25,000
Subtotal	157,467	157,467	34,993	34,993	192,460
Short-term restricted funds:					
U.S. Treasury notes	—	—	200,339	200,339	200,339
Subtotal	—	—	200,339	200,339	200,339
Short-term investments:					
Corporate bonds	—	—	848,307	848,307	848,307
Commercial paper	—	—	391,073	391,073	391,073
Certificates of deposits	—	—	80,000	80,000	80,000
Subtotal	—	—	1,319,380	1,319,380	1,319,380
Long-term restricted funds:					
U.S. Treasury notes	—	—	104,496	104,496	104,496
Subtotal	—	—	104,496	104,496	104,496
Long-term investments:					
Commercial paper	—	—	6,967	6,967	6,967
Corporate bonds	—	—	7,694	7,694	7,694
Subtotal	—	—	14,661	14,661	14,661
Total	$157,467	$157,467	$1,673,869	$1,673,869	$1,831,336

(1) As of December 31, 2014 and 2013, the Company did not record any OTTI on these assets.

8. Property, Plant, and Equipment

Property, plant, and equipment is stated at cost less accumulated depreciation/amortization and consisted of the following:

	Estimated Useful Life (Years)	December 31, 2014	December 31, 2013
		($ in thousands)	
Oil and Gas Properties:			
Proved properties:			
Well and development costs		$ 183,221	$ 92,579
Total proved properties		183,221	92,579
Unproved properties:			
Oil and gas leasehold		762,518	754,894
Less: accumulated valuation allowance		(211,224)	(160,913)
		551,294	593,981
Exploration wells in process		1,186,464	777,823
Total unproved properties		1,737,758	1,371,804
Total oil and gas properties, net		1,920,979	1,464,383
Other Property and Equipment:			
Computer equipment and software	3	5,672	5,115
Office equipment and furniture	3 - 5	2,139	2,132
Vehicles	3	265	265
Leasehold improvements	3 - 10	2,488	2,456
Running tools and equipment	3	9,795	6,318
		20,359	16,286
Less: accumulated depreciation and amortization		(8,977)	(4,394)
Total other property and equipment, net		11,382	11,892
Property, plant, and equipment, net		$1,932,361	$1,476,275

The Company recorded $4.6 million, $1.9 million, and $1.2 million of depreciation and amortization expense for the years ended December 31, 2014, 2013 and 2012, respectively.

Proved Oil and Gas Properties

The Heidelberg project was formally sanctioned for development in mid-2013. As a result of the project sanction, the Company reclassified its Heidelberg exploration well costs to proved property well and development costs and these costs will be amortized when the related proved developed reserves are produced. As of December 31, 2014, the well and development costs consist of $51.1 million relating to exploration well costs for the Heidelberg #1 exploration well, Heidelberg #3 appraisal well, Heidelberg #4 and Heidelberg #6 development wells and $132.1 million for costs associated with field development. As of December 31, 2013, the well and development costs consist of $31.6 million

8. Property, Plant, and Equipment (Continued)

relating to exploration well costs for the Heidelberg #1 exploration well and Heidelberg #3 appraisal well and $61.0 million for costs associated with field development.

Unproved Oil and Gas Properties

As of December 31, 2014 and 2013, the Company has the following unproved property acquisition costs, net of valuation allowance on the consolidated balance sheets:

	December 31, 2014	December 31, 2013
	($ in thousands)	
U.S. Gulf of Mexico:		
Individual oil and gas leaseholds with carrying value greater than $1 million	$ 320,731	$ 328,128
Individual oil and gas leaseholds with carrying value less than $1 million	83,916	68,895
	404,647	397,023
Accumulated valuation allowance & impairment	(208,724)	(160,913)
	195,923	236,110
West Africa:		
Blocks 9, 20 and 21 offshore Angola	355,876	355,876
Diaba Block offshore Gabon	1,995	1,995
	357,871	357,871
Accumulated impairment	(2,500)	—
	355,371	357,871
Total oil and gas leasehold	$ 551,294	$ 593,981

As of December 31, 2014 and 2013, the Company has $353.4 million and $355.9 million, respectively, of unproved property acquisition costs, net of valuation allowance for impairment, relating to its 40% working interest each in Blocks 9, 20 and 21 offshore Angola and $2.0 million of unproved property acquisition costs relating to its 21.25% working interest in the Diaba Block, offshore Gabon. On December 20, 2011, the Company acquired a 40% working interest in Block 20 offshore Angola for a consideration of $347.1 million, of which $337.1 million is contractually scheduled to be paid over five years commencing in January 2012. As of December 31, 2014, the remaining unpaid balance of $128.6 million was accrued in short-term and long-term contractual obligations. *See Note 11—Contractual Obligations*.

As of December 31, 2014 and 2013, the Company also has $195.9 million and $236.1 million, respectively, net of valuation allowance for impairment, of unproved property acquisition costs relating to its U.S. Gulf of Mexico properties. In June and July of 2014, the Company paid a total consideration of $27.8 million for the acquisition of ownership interests in unproved oil and gas properties in the deepwater U.S. Gulf of Mexico. On February 26, 2013, the Company executed a Purchase and Sale agreement (the "PSA") to sell its ownership interests on an unproved oil and gas property on Mississippi Canyon Block 209 for a total consideration of $5.6 million. The Company received $1.5 million at closing and an additional $1.5 million in September 2013 when the buyer commenced

8. Property, Plant, and Equipment (Continued)

operations on the property. Pursuant to the terms and conditions of the PSA, the Company will receive the remaining $2.6 million contingent upon the purchaser's commencement of production on this property in the future. For the year ended December 31, 2013, the Company recognized a gain of $3.0 million on the sale of assets as a result of this transaction. During the year ended December 31, 2013, the Company paid a total consideration of $37.6 million for the acquisition of ownership interests in unproved oil and gas properties on Garden Banks Block 822, Mississippi Canyon Block 605 and Walker Ridge Block 232 in the deepwater U.S. Gulf of Mexico.

As of December 31, 2014 and 2013, the Company has a net total of $551.3 million and $594.0 million, respectively, of unproved property acquisition costs on the consolidated balance sheets.

Acquisition costs of unproved properties are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent associated with successful exploration activities. There are no impairment indicators to date that would require the Company to impair the unproved properties in Blocks 20 and 21 offshore Angola and in the Diaba Block offshore Gabon. For the unproved properties associated with Block 9 offshore Angola, the Company recorded an impairment allowance of $2.5 million on its 40% ownership interest on Block 9 since the Company has no plan to extend its exploration obligations under the Risk Services Agreement for Block 9. Oil and gas leases for unproved properties in the U.S. Gulf of Mexico with a carrying value greater than $1.0 million are assessed individually for impairment based on the Company's current exploration plans and an allowance for impairment is provided if impairment is indicated. Leases that are individually less than $1.0 million in carrying value or are near expiration are amortized on a group basis over the average terms of the leases at rates that provide for full amortization of leases upon lease expiration. These leases have expiration dates ranging from 2015 through 2024. As of December 31, 2014 and 2013, the balance for unproved properties that were subject to amortization before impairment provision was $83.7 million and $68.9 million, respectively. The Company recorded a lease impairment allowance of $70.5 million, $87.0 million and $60.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Capitalized Exploration Well Costs

If an exploration well provides evidence as to the existence of sufficient quantities of hydrocarbons to justify evaluation for potential development, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally, deepwater and international locations) depending upon, among other things, (i) the amount of hydrocarbons discovered, (ii) the outcome of planned geological and engineering studies, (iii) the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan and (iv) the requirement for government sanctioning in international locations before proceeding with development activities. The

8. Property, Plant, and Equipment (Continued)

following tables reflect the Company's net changes in and the cumulative costs of capitalized exploration well costs (excluding any related leasehold costs):

	December 31, 2014	December 31, 2013	December 31, 2012
		($ in thousands)	
Beginning of period	$ 777,823	$ 451,024	$178,338
Additions to capitalized exploration			
U.S. Gulf of Mexico:			
Exploration well costs	143,431	154,877	178,295
Capitalized interest	6,965	3,928	—
West Africa:			
Exploration well costs	379,461	457,608	168,309
Capitalized interest	44,243	12,271	—
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	—	(38,446)	—
Amounts charged to expense(1)	(165,459)	(263,439)	(73,918)
End of period	$1,186,464	$ 777,823	$451,024

(1) The amount of $165.5 million for the year ended December 31, 2014 represents $64.3 million of impairment charges on exploration wells drilled in the U.S. Gulf of Mexico and $101.2 million of impairment charges on exploration wells drilled offshore Angola, all of which did not encounter commercial hydrocarbons. The amount of $263.4 million for the year ended December 31, 2013 represents $120.0 million of impairment charges on exploration wells drilled in the U.S. Gulf of Mexico which did not encounter commercial hydrocarbons, $126.3 million of impairment charges on exploration wells drilled offshore Angola which failed to flow measurable hydrocarbons from drill stem tests and a portion of the cost of exploration wells drilled offshore Angola that were determined to have no utility in the lowest interval beneath the pay zone and $17.1 million of impairment charges on the exploration well drilled offshore Gabon which needed to be re-spud due to mechanical problems with the wellbore.

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cumulative costs:		
U.S. Gulf of Mexico		
Exploration well costs	$ 283,885	$204,707
Capitalized interest	10,894	3,928
West Africa		
Exploration well costs	835,171	556,917
Capitalized interest	56,514	12,271
	$1,186,464	$777,823

8. Property, Plant, and Equipment (Continued)

Well costs capitalized for a period greater than one year after completion of drilling (included in the table above) are summarized as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
U.S. Gulf of Mexico	$208,634	$186,510	$ 89.490
West Africa	566,745	213,265	105,363
	$775,379	$399,775	$194,853
Number of projects with exploration well costs that have been capitalized more than a year	8	3	3

The above capitalized exploration well costs suspended over a year are pending ongoing evaluation including, but not limited to, results of additional appraisal drilling, well-test analysis, additional geological and geophysical data and approval of a development plan. Management believes these discoveries exhibit sufficient indications of hydrocarbons to justify potential development and is actively pursuing efforts to fully assess them. If additional information becomes available that raises substantial doubt as to the economic or operational viability of these discoveries, the associated costs will be expensed at that time.

9. Other Assets

As of December 31, 2014 and 2013, the balance in other assets consisted of the following:

	December 31,	
	2014	2013
	($ in thousands)	
Debt issue cost(1)	$36,708	$20,983
Long-term portion of prepaid shorebase leases	2,244	3,241
Rig mobilization costs(2)	14,984	11,153
Long-term accounts receivable(3)	—	17,923
Other	—	437
	$53,936	$53,737

(1) As of December 31, 2014, the $36.7 million in debt issue costs included $18.5 million and $18.2 million in costs related to the issuance of the Company's 2.625% convertible senior notes due 2019 and the Company's 3.125% convertible senior notes due 2024, respectively, as described in *Note 10—Long-term Debt*. As of December 31, 2013, the $21.0 million in debt issue costs was related to the issuance of the Company's 2.625% convertible senior notes due 2019 as described in *Note 10—Long-term Debt*. These debt issue costs are amortized over the life of the notes using the effective interest method.

(2) As of December 31, 2014 and 2013, the $15.0 million and $11.2 million, respectively, relate to costs associated with the long-term mobilization and the regulatory acceptance testing of the SSV Catarina drilling rig which is currently drilling in West Africa, and

9. Other Assets (Continued)

costs relating to the Rowan Reliance drilling rig which was delivered in January 2015 and is currently drilling our North Platte #2 appraisal well. These costs are or will be amortized over the term of the drilling rig contracts.

(3) As of December 31, 2013, the $17.9 million of long-term accounts receivable was related to a 3.75% cost interest disputed by one of our former partners on Block 9 and 21 offshore Angola. On October 30, 2014, the Company collected the entire balance due from the Company's partner on Block 9 and 21.

10. Long-term Debt

As of December 31, 2014, the Company's long-term debt consists of the 2.625% convertible senior notes due 2019 issued on December 17, 2012 (the "2.625% Notes") and the 3.125% convertible senior notes due 2024 issued on May 13, 2014 (the "3.125% Notes", and, collectively with the 2.625% Notes, the "Notes") as follows:

2.625% Convertible Senior Notes due 2019

On December 17, 2012, the Company issued $1.38 billion aggregate principal amount of the 2.625% Notes. The 2.625% Notes are the Company's senior unsecured obligations and interest is payable semi-annually in arrears on June 1 and December 1 of each year. The 2.625% Notes will mature on December 1, 2019, unless earlier repurchased or converted in accordance with the terms of the 2.625% Notes. The 2.625% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the maturity date, in multiples of $1,000 principal amount. The 2.625% Notes are convertible at an initial conversion rate of 28.023 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $35.68 per share for a total of approximately 38.7 million underlying shares. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 2.625% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

3.125% Convertible Senior Notes due 2024

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of the 3.125% Notes. The 3.125% Notes are the Company's senior unsecured obligations and rank equal in right of payment to the 2.625% Notes. Interest on the 3.125% Notes is payable semi-annually in arrears on May 15 and November 15 of each year. The 3.125% Notes will mature on May 15, 2024, unless earlier repurchased, converted or redeemed in accordance with the terms of the Notes. Prior to November 15, 2023, the 3.125% Notes are convertible only under the following circumstances: (1) during any fiscal quarter commencing after September 30, 2014 (and only during such fiscal quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during a 30 consecutive trading-day period ending on, and including, the last trading day of the immediately preceding fiscal quarter exceeds $30.00 on each applicable trading day; (2) during the five business-day period after any five consecutive trading-day period (the "3.125% Notes Measurement Period") in which the trading price per $1,000 principal amount of notes for each trading day of the

10. Long-term Debt (Continued)

3.125% Notes Measurement Period was less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; (3) if the Company calls all or any portion of the 3.125% Notes for redemption, at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the related redemption date; or (4) upon the occurrence of specified distributions or the occurrence of specified corporate events. On or after November 15, 2023, the 3.125% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the stated maturity date, in multiples of $1,000 principal amount. As of December 31, 2014 and 2013, none of the conditions allowing holders of the 3.125% Notes to convert had been met.

The 3.125% Notes are convertible at an initial conversion rate of 43.3604 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $23.06 per share for a total of approximately 56.4 million underlying shares. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 3.125% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

Holders of the Notes who convert their Notes in connection with a "make- whole fundamental change", as defined in the indenture governing these Notes, may be entitled to a make-whole premium in the form of an increase in the conversion rate. Additionally, in the event of a fundamental change, as defined in the indenture governing the Notes, holders of the Notes may require the Company to repurchase for cash all or a portion of their Notes equal to $1,000 or a multiple of $1,000 at a fundamental change repurchase price equal to 100% of the principal amount of Notes, plus accrued and unpaid interest, if any, to, but not including, the fundamental change repurchase date.

Upon the occurrence of an Event of Default, as defined within the indenture governing the Notes, the trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding may declare 100% of the principal of, and accrued and unpaid interest on, all the Notes to be due and payable immediately.

In accordance with accounting guidance relating to, "*Debt with Conversion and Other Options*", the Company separately accounts for the liability and equity conversion components of the Notes due to the Company's option to settle the conversion obligation in cash. The fair value of the Notes excluding the conversion feature at the date of issuance was calculated based on the fair value of similar non-convertible debt instruments. The resulting value of the conversion option of the Notes was recognized as a debt discount and recorded as additional paid-in capital on the Company's consolidated balance sheets. Total debt issue cost on the Notes was allocated to the liability component and to the equity component of the Notes accordingly. The debt discount and the liability component of the debt issue costs are amortized over the term of the Notes. The effective interest rate used to amortize the debt discount and the liability component of the debt issue costs were approximately 8.40% and 8.97% on the 2.625% Notes and the 3.125% Notes, respectively, based on the Company's estimated non-convertible borrowing rate as of the date the Notes were issued. Since the Company incurred losses for all periods, the impact of the conversion option would be anti-dilutive to the earnings per share and therefore was not included in the calculation.

10. Long-term Debt (Continued)

The carrying amounts of the liability components of the Notes were as follows:

	December 31, 2014			December 31, 2013		
	Principal Amount	Unamortized discount(1)	Carrying Amount	Principal Amount	Unamortized discount	Carrying Amount
	($ in thousands)					
Carrying amount of liability component						
2.625% Notes	$1,380,000	$(295,509)	$1,084,491	$1,380,000	$(344,020)	$1,035,980
3.125% Notes	1,300,000	(455,963)	844,037	—	—	—
Total	$2,680,000	$(751,472)	$1,928,528	$1,380,000	$(344,020)	$1,035,980

(1) Unamortized discount will be amortized over the remaining life of the Notes which is 5 years for the 2.625% Notes and 9.50 years for the 3.125% Notes.

The carrying amounts of the equity components of the Notes were as follows:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Debt discount relating to value of conversion option	$866,340	$390,540
Debt issue costs	(20,185)	(9,124)
Total	$846,155	$381,416

Fair Value The fair value of the Notes excluding the conversion feature was calculated based on the fair value of similar non-convertible debt instruments since an observable quoted price of the Notes or a similar asset or liability is not readily available. As of December 31 2014 and 2013, the fair values of the Notes were as follows:

	December 31, 2014	December 31, 2013
	($ in thousands)	
2.625% Notes	$1,361,000	$1,227,000
3.125% Notes	1,047,000	—
Total	$2,408,000	$1,227,000

As of December 31, 2014, the Company had $8.0 million in accrued interests on the Notes.

10. Long-term Debt (Continued)

Interest expense associated with the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024 was as follows:

	For Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Interest expense associated with accrued interest(1)	$ 3,271	$18,529	$1,294
Interest expense associated with accretion of debt discount	68,348	44,789	1,843
Interest expense associated with amortization of debt issue costs	3,149	2,058	75
	$74,768	$65,376	$3,212

(1) The $3.3 million, $18.5 million and $1.3 million for the years ended December 31, 2014, 2013 and 2012, respectively, represent interest expense net of capitalized amounts of $58.5 million, $17.7 million and $0 million, respectively.

As of December 31, 2014, and December 31, 2013, the debt discounts associated with our convertible senior notes resulted in the recognition of $264.3 million and $121.0 million of deferred tax liability, respectively. The Company is in an overall net deferred tax assets position with a full valuation allowance. Therefore, the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized.

11. Contractual Obligations

The short-term and long-term contractual obligations consist of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Short-term Contractual Obligations:		
Social obligation payments for Block 9, offshore Angola	$ 560	$ 150
Social obligation payments for Block 21, offshore Angola	1,156	300
Social obligation and bonus payments for Block 20, offshore Angola(1)	48,569	48,569
	$ 50,285	$ 49,019
Long-term Contractual Obligations:		
Social and work program obligation payments for Block 9, offshore Angola	$ 21,875	$ 669
Social obligation payments for Block 21, offshore Angola	74	1,381
Social obligation and bonus payments for Block 20, offshore Angola(1)	79,996	122,851
	$101,945	$124,901

(1) The total amount of $128.6 million under social obligation payments for Block 20 has been capitalized in unproved oil and gas leasehold. *See Note 8—Property, Plants and Equipment.*

12. Stockholders' Equity

On January 15, 2012, the Company withheld the issuance of an aggregate amount of 9,127 shares of its common stock, at a price of $18.74 per share, to satisfy tax withholding obligations of certain of its officers that arose upon the distribution of deferred stock compensation.

On February 29, 2012, the Company issued 18,050,000 shares of common stock at a public offering price of $28.00 per share.

On December 17, 2012, the Company issued $1.38 billion aggregate principal amount of its 2.625% convertible senior notes due 2019. As of December 31, 2013 and 2012, $381.4 million was recorded as the equity component of the 2.625% Notes. *See also Note 10—Long-term Debt.*

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of its 3.125% convertible senior notes due on 2024. As of December 31, 2014, $464.7 million was recorded as the equity component of the 3.125% Notes. *See also Note 10—Long-term Debt.*

13. Seismic and Exploration Expenses

Seismic and exploration expenses consisted of the following:

	For Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Seismic costs	$34,359	$63,721	$42,447
Leasehold delay rentals	7,391	6,660	6,383
Drilling rig expense and other exploration expense	43,817	3,832	12,753
	$85,567	$74,213	$61,583

14. Equity based Compensation

Overview. Under the Company's Long Term Incentive Plan (the "Incentive Plan"), the Company may issue stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock-based awards to employees. At December 31, 2014, 4,043,263 shares remain available for grant under the Incentive Plan. However, on January 15, 2015 the Company granted a total of 379,746 shares of restricted stock and 746,268 stock options to three senior officers as required pursuant to their employment agreements. In addition, on February 19, 2015, the Company awarded 2,757,982 shares of restricted stock and 1,526,835 stock appreciation rights to employees as part of the Company's annual long-term equity incentive program. These awards combined with first quarter new hire and termination activity representing a net new issuance of 26,853 shares has resulted in 132,414 shares remaining available for issuance under the Incentive Plan as of February 19, 2015.

On January 28, 2010, the Company adopted the Non-Employee Directors Compensation Plan (the "NED Plan"). Under the NED Plan, the Company may issue options, restricted stock units, other stock-based award or retainers to non-employee directors. At December 31, 2014, 415,682 shares remain available for grant under the NED Plan.

In accordance with ASC No. 718, *Compensation—Stock Compensation,* the Company recognizes compensation cost for equity-based compensation to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant, net of estimated forfeitures. If actual forfeitures differ from the Company's estimates, additional adjustments to compensation expense will be required in future periods.

Restricted Stock. The Company accounted for the restricted stock based on ASC Topic 718 as described above. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

14. Equity based Compensation (Continued)

The following table summarizes the information about the restricted stock awarded to employees for years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,					
	2014		2013		2012	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested shares at beginning of year	4,334,886	$14.31	4,040,825	$13.05	4,599,783	$11.27
Granted	2,275,317	$14.53	620,840	$24.58	487,710	$26.01
Vested	(1,433,172)	$16.32	(239,317)	$17.37	(738,628)	$13.05
Forfeited or expired(1)	(2,374,242)	$10.63	(87,462)	$20.91	(308,040)	$12.17
Non-vested shares at end of year	2,802,789	$16.44	4,334,886	$14.31	4,040,825	$13.05
Weighted-average vesting period remaining	3.08 years		1.22 years		1.87 years	
Unrecognized compensation ($ in thousands)	$ 34,066		$ 22,467		$ 23,827	

(1) The 2,374,242 forfeited or expired restricted shares for the year ended December 31, 2014 include 2,306,173 restricted shares that were forfeited on December 21, 2014 because the market condition attached to the vesting terms of the awards was not met.

A total of 58,038 restricted stock units were granted to non-employee directors during the year ended December 31, 2014. As of December 31, 2014, the Company has granted a cumulative total of 235,801 restricted stock units to non-employee directors. For the years ended December 31, 2014, 2013 and 2012, the Company also granted 26,438, 15,318 and 12,221 shares of common stock, respectively, for annual retainers to non-employee directors who elected to be compensated by stock in lieu of cash payments. For the years ended December 31, 2014, 2013 and 2012, the weighted average fair values of these shares at grant date were $17.52, $25.40 and $21.35 per share, respectively.

Non-Qualified Stock Options. The Company grants non-qualified stock options to employees at an exercise price equal to the market value of the Company's common stock on the grant date. The non-qualified stock option awards have contractual terms of 10 years. The options granted in February 2014 and 2013 will vest 50% at the end of the third year from date of grant and 50% at the end of the fourth year from date of grant. The options granted in 2012 were fully vested during the year ended December 31, 2014.

The fair value of each stock option granted is determined using the Black-Scholes-Merton option-pricing model based on several assumptions. These assumptions are based on management's best

14. Equity based Compensation (Continued)

estimate at the time of grant. The Company used the following the weighted average of each assumption based on the grants in 2014:

	2014
Expected Term in Years	5.5
Expected Volatility	57.27%
Expected Dividends	—%
Risk-Free Interest Rate	1.69%

The Company estimates expected volatility based on an analysis of its stock price since the IPO and comparing the stock price volatility for the period from IPO date through December 31, 2014 with the historical stock price volatility of a similar exploration and production company. The Company estimates the expected term of its option awards based on the vesting period and average remaining contractual term, referred to as the "simplified method". The Company uses this method to provide a reasonable basis for estimating its expected term based on a lack of sufficient historical employee exercise data on stock option awards.

A summary of the stock options activities for the year ended December 31, 2014 is presented below:

	Shares	Weighted Average Exercise Price	Weighted-Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (thousands)
Outstanding at January 1, 2014	2,338,718	$20.24	8.0	$ —
Granted	812,055	$17.50		
Exercised	(3,005)	$12.45		$17,837
Forfeited or expired	(11,221)	$24.02		
Outstanding at December 31, 2014	3,136,547	$19.52	7.57	$ —
Vested or expected to vest at December 31, 2014	1,693,193	$20.82	8.61	$ —
Exercisable at December 31, 2014	1,411,271	$17.93	6.30	$ —

The weighted-average grant-date fair value of stock options granted during 2014 and 2013 was $9.12 and $14.08 per option, respectively, using the Black-Scholes option-pricing model. As of December 31, 2014, $12.2 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 2.46 years.

Restricted Stock Units. On December 3, 2010, the Company granted 198,838 restricted stock units to employees pursuant to a Restricted Stock Unit (RSU) Award Agreement. Under the RSU Award Agreement the share-based payment was earned based on the number of successful wells drilled during the three year period ending December 31, 2013. The RSU award vested within a range of 0% to 200% of the number of RSU shares awarded on scheduled vesting dates contingent upon the recipient's continued service at each vesting date and based on the achievement of successful wells drilled as defined in the RSU Award Agreement. The recipients could not vest in an amount greater than 200% of the Award or in aggregate 397,676 RSU shares. The percentage of the RSU awards vested at each of the three year periods ending December 31, 2013 was calculated by the number of

14. Equity based Compensation (Continued)

successful wells drilled during the respective years multiplied by vesting percentages ranging from 25% to 37.5%. As of December 31, 2014, the RSU shares were fully vested.

A summary of the restricted stock units activities for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Year Ended December 31,					
	2014		2013		2012	
	Number of shares relating Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units	Weighted Average Grant Date Fair Value Per Unit
Non-vested at beginning of year	21,624	$30.50	109,275	$30.50	198,838	$12.45
Granted	—	—	—	—	—	—
Vested	(21,624)	$30.50	(87,401)	$30.50	(74,537)	$30.50
Forfeited or expired	—	—	(250)	$30.50	(15,026)	$30.50
Non-vested at end of year	—	—	21,624	$30.50	109,275	$30.50
Weighted-average period remaining	—		—		1 year	

The table below summarizes the equity-based compensation costs recognized for years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Restricted stock:			
Employees	$20,971	$15,470	$13,378
Non-employee directors	1,476	1,260	970
Stock options:			
Employees	9,295	7,405	3,790
Restricted stock units (performance-based)	—	4,619	4,272
	$31,742	$28,754	$22,410

15. Employee Benefit Plan

In 2006, the Company established the Cobalt International Energy, L.P., defined contribution 401(k) plan (the Plan). All employees of the Company after three months of continuous employment are eligible to participate in the Plan. The plan is discretionary and provides a 6% employee contribution match as determined by the Company's Board of Directors. Effective December 31, 2009, the Plan was amended to discontinue the employer's matching contributions. Effective January 1, 2012, the Company reinstituted the 6% employee contribution match. For the years ended December 31, 2014, 2013 and 2012, the Company recorded $1.0 million, $0.8 million, and $0.5 million, respectively, in benefits contributions to the Plan, which are included in general and administrative expenses.

16. Income Taxes

For the years ended December 31, 2014, 2013 and 2012, the Company recorded a net deferred tax asset of $568.0 million, $461.6 million, and $269.6 million, respectively with a corresponding full valuation allowance of $568.0 million, $461.6 million, and $269.6 million, respectively, for the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The components of the income tax provision (benefit) are as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Current taxes:			
U.S. federal	$—	$—	$—
Foreign	—	—	—
Deferred taxes:			
U.S. federal	—	—	—
Foreign	—	—	—
Total	$—	$—	$—

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) for years ended December 31, 2014, 2013 and 2012 are as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
U.S.:			
Net income (loss) as reported	$(307,025)	$(387,210)	$(229,372)
Less: net income (loss) applicable to period before corporate reorganization	—	—	—
Foreign:			
Net income (loss) as reported	(203,738)	(201,814)	(53,627)
Less: net income (loss) applicable to period before corporate reorganization	—	—	—
Net income (loss) applicable to period after corporate reorganization	$(510,763)	$(589,024)	$(282,999)

16. Income Taxes (Continued)

	Year Ended December 31,					
	2014		2013		2012	
	($ in thousands)					
Income tax expense (benefit) at the federal statutory rate	$(178,767)	35.0%	$(206,159)	35.0%	$(99,050)	35.0%
State income taxes, net of federal income tax benefit	(828)	0.2%	(489)	0.1%	(512)	0.2%
Foreign income tax	(111,151)	21.8%	(70,994)	12.1%	4,447	−1.6%
Other	9,098	−1.8%	366	−0.1%	2,678	−0.9%
Valuation allowance(1)	281,648	−55.2%	277,276	−47.1%	92,437	−32.7%
	$ —	—%	$ —	—%	$ —	—%

(1) The change in the deferred tax asset valuation allowance of $277.3 million for the year end December 31, 2013, excludes a $85.3 million net decrease in valuation allowance due to previously unrecorded foreign deferred tax assets and a deferred tax liability related to the Company's convertible debt instrument that did not impact the rate reconciliation.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax

16. Income Taxes (Continued)

purposes. The significant components of the Company's deferred tax assets and liabilities were as follows:

	As of December 31, 2014	As of December 31, 2013
	($ in thousands)	
Short-term deferred tax liabilities:		
2.625% convertible senior notes due 2019(1)	$ 18,479	$ 17,061
3.125% convertible senior notes due 2024(1)	11,855	—
Total short-term deferred tax liabilities	30,334	17,061
Long-term deferred tax liabilities:		
2.625% convertible senior notes due 2019	$ 85,471	$ 103,951
3.125% convertible senior notes due 2024	148,507	—
Oil and gas properties	54,461	22,135
Total long-term deferred tax liabilities	288,439	126,086
Long-term deferred tax assets:		
Seismic and exploration costs	457,854	280,095
Stock based compensation	18,092	20,842
Domestic NOL carry forwards	415,608	273,163
Foreign NOL carry forwards	38,200	28,633
Other	(43,021)	1,976
Valuation allowance	(567,960)	(461,562)
Total long-term deferred assets	318,773	143,147
Net long-term deferred assets	30,334	17,061
Net deferred tax assets	$ —	$ —

(1) The recognition of the liability and equity components of the debt resulted in a taxable temporary basis difference and recorded as an adjustment to additional paid-in capital.

The Company has established a full valuation allowance against the deferred tax assets where the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized. Because of the full valuation allowance, no income tax expense or benefit is reflected on the consolidated statement of operations for years ended December 31, 2014, 2013 and 2012.

The NOL carryforward for federal and state income tax purposes of approximately $1.2 billion and $65.2 million as of December 31, 2014 begins to expire in 2025 and 2024, respectively. The utilization of the NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period.

As of December 31, 2014, the Company had NOL carryforward for foreign income tax purposes of approximately $73.8 million which begins to expire in 2014. The Company has determined that it is more likely than not, that the foreign NOLs will not be fully realized. Therefore, a full valuation allowance was established for these net deferred tax assets.

16. Income Taxes (Continued)

There were no unrecognized tax benefits or accrued interest or penalties associated with unrecognized tax benefits as of December 31, 2014 and 2013.

17. Commitments

The following table summarizes by period the payments due for the Company's estimated commitments, excluding long-term debt, as of December 31, 2014:

	Payments Due By Year					
	2015	2016	2017	2018	2019	Thereafter
	($ in thousands)					
Drilling Rig and Related Contracts	$544,559	$299,702	$208,104	$17,104	$ —	$ —
Operating Leases	9,755	4,801	2,309	2,369	2,405	5,626
Lease Rentals(1)	7,353	5,460	5,007	2,282	1,973	7,223
Social and Work Program Payment Obligations(2)	55,999	84,729	5,714	5,714	—	—
Total	**$617,666**	**$394,692**	**$221,134**	**$27,469**	**$4,378**	**$12,849**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to the Company's U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

(2) Includes the Company's contractual payment obligations for (i) social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that the Company was and is contractually obligated to pay in consideration for the Angolan government granting it the licenses to explore for and develop hydrocarbons offshore Angola and (ii) the Company's remaining work program obligations on Block 9 offshore Angola. Pursuant to the terms of the Risk Services Agreements for Blocks 9 and 21 and the Production Sharing Agreement for Block 20, the Company is not required to pay annual rental payments to maintain the licenses from year to year.

The Company recorded $12.8 million, $6.7 million, and $12.1 million of office and delay rental expense for the years ended December 31, 2014, 2013 and 2012, respectively.

18. Segment Information

The Company currently has two geographic operating segments for its operations. The operating segments are focused in the deepwater U.S. Gulf of Mexico and offshore West Africa. The following

18. Segment Information (Continued)

tables provide the geographic operating segment information for years ended December 31, 2014, 2013 and 2012:

	United States	West Africa	Total
	($ in thousands)		
Year ended December 31, 2014			
Operating costs and expense	$ 238,214	$ 203,727	$ 441,941
Operating income (loss)	(238,214)	(203,727)	(441,941)
Other income (expense)			(68,822)
Net income (loss)			$(510,763)
Additions to Property and Equipment, net(1)	$ 135,449	$ 320,637	$ 456,086
Year ended December 31, 2013			
Operating costs and expense	$ 329,832	$ 202,852	$ 532,684
Operating income (loss)	(329,832)	(202,852)	(532,684)
Other income (expense)			(56,340)
Net income (loss)			$(589,024)
Additions to Property and Equipment, net(1)	$ 44,124	$ 332,395	$ 376,519
Year ended December 31, 2012			
Operating costs and expense	$ 231,196	$ 53,632	$ 284,828
Operating income (loss)	(231,196)	(53,632)	(284,828)
Other income (expense)			1,829
Net income (loss)			$(282,999)
Additions to Property and Equipment, net(1)	$ 67,068	$ 169,362	$ 236,430

(1) These amounts are net of accumulated allowance for impairment on oil and gas properties and accumulated depreciation and amortization on other property and equipment.

19. Contingencies

The Company is currently, and from time to time may be, subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. It is not presently possible to determine whether any such matters will have a material adverse effect on the Company's consolidated financial position, results of operations, or liquidity.

20. Other Matters

As previously disclosed, in November 2011 a formal order of investigation was issued by the SEC related to our operations in Angola. In August 2014, we received a Wells Notice from the SEC related to this investigation. In January 2015, we received a termination letter from the SEC advising us that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. We continue to

20. Other Matters (Continued)

cooperate with the Department of Justice ("DOJ") with regard to its ongoing parallel investigation. We are unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue.

21. Related Party Transactions

On February 20, 2013, the Company entered into software licensing and consulting service agreements with Quorum Business Solutions, Inc. ("Quorum") and Quorum Business Solutions (U.S.A.), Inc, related to certain enterprise resource planning software. Under these agreements, Quorum will license, host, and support this software for us for an initial term of three years. The approximate value of these agreements is $1.5 million. Quorum is owned in part by Riverstone Holdings, LLC, one of our former financial sponsors. For the years ended December 31, 2014 and 2013, the Company incurred a total of 1.5 million and $1.3 million, respectively, in costs relating to Quorum. The Company did not have any material related party transactions for the year ended December 31, 2012.

22. Selected Quarterly Financial Data—Unaudited

Unaudited quarterly financial data for the years ended December 31, 2014 and 2013 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	($ in thousands, except per share data)			
Year ended December 31, 2014				
Operating costs and expenses	$ 47,293	$ 77,591	$ 120,961	$ 196,097
Operating income (loss)	(47,293)	(77,591)	(120,961)	(196,097)
Net income (loss)	(56,915)	(94,756)	(142,529)	(216,564)
Basic and diluted income (loss) per common share(1)	$ (0.14)	$ (0.23)	$ (0.35)	$ (0.53)
Year ended December 31, 2013				
Operating costs and expenses	$ 112,452	$ 65,365	$ 145,663	$ 209,204
Operating income (loss)	(112,452)	(65,365)	(145,663)	(209,204)
Net income (loss)	(128,087)	(78,818)	(160,000)	(222,119)
Basic and diluted income (loss) per common share(1)	$ (0.31)	$ (0.19)	$ (0.39)	$ (0.55)

(1) Totals may not add due to rounding.

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)

The unaudited supplemental information on oil and gas exploration activities that follows is presented in accordance with supplemental disclosure requirements under ASC No. 932, *"Extractive Activities—Oil and Gas"* ("ASC No. 932") and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting.* Disclosures include (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Since the Company did not have any production activities for years ended December 31, 2014, 2013

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

and 2012, there will be no disclosures on results of operations related to oil and gas producing activities.

Capitalized Costs Related to Oil and Gas Activities

	U.S. Gulf of Mexico	West Africa	Total
		($ in thousands)	
As of December 31, 2014			
Unproved properties(1)	$ 699,426	$1,249,556	$1,948,982
Accumulated valuation allowance	(208,724)	(2,500)	(211,224)
	490,702	1,247,056	1,737,758
Proved properties	183,221	—	183,221
Net capitalized costs	$ 673,923	$1,247,056	$1,920,979
As of December 31, 2013			
Unproved properties	$ 605,658	$ 927,059	$1,532,717
Accumulated valuation allowance	(160,913)	—	(160,913)
	444,745	927,059	1,371,804
Proved properties	92,579	—	92,579
Net capitalized costs	$ 537,324	$ 927,059	$1,464,383

(1) Unproved properties include capitalized costs net of sale/like-kind exchange of leasehold interest transactions that occurred in 2014 and 2013 of approximately $5.6 million and $10.7 million, respectively, for the U.S. Gulf of Mexico. No gain or loss was recognized for these transactions for the years ended December 31, 2014 and 2013.

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

Costs Incurred in Oil and Gas Activities

The following table reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration and development activities:

	U.S. Gulf of Mexico	West Africa	Total
		($ in thousands)	
Year ended December 31, 2014			
Property acquisition			
Unproved	$ 27,784	$ —	$ 27,784
Proved	—	—	—
Exploration			
Capitalized	150,396	423,704	574,100
Expensed	31,531	54,036	85,567
Development	90,642	—	90,642
Total Costs Incurred	$300,353	$477,740	$778,093
Year ended December 31, 2013			
Property acquisition			
Unproved	$ 37,584	$ —	$ 37,584
Proved	—	—	—
Exploration			
Capitalized	158,806	469,879	628,685
Expensed	48,688	25,525	74,213
Development	54,133	—	54,133
Total Costs Incurred	$299,211	$495,404	$794,615
Year ended December 31, 2012			
Property acquisition			
Unproved	$ 19,961	$ —	$ 19,961
Proved	—	—	—
Exploration			
Capitalized	178,295	168,309	346,604
Expensed	32,874	28,709	61,583
Development	—	—	—
Total Costs Incurred	$231,130	$197,018	$428,148

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

All of the Company's proved reserves are located in the U.S. Gulf of Mexico. Reserve quantity information for the years ended December 31, 2014, 2013 and 2012 are as follows:

	Natural Gas (in Bcf)	Oil and Condensate (in MMBbls)	Equivalent Volumes (in MMBOE)
Proved undeveloped reserves:			
Balance at December 31, 2012	—	—	—
Discoveries	3.4	7.9	8.5
Balance at December 31, 2013	3.4	7.9	8.5
Revisions	0.3	0.5	0.5
Balance at December 31, 2014	3.7	8.4	9.0

The reserves as of December 31, 2014 presented above were prepared by the independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). These reserves are located in the U.S. Gulf of Mexico. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine the Company's proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of the Company's fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company follows the guidelines prescribed in ASC No. 932 for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and natural gas properties as of December 31, 2014 and 2013. The Company did not have proved reserves as of December 31, 2012. These estimates were prepared by NSAI.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

(1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

(2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves.

(3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred.

(4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves.

(5) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the U.S. Generally Accepted Accounting Principles. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Prices used in the report prepared by NSAI are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil volumes, the average Light Louisiana Sweet spot price of $98.48 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $4.350 per MMbtu is adjusted for energy content, transportation fees, and a regional price differential. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are $95.24 per barrel of oil and $4.770 per Mcf of gas.

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

Information with respect to the Company's estimated discounted future net cash flows related to its proved oil and natural gas reserves as of December 31, 2014 and 2013 are as follows:

	2014	2013
	($ in thousands)	
Future cash inflows	$ 814,394	$ 830,287
Future production costs	(12,710)	(6,400)
Future development costs	(244,306)	(302,278)
Future income tax expense(1)	—	—
Future net cash flows	557,378	521,609
10% annual discount for estimated timing of cash flows	(192,094)	(244,976)
Standardized measure of discounted future net cash flows	$ 365,284	$ 276,633

(1) There is no future income tax expense as of December 31, 2014, as the tax basis of the oil and gas properties in the United States and net operating losses attributable to oil and gas operations exceed the future net revenues.

Information with respect to the Company's standardized measure of discounted future net cash flows as of December 31, 2014 and 2013 are as follows:

	2014	2013
	($ in thousands)	
Standardized measure, beginning	$276,633	$ —
Discoveries	—	276,633
Revisions of previous estimates:	—	—
Changes in prices and costs	(36,869)	—
Changes in future development costs	49,700	—
Changes in quantities	17,351	—
Accretion of discount	27,663	—
Changes in timing and other	30,806	—
Standardized measure, ending	$365,284	$276,633

Exhibit Index

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.2	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.3	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.4	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

Exhibit Number	Description of Document
10.5	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.6	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.7	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.8	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.10	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.11	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.12	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.13	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.14	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.15†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.17†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

Exhibit Number	Description of Document
10.18†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.19†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.20†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.21†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.22†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.23†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.24†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.25†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.26†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.28†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.29†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.30†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.31†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.32†	Form of Restricted Stock Unit Award Notification under the Non- Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.33†*	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield

Exhibit Number	Description of Document
10.34†*	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth
10.35†*	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter
10.36†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2015
10.37†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015
10.38†*	Form of Stock Appreciation Right Award Agreement under the Company's Long Term Incentive Plan
10.39†*	Form of Restricted Stock Unit Award Agreement under the Company's Long Term Incentive Plan
10.40†*	Form of Restricted Stock Award Agreement under the Company's Long Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).