Cobalt International Energy

2016 ANNUAL REPORT

BUILDING ON OUR SUCCESS

ABOUT COBALT

Cobalt International Energy, Inc. (NYSE: CIE) is a publicly traded independent exploration and production company (E&P) which was formed in 2005 and is headquartered in Houston, Texas.

OUR VALUES

COMMITMENT TO HEALTH, SAFETY, SECURITY AND ENVIRONMENT

Apply the highest level health, safety, security and environmental standards in everything we do

FOCUS ON SHAREHOLDER VALUE

Focus all our decisions to deliver the greatest value to our shareholders and investors

SUPERIOR TALENT, TEAM AND RESOURCES

Attract and leverage world class talent, team and resources, bringing together our core competencies for excellence

ACTION ORIENTED AND RESULTS FOCUSED

Action driven with thoughtful analysis, nimbleness, and efficiency to achieve results

ENTREPRENEURSHIP

Be renowned leaders who navigate a strategy for high performance and entrepreneurship

OPERATE WITH INTEGRITY

Work with the highest levels of integrity, being trustworthy as partners and as colleagues

SOCIALLY AND PROFESSIONALLY REWARDING

Provide a positive productive work environment for great ideas to incubate and where significant contributions lead to substantial rewards

LETTER TO SHAREHOLDERS

Timothy J. Cutt
Chief Executive Officer

I was attracted to Cobalt in mid-2016 by the significant success the company had delivered in finding oil and gas in offshore basins around the globe. My introduction to the offshore came in 1978 when I worked as a welder's helper on a lay barge in the Gulf of Mexico. I have watched the industry move from the shallow waters of the Gulf to ultra-deepwater and have lived through the exciting and significant advancement in offshore technology. Since joining Cobalt, I have come to learn that I am working daily with some of the very best explorers and drillers anywhere in the industry and I am personally honored to have the opportunity to work with and learn from these talented individuals.

Over the last decade, the company has discovered over 4 billion gross barrels of oil equivalent (BOE) in the Gulf of Mexico and offshore West Africa. During 2016, Cobalt discovered 750 million gross barrels of oil equivalent in Angola, bringing the total gross discovered resource in Angola to approximately 3 billion barrels of oil equivalent or approximately 1.3 billion barrels of oil. We drilled or participated in the drilling of three key appraisal wells in the Gulf of Mexico, the results of which bring Cobalt's net fully appraised resource in the Gulf to approximately 500 MMBOE, with additional upside yet to be appraised. Our 60% operated North Platte field is world class in both size and reservoir quality and has become the cornerstone of our business.

Cobalt has enough cash available to continue to progress the company's development plans and consider our options into 2018. To progress development of Cobalt's highest value assets in the Gulf of Mexico, we are currently marketing our position in Angola and Shenandoah to lower capital spend and to help fund the developments of North Platte and Anchor. Net production from North Platte, combined with Anchor, is expected to be ~ 80 KBD and will likely generate over a billion dollars per annum of operating cash flow when these fields come online during the early 2020's.

I believe that 2017 will be both exciting and challenging. I can assure you that everyone at Cobalt is committed to doing the work necessary to forge through the challenges so that we can deliver the value that lies in our exceptional assets to you, our shareholders.

On behalf of the Board of Directors and our entire team, thank you for your continued confidence in and support of Cobalt.

Timothy J. Cutt
Chief Executive Officer

"Over the last decade, the company has discovered over 4 billion gross barrels of oil equivalent (BOE) in the Gulf of Mexico and offshore West Africa."

COBALT 2016 HIGHLIGHTS

- Drilled two new discoveries offshore Angola
- Advanced appraisal of Gulf of Mexico discovered resources at North Platte, Anchor and Shenandoah
- Drilled and completed two additional development wells at Heidelberg, increasing production to ~27,000 BOE/day
- Successfully renegotiated Rowan rig contract, resulting in a savings of ~$80 million, while securing market rates for future development drilling
- Completed debt restructuring transaction to better align debt with timing of first production in the Gulf of Mexico

2016 FINANCIALS

Results of Operations

Cobalt 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. The Company operates in one reportable segment and no longer accounts for its Angolan operations as discontinued operations.

Fiscal Year ended December 31, 2016 as compared to year ended December 31, 2015 and year ended December 31, 2014:

	Year Ended December 31,		
	2016	2015	2014
		($ in thousands except per share data)	
Operations:			
Oil, natural gas and natural gas liquids revenue	$ 16,805	$ —	$ —
Operating costs and expenses			
Seismic and exploration costs	58,170	61,844	85,567
Dry hole costs and impairments	1,967,180	462,234	236,930
Loss on amendment of contract	95,908	—	—
Lease operating expenses	7,574	—	—
General and administrative expenses	127,860	110,634	114,860
Accretion expense	550	99	—
Depreciation, depletion and amortization	21,983	3,881	4,584
Total operating costs and expenses	**2,279,225**	**638,692**	**441,941**
Operating loss	**(2,262,420)**	**(638,692)**	**(441,941)**
Other (expense) income, net			
Other (expense) income	(2,505)	1,555	(12)
Interest income	4,661	6,087	5,958
Interest expense	(83,045)	(63,376)	(74,768)
Total other (expense) income, net	**(80,889)**	**(55,734)**	**(68,822)**
Net loss	**$ (2,343,309)**	**$ (694,426)**	**$ (510,763)**
Basic and diluted loss per share	$ (5.69)	$ (1.70)	$ (1.25)
Weighted average common shares outstanding (basic and diluted)	412,080	408,535	407,116

LEADERSHIP

Board of Directors

William P. Utt
Chairman of the Board of Directors, Former Chairman, President and CEO of KBR, Inc.

Timothy J. Cutt
Chief Executive Officer

Jack E. Golden
Former Group Vice President—Exploration and Production for BP

Jon A. Marshall
Former CEO of GlobalSantaFe Corporation

Kenneth W. Moore
Former Managing Director of First Reserve Corporation

John E. Hagale
Former Executive Vice President and Chief Financial Officer of Rosetta Resources, Inc.

Kay Bailey Hutchison
Former U.S. Senator

Myles W. Scoggins
President Emeritus of the Colorado School of Mines

D. Jeff van Steenbergen
Co-founding and General Partner of Azimuth Capital Management

Van P. Whitfield
Former Chief Operating Officer and Executive Vice President of Cobalt International Energy, Inc.

Martin H. Young, Jr.
Former Senior Vice President and Chief Financial Officer of Falcon Seaboard Diversified, Inc.

Officers

Timothy J. Cutt
Chief Executive Officer

Rod Skaufel
President, Operations

Jeffrey A. Starzec
Executive Vice President and General Counsel

David D. Powell
Chief Financial Officer

James H. Painter
President, Exploration and Appraisal

Richard A. Smith
Senior Vice President, Strategy and Business Development

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, 2016

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, 2016, 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 $486.6 million.

As of January 31, 2017, the registrant had 447,296,474 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s proxy statement relating to the 2017 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.

CAUTIONARY NOTE REGARDING FORWARD–LOOKING STATEMENTS

This Annual Report on Form 10–K contains forward–looking statements within the meaning of the federal securities laws including, but not limited to, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act (each a "forward–looking statement"). We have based our forward–looking statements 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 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 risk factors identified in Item 1A of this Annual Report on Form 10–K, may have a material adverse effect on 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 forward-looking statements may be influenced by the following factors, among others:

- our liquidity and ability to finance our exploration, appraisal, development, and acquisition activities and continue as a going concern;
- the availability and cost of financing, and refinancing, our indebtedness;
- the financial and operational implications of the termination of the purchase and sale agreement with Sociedade Nacional de Combustiveis de Angola–Empresa Publica for the sale of our working interest in Blocks 20 and 21 offshore Angola;
- our ability to sell our interests in Blocks 20 and 21 offshore Angola, U.S. Gulf of Mexico or other assets on acceptable terms;
- our ability to evaluate and execute upon potential strategic alternatives and initiatives to improve liquidity;
- our ability to meet our obligations under the agreements governing our current or any future indebtedness;
- volatility and extended depression of oil and natural gas prices;
- our ability to successfully and efficiently execute our project appraisal, development and exploration activities;
- projected and targeted capital expenditures and other costs and commitments;
- lack or delay of partner, government and regulatory approvals related to our business or required pursuant to agreements to which we are party;
- changes in environmental, safety, health, climate change or greenhouse gas laws and regulations or the implementation or interpretation of those laws and regulations;
- current and future government regulation of the oil and natural gas industry and our operations;
- oil and natural gas production rates on our properties that are currently producing oil and natural gas;
- uncertainties inherent in making estimates of our oil and natural gas data;
- our and our partners' ability to obtain permits to drill and develop our properties;
- termination of or intervention in concessions, licenses, permits, rights or authorizations granted by the United States, Angolan and Gabonese governments to us;

- our dependence on our key management personnel and our ability to attract and retain qualified personnel;
- our ability to find, acquire or gain access to new prospects;
- 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 oil and natural gas transportation and infrastructure;
- 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, and the ability to collect under our insurance policies;
- the results or outcome of any legal proceedings or investigations;
- our ability to maintain the listing of our common stock on the New York Stock Exchange or another national securities exchange; and
- other risk factors discussed in the "Risk Factors" section of this Annual Report on Form 10–K.

The words "anticipate," "believe," "may," "will," "aim," "estimate," "continue," "intend," "could," "expect," "plan" and other similar expressions, and the negative thereof, are intended to identify forward–looking statements. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward–looking" information. The 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. All of our forward–looking information involve risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors and the timing of any of these risk factors identified in "Item 1A. Risk Factors" in this Annual Report on Form 10–K.

PART I

ITEM 1. BUSINESS

Overview

Cobalt International Energy, Inc. ("we," "our," or "us") 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. In the U.S. Gulf of Mexico, we have four discoveries: North Platte, Shenandoah, Anchor and Heidelberg. Heidelberg began initial production in January 2016 and North Platte, Shenandoah and Anchor are currently in various stages of appraisal. In West Africa, we have made seven aggregate discoveries offshore Angola on Blocks 20 (Orca, Zalophus, Golfinho and Lontra) and 21 (Cameia, Bicuar and Mavinga). We also have a non–operated interest in the Diaba block offshore Gabon.

U.S. Gulf of Mexico

Production and Development

The Heidelberg field is located approximately 140 miles south of Port Fourchon off the Louisiana coast in 5,300 feet of water in the Green Canyon area. Anadarko Petroleum Corporation ("Anadarko") is the operator, and we own a 9.375% working interest. The Heidelberg field was discovered in 2009, appraised in 2012, formally sanctioned in 2013 and began initial production in early 2016.

Heidelberg is currently producing approximately 27,000 BOE per day gross from five wells (the fifth production well was completed in early 2017). As of December 31, 2016, our share of the Heidelberg field had estimated net proved reserves of 3.0 MMBbls of oil, 1.2 Bcf of natural gas and 0.1 MMBbls of natural gas liquids, or 3.3 MMBOE, and a standardized measure of $39.0 million. This oil, natural gas and natural gas liquids reserve information is derived from our reserve report prepared by Netherland, Sewell and Associates, Inc. ("NSAI"), our independent reserve engineering firm.

Appraisal and Development

North Platte

The North Platte field is located approximately 190 miles south of Port Fourchon off the Louisiana coast in 4,500 feet of water in the Garden Banks area. We are the operator, and we own a 60% working interest.

In 2012, we announced the North Platte discovery well encountered over 550 net feet of oil pay in multiple high quality Inboard Lower Tertiary reservoirs. In 2015, we completed drilling the initial appraisal well on North Platte, which also encountered over 550 feet of net oil pay. A subsequent sidetrack to this appraisal well was also successful. In January 2017, we announced the completion of a second appraisal well, North Platte #4. This well encountered approximately 650 feet of net oil pay and results indicate high quality Inboard Lower Tertiary Wilcox reservoirs on the eastern flank of the North Platte field. We recently completed the drilling of the North Platte #4 sidetrack well to further analyze the extent of the eastern flank of the North Platte field. The well encountered oil and has confirmed that reservoir quality sands are present across the entirety of the eastern flank. We are commencing a final sidetrack with the intention of gathering conventional core and fluid samples and expect to complete these operations in the second quarter of 2017. Reservoir characterization, fluid analysis and modeling studies are ongoing to better understand reservoir continuity, productivity and potential resource range in order to optimize the development of the North Platte field. In addition, we are conducting feasibility studies to evaluate varying development concepts to maximize value while attempting to minimize risk.

The primary term in certain leases covering North Platte expired in late 2016 but we continue to hold these leases by conducting continuous operations in the North Platte Unit. This means that we cannot discontinue operations at North Platte for more than 180 days or such leases will terminate unless we apply for and are granted a Suspension of Production ("SOP"). We intend to file for an SOP upon the completion of the current North Platte #4 sidetrack.

Shenandoah

The Shenandoah field is located approximately 170 miles south of Port Fourchon off the Louisiana coast in 5,800 feet of water in the Walker Ridge area. Anadarko is the operator, and we own a 20% working interest.

In 2009, the Shenandoah discovery well was drilled into Inboard Lower Tertiary reservoirs 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. We since have drilled several appraisal wells on Shenandoah. The Shenandoah #2 appraisal well was spud in 2012 and 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 2014 and evaluated the same well–developed reservoir sands 1,500 feet down–dip and 2.3 miles east of the first appraisal well. The Shenandoah #4 appraisal well was drilled in 2015 and tested the updip extent of the basin. The subsequent Shenandoah #4 sidetrack encountered over 600 feet of net oil pay, extending the lowest known oil column downdip. In 2016, Shenandoah #5 was drilled to a total depth of 31,000 feet and encountered more than 1,000 feet of net pay in multiple Inboard Lower Tertiary sands. Approximately 80 feet of conventional core was acquired in the upper Wilcox pay interval. Finally, Shenandoah #6 was spud in late 2016 and encountered water. We are currently sidetracking this well.

The primary terms in certain leases covering our Shenandoah Unit expired in 2014 but are being held by continuous operations. We do not expect the operator to file for approval of an SOP. Unless they do so, we will be required to conduct another operation to perpetuate the acreage within 180 days of the completion of the Shenandoah #6 operations.

Anchor

The Anchor field is located approximately 150 miles south of Port Fourchon off the Louisiana coast in 5,183 feet of water. Chevron Corporation ("Chevron") is the operator, and we own a 20% working interest.

The initial Anchor exploratory well was drilled in 2014 to a total depth of approximately 33,700 feet and encountered 690 feet of net oil pay in multiple Inboard Lower Tertiary reservoirs. In 2015, an appraisal sidetrack well was drilled down dip to delineate the Anchor discovery well. The appraisal well encountered 694 feet of net oil pay in a hydrocarbon column of at least 1,800 feet in Inboard Lower Tertiary reservoirs. A second successful appraisal well, Anchor #3, was drilled in 2016 to a total depth of 34,022 feet. A third successful appraisal well, Anchor #4, was spud in late 2016 and resulted in approximately 800 feet of net oil pay.

The primary terms in certain leases covering our Anchor Unit expired in 2014 and are expected to be held by continuous operations or the filing of and approval of an SOP.

We also operate and own a 100% working interest in two leases that are immediately south of the current Anchor Unit. The Anchor Unit reservoir extends onto these blocks and reservoir simulation suggests additional wells in these leases are required to maximize recovery from this reservoir. We are in discussions with Chevron and the Bureau of Safety and Environmental Enforcement ("BSEE") to bring these two leases into the Anchor Unit as we seek to optimize the development of this field.

Exploration

As of December 31, 2016, we owned interests in 170 blocks within the deepwater U.S. Gulf of Mexico, representing approximately 979,200 gross (504,372 net) acres. While we are currently focused on progressing our existing U.S. Gulf of Mexico discoveries into production, we also plan to continue our exploration activities, including searching for liquids–rich, high–value opportunities in the Atlantic Basin.

Geologic Overview

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. These horizons are characterized by well–defined hydrocarbon systems, comprised primarily of high quality source rock and 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 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 reservoir 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 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.

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 and full azimuth seismic data, to further our understanding of a particular prospect's characteristics, including both trapping mechanics and fluid migration patterns.

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 and/or appraisal wells 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 formal 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 formal project sanction and production."

Alliance with Total

In 2009, we announced a 10 year alliance with TOTAL E&P USA, INC. ("Total") in which, through a series of transactions, we combined our respective U.S. Gulf of Mexico exploratory lease inventory (which excludes our Heidelberg project, Shenandoah project and our Anchor project (which was subsequently added to the excluded inventory), 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. The initial mandatory five well program and Total's obligation to carry a substantial share of our drilling costs has concluded, but Total still remains obligated to pay its share of certain of the general and administrative costs relating to our operations in the deepwater U.S. Gulf of Mexico during the term of the alliance.

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. During the term of the alliance, we agreed to form a reciprocal area of mutual interest ("AMI") with Total that covers substantially all of the deepwater U.S. Gulf of Mexico, subject to certain exclusions. Pursuant to the AMI, we may be obligated to offer Total its 40% share of any U.S. Gulf of Mexico leasehold interests we acquire and Total may be obligated to offer us our 60% share of any U.S. Gulf of Mexico leasehold interests that Total acquires.

West Africa

Our operations in West Africa consist of Block 20 and Block 21, both offshore Angola, and the Diaba Block offshore Gabon. We forfeited our license on Block 9 offshore Angola in March 2016 pursuant to the terms of the Block 9 Risk Services Agreement with Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol").

Angola Transaction

On August 22, 2015, we executed a Purchase and Sale Agreement (the "Agreement") with Sonangol for the sale by us to Sonangol of the entire issued and outstanding share capital of our indirect wholly–owned subsidiaries, CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold our 40% working interest in each of Block 20 and Block 21 offshore Angola. The requisite Angolan government approvals were not received within one year from the execution date and the Agreement terminated by its terms in August 2016. Since then, we have been working with Sonangol to understand and agree on the financial and operational implications of the termination of the Agreement. As part of these discussions, we have requested that Sonangol extend certain deadlines for exploration and development milestones under the Production Sharing Contract ("PSC") and Risk Services Agreement ("RSA") governing Blocks 20 and 21, respectively (collectively, the "License Agreements"). Under the Agreement, we are entitled to be put back in our original position as if no agreement had been concluded, which we believe requires Sonangol to extend all such deadlines by, at a minimum, the one year period the Agreement was pending plus the period of time from the termination of the Agreement until this matter is resolved.

No extensions have been granted to date. Over six months have passed since the termination of the Agreement and there can be no assurance that such extensions will be forthcoming on favorable terms or at all. The failure to receive such extensions would have a material adverse effect on the value of these License Agreements. See "Risk Factors—Risks Relating to Our Business—We may be unable to consummate the sale of our Angolan assets on favorable terms, or at all" and "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. Failure to do so may result in substantial license renewal costs or loss of our interests in these license areas."

We reserve the right to and will vigorously enforce the provisions of the Agreement if Sonangol does not grant the extensions we believe we are entitled to under the Agreement. The dispute resolution procedures of the Agreement require that any dispute be finally resolved under the Rules of Arbitration of the International Chamber of Commerce, with proceedings seated in London, England. In addition, prior to commencing arbitration proceeding, a party must provide the other party with a Notice of Dispute describing the nature of the dispute and the relief requested. Given Sonangol's delays and failure to date to grant the extensions, on March 8, 2017, we submitted such a Notice of Dispute to Sonangol under the Agreement. If Sonangol does not timely resolve this matter to our satisfaction, we intend to move forward with arbitration and at that time we will seek all available remedies at law or in equity. Further, our Angolan assets are indirectly held by a German subsidiary, and we therefore believe we are entitled to certain protections provided under international law under the bilateral investment treaty between Germany and Angola, dated October 30, 2003, including its substantive and procedural protections to investments of German investors.

In 2016, we recorded an impairment of $1,629.8 million related to our Angolan assets in accordance with Accounting Standards Codification 932, *Extractive Activities – Oil and Gas* ("ASC 932"), which requires, among other things, that "sufficient progress" be made with respect to oil and natural gas projects in order to avoid the requirement to expense previously capitalized exploratory or appraisal well costs. Given Sonangol's delays and failure to date to grant the extensions as well as the general investment climate in the Angolan oil and natural gas industry, the procedures of ASC 932 require us to record a full impairment of our Angolan assets at this time. It is important to note that this impairment represents previously capitalized exploratory and appraisal well and other costs. The impairment is not associated with, nor is it indicative of, what we believe to be the intrinsic or fair market value of our Angolan assets. While we continue to market our Angola assets and believe they have substantial value to Cobalt, we believe the sale process has been negatively impacted by the uncertainty surrounding the extensions. We further believe that Sonangol's preference is for us to present potential buyers to them prior to finalizing the terms of the extensions.

Although we plan to continue to fulfill our obligations as operator, we do not plan to make any material additional investments in Angola until the financial and operational implications of the termination of the Agreement are resolved to our satisfaction. In addition, we are currently holding the $250 million initial payment that Sonangol made to us under the Agreement and do not plan to return any part of it until this matter, and the related matter concerning the joint interest receivable owed to us by Sonangol Pesquisa e Produção, S.A. ("Sonangol P&P") under the RSA, is resolved.

Block 20

Block 20 is approximately 1.2 million acres 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. We are the operator of and hold a 40% working interest in Block 20. Our partners on Block 20 include BP Exploration Angola (Kwanza Benguela) Limited ("BP") and Sonangol P&P, with each partner holding a 30% working interest.

Orca

In 2014, we drilled the successful Orca #1 exploratory well to a measured depth of 12,703 feet and encountered approximately 250 feet of net oil pay in the sag and syn–rift reservoirs, and we submitted a declaration of commercial well to Sonangol. We completed drilling the Orca #2 appraisal well in 2015. The results from this well, which included a drill stem test, were successful and confirmed the presence of a large oil accumulation in the sag section of the pre–salt and the discovery of oil in the deeper syn–rift reservoir of the pre–salt. The deadline to submit a declaration of commercial discovery was April 2016, but we were granted an extension to April 2017. Notwithstanding the extensions we are seeking pursuant to the Agreement, we plan to timely file such declaration.

Zalophus and Golfinho

In 2016, we completed the drilling of the Zalophus and Golfinho exploratory wells and submitted declarations of commercial well to Sonangol. Without an extension pursuant to the Agreement, the deadlines for submitting a declaration of commercial discovery for Zalophus and Golfinho are not until April 2018 and June 2018, respectively. Both of these wells have been abandoned pending the results of studies in support of an appraisal decision. The drilling of these two exploratory wells satisfied our minimum work obligations on Block 20, and our letter of credit collateralized by approximately $82.5 million in cash was released in 2016.

Lontra

In 2013, the initial Lontra #1 exploratory well was successfully drilled to a total depth of 13,763 feet and encountered approximately 250 feet of net pay in a very high quality reservoir section. The well encountered both a high liquids content natural gas interval and an oil interval. We submitted a declaration of commercial well to Sonangol in 2013, and the deadline to file a declaration of commercial discovery was in December 2015. We requested an extension of this deadline from Sonangol and such extension was denied. In addition, Presidential Decree No. 212/15 was passed in December 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of the Presidential Decree has on our rights to develop Lontra under the PSC. In light of the apparent conflict between Presidential Decree No. 212/15 and our rights under the PSC and the denial of our request for an extension of the declaration of commercial discovery deadline, we impaired the value of our Lontra discovery in 2015.

License Information

We acquired our license to explore for, develop and produce oil from Block 20 by executing a PSC with Sonangol. The PSC governs our 40% working interest in and operatorship of Block 20 and forms the basis of our exploration, development and production operations on Block 20. The PSC provides for an initial exploration period of five years, which expired on January 1, 2017. We have asked Sonangol to extend this deadline, but there can be no assurance that such an extension will be forthcoming. Without this extension, or the extensions we believe we are entitled to under the Agreement, the exploration period for Block 20 has ended. We do not have contractual rights to sell natural gas on Block 20, but we have the right to use the natural gas during lease and production operations. Any stand–alone natural gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20.

As required by the PSC, we are required to submit a declaration of commercial well to Sonangol within thirty days following a successful exploratory well. Within the earlier of (i) two years after the date of the declaration of commercial well or (ii) six months after the second appraisal well is drilled, we must submit a formal, declaration of commercial discovery to Sonangol. Within thirty days 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 42 months after the formal declaration of commercial discovery, we are required to commence first production from such discovery.

Block 21

Block 21 is approximately 1.2 million acres in size and is 30 to 90 miles offshore Angola in water depths of 1,300 to 5,900 feet in the central portion of the Kwanza Basin. We are the operator of and hold a 40% working interest in Block 21. Our partner on Block 21 is Sonangol P&P with a 60% working interest.

Cameia

In 2012, the Cameia #1 exploratory well was successfully drilled in 5,518 feet of water to a total depth of 16,030 feet, at which point an extensive wireline evaluation program was conducted. The results of this wireline evaluation program confirmed the presence of a 1,180 foot gross continuous hydrocarbon column with over a 75% net to gross pay estimate. Through 2016, we have drilled an additional three wells at Cameia. No natural gas/oil or oil/water contact was evident on the wireline logs. We submitted a declaration of commercial well to Sonangol with respect to the Cameia #1 exploratory well in 2012. We also drilled the Cameia #2 appraisal well in 2012, which was located approximately 2.2 miles south of the Cameia #1 exploratory well and was successful in demonstrating lateral continuity within the reservoir originally encountered by the Cameia #1 exploratory 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 deeper than that which was observed in the Cameia #1 exploratory well.

In 2014, we submitted a formal declaration of commercial discovery to Sonangol, and we submitted the initial integrated field development plan for our Cameia project for approval by Sonangol and the Angola Ministry of Petroleum. Since 2014, we have successfully drilled the Cameia #3, #4 and #5 development wells and completed additional drilling operations on the Cameia #1A well, each of which is planned to be used as part of a Cameia development. Sonangol has not acted on our integrated field development plan for Cameia. Pursuant to discussions with Sonangol, further work on the Cameia development project was ceased while the sale to Sonangol was pending. We do not plan to reinitiate work on the Cameia development plan until, at the earliest, we understand and have agreed on the operational and financial implications of the termination of the Agreement, including the first oil deadline for Cameia. Without an extension pursuant to the Agreement, the first oil deadline for Cameia is August 2017.

Bicuar

In 2014, the Bicuar #1A exploratory well was successfully drilled to a total depth of 18,829 feet and encountered approximately 180 feet of net pay from multiple pre–salt intervals, and we submitted a declaration of commercial well to Sonangol. Without an extension pursuant to the Agreement, the deadline for submitting a declaration of commercial discovery for Bicuar has passed.

Mavinga

In 2013, we announced that the Mavinga #1 exploratory well had reached total depth and encountered approximately 100 feet of net oil pay. This discovery was confirmed by the successful production of oil from mini drill stem tests, direct pressure and permeability measurements and log and core analysis. We submitted a declaration of commercial well to Sonangol in 2013 regarding the Mavinga #1 exploration well. Without an extension pursuant to the Agreement, the deadline for submitting a declaration of commercial discovery for Mavinga has passed.

License Information

We acquired our license to explore for, develop and produce oil from Block 21 by executing an RSA with Sonangol. The RSA governs our 40% working interest in and operatorship of Block 21 and forms the basis of our exploration, development and production operations on this block. The RSA provides for an initial exploration period of five years. Pursuant to Executive Decree No. 259/15, this five year period was extended by two years to March 2017. Without an extension pursuant to the Agreement, the exploration period for Block 21 ends in March 2017. 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 natural gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21.

As required by the RSA, we are required to submit a declaration of commercial well to Sonangol within thirty days following a successful exploratory well. Within the earlier of two years after the date of the declaration of commercial well or six months after the second appraisal well is drilled, we must submit a formal, declaration of commercial discovery to Sonangol. Within ninety days 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 42 months after the formal declaration of commercial discovery, we are required to commence first production from such discovery.

Diaba Block

The Diaba Block is approximately 2.2 million acres in size or approximately 370 U.S. Gulf of Mexico blocks. The block is 40 to 120 miles offshore in water depths of 300 to 10,500 feet in the central portion of the offshore South Gabon Coastal basin. Total Gabon, S.A. ("Total Gabon") is the operator and we own a 21.25% working interest.

We acquired our 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 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.

Under the terms of the PSA and certain approved extensions, acreage not defined by an approved development area will expire in January 2018, subject to certain additional extensions.

In 2013, the Diaman #1B exploratory well was drilled to a total depth of 18,323 feet and encountered approximately 160 to 180 feet of net hydrocarbons in the objective pre–salt formations. Through 2016, we have not drilled any additional wells. Total Gabon does not currently expect to resume exploration drilling on the Diaba block until at least 2018, and is currently evaluating the various extension options on such block, at least one of which it expects to seek.

Geologic Information

Offshore Angola and Gabon are characterized by the presence of salt formations and oil bearing sediments located in pre–salt and above salt horizons. Pre–salt refers to oil accumulations trapped in formations that are beneath and older than the original in–place salt layer. In pre–salt areas, exploration is focused on potential reservoirs that were deposited prior to salt formation. 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 and producing fields 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 that 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.

Oil, Natural Gas and Natural Gas Liquids Data

Reserves

Our reserve information is derived from our reserve report prepared by NSAI, our independent reserve engineering firm. Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids 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 – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimate.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI used 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). NSAI 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.

The data in the table below represents estimates only. Oil, natural gas and natural gas liquids reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and natural gas liquids that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and natural gas liquids that are ultimately recovered.

The following table presents our estimated net proved reserves at December 31, 2016:

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	MMBOE
Proved reserves:				
Developed	1.9	0.8	0.1	2.1
Undeveloped	1.1	0.4	—	1.2
Total	3.0	1.2	0.1	3.3

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves ("PUDs") are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. All proved undeveloped locations conform to the SEC rules defining proved undeveloped locations. We do not have any reserves that would be classified as synthetic oil or synthetic natural gas.

We annually review all PUDs to ensure an appropriate plan for development exists. As of December 31, 2016, none of our PUDs have remained part of our PUD inventory for more than five years following the date they were initially classified as PUDs. We plan to convert our PUDs as of December 31, 2016 to proved developed reserves within five years of the date they were included as part of our PUD inventory of drilling locations by drilling one gross well at a total estimated gross capital cost of $80.9 million.

The following table describes the changes in our PUDs during 2016:

	MMBOE
PUDs as of December 31, 2015	6.2
Revisions of previous estimates	(2.5)
Converted to proved developed reserves	(2.5)
PUDS as of December 31, 2016	1.2

Internal Controls Applicable to our Reserve Estimates

Our policies and procedures regarding internal controls over the recording of our reserves is structured to objectively and accurately estimate our reserves quantities and present values in compliance with both accounting principles generally accepted in the United States and the SEC's regulations.

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. Rod Skaufel, our President, Operations, is accountable for the Reserve Evaluation Policy and the completion of the annual and any in–year reserves estimates. Mr. Skaufel has over 30 years of experience leading oil and natural gas exploration and production operations activities globally. He has a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines.

Our 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 NSAI. James H. Painter, our President, Exploration and Appraisal, acts in the role of RPC. Mr. Painter has over 37 years of experience in the oil and natural gas industry. Mr. Painter has a Bachelor of Science in Geology from Louisiana State University.

For each reserve estimation, 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 natural 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.

The geotechnical, engineering and commercial inputs and interpretations required to calculate the reserves for our portfolio are compiled by our staff, and NSAI is provided full access to information pertaining to the assets and to all applicable personnel. Any differences between reserve estimates internally generated by us and NSAI 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 principal engineers and geoscientists at NSAI primarily responsible for preparing our reserve estimates are Mr. Joseph J. Spellman and Mr. Ruurdjan (Rudi) de Zoeten. 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. 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. Both technical principals meet or exceed the education, training, and experience requirements as defined by the standards of 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.

The audit committee of our board of directors reviews the processes utilized in the development of our Reserve Evaluation Policy and our reserve report prepared by NSAI annually.

Developed and Undeveloped Acreage

The following table sets forth information related to our developed and undeveloped acreage as of December 31, 2016:

	Developed Lease Acres		Undeveloped Lease Acres [1]	
	Gross	**Net**	**Gross**	**Net**
United States:				
Heidelberg	17,280	1,620	—	—
North Platte	—	—	23,040	13,824
Shenandoah	—	—	14,400	2,880
Anchor	—	—	20,160	4,032
Other	—	—	904,320	482,016
Total United States	17,280	1,620	961,920	502,752
West Africa:				
Block 20 [2]	—	—	1,210,569	484,228
Block 21 [2]	—	—	1,210,816	484,326
Gabon	—	—	2,242,634	476,560
Total West Africa	—	—	4,664,019	1,445,114
Total	17,280	1,620	5,625,939	1,947,866

[1] Projects not yet sanctioned for development are classified as undeveloped. If development projects are sanctioned, we will evaluate which acreage associated with these projects could then be classified as developed acreage.

[2] As Sonangol has not yet extended certain deadlines for exploration and development milestones under the License Agreements, we impaired these leases in 2016.

The royalties on our lease blocks in the Gulf of Mexico range from 12.5% to 18.75% with an average of 16.86%.

Most of our U.S. Gulf of Mexico blocks have a 10 year primary term, expiring between 2017 and 2025. 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.

The table below summarizes our undeveloped acreage scheduled to expire in the next five years:

	Year Ended December 31,									
	2017 [1] [2]		2018 [2] [3] [4]		2019		2020		2021 and Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States [5]	28,800	14,132	420,480	204,618	63,360	39,317	11,520	5,184	380,160	218,765
West Africa [6]	2,421,385	968,554	2,242,634	476,560	—	—	—	—	—	—
Total	2,450,185	982,686	2,663,114	681,178	63,360	39,317	11,520	5,184	380,160	218,765

(1) Includes portions of the estimated acreage covering our Shenandoah project in the U.S. Gulf of Mexico. Exploratory and appraisal wells have both discovered hydrocarbons, but a development project has not yet be sanctioned. The acreage in the Shenandoah project is part of the Shenandoah Unit, which was federally approved in 2014. We expect that operations will continue to be conducted on this project in 2017 and that an application for an SOP in order to perpetuate this acreage will be filed at a future date.

(2) Includes portions of the estimated acreage covering our North Platte project in the U.S. Gulf of Mexico. Exploratory and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The acreage in the North Platte project is part of the North Platte Unit, which was federally approved in 2016. We expect that operations will continue to be conducted on the project in 2017 or that an application for an SOP in order to perpetuate this acreage will be filed at a future date.

(3) Include portions of the estimated acreage covering our Anchor project in the U.S. Gulf of Mexico. Exploratory and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The acreage in the Anchor project is part of the Anchor Unit, which was federally approved in 2014. We expect that operations will continue to be conducted on this project in 2017 or that an application for an SOP in order to perpetuate this acreage will be filed at a future date.

(4) Includes 11,520 gross (9,792 net) of acreage in two leases that are contiguous to the south of the Anchor Unit. This acreage may have the potential to be included within the Anchor Unit.

(5) Does not include acreage associated with our North Platte, Shenandoah and Anchor projects, whose primary terms have expired but are being held by continuous operations. We expect that operations will continue to be conducted on these projects during 2017 or that an application for an SOP in order to perpetuate this acreage will be filed at a future date.

(6) As Sonangol has not yet extended certain deadlines for exploration and development milestones under the License Agreements, we impaired these leases in 2016.

Drilling Activity

The following table summarizes our approximate gross and net interest in wells completed by us during 2016, 2015 and 2014, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of wells drilled, quantities of reserves found or economic value.

	2016		2015		2014	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States:						
Exploratory wells:						
Productive	3	1.0	3	1.0	1	0.2
Dry	1	0.7	—	—	2	0.3
Total	4	1.7	3	1.0	3	0.5
Development wells:						
Productive	1	0.1	2	0.2	1	0.1
Dry	—	—	1	0.1	—	—
Total	1	0.1	3	0.3	1	0.1
Total	5	1.8	6	1.3	4	0.5
West Africa:						
Exploratory wells:						
Productive	2	0.8	1	0.4	3	1.2
Dry	—	—	—	—	2	0.8
Total	2	0.8	1	0.4	5	2.0
Development wells:						
Productive	—	—	4	1.2	—	—
Dry	—	—	—	—	—	—
Total	—	—	4	1.2	—	—
Total	2	0.8	5	1.6	5	2.0

As of December 31, 2016, we were participating in the drilling of four gross (1.1 net) wells in the U.S. Gulf of Mexico (including wells that are temporarily suspended). This does not include wells that have been drilled to their targeted depth and then temporarily or permanently plugged and abandoned.

Productive Wells

As of December 31, 2016, we had four gross (0.4 net) productive oil wells in our Heidelberg field.

Drilling Rig Commitments

United States

In 2013, we executed a drilling contract with Rowan (UK) Reliance Companies plc ("Rowan") that provided for a firm three–year commitment which began in February 2015, at a day rate of $0.6 million (inclusive of mobilization fees). We amended this contract in 2016. This amendment provides for the following:

- the contract terminates on March 31, 2017 instead of February 1, 2018;
- we agreed to pay Rowan $95.9 million, of which $76.3 million was paid in 2016, in order to compensate Rowan for amending the term of the contract;
- the early termination fee provided for in the contract was removed;
- should our usage of the drillship be ongoing after March 31, 2017, the operating rate will be reduced from $0.6 million per day to $0.3 million per day and we will have the option to use the drillship or a comparable one at the reduced rate from March 31, 2017 through February 1, 2018; and
- we will provide Rowan a five–year commitment to use Rowan as our exclusive provider of drilling services at market rate, provided Rowan is able to provide the necessary equipment and services that are legally and operationally qualified to perform the drilling services on the schedule we require.

West Africa

We released the Petroserv SSV Catarina in 2016 upon completion of operations on the Golfinho exploratory well.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major and national oil and natural gas companies in acquiring properties, contracting for drilling equipment 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 better able to withstand the financial pressures of significant declines in oil and natural 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 unsuccessful drill attempts and the burdens resulting from changes in relevant laws and regulations, which would have a material adverse effect on our competitive position.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and there can be no assurances 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 leasehold and license interests in accordance with standards generally accepted in the oil and natural gas industry. 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 U.S. Gulf of Mexico leases and, subject to negotiation of terms, our Gabon license area. Our prospect interests are subject to applicable customary royalty and other interests, liens under operating agreements and secured credit facilities, liens for current taxes, and other burdens, easements, restrictions and encumbrances customary in the oil and natural gas industry that we believe do not materially interfere with the use of or affect our carrying value of the prospect interests. Our 10.75% first lien notes and 7.75% second lien notes are secured by mortgages over substantially all of our oil and natural gas properties in the U.S. Gulf of Mexico. With respect to our Angolan assets, we believe we are entitled to the extension of certain deadlines pursuant to the Agreement. There can be no assurance that such extensions will be forthcoming, on favorable terms or at all. The failure to receive such extensions would have a material adverse effect on the value of and title to these License Agreements. See "Item 1 – Business – West Africa – Angola Transaction."

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 HWCG, LLC, formerly Helix Well Containment Group, ("HWCG"), Clean Gulf Associates ("CGA"), the Marine Preservation Association ("MPA"), and National Response Corporation ("NRC").

HWCG serves 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 Fast Response System which is currently capable of facilitating control and containment of spills in water depths up to 10,000 feet and can handle deep, higher pressure wells and could be used in the event a blowout preventer is ineffective.

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 to the memberships above, we also 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 offshore West Africa, when we had active drilling operations, we had contracts in place with Wild Well Control which provided for subsea well control planning, response management, and access to two capping stack systems, subsea debris removal equipment package, and subsea dispersant application equipment in air freight configuration for mobilization to Angola. We also had contracts in place for the provision of oil spill management, equipment and response services. Specifically, we had 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 and The Response Group 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 one 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.

Insurance Coverage

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. In general, our current insurance policies cover physical damage to our oil and natural 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 certain operator's extra expense and 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.

For our U.S. Gulf of Mexico operations, we purchase (i) operator's extra expense insurance with limits per well of $650 million, which covers costs to regain control of a well, to redrill the well and for pollution cleanup expenses associated with a loss of well control incident, (ii) third party liability insurance with limits of $450 million including coverage for third party bodily injury or death, property damage and cleanup of pollution on a sudden and accidental basis, (iii) an insurance policy with limits of $150 million for pollution damages as defined under the Oil Pollution Act of 1990 ("OPA"), and (iv) property insurance for our interest in the Anadarko operated Heidelberg field with limits of full replacement cost value.

In July 2016, the Bureau of Ocean Energy Management ("BOEM") issued Notice to Lessees No. 2016-N01 ("NTL") detailing procedures to determine a lessee's ability to carry out its lease obligations – primarily the decommissioning of Outer Continental Shelf (OCS) facilities – and whether to require lessees to furnish additional financial assurance. While we do not currently foresee this obligation to have a material adverse effect on our liquidity and ability to operate in the U.S. Gulf of Mexico, changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations and consequently have a material adverse effect on our business and results of operations.

We believe that our coverage limits are sufficient and are consistent with what is held by our peers; 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. The continuation of the recent severe declines in oil and natural gas prices has had a negative impact on the foreign currency exchange market for the Angola Kwanza, which in turn has made it more difficult for our insurance provider in Angola to obtain foreign currency in an amount sufficient to procure adequate reinsurance. The inability of our insurance provider to obtain adequate reinsurance may jeopardize our insurance coverage or otherwise impair their ability to perform their obligations under our insurance policies and agreements.

We also purchase director and officer liability insurance. Recoveries under such insurance policies are subject to various deductibles or retentions as well as specific terms, conditions and exclusions. Certain of our insurance providers are disputing coverage for certain expenses and potential liabilities, including with respect to, our current shareholder litigation matters. We are enforcing our rights to coverage pursuant to our insurance agreements with these insurance providers and believe such expenses and potential liabilities are covered by such insurance, within certain thresholds. Additional information about this matter is set forth in "Item 3. Legal Proceedings" contained herein.

We re–evaluate the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to self–insure or maintain only catastrophic coverage for certain risks in the future.

Environmental, Health and Safety Matters and Regulation

Our operations are subject to stringent and complex international, foreign, federal, state and local laws and regulations that govern the protection of the environment as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use or disposal of the material utilized in our operations;
- 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;
- govern gathering, transportation and marketing of oil and natural gas pipeline and facilities construction;
- require remedial measures to mitigate or address pollution from our operations; and
- require the expenditure of significant amounts in connection with worker health and safety.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry continues to be the subject of increased legislation and regulatory attention with respect to environmental matters. The U.S. Environmental Protection Agency (the "EPA") has renewed environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2017 through 2019.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

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

Public interest in the protection of the environment and human health has increased, particularly in light of the Deepwater Horizon incident in the U.S. Gulf of Mexico. In 2010, a semi–submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico 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 natural 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 ("SEMS") for oil and natural gas operations and codifies and makes mandatory the American Petroleum Institute's Recommended Practice 75, (iii) Notice to Lessees ("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.

In 2013, we conducted our own internal SEMS assessment and conducted a third party SEMS audit to ensure we were in compliance with all applicable regulations related to our SEMS; however, in June 2013, the so–called SEMS II Rule amended the Work Place Safety rule to include additional safety requirements. Operators, including us, were required to comply with the SEMS II Rule, and have an independent audit completed by June 2015, which we completed in advance of the deadline. In addition, BSEE proposed revisions in 2013 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 natural gas from Outer Continental Shelf ("OCS") leases. In September 2016, BSEE published the final rule which 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. These new regulations may result in delays in the permitting process.

In April 2016, BSEE finalized new well control regulations, which include more stringent design requirements and operational procedures for critical well control equipment. These requirements include those aimed at improving equipment reliability, regulating drilling margin and preventing blowouts, as well as reforms in well design, well control, casing, cementing, real–time well monitoring and subsea containment. The majority of the requirements became effective in 2016; however, several requirements have more extended timeframes for implementation and compliance. To date, compliance with these new regulations has been managed with minimal operational impact; however, the regulations required to be implemented in the future could result in some delays of our drilling or production operations.

Finally, in July 2016, BOEM issued Notice to Lessees No. 2016-N01 ("NTL") detailing procedures to determine, on an annual basis, a lessee's ability to carry out its lease obligations – primarily the decommissioning of OCS facilities – and whether to require lessees to furnish additional financial assurance. In January 2017, BOEM announced its decision to extend the implementation timeline for the NTL by an additional six months as to leases, rights–of–way and rights–of–use and easement for which there are co-lessees and/or predecessors in interest, in order to continue its interactive process to gather additional input from all interested parties, including industry stakeholders. We do not foresee this obligation to have a material adverse effect on our liquidity and ability to operate in the U.S. Gulf of Mexico.

Resource Conservation and Recovery Act

The U.S. Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non–hazardous wastes. Although drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of oil or natural gas are currently exempt from regulations as hazardous waste under RCRA, we generate waste as a routine part of our operations that may be subject to RCRA. Although a substantial amount of the waste generated in our operations is regulated as non–hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous or exempt waste or categorize some non–hazardous or exempt waste as hazardous in the future. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA") imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties ("PRPs") include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent statutes.

Clean Water Act

The Federal Water Pollution Control Act of 1972, or Clean Water Act, as amended ("CWA"), imposes restrictions and strict controls on the discharge of pollutants, produced waters and other oil and natural gas wastes into waters of the United States. 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 from the EPA 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 natural 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.

Oil Pollution Act

The primary federal law for oil spill liability is the Oil Pollution Act of 1990, (the "OPA"), which amends and augments oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. A liable "responsible party" includes the lessee or permittee of the area in which a discharging 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. 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. Although defenses exist to the liability imposed by OPA, they are limited.

Clean Air Act

Our operations are subject to the federal Clean Air Act, or CAA, and analogous state laws and local ordinances governing the control of emissions from sources of air pollution. 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. The EPA also proposed new air regulations for oil and natural gas exploration, production, transmission and storage. In May 2016, the EPA issued final updated new source performance standards and permitting requirements aimed to limit emissions of methane, certain volatile organic compounds and toxic air pollutants, such as benzene from new, reconstructed and modified oil and natural gas sources. 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.

Protected Species and Habitats

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. 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.

Executive Order 13158, issued in 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States 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 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 have a material adverse effect on 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.

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 United States, 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 ("OSHA"). 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.

Climate Change Legislation

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. Some states, regions and localities have adopted or have considered programs to address GHG emissions. In addition, the U.S. Congress has at times considered the passage of laws to limit GHG emissions, while some members of Congress have publicly indicated an intention to introduce legislation to curb EPA's regulatory authority over GHGs. It is possible that federal legislation related to GHG emissions will be considered by Congress in the future. More stringent laws and regulations relating to climate change and GHGs may be adopted in the future and could cause us to incur material expenses in complying with them.

In the absence of comprehensive U.S. federal legislation on GHG emission control, 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 (the "GHG Reporting Rule"), operators of stationary sources emitting more than established annual thresholds of carbon dioxide equivalent GHGs, as well as onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, must monitor, inventory and report the GHG emissions annually. Significant financial expenditures could be required to comply with the monitoring, recordkeeping and reporting requirements under the EPA's GHG reporting program. We do not believe, however, that our compliance with applicable monitoring, recordkeeping and reporting requirements under the GHG reporting program as recently amended will have a material adverse effect on our results of operations or financial position. We have submitted annual reports for emissions starting with our 2012 GHG emissions. Under EPA regulations finalized in May 2010 (formerly referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The EPA attempted to require the permitting of GHG emissions; although the U.S. Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants.

In June 2013, the Obama Administration released its Climate Action Plan ("CAP") that, among other things, called upon the EPA to promulgate greenhouse gas regulations for new and existing power plants. To that end, the EPA finalized the Clean Power Plan in August 2015, which sets forth binding guidelines for GHG emissions from existing power plants, as well as rules relating to GHG emissions from new, modified and reconstructed power plants. 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, CAP called upon the EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and natural gas industry. In August 2015 the EPA proposed new regulations to reduce methane emissions from oil and natural gas operations in an effort to reduce methane emissions from the oil and natural gas sector by up to 45 percent by 2025. The EPA issued updated and final new source performance standards regulations in 2016 for reducing methane from new and modified oil and natural gas production sources and natural gas processing and transmission sources. Additionally, the EPA and the National Highway Traffic Safety Administration administer GHG emissions standards for heavy, medium and light duty vehicles, which have become increasingly stringent over time. The most recent standards were issued in 2012 for light duty vehicle model years 2017 through 2025 and, in August 2016, the two agencies finalized a new set of such standards for medium and heavy duty vehicles model years 2018 through 2027. Depending on the regulatory reach of CAA legislation implementing regulations or new EPA and/or state, regional or local rules restricting the emission of GHGs, we could incur significant costs to control our emissions and comply with regulatory requirements.

On the international level, in April 2016, 195 nations, including the United States, Angola and Gabon, signed and officially entered into an international climate change accord (the "Paris Agreement"), which calls for countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG emissions targets. A long–term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre–industrial era. The Paris Agreement is in effect a successor to the Kyoto Protocol, pursuant to which protocol various nations, including Angola and Gabon, have committed to reducing their GHG emissions. The Kyoto Protocol has been extended until 2020.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. Moreover, the federal, regional, state and local regulatory initiatives also could have a material adverse effect on the marketability of the oil, natural gas and natural gas liquids we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors. Each of these pending, proposed and future laws, regulations and initiatives could have a material adverse effect on us directly as well as indirectly, as they could decrease the demand for oil and natural gas.

OSHA and Other Laws and Regulations

To the extent not preempted by other applicable laws, we are subject to the requirements of OSHA and comparable state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes, where applicable, 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. We believe that we are in substantial compliance with all such existing laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations; however, we cannot assure you that the passage of more stringent laws and regulations in the future will not have a negative impact our business activities, financial condition or results of operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential sanctions for noncompliance. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry may increase our cost of doing business, 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.

Exploration and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making difficult the prediction of future costs or the impact of regulatory compliance attributable to new laws and statutes. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most jurisdictions in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the plugging and abandoning of wells and decommissioning of related equipment; and
- produced water and disposal of waste water, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

Federal Regulation of Transportation 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.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural 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

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 byproducts 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.

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 natural 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 natural 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. New legislation reorganizing the Petroleum Sector currently being proposed could change these powers but, to date, Sonangol's powers in this respect have not changed.

The Foreign Exchange Law for the Petroleum Sector requires, among other things, that all foreign exchange operations be carried out through Angolan banks and that oil and natural gas companies open local bank accounts in foreign currencies in order to pay local taxes, to pay for local petroleum operations related expenses, and to pay for goods and services supplied by both resident and non–resident suppliers and service providers. As a consequence, foreign currency proceeds obtained by oil and natural 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.

The Foreign Exchange Law for the Petroleum Sector was further supplemented by the Banco Nacional de Angola's (the "BNA") Order 20/2012. Under this statute, oil and natural gas companies (including 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. In addition, the BNA issued Order 7/14 which determines that oil and natural gas companies shall sell the foreign currency required to pay taxes and other tax dues before the State to the BNA. The operators shall also sell to BNA the foreign currency necessary to pay foreign exchange residents.

Executive Decree 333/13 ("ED 333/13") had required companies that provide taxable services to oil and natural gas companies to assess the applicable consumption tax, and oil and natural gas 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. ED 333/13 was repealed by Presidential Legislative Decree 3–A/14 which provides that there will be no consumption tax applicable to the oil and natural gas companies which are in the exploration and development phases until first oil, subject to certain exceptions. Subject to the approval of the Ministry of Finance and Sonangol, oil and natural gas 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 224/12 approved the Operational Discharge Management Regulations which 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% as a base for the manufacture of drilling fluids are prohibited. In 2014, Executive Decree 97/14 approved a moratorium on the implementation of the above mentioned regulations.

Gabon

In 2014, a new Hydrocarbons Law entered into force to regulate oil and natural gas activities in Gabon. 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 natural 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.

All oil and natural gas 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 and natural gas companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile site rehabilitation funds for the Hydrocarbon activities 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, Gabon's national oil company 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 and to the State's preemption rights. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within two years from the incorporation of the local branch.

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

Hydrocarbons agreements entered into prior to the Hydrocarbons Law's publication remain in force until their expiration 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 Hydrocarbons 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 Hydrocarbons Law will not have a material adverse effect on our operations or assets in Gabon.

Employees

As of December 31, 2016, we had 111 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, 2016, we had 37 contractors, consultants and secondees working in our offices and field locations.

In 2016, in response to the decline in oil prices and in light of the then proposed sale transaction with Sonangol, we undertook a reduction in force that eliminated 117 full time employees and 98 contractors.

Available Information

Our annual reports on Form 10–K, quarterly reports on Form 10–Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are made available free of charge on our website at www.cobaltintl.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. Our website also includes our Code of Business Conduct and Ethics and our corporate governance guidelines. No information from either the SEC's website or our website is incorporated herein by reference.

EXECUTIVE OFFICERS

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

Name	Age	Position
Timothy J. Cutt	56	Chief Executive Officer
David D. Powell.....	58	Chief Financial Officer
Rodney M. Skaufel....	54	President, Operations
James H. Painter.....	59	President, Exploration and Appraisal
Jeffrey A. Starzec.....	40	Executive Vice President, General Counsel and Secretary
Richard A. Smith.....	57	Senior Vice President, Strategy and Business Development

Timothy J. Cutt has served as Chief Executive Officer since July 2016. Prior to joining Cobalt, Mr. Cutt served as President, Petroleum of BHP Billiton, accountable for its global oil and natural gas business from July 2013 until March 2016. Mr. Cutt joined BHP Billiton in 2007 as the President of the Production Division in the Petroleum business where he was accountable for running operations in the UK, Pakistan, Trinidad & Tobago, Algeria, Australia and the U.S. During this time, he was instrumental in building the operating capacity for BHP Billiton's Deepwater Business. Before joining BHP Billiton, Mr. Cutt held positions in engineering, operations and senior management for 24 years with Mobil Oil Corporation and then ExxonMobil. During this time he spent 10 years supporting exploration and production activities in the Gulf of Mexico and held positions of President Hibernia Management and Development Co. and President of ExxonMobil de Venezuela. Mr. Cutt has a Bachelor of Science Degree in Petroleum Engineering from Louisiana Tech University.

David D. Powell joined Cobalt in July 2016 and serves as Chief Financial Officer. Mr. Powell has more than 35 years of experience in the oil and natural gas industry. He previously served as Chief Financial Officer for BHP Billiton – Petroleum and was accountable for all finance, accounting, commercial assurance, supply chain and information technology activities from March 2009 until May 2016. Mr. Powell joined BHP Billiton from Occidental Oil and Gas Corporation where he served as Vice President Houston Finance from November 2007 to February 2009. Mr. Powell began his employment with Occidental Oil and Gas Corporation in 1981 and held progressively more senior roles in the United States, Argentina, Russia, Malaysia and Qatar until he joined BHP Billiton - Petroleum. Mr. Powell started his career in 1980 with the public accounting firm Deloitte, Haskins and Sells. Mr. Powell holds a Bachelor of Science in Accounting, graduating summa cum laude from William Jewell College, he completed the Advanced Management Program at the Harvard Business School and he holds a Certified Public Accountant certificate from the state of Missouri.

Rodney M. Skaufel joined Cobalt in August 2016 and serves as President, Operations. Mr. Skaufel has more than 30 years of experience in the oil and natural gas industry and brings deep technical capability and strategic focus. Prior to joining Cobalt, Mr. Skaufel served as Head of Strategic Planning, Corporation for BHP Billiton and was the head of strategic planning, value management and the investment office. Mr. Skaufel joined BHP Billiton in 2007 and, prior to his promotion to his most recent position there, he served as President, North America Shale from 2013 to 2015. Prior to that, in 2012 he held the title of President, Conventional Business. He also led BHP Billiton's engineering function and Central Engineering organization comprised of subject matter experts in deepwater floating systems including subsea, subsurface, and umbilicals. Mr. Skaufel joined BHP Billiton from ExxonMobil where he served as Technical Operations Manager – Chad–Cameroon from 2003 to 2007 and Planning Advisor from 2000 to 2003. Mr. Skaufel began his career in 1985 with Mobil Oil Corporation and held progressively more senior roles until he joined ExxonMobil. Mr. Skaufel holds a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines.

James H. Painter has served as President, Exploration and Appraisal since January 2017. Mr. Painter previously served as Executive Vice President from April 2013 until December 2016, and as Executive Vice President, Gulf of Mexico from our inception in November 2005 until April 2013. Mr. Painter has more than 37 years of experience in the oil and natural 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 natural 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 natural 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.

Jeffrey A. Starzec has served as Executive Vice President, General Counsel and Secretary 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 2006 until 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, Strategy and Business Development since August 2016. Mr. Smith previously served as Senior Vice President from September 2014 until July 2016. Prior to that, 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, International. Mr. Smith has over 34 years of oil and natural 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 natural 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 natural gas exploration and production company operating in Angola. Mr. Smith's additional industry experience includes leadership positions at various companies in the oil and natural 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.

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 have a material adverse effect on 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

Our substantial level of indebtedness, which may increase over time, could reduce our financial flexibility. We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

As of March 1, 2017, we have $1.8 billion aggregate principal amount of convertible senior notes (the "Convertible Notes") and $1.2 billion aggregate principal amount of first lien and second lien senior secured notes (the "Secured Notes" and, together with the Convertible Notes, the "Notes,") outstanding. We are restricted from incurring certain additional indebtedness pursuant to these debt instruments in the future. In addition to our debt obligations, we have a substantial amount of contractual commitments pursuant to our license and lease agreements, among other things. Our level of indebtedness could affect our operations in several ways, including the following:

- 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 significant portion or all of our cash flows could be used to service our indebtedness;

- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions, such as the continued downturn in oil and natural gas prices; and

- 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.

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 and our ability to borrow or otherwise use money to service, repay or refinance our indebtedness. 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.

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, restrictive covenants in our existing debt agreements, the value of our assets and our performance at the time we need capital. In particular, weakness in the financial markets or other financing sources due to continued depressed prices for oil and natural gas may delay or prevent us from accessing additional funding sources to refinance and/or service our existing indebtedness. Further, there may be a material adverse effect on our liquidity and financial condition if we are unable to consummate key operational transactions, including the sale of our working interests in Blocks 20 and 21 offshore Angola and certain U.S. Gulf of Mexico assets. If any of these adverse conditions occur or continue, we may not be able to generate sufficient cash flows to pay the principal and interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. If we are unable to satisfy our obligations under our debt agreements, our creditors could elect to declare some or all of our debt to be immediately due and payable, our secured noteholders could elect to commence foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation.

In order to increase our liquidity to levels sufficient to meet our debt service obligations, we are currently considering a number of actions, including minimizing capital expenditures, considering asset sales, aggressively managing working capital and issuing new debt or equity. There can be no assurance that sufficient liquidity can be raised from one or more of these transactions. Furthermore, we cannot assure you that any of our strategies will yield sufficient funds to meet our liquidity needs, including for payments of interest and principal on our debt in the future, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations.

We may be unable to continue as a going concern.

We have substantial debt obligations and our ongoing capital and operating expenditures will vastly exceed the revenue we expect to receive from our oil and natural gas operations in the near future. If we are unable to raise substantial additional funding or consummate significant asset sales on a timely basis and/or on acceptable terms, we may be required to significantly curtail our exploration, appraisal and development activities.

The consolidated financial statements included in this Annual Report on Form 10–K have been prepared on a going concern basis of accounting, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The consolidated financial statements do not reflect any adjustments that might be necessary should we be unable to continue as a going concern. Our ability to continue as a going concern is subject to, among other factors, our ability to monetize assets, our ability to obtain financing or refinance existing indebtedness, our ability to continue our cost cutting efforts, the production rates achieved from our discoveries, oil and natural gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed and cost 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. There can be no assurance that we will be able to obtain additional funding on a timely basis and on satisfactory terms, or at all. In addition, no assurance can be given that any such funding, if obtained, will be adequate to meet our capital needs and support our growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then our operations would be materially negatively impacted.

If we become unable to continue as a going concern, we may find it necessary to file a voluntary petition for reorganization under the Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure. For additional information, please see “Item 8. Financial Statements and Supplementary Data” contained herein.

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.

In 2016, we generated $16.8 million of oil, natural gas and natural gas liquids revenues. Our capital outlays and operating expenditures will increase substantially over at least the next several years as we expand our operations and will vastly exceed the revenue we receive from our oil and natural gas operations. Developing major offshore oil and natural 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. The recent significant and sustained 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:

- our ability to consummate key divestments or acquisitions, including the sale of our interests in Blocks 20 and 21 offshore Angola;
- the performance of the producing wells on our Heidelberg development;
- the scope, rate of progress and cost of our exploration, appraisal and development activities;
- lack of partner participation in exploration, appraisal or development operations;
- 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 meet the timelines for development set forth in our leases;
- the terms and timing of any drilling and other production-related arrangements that we may enter into; and
- the timing of partner and governmental approvals and/or concessions.

Our business plan requires us to raise a substantial amount of capital. Additional financing may not be available on favorable terms, or at all, due to our substantial level of indebtedness, the restrictions in our indentures governing our Secured Notes, the continuing downturn in oil and natural gas prices or otherwise. Even if we succeed in selling additional securities to raise additional capital, 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 similar to, or more restrictive than, those that govern our Secured Notes, that would restrict our business activities. If we choose to farmout interests in our leases or licenses, we would dilute our ownership interest subject to the farmout and any potential value resulting therefrom, and we may lose operating control over such leases or licenses.

In response to the continued decline in oil and natural gas prices, certain of our partners have announced significant 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 dramatically increase our share of the costs of such operation and may cause us to cancel or delay certain operations and could have a material adverse effect on our liquidity and results of operations.

We may be unable to consummate the sale of our Angolan assets on favorable terms, or at all.

In August 2016, the Agreement for the sale of our 40% working interest in each of Block 20 and Block 21 offshore Angola was automatically terminated pursuant to its terms. The Agreement provided that, upon termination of the Agreement, the parties are to be restituted in order to put them in their original positions as if no agreement had been executed. We are working with Sonangol to understand and agree on the financial and operational implications of the termination. We have requested that Sonangol extend certain deadlines for exploration and development milestones under our License Agreements. See "–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. Failure to do so may result in substantial license renewal costs or loss of our interests in these license areas." There can be no assurance that such extensions will be forthcoming, on favorable terms or at all. The failure to receive such extensions would have a material adverse effect on the value of these License Agreements.

We reserve the right to and will vigorously enforce the provisions of the Agreement if Sonangol does not grant the extensions we believe we are entitled to under the Agreement. The dispute resolution procedures of the Agreement require that any dispute be finally resolved under the Rules of Arbitration of the International Chamber of Commerce, with proceedings seated in London, England. In addition, prior to commencing arbitration proceeding, a party must provide the other party with a Notice of Dispute describing the nature of the dispute and the relief requested. Given Sonangol's delays and failure to date to grant the extensions, on March 8, 2017, we submitted such a Notice of Dispute to Sonangol under the Agreement. If Sonangol does not timely resolve this matter to our satisfaction, we intend to move forward with arbitration and at that time we will seek all available remedies at law or in equity.

In addition, discussions concerning the payment of certain joint interest receivables owed to us by an affiliate of Sonangol and the return of the first installments paid to us by Sonangol upon the execution of the Agreement are ongoing. Furthermore, the Angolan government passed Presidential Decree No. 212/15 which established a new Block 20/15 concession area covering our Lontra discovery. This decree ostensibly conflicts with our rights to develop oil from the Lontra discovery under the PSC. Accordingly, it is unclear what effect the passage of this decree has on our rights to develop Lontra under the PSC. There can be no assurance that we will be able to come to an agreement with Sonangol concerning these items on satisfactory terms or at all. The failure to do so could have a material adverse effect on the value of our licenses and our ability to sell them. The inability to sell our Angolan assets to a third party on acceptable terms, or at all, or the failure to receive payment in full of the joint interest receivables owed to us, would each have a material adverse effect on our business, results of operations and financial condition, including our ability to service and/or repay our substantial existing indebtedness.

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. Failure to do so may result in substantial license renewal costs or loss of our interests in these 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) may lapse and we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses.

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 the earlier of (i) two years after the date of the declaration of commercial well or (ii) six months after the second appraisal well is drilled, we must submit a formal, declaration of commercial discovery to Sonangol. Within thirty days (in the case of Block 20) or 90 days (in the case of Block 21) 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 42 months after the formal declaration of commercial discovery, we are required to commence first production from such discovery. 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.

Certain drilling and declaration requirements will be very difficult to achieve with respect to our Cameia, Orca and Lontra discoveries and may require the need to renegotiate our License Agreements with Sonangol. Without the extensions we believe we are entitled to under the Agreement, the deadline to file a declaration of commercial discovery with respect to our Lontra discovery was in December 2015. Given the sale of our Angolan assets was pending at such time, we did not meet that deadline, although we requested an extension of this deadline from Sonangol and such extension was denied. Furthermore, Presidential Decree No. 212/15 was passed in December 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of this Presidential Decree has on our rights under the PSC with respect to our Lontra discovery. Presidential Decree Laws may need to be passed in Angola, along with the renegotiation of our PSC, in order to preserve our development rights with respect to Lontra. In light of (i) the apparent conflict between Presidential Decree No. 212/15 and our rights under the PSC and (ii) the denial of our request for an extension of the declaration of commercial discovery deadline with respect to Lontra, we impaired the value of our Lontra discovery in 2015.

In addition, most of our deepwater U.S. Gulf of Mexico blocks have a 10 year primary term, expiring between 2017 and 2025. 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 North Platte, Shenandoah and Anchor discoveries are beyond their primary term, and the operator must conduct continuous operations or obtain an SOP in order to maintain such leases. In addition, certain of our targeted exploration prospects have leases that expire within the next 12 months and even if we were to commence exploration activities prior to lease expiration, we could be required to conduct continuous operations on those prospects if the initial exploration activities were to be successful. This requirement to conduct continuous drilling operations may cause us to relinquish such leases despite the fact that an exploration well on such leases was successful. 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 we, or 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 an SOP. 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 have a material adverse effect on our business. For each of our lease 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.

A decline in prices for oil and natural gas may have a material adverse effect on our business, financial condition and results of operations.

The severe downturn in oil and natural gas prices over the last few years has had, and any future downturn will have, a significant material adverse effect on our business, results of operations, liquidity and the market price of our common stock. The prices that we receive for our oil, natural gas and natural gas liquids production affects our revenues, profitability, liquidity, access to capital and future growth rate. Historically, prices for oil and natural gas have been volatile and will likely continue to be volatile in the future. These prices depend on numerous factors, all of which are beyond our control.

These factors include, but are not limited to:

- 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 oil and natural gas properties; or
- limiting our access to sources of capital, such as equity and long–term debt.

Any future substantial and extended decline in oil and natural gas prices may have a material adverse effect on our future business, financial condition, the market price of our common stock results of operations, liquidity or ability to finance planned capital expenditures.

Our indentures governing the Secured Notes contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could have a material adverse effect on our ability to meet our future goals or raise additional capital.

Our indentures governing the Secured Notes include certain covenants that, among other things, restrict:

- our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;
- our incurrence of additional secured indebtedness (including project finance indebtedness);
- the granting of liens, other than liens created pursuant to the indenture governing the Senior Secured Notes and certain permitted liens;

- mergers, consolidations and sales of all or a substantial part of our business or licenses; and

- the sale of assets.

All of these restrictive covenants may limit our ability to expand or pursue our business strategies as well as raise additional capital to fund our business operations or service our debt obligations. Our ability to comply with these and other provisions of our indentures governing the Secured Notes may be impacted by changes in economic or business conditions, our results of operations or events beyond our control. The breach of any of these covenants could result in a default under the indentures governing the Secured Notes or the indenture governing the Convertible Notes, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under such indentures, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders, successors or assignees under the Secured Notes could proceed against the collateral securing the indebtedness. If the indebtedness under our indentures governing the Secured Notes were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. In addition, the limitations imposed by the indenture governing the Secured Notes on our ability to incur additional debt and to take other actions might significantly impair our ability to obtain other financing.

Provisions of our indentures governing the Notes could discourage an acquisition of us by a third party.

Certain provisions of the indentures governing 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 "change of control" (as defined in the indentures governing the Secured Notes) and a "fundamental change" (as defined in the indentures governing the Convertible Notes), 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 at, in the case of the Secured Notes, a premium to the aggregate principal amount of such Notes, and in the case of the Convertible Notes, to the aggregate principal amount of such Notes (in each case plus accrued and unpaid interest). In addition, the acquisition of us by a third party could require us, under certain circumstances, to increase the conversion rate for our Convertible Notes 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.

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

All of our appraisal and development projects 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 which began producing oil and natural gas in 2016. 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 production facilities, pressure maintenance systems, natural 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 natural gas from Inboard Lower Tertiary reservoirs.

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:

- the timing or occurrence of the closing of the sale of our interests in Blocks 20 and 21 offshore Angola;
- persistent low oil and natural gas prices;
- 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;
- inability to obtain 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.

The productivity of the Heidelberg field is uncertain.

Oil, natural gas and natural gas liquids production from the Heidelberg field commenced in January 2016. Production rates from deepwater oil and natural gas developments may deviate substantially from expectations due to a variety of factors, including unforeseen geologic complexities, inability to maintain adequate pressures within the field reservoir, and failure or non–performance of key production equipment and infrastructure, including production facilities. Deepwater oil and natural gas developments are extremely complex and the downside risks to production levels are especially acute in the early stages of production. If we realize lower production rates than expected from Heidelberg, this may cause a material adverse effect on our results of operations, liquidity and financial condition.

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 natural gas or other hydrocarbons we may not have rights to develop or produce (such as in Angola). 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. 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, as applicable, and transportation costs may prevent such prospects from being economically viable. 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, there could be a material adverse effect on our business, financial condition and results of operations.

To date, there has been limited exploration, appraisal and development drilling which has targeted the Inboard Lower Tertiary trend in the deepwater U.S. Gulf of Mexico, an area in which we intend to focus a substantial amount of our exploration, appraisal 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" refers to our existing discoveries upon which we have conducted appraisal or development drilling. Our use of the term "discoveries" refers to our existing discoveries 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 exploratory 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 exploratory 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 natural 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.

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 and where we may have already made a significant investment. We may also decide to abandon a project based on forecasted oil and natural 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.

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.

Numerous uncertainties are inherent in estimating quantities of our reserves. Our estimates of our net proved reserve quantities are based upon reports from NSAI, the independent petroleum engineering firm used by us. The process of estimating oil, natural gas and natural gas liquids reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding future oil, natural gas and natural gas liquids prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and natural gas liquids attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, our wells are characterized by low production rates per well. As a result, changes in future production costs assumptions could have a significant effect on our proved reserve quantities.

The standardized measure of discounted future net cash flows of our estimated net proved reserves is not necessarily the same as the current market value of our estimated net proved reserves. We base the discounted future net cash flows from our estimated net proved reserves on average prices for the 12 month period preceding the date of the estimate. Actual prices received for production and actual costs of such production will be different than these assumptions, perhaps materially.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracy in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We are not, and may not be in the future, the operator of all our properties, and do not, and may not in the future, hold all of the working interests in our properties. 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.

As we do not operate our Heidelberg, Shenandoah and Anchor projects, we are subject to additional risks to our business and financial condition as the ultimate technical, operational and economic success of these projects will depend upon the efforts of the operators of the projects. The long–term success of our business will depend in part upon whether these projects are successful from a technical, operational and economic perspective, which we will have limited ability to control or influence as a non–operator.

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.

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.

Development drilling may not result in commercially productive quantities of oil and natural 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 out 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 natural gas from these or any other potential drilling locations.

Further, some of the U.S. Gulf of Mexico leases we own may benefit from unitization with adjacent leases, controlled by third parties. If these third parties are unwilling to unitize such leases with ours, this may necessitate our drilling additional, unforeseen wells to preserve our leases. Failure to drill these wells could result in the loss of acreage through lease expirations. Our actual drilling and development plans and locations may be materially different from our current expectations which could have a material adverse effect 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 offshore Gabon due to a general lack of infrastructure and, in the case of offshore Gabon, underdeveloped oil and natural 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 continued depression of 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 a material adverse effect on our business, financial position and results of operations.

We only recently began producing oil and natural gas and our future performance is uncertain.

In January 2016, we began producing oil and natural gas from our Heidelberg project in which we own just a 9.375% working interest. We do not currently produce oil or natural gas from any of our other properties and do not expect to commence production from those properties for a significant amount of time. Production from our oil and natural 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 from our other properties will also depend upon us being able to obtain substantial additional capital funding on a timely basis and attract and retain adequate personnel. We have only been generating revenue from operations for a very short period of time and expect to generate only limited revenue from production for several years. 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 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, there would be a material adverse effect on our operating results 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.

The inability of one or more third parties who contract with us to meet their obligations to us may have a material adverse effect on 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. The significant decline in oil and natural gas prices over the past eighteen months may make it more difficult for our partners to meet their obligations to us under applicable joint operating and other agreements. We may be unable to recover such outstanding amounts, which would materially negatively impact our liquidity and financial position. Furthermore, in response to the recent decline in oil and natural gas prices, certain of our partners have announced significant 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 dramatically increase our share of the costs of such operation and may cause us to cancel or delay certain operations and there could be a material adverse effect on our liquidity and results of operations.

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 severe decline in oil and natural gas prices and the resulting adverse impact on our industry may have an material adverse impact on or contribute to the insolvency of certain third parties from which we contract drilling, development and related oilfield services, as well as block partners, 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 have a material adverse effect on 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. 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.

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 natural 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 natural 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. 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.

Our operations 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 capital and 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 onshore exploration or exploration in shallow waters. 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. 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 in the U.S. Gulf of Mexico generally lack the physical and oilfield service infrastructure present in shallower waters. 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 natural 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 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 actual and projected path of the tropical storms or hurricanes. In the future, during a shutdown period, we may be unable to access well sites 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 operations subjects us to an increased risk from factors specifically affecting those areas.

Our operations are currently concentrated in the deepwater U.S. Gulf of Mexico and offshore West Africa in Angola. In addition, we have an interest in the Diaba Block offshore 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 natural gas exploration, including the DOI, BOEM and 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 natural 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.

We are subject to regulatory risk in the U.S. Gulf of Mexico, and regulations enacted over the past several years may have significantly increased certain of the risks we face and increased the cost of operations in the U.S. Gulf of Mexico.

In 2010, the Transocean Deepwater Horizon, a semi–submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico, 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 natural gas exploration, including the DOI, BOEM and 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.

If we sell our Angolan assets, our business will be almost entirely focused on 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 have a material adverse effect on our business, financial position or future results of operations.

In April 2015, BSEE proposed new well control regulations, which include more stringent design requirements and operational procedures for critical well control equipment, including those aimed at improving equipment reliability, regulating drilling margin and preventing blowouts, as well as reforms in well design, well control, casing, cementing, real-time well monitoring and subsea containment. Certain studies suggest that many wells drilled safely since 2010 could not be drilled as designed under the proposed regulations. If the rule were to be finalized as drafted, certain of our drilling operations may be delayed as required controls are implemented or may become infeasible or impossible due to the increased requirements.

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

- 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, financial assurance requirements 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 natural gas exploration and development activities.

Opposition toward oil and natural gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and natural 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, seismic acquisition activities 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 (the "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 2010, we were made aware of allegations of a connection between senior Angolan government officials and one of these companies. In 2011, a formal order of investigation was issued by the SEC related to these allegations and, to avoid non–overlapping information requests, we voluntarily contacted the U.S. Department of Justice ("DOJ") with respect to the SEC's investigation and offered to respond to any requests the DOJ may have.

We were notified in January 2015 that the SEC's investigation had concluded and that the SEC did not intend to recommend any enforcement action. In February 2017, we received a letter from the DOJ advising us that the DOJ has closed its investigation into our operations in Angola. This formally concluded the DOJ investigation and no regulatory action has been taken against us as a result of these investigations.

On March 13, 2017, the SEC informed us by telephone that it had initiated an informal inquiry regarding Cobalt related to the Sonangol Research and Technology Center (the "Technology Center"). As background, on December 20, 2011, we executed the PSC under which we and BP are required to make certain social contributions to Sonangol, including for the Technology Center. On March 13, 2017, we also received a voluntary request for information regarding such inquiry. We believe our activities in Angola have complied with all applicable laws, including the FCPA, and we will cooperate with the SEC's inquiry.

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. There can be no assurance that we will not become subject to additional investigations or inquiries by the SEC, DOJ or other governmental authorities in the future.

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 have resulted in a significant increase in the fuel economy of cars and light trucks and have reduced the future demand for 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 natural 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. We intend to vigorously defend and prosecute any such lawsuits and do not believe they will have a material adverse effect on our business. In addition, on March 8, 2017, we submitted a Notice of Dispute to Sonangol reserving our rights to file an arbitration proceeding under the Agreement if Sonangol does not timely resolve the matters relating to the extensions to our satisfaction. If it is not resolved to our satisfaction, we intend to move forward with arbitration and will seek all available remedies at law or in equity. 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 natural 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, or seek, the exclusive jurisdiction of courts or other tribunals 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 jurisdictions, including Angola, Gabon, the United States, the Cayman Islands, Germany and other jurisdictions, or international treaties 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.

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

The international oil and natural gas industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of oil and natural 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 natural 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 natural 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 natural 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, in Angola we are subject to the 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 natural 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 natural 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. As a result of the significant downturn in oil and natural gas prices and recent devaluation of the Angola kwanza versus the U.S. dollar, it has become more difficult to conduct foreign currency transactions in Angola. Any of these consequences could have a material adverse effect on our results of operations.

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, there may be a material adverse effect on our results of operations.

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 natural 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, there may be 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 natural gas industry has become increasingly dependent on digital technologies to conduct day–to–day operations including certain exploration, development, production and financial 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 natural 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 natural gas in increasingly difficult physical environments, such as below–salt deepwater, and global competition for oil and natural gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber–attacks, 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.

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 are subject to change and may also 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 natural 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 GHGs, 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 attempted to require the permitting of GHG emissions. The U.S. Supreme Court struck down the permitting requirements, but upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. 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 CAP, the EPA finalized the Clean Power Plan in August 2015, which sets forth binding guidelines for GHG emissions from existing power plants, as well as rules relating to GHG emissions from new, modified and reconstructed power plants. 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. 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 natural gas industry. In addition, in August 2015 the EPA proposed new regulations to reduce methane emissions from oil and natural gas operations in an effort to reduce methane emissions from the oil and natural gas sector by up to 45 percent by 2025. The EPA is also expected to expand the GHG Reporting Rule to cover all segments of the oil and natural gas industry. Additionally, the EPA and the National Highway Traffic Safety Administration administer GHG emissions standards for heavy, medium and light duty vehicles, which have become increasingly stringent over time. 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 have a material adverse effect on our operations and the demand for our products.

It is unclear what impact the new administration may have on the aforementioned laws and regulations. To the extent that such laws or regulations are modified, the change could materially impact our business and operations.

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 have a material adverse effect on 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 natural 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 natural 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 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.

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. The continuation of the recent severe declines in oil and natural gas prices has had a negative impact on the foreign currency exchange market for the Angola Kwanza, which in turn has made it more difficult for our insurance provider in Angola to obtain foreign currency in an amount sufficient to procure adequate re-insurance. The inability of our insurance provider to obtain adequate re-insurance may jeopardize our insurance coverage or otherwise impair its ability to perform its obligations under our insurance policies and agreements. 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.

In addition, even when insurance is purchased, we may encounter disputes with our insurance providers concerning coverage and such providers may attempt to deny coverage. For example, certain of our insurance providers are disputing coverage for certain expenses and potential liabilities, including with respect to our current shareholder litigation matters. We are enforcing our rights to coverage pursuant to our insurance agreements with these insurance providers and believe such expenses and potential liabilities are covered by such insurance, within certain thresholds. Should we be unsuccessful in enforcing rights under our insurance agreements, should we breach the terms of our insurance agreements or should such insurance agreements not provide the coverage we believed to be in place, any losses we incur which are not covered wholly or partially by insurance could have a material adverse effect on our results of operations and financial condition.

We may be required to pay a material cash sum to Whitton Petroleum Services Limited ("Whitton") in connection with the closing of the sale of our interests in Blocks 20 and 21 offshore Angola.

In February 2009, we entered into a restated overriding royalty agreement (the "Royalty Agreement") with Whitton. Pursuant to the terms of the Royalty Agreement, in consideration for Whitton's consulting services in connection with Blocks 9, 20 and 21 offshore Angola and our business and operations in Angola, Whitton is to receive quarterly payments (measured in U.S. Dollars) equal to 2.5% of the market price of our share of the crude oil produced in such quarter and not used in petroleum operations, less the cost recovery crude oil, assuming the applicable government contract is a production sharing agreement. If the applicable government contract is a risk services agreement and not a production sharing agreement (which is the case with respect to Blocks 9 and 21), pursuant to the Royalty Agreement, we have undertaken to agree with Whitton an economic model (the "RSA Economic Model") containing terms equivalent to those in such risk services agreement and using actual production and costs. The RSA Economic Model has not yet been agreed with Whitton. If we assign all of our interests in such blocks, or if we sell the company, Whitton may have the right to receive the market value of its rights and obligations under the Royalty Agreement, based upon the amount in cash a willing transferee of such rights and obligations would pay a willing transferor in an arm's length transaction. Given potential issues regarding how such market value of Whitton's rights and obligations under the Royalty Agreement could be calculated, including, without limitation, outstanding issues related to the RSA Economic Model, the amount of any such payment that could be owed to Whitton upon consummation of any sale of our interests in Blocks 20 and 21 offshore Angola is uncertain, but may be significant. Resolution of any such payment may include an expert determination of such cash value payment. We can make no assurance that any results from an expert determination process will be favorable to us. If we are ultimately required to pay a significant sum under the Royalty Agreement, there could be a material adverse effect on our business and financial condition.

Conversions of the Convertible Notes may have a material adverse effect on our financial condition and operating results.

Holders of the Convertible Notes are entitled to convert the notes at their option at any time up until the respective maturity dates. 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 have a material adverse effect on 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.

A requirement by such holders for us to repurchase some or all of such notes for cash will have a material adverse effect on our business, financial condition and results of operations, including if we do not have sufficient funds or are otherwise unable to comply with such requirement in accordance with the indentures governing the Convertible Notes.

Risks Relating to our Common Stock

We are currently out of compliance with the New York Stock Exchange's (the "NYSE") minimum share price requirement and are at risk of the NYSE delisting our common stock, which would have a material adverse effect on our business, financial condition, prospects and liquidity and value of our common stock.

Our common stock is currently listed on the NYSE, and the continued listing of our common stock is subject to our compliance with a number of listing standards. On February 27, 2017, we were notified by the NYSE that we are no longer in compliance with the continued listing standards because the average closing price of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days. If we are unable to cure such non–compliance with the continued listing standards in the six–month period following such notice, the NYSE may commence suspension and delisting procedures. In addition, if our common stock price remains below the $1.00 per share threshold and the NYSE at any time considers the stock price to be "abnormally low," the NYSE has the discretion to begin delisting procedures immediately, including during the six–month cure period.

During the six–month cure period, our common stock will continue to be listed and traded on the NYSE, subject to compliance with the other NYSE continued listing standards. In order to cure such non–compliance during the cure period, we may elect to effect a reverse stock split, subject to and upon approval by our stockholders and our board of directors. At our 2017 annual meeting of stockholders, we intend to present to stockholders a proposal to authorize our Board Directors, in its sole discretion, to amend our certificate of incorporation to effect a reverse stock split at a ratio within the range of 1:5 to 1:15 (such ratio to be determined by the Board of Directors). There can be no assurance, however, that any reverse stock split will be approved or implemented on such terms or at all. Further, even if a reverse stock split is approved and successfully implemented, there can be no assurance that such action will directly or indirectly cure any non-compliance with NYSE continued listing standards.

In the event of a delisting, our common stock could be traded on the over–the–counter bulletin board, also known as the "pink sheets." A delisting of our common stock could have a material adverse effect on us by, among other things:

- reducing the liquidity and market price of our common stock;
- reducing the number of investors, including institutional investors, willing to hold or acquire our common stock, which could negatively impact our ability to raise equity financing;
- limiting our ability to issue additional securities, obtain additional financing or pursue strategic restructuring, refinancing or other transactions; and
- adversely impacting our reputation, including our relationship with business partners.

In addition to the minimum average closing price criteria, we would also be considered to be below compliance with the continued listing standards if our average market capitalization over a consecutive 30 day-trading period is less than $50 million and, at the same time, our stockholders' equity is less than $50 million. As of December 31, 2017, we had a stockholders' deficit of $841.3 million, and we were not in compliance with the stockholders' equity portion of such listing standard. Although we are currently in compliance with the $50 million average market capitalization requirement, continued deterioration of our stock price could result in us being out of compliance with such requirement. In addition, if our average global market capitalization over a consecutive thirty trading-day period is less than $15 million, the NYSE will promptly initiate suspension and delisting procedures and, under the NYSE's continued listing standards, we will not have any opportunity to regain compliance.

The failure of our common stock to be listed on any of The New York Stock Exchange, The NASDAQ Global Select Market or The NASDAQ Global Market would constitute a "fundamental change" under the terms of the indentures governing our Convertible Notes. In such case, we would be required to provide notice to the holders of our Convertible Notes of such fundamental change and could be required, at the option of the holders of our Convertible Notes, to repurchase for cash any such Convertible Notes following the date of the notice. A requirement by such holders for us to repurchase some or all of such notes for cash will have a material adverse effect on our business, financial condition and results of operations, including if we do not have sufficient funds or are otherwise unable to comply with such requirement in accordance with the indentures governing our Convertible Notes.

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

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:

- the timing or occurrence of the closing of the sale of our interests in Blocks 20 and 21 offshore Angola;
- the price of oil and natural gas;

- the success of our development and production operations, and the marketing of any oil and natural gas we produce;
- to what extent our exploratory wells are successful;
- 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 Convertible 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 Convertible 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 Convertible 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 stock 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 bylaws could discourage potential acquisition proposals and could deter or prevent a change in control.

Some provisions in our certificate of incorporation and bylaws, 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 bylaws, 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.

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

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in “Item 1. Business” contained herein.

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.

In November 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, asserted 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.

In December 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 asserted 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.

In March 2015, the Court entered an order consolidating the Neuman lawsuit with the St. Lucie lawsuit (the "Consolidated Action") and also entered an order in the Consolidated Action appointing Lead Plaintiffs and Lead Counsel. Lead Plaintiffs filed their consolidated amended complaint in May 2015. Among other remedies, the Consolidated Action seeks damages in an unspecified amount, along with an award of attorney fees and other costs and expenses to the plaintiffs. We filed a motion to dismiss the consolidated amended complaint in June 2015, and the other defendants also filed motions to dismiss. The Court denied our motion to dismiss in January 2016, and, in March 2016, the Court also denied our motion requesting that the Court certify its order on the motions to dismiss so that we may seek interlocutory appellate review of the order. Lead Plaintiffs also have filed a motion for class certification, seeking to certify a class of all persons and entities who purchased or otherwise acquired our securities between March 1, 2011 and November 3, 2014. The matter remains ongoing.

In May 2016, Gaines, a purported stockholder, filed a derivative action in the 295th District Court in Harris County, Texas against us, as a nominal defendant, certain of our current and former officers and directors, and certain investment firms and funds. The lawsuit alleges that current and former officers and directors breached their fiduciary duties by making, and permitting us to make, alleged misrepresentations about two of our exploration wells offshore Angola; that certain officers received performance-based compensation in excess of what they were entitled; and that the investment firms and funds owed a fiduciary duty to us as controlling stockholders and breached that duty by engaging in insider trading. The lawsuit further alleges that demand was wrongfully refused. The plaintiff asserts claims for breach of fiduciary duty and unjust enrichment and seeks damages in an unspecified amount, disgorgement of profits, appropriate equitable relief, and an award of attorney fees and other costs and expenses. In July 2016, we filed our answer and special exceptions challenging the plaintiff's standing to bring such claims against us. The Court heard arguments on our special exceptions in December 2016. The matter remains ongoing.

In November 2016, McDonaugh, a purported stockholder, filed a derivative action in the 80th District Court in Harris County, Texas against us, as a nominal defendant, and certain of our current and former officers and directors. The lawsuit alleges that defendants breached their fiduciary duties by failing to maintain adequate internal controls and by permitting or failing to prevent alleged misrepresentations and omissions in our SEC filings and other public disclosures, including in relation to compliance with the FCPA in our Angolan operations and regarding the performance of certain wells offshore Angola. The lawsuit also alleges that defendants received compensation or other benefits in excess of what they were entitled and that certain officers and directors engaged in unlawful trading and misappropriation of information. The lawsuit further alleges that demand was wrongfully refused. The plaintiff asserts claims for breach of fiduciary duty and unjust enrichment and seeks damages in an unspecified amount, reform of our governance and internal controls, restitution and disgorgement of profits, and an award of attorney fees and other costs and expenses. We filed our answer and special exceptions challenging the plaintiff's standing to bring such claims against us in January 2017. The matter remains ongoing.

In May 2016, we filed suit against XL Specialty Insurance Company ("XL") in Harris County District Court in Houston, Texas. We assert XL improperly denied coverage for insurance claims made in July 2012 and other claims subsequently submitted to them in connection with our defending against the St. Lucie lawsuit, the Ogden derivative action, and other investigations and actions. In December 2016, we amended our petition to add Axis Insurance Company ("Axis"). Axis provides coverage in excess of the XL policy's limit of liability. We allege breach of contract, violation of the Texas Prompt Payment of Claims Act, and seek a declaratory judgment that XL and Axis are obligated to pay any additional loss suffered by us due to the circumstances, investigation, and claims described in the suit. In December 2016, we also amended our petition to add claims against Illinois National Insurance Company, an AIG subsidiary ("AIG"), which served as our insurer after XL Against AIG, we allege breach of contract, violation of the Texas Prompt Payment of Claims Act, violation of the Texas Deceptive Trade Practices-Consumer Protection Act, and seek a declaratory judgment that AIG is obligated to pay any additional loss suffered by us due to the circumstances, investigations, and actions related to the Lontra and/or Loengo wells. Discovery is ongoing in the case and trial is set for June 2017.

In February 2017, we received a letter from the DOJ advising us that the DOJ has closed its investigation into our operations in Angola. This formally concluded the DOJ investigation, which was the last investigation by any U.S. regulatory agency into our Angolan operations. No regulatory action has been taken against us as a result of these investigations.

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.

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

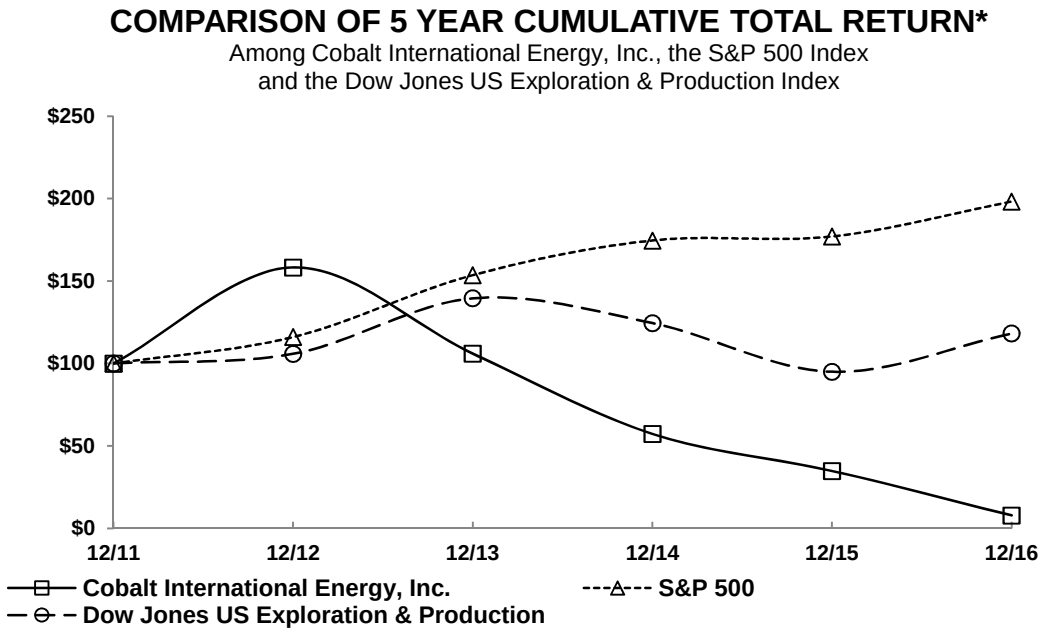
Our common stock is traded on the NYSE under the symbol "CIE." At the close of business on February 1, 2017, based on information received from our transfer agent and brokers and nominees, we had approximately 150 holders of record of our common stock. This number does not include owners for whom our common stock may be held in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

The following table sets forth the range of the daily high and low sales prices for our common stock for 2016 and 2015:

	Price Range	
	High	**Low**
2016:		
First Quarter	$ 5.46	$ 2.02
Second Quarter	3.50	1.32
Third Quarter	1.81	0.77
Fourth Quarter	1.46	0.83
2015:		
First Quarter	$ 10.24	$ 7.73
Second Quarter	11.20	9.38
Third Quarter	9.82	6.73
Fourth Quarter	9.43	5.14

Corporate Performance Graph

The following graph compares the yearly percentage change in our cumulative total stockholder return on our common stock with the cumulative total return on the published Standard & Poor's ("S&P") 500 Stock Index and the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) for the period January 1, 2012 through December 31, 2016. The graph assumes an investment of $100 was 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 31, 2011 and its relative performance is tracked through December 31, 2016:



	Year Ended December 31,					
	2011	2012	2013	2014	2015	2016
Cobalt International Energy, Inc.	$ 100.00	$ 158.25	$ 105.99	$ 57.38	$ 34.79	$ 7.86
S&P's Composite 500 Stock Index	100.00	116.00	153.58	174.60	177.01	198.18
Dow Jones U.S. Exploration & Production Index	100.00	105.82	139.52	124.48	94.94	118.19

The corporate performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such 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.

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.

Unregistered Sales of Equity Securities

Reference is made to the description of our unregistered issuance of shares of common stock on December 6, 2016, as disclosed in Items 1.01 and 3.02 of our Current Report on Form 8–K previously filed with the SEC on December 7, 2016, which is incorporated herein by reference.

Issuer Purchases of Equity Securities

None.

Equity Compensation Plans

Information on securities authorized under our equity compensation plans is set forth in the section entitled "Executive Compensation—Equity Compensation Plan Information" in our definitive Proxy Statement for our 2017 annual stockholders meeting, which sections are incorporated by reference.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial data for the periods and as of the dates indicated. The selected financial data are derived from our audited financial statements. The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data," both contained herein.

	Year Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
	($ in thousands)				
Statement of Operations Data:					
Oil, natural gas and natural gas liquids revenues	$ 16,805	$ —	$ —	$ —	$ —
Operating loss [1]	(2,262,420)	(638,692)	(441,941)	(532,684)	(284,828)
Other (expense) income, net	(80,889)	(55,734)	(68,822)	(56,340)	1,829
Net loss	$(2,343,309)	$ (694,426)	$ (510,763)	$ (589,024)	$ (282,999)
Basic and diluted loss per share	$ (5.69)	$ (1.70)	$ (1.25)	$ (1.45)	$ (0.70)
Financial Position (at end of period):					
Working capital	$ 613,237	$1,043,326	$1,699,534	$1,626,476	$2,295,786
Total assets [2]	2,230,478	4,061,219	4,415,155	3,612,690	3,988,417
Long-term debt, net [2]	2,479,349	1,981,895	1,891,820	1,014,997	968,149
Stockholders' equity	(841,334)	1,446,137	2,114,266	2,129,146	3,689,218

[1] Includes dry hole costs and impairments of $1,967.2 million, $462.2 million, $236.9 million, $351.1 million and $134.1 million in 2016, 2015, 2014, 2013 and 2012, respectively. Dry hole costs and impairments for 2016 include $1,691.8 million related to the impairment of our assets in Angola.

[2] We adopted Accounting Standards Update ("ASU") No. 2015–03 and 2015–15, *Interest – Imputation of Interest*, on January 1, 2016. These ASUs change the presentation of debt issuance costs in financial statements. An entity is not to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. We were required to apply the guidance on a retrospective basis. Accordingly, as of December 31, 2015, 2014, 2013 and 2012, we reclassified $32.9 million, $36.7 million, $21.0 million and $23.0 million, respectively, of debt issuance costs previously reported in "Total assets" to "Long–term debt, net."

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

The following discussion of our financial condition and results of operations should be read in conjunction with "Item 8. Financial Statements and supplementary Data" contained herein.

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. In the U.S. Gulf of Mexico, we have four discoveries: North Platte, Shenandoah, Anchor and Heidelberg. Heidelberg began initial production in January 2016, and North Platte, Shenandoah and Anchor are currently being appraised. In West Africa, we have made seven aggregate discoveries offshore Angola on Blocks 20 (Orca, Zalophus, Golfinho and Lontra) and 21 (Cameia, Bicuar and Mavinga). We also have a non–operated interest in the Diaba block offshore Gabon.

Angola Transaction

On August 22, 2015, we executed the Agreement with Sonangol for the sale by us to Sonangol of the entire issued and outstanding share capital of our indirect wholly–owned subsidiaries, CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold our 40% working interest in each of Block 20 and Block 21 offshore Angola. The requisite Angolan government approvals were not received within one year from the execution date and the Agreement terminated by its terms in August 2016. Since then, we have been working with Sonangol to understand and agree on the financial and operational implications of the termination of the Agreement. As part of these discussions, we have requested that Sonangol extend certain deadlines for exploration and development milestones under the License Agreements. Under the Agreement, we are entitled to be put back in our original position as if no agreement had been concluded, which we believe requires Sonangol to extend all such deadlines by, at a minimum, the one year period the Agreement was pending plus the period of time from the termination of the Agreement until this matter is resolved.

No extensions have been granted to date. Over six months have passed since the termination of the Agreement and there can be no assurance that such extensions will be forthcoming on favorable terms or at all. The failure to receive such extensions would have a material adverse effect on the value of these License Agreements. See "Risk Factors—Risks Relating to Our Business—We may be unable to consummate the sale of our Angolan assets on favorable terms, or at all" and "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. Failure to do so may result in substantial license renewal costs or loss of our interests in these license areas."

We reserve the right to and will vigorously enforce the provisions of the Agreement and our rights under international law if Sonangol does not grant the extensions we believe we are entitled to under the Agreement. The dispute resolution procedures of the Agreement require that any dispute be finally resolved under the Rules of Arbitration of the International Chamber of Commerce, with proceedings seated in London, England. In addition, prior to commencing arbitration proceedings, a party must provide the other party with a Notice of Dispute describing the nature of the dispute and the relief requested. Given Sonangol's delays and failure to date to grant the extensions, we submitted such a Notice of Dispute on March 8, 2017 to Sonangol under the Agreement. If Sonangol does not timely resolve this matter to our satisfaction, we intend to move forward with arbitration and at that time we will seek all available remedies at law or in equity. Further, our Angolan assets are indirectly held by a German subsidiary, and we therefore believe we are entitled to certain protections provided under international law under the bilateral investment treaty between Germany and Angola, dated October 30, 2003, including its substantive and procedural protections to investments of German investors.

In 2016, we recorded an impairment of $1,629.8 million related to our Angolan assets in accordance with ASC 932, which requires, among other things, that "sufficient progress" be made with respect to oil and natural gas projects in order to avoid the requirement to expense previously capitalized exploratory or appraisal well costs. Given Sonangol's delays and failure to date to grant the extensions as well as the general investment climate in the Angolan oil and natural gas industry, the procedures of ASC 932 require us to record a full impairment of our Angolan assets at this time. It is important to note that this impairment represents previously capitalized exploratory

and appraisal well and other costs. The impairment is not associated with, nor is it indicative of, what we believe to be the intrinsic or fair market value of our Angolan assets. While we continue to market our Angola assets and believe they have substantial value to Cobalt, we believe the sale process has been negatively impacted by the uncertainty surrounding the extensions. We further believe that Sonangol's preference is for us to present potential buyers to them prior to finalizing the terms of the extensions.

Although we plan to continue to fulfill our obligations as operator, we do not plan to make any material additional investments in Angola until the financial and operational implications of the termination of the Agreement are resolved to our satisfaction. In addition, we are currently holding the $250 million initial payment that Sonangol made to us under the Agreement and do not plan to return any part of it until this matter, and the related matter of the joint interest receivable owed to us by Sonangol P&P under the RSA, is resolved.

Other Developments

In December 2016, we completed a debt exchange and financing transaction (the “Transaction”) with certain holders (the “Holders”) of our outstanding 2019 Notes and 2024 Notes. The Transaction consisted of (i) the issuance and sale of $500.0 million aggregate principal amount of our new first lien senior secured notes due 2021 to the Holders for cash at a price of 98% and (ii) the issuance of $584.7 million aggregate principal amount of our new second lien senior secured notes due 2023 and 30.0 million shares of our common stock to the Holders in exchange for $616.6 million aggregate principal amount of our 2019 Notes and $95.9 million aggregate principal amount of our 2024 Notes held by the Holders. The Transaction raised approximately $490.0 million of additional liquidity but caused our annual interest payments to increase by approximately $79.9 million beginning in 2017. This was the first step in improving our financial condition while also better aligning our debt maturities with our likely development plans.

In January 2017, we consummated a follow–on debt exchange transaction with certain of the Holders whereby we issued an aggregate principal amount of $139.2 million in additional second lien senior secured notes due 2023 in exchange for $137.8 million aggregate principal amount of the 2019 Notes and $60.0 million aggregate principal amount of the 2024 Notes held by the Holders.

In September 2016, we entered into an amendment to our drilling contract in the U.S. Gulf of Mexico with Rowan and recorded a charge of $95.9 million, of which $76.3 million was paid in 2016. This amendment provides for the early termination of our long–term drilling contract for one of their drillships. The drilling contract was originally scheduled to terminate in February 2018, but the amendment provides for a contract termination date in March 2017. This amendment resulted in future savings to us of approximately $80.1 million.

CRITICAL ACCOUNTING POLICIES

This discussion and analysis of our financial condition and results of operations is based upon 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 these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of our accounting policies involve estimates and assumptions to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We base these estimates and assumptions on historical experience and on various other information and assumptions that we believe to be reasonable at the time, the results of which form the basis for making judgements about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as our operating environment changes and as new events occur.

We have defined a critical accounting policy as one that is both important to the portrayal of either our financial condition and results of operations and requires us to make difficult, subjective or complex assumptions or estimates about matters that are uncertain. There are other policies within our consolidated financial statements that require us to make estimates and assumptions, but they are not deemed critical as defined above. We believe that the following are the critical accounting policies used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over 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 proved developed reserves on a units–of–production basis.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management's outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Estimates of Oil, Natural Gas and Natural Gas Liquids Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids 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 – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimate. Reserves for proved developed producing wells were estimated using production performance and material balance methods. New producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods. These methods provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Independent reserve engineers prepare our reserve estimates at the end of each year.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units–of–production method to amortize the costs of our oil and natural gas properties, the quantity of reserves could significantly impact our depreciation, depletion and amortization expense. Our reserves are also the basis of our supplemental oil and natural gas disclosures.

Accounting for Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit–of–production basis.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Accounting for Embedded Derivatives

Our Secured Notes have derivatives related to the requirement to pay an applicable premium upon a change in control or an event of default embedded within the notes. In addition, our second lien senior secured notes also have a derivative related to a put option in an asset sale embedded within the notes. These embedded derivatives were accounted for as a liability at the inception of the obligations. We have elected not to apply hedge accounting to these embedded derivatives, and, accordingly, we carry these derivatives at fair value on our consolidated balance sheet, with the changes in the fair value included in our consolidated statement of operations in the period in which the change occurs. Our current results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on these embedded derivatives.

We use the risk–neutral probability of default debt model to calculate the fair value of these embedded derivatives. Inherent in this model are various factors that include observable market prices for our Secured Notes and our Convertible Notes and the risk–free interest rates. The accuracy of the fair value calculation is a function of the quality of available data and judgment. Any significant variance in these assumptions could materially affect the estimated fair value of our embedded derivatives.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production.

Income Taxes

We use the liability method to determine our income tax provisions, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining the need for valuation allowances, we have considered and made judgments and estimates regarding estimated future taxable income and ongoing prudent and feasible tax planning strategies. These estimates and judgments include some degree of uncertainty and changes in these estimates and assumptions could require us to adjust the valuation allowances for our deferred tax assets. The ultimate realization of the deferred tax assets depends on the generation of sufficient taxable income in the applicable taxing jurisdictions.

We are subject to the jurisdiction of various domestic and foreign tax authorities. Our operations in these different jurisdictions are taxed on various bases and determination of taxable income in any jurisdiction requires the interpretation of the related tax laws and regulations and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of deductions, permissible revenue recognition methods under the tax law and the sources and character of income and tax credits. Changes in tax laws, regulations, agreements and treaties, or our level of operations or profitability in each taxing jurisdiction could have an impact on the amount of income taxes that we provide during any given year.

RESULTS OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
Production data:			
Oil (MBbls)	383.6	—	—
Natural gas (MMcf)	103.7	—	—
Natural gas liquids (MBbls)	12.2	—	—
Net production (MBOE)	413.1	—	—
Average sales price per unit:			
Oil (Bbls)	$ 42.29	$ —	$ —
Natural gas (Mcf)	2.97	—	—
Natural gas liquids (Bbl)	0.01	—	—
BOE	40.68	—	—
Average unit cost per BOE:			
Lease operating expenses	$ 18.33	$ —	$ —
Depreciation, depletion and amortization	53.21	—	—

Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

Net loss for 2016 was $2,343.3 million compared with $694.4 million for 2015. The significant factors in the change were (i) a $1,504.9 million increase in dry hole costs and impairments; (ii) a $95.9 million loss on the amendment of the Rowan contract; (iii) an $18.1 million increase in depreciation, depletion and amortization ("DD&A"); and (iv) an $17.2 million increase in general and administrative ("G&A") expenses.

Oil, natural gas and natural gas liquids revenues for 2016 totaled $16.8 million. These revenues are from the initial production of oil, natural gas and natural gas liquids from the Heidelberg field in the U.S. Gulf of Mexico which came on line in January 2016.

Seismic and exploration costs for 2016 decreased $3.7 million compared with 2015 as a result of decreases of $14.1 million in seismic acquisition costs due to our efforts to control costs and $1.3 million in delay rentals offset by an increase of $11.7 million in other exploration costs primarily related to the write–off of costs of projects that had not yet been sanctioned.

In 2016, we incurred $1,967.2 million of dry hole costs and impairments. Of this amount, $1,629.8 million related to costs associated with our wells and underlying leases in Angola, $195.6 million related to costs associated with the Goodfellow #1 well and sidetrack and the underlying leases, $62.0 million related to the impairment of inventory and other property in Angola and $56.9 million related to costs associated with the Shenandoah #3 well as it is no longer reasonably possible that the wellbore could be used in the development of the project, should a final investment decision be reached. In 2015, we incurred $462.2 million of dry hole costs and impairments. Of this amount, $256.8 million related to the impairment of our Heidelberg field, $151.4 million related to costs association with our Lontra #1 exploratory well offshore Angola, $26.9 million related to impairments of our unproved leaseholds and $18.4 million related to costs associated with our North Platte #2 appraisal well in the U.S. Gulf of Mexico.

In 2016, we announced that we entered into an amendment to our drilling contract with Rowan and recorded a charge of $95.9 million, of which $76.3 million was paid in 2016. This amendment provides for the early termination of our long–term drilling contract for one of their drillships. The drilling contract was originally scheduled to terminate in February 2018, but the amendment provides for a contract termination date in March 2017.

Lease operating expenses totaled $7.6 million, or $18.33 per BOE, in 2016. These lease operating expenses relate to fixed and variable costs of the Heidelberg field and associated transportation costs.

G&A expenses for 2016 increased $17.2 million compared with 2015. The increase was primarily attributable to (i) $19.6 million of fees associated with the Transaction; (ii) a $13.9 million reduction in amounts reimbursed from our partners due to lower activity levels in Angola; and (iii) a $8.1 million increase in legal fees related to our ongoing litigation offset by (iv) a $15.9 million decrease in payroll and equity–based compensation costs due to lower equity–based compensation costs from the reversal of costs related to forfeitures of unvested equity awards associated with our workforce reduction plan and (v) an $8.5 million overall decrease in other expenses due to lower activity levels in Angola and our cost cutting efforts.

DD&A for 2016 increased $18.1 million compared with 2015 due to the recording of depletion on our Heidelberg field. DD&A was $53.21 per BOE in 2016.

Interest expense for 2016 increased $19.7 million compared with 2015 due to $11.2 million of increased interest related to effects of the Transaction, $6.3 million of decreased interest capitalization as we are no longer capitalizing interest on our Angolan exploratory wells, and $2.2 million of net increased interest ($3.3 million of debt issuance costs written off offset by $1.1 million of decreased interest) associated with our borrowing base facility that was terminated in 2016.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

Net loss for 2015 was $694.4 million compared with $510.8 for 2014. The significant factors in the change were (i) a $225.3 million increase in dry hole costs and impairments; (ii) a $23.7 million decrease in seismic and exploration costs; and (iii) an $11.4 million decrease in interest expense.

Seismic and exploration costs for 2015 decreased $23.7 million compared with 2014. The decrease was primarily due to standby costs incurred in 2014 associated with two drilling rigs in West Africa.

In 2015, we incurred $462.2.0 million of dry hole costs and impairments. Of this amount, $256.8 million related to the impairment of our Heidelberg field, $151.4 million related to costs association with our Lontra #1 exploratory well offshore Angola, $26.9 million related to impairments of our unproved leaseholds, and $18.4 million related to costs associated with our North Platte #2 appraisal well in the U.S. Gulf of Mexico. In 2014, we incurred dry hole costs and impairments of $236.9 million. Of this amount, $68.0 million related to impairments of our unproved leaseholds and $154.6 million related to costs associated with our Anchor #1 and Yucatan #2 exploratory wells in the U.S. Gulf of Mexico and our Loengo #1 and Mupa #1 exploratory wells offshore Angola.

G&A expenses for 2015 decreased $4.2 million compared with 2014. The decrease was primarily attributable to a $10.8 million overall decrease in other expenses due to lower activity levels in Angola offset by a $3.5 million increase in payroll and equity–based compensation related to a higher bonus accrual and a $3.1 million increase in legal fees related to our ongoing litigation.

Interest expense for 2015 decreased $11.4 million compared with 2014 due to increased interest capitalization of $47.4 million offset by a $16.8 million increase in interest expense related to the 3.125% convertible senior notes due 2024 that were issued in May 2014 and a $19.1 million increase in amortization of debt issuance costs and accretion of discount.

LIQUIDITY AND CAPITAL RESOURCES

As of December 31, 2016, we had approximately $956.5 million in cash and cash equivalents, restricted cash and short–term investments. This amount (i) includes the $250.0 million paid to us by Sonangol pursuant to the Agreement that we intend to retain, along with other payments due to Sonangol, until the matters with respect to the extensions are resolved, and (ii) excludes the $159.1 million receivable owed to us by Sonangol. For more information, please see “Item 1 – Business – West Africa – Angola Transaction.”

In 2017, we currently expect to spend approximately $275.0 million for our development activities, and expect that our outlays will significantly decrease after the first quarter of 2017 as we complete our drilling activities at our North Platte, Shenandoah and Anchor discoveries. Total 2017 cash outlays are currently expected to be between $550 million and $650 million.

Although we commenced initial production from our Heidelberg project in January 2016, our ongoing capital and operating expenditures will vastly exceed the revenue we expect to receive from our oil and natural gas operations for the foreseeable future. We expect to incur substantial expenditures and generate significant operating losses as we:

- progress our discoveries toward project sanction; all of which are subject to, or will soon be subject to, the requirement that we conduct continuous operations on such leases or until such time as we are granted an SOP;
- continue development drilling activities on the Heidelberg field with the aim to increase its oil and natural gas production over time;
- selectively conduct exploration drilling on our current acreage;
- incur increased interest expense; and
- incur expenses related to operating as a public company and compliance with regulatory requirements.

These activities will require that we raise substantial additional funding. If we are unable to raise substantial additional funding on a timely basis or on acceptable terms, we may be required to significantly curtail our exploration, appraisal and development activities.

We adopted ASU 2014–15, *Presentation of Financial Statements – Going Concern*, on December 31, 2016. This ASU required us to evaluate and disclose whether there is substantial doubt about our ability to continue as a going concern. Our assessment included the preparation of a detailed cash forecast that included all projected cash inflows and outflows as well as consideration of any cash related covenants associated with our financing structure.

In December 2016, we entered into the Transaction as a part of obtaining new capital. The indentures governing our Secured Notes contain certain covenants including the maintenance of a minimum consolidated cash balance of at least $200.0 million. As our detailed cash forecast shows that our projected cash balances would be out of compliance with the minimum consolidated cash balance covenant within one year after the date this consolidated financial statements are issued, we have concluded that there is substantial doubt about our ability to continue as a going concern.

Our ability to continue as a going concern is subject to, among other factors, our ability to monetize assets, our ability to obtain financing or refinance existing indebtedness, our ability to continue our cost cutting efforts for long–term rig and support services, the production rates achieved from our Heidelberg project, oil and natural gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed and cost 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.

There can be no assurance that we will be able to obtain additional funding on satisfactory terms or at all. In addition, no assurance can be given that any such financing, if obtained, will be adequate to meet our capital needs and support our growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then our operations would be materially negatively impacted.

If we become unable to continue as a going concern, we may find it necessary to file a voluntary petition for reorganization under the Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure.

Long–term Debt

As of December 31, 2016, we have $3,052.3 million in aggregate principal amount of long–term debt outstanding. For additional information about our long–term debt, please see “Item 8. Financial Statements and Supplementary Data” contained herein.

Royalty Agreement

In February 2009, we entered into the Royalty Agreement with Whitton. Pursuant to the terms of the Royalty Agreement, in consideration for Whitton's consulting services in connection with Blocks 9, 20 and 21 offshore Angola and our business and operations in Angola, Whitton is to receive quarterly payments (measured in U.S. Dollars) equal to 2.5% of the market price of our share of the crude oil produced in such quarter and not used in petroleum operations, less the cost recovery crude oil, assuming the applicable government contract is a production sharing agreement. If the applicable government contract is a risk services agreement and not a production sharing agreement (which is the case with respect to Blocks 9 and 21), pursuant to the Royalty Agreement, we have undertaken to agree with Whitton an economic model (the "RSA Economic Model") containing terms equivalent to those in such risk services agreement and using actual production and costs. The RSA Economic Model has not yet been agreed with Whitton. If we assign all of our interests in such blocks, or if we sell the company, Whitton may have the right to receive the market value of its rights and obligations under the Royalty Agreement, based upon the amount in cash a willing transferee of such rights and obligations would pay a willing transferor in an arm's length transaction. Given potential issues regarding how such market value of Whitton's rights and obligations under the Royalty Agreement could be calculated, including, without limitation, outstanding issues related to the RSA Economic Model, the amount of any such payment that could be owed to Whitton upon consummation of any sale of our interests in Blocks 20 and 21 offshore Angola is uncertain, but may be significant. Resolution of any such payment may include an expert determination of such cash value payment. We can make no assurance that any results from an expert determination process will be favorable to us. Please see "Item 1A. Risk Factors—We may be required to pay a material cash sum to Whitton Petroleum Services, Ltd. ("Whitton") in connection with the closing of the sale of our interest in Blocks 20 and 21 offshore Angola."

Cash Flows

Cash flows provided by (used in) type of activity were as follows:

	Year Ended December 31.		
	2016	2015	2014
Operating activities	$ (165,665)	$ (1,646)	$ (61,760)
Investing activities	152,830	(114,121)	(1,141,159)
Financing activities	490,000	(4,068)	1,269,180

Operating Activities

Cash flows from operating activities used $165.7 million and $1.6 million in 2016 and 2015, respectively. The significant factors in the change were $76.3 million of payments related to the amendment of our U.S. Gulf of Mexico drilling contract, $19.6 million of costs related to the Transaction and an unfavorable change in working capital.

Cash flows from operating activities used $1.6 million and $61.8 million in 2015 and 2014, respectively. The significant factors in the change were decreases in seismic and exploration costs and general and administrative expenses and a favorable change in working capital.

Investing Activities

In 2016, cash flows provided by investing activities consisted of $3,390.1 million in proceeds from maturity of our held–to–maturity investments offset by $2,545.9 million of purchases of held–to–maturity investments, $687.9 million for additions to our oil and natural gas properties and $3.5 million of additions to other property.

In 2015, cash flows used in investing activities consisted of $1,999.4 million in proceeds from maturity of our held–to–maturity investments offset by $1,192.9 million of purchases of held–to–maturity investments, $915.9 million for additions to our oil and natural gas properties and $4.8 million of additions to other property.

In 2014, cash flows used in investing activities consisted of $2,350.7 million in proceeds from maturity of our held–to–maturity investments offset by $2,739.1 million of purchases of held–to–maturity investments, $748.7 million for additions to our oil and natural gas properties and $4.1 million of additions to other property.

Financing Activities

In 2016, we received $490.0 million in proceeds from the issuance of our 10.75% first lien notes due 2021.

In 2015, we paid $4.0 million of debt issuance costs related to our facility entered into in May 2015.

In 2014, we received $1,269.8 million in net proceeds from the issuance of our 3.125% convertible senior notes due 2024.

Capital Requirements

In order to grow our production, we need to develop our discoveries into producing oil and natural gas properties. In 2017, we currently expect to spend approximately $275.0 million for these development activities, and expect that our outlays will significantly decrease after the first quarter of 2017 as we complete our drilling activities at our North Platte, Shenandoah and Anchor discoveries. Total 2017 cash outlays are currently expected to be between $550 million and $650 million.

Contractual Obligations

	Payments Due By Year ($ in thousands)				
	2017	**2018 - 2019**	**2020 - 2021**	**After 2021**	**Total**
Long-term debt:					
Principal	$ —	$ 763,446	$ 500,000	$ 1,788,877	$ 3,052,323
Interest	156,737	313,475	273,392	184,707	928,311
Drilling rig commitments	85,269	—	—	—	85,269
Social obligation payments [1]	86,473	74	—	—	86,547
Delay rental payments [2]	5,243	6,963	7,190	7,492	26,888
Operating leases	2,309	4,774	4,955	671	12,709
Total	$ 336,031	$ 1,088,732	$ 785,537	$ 1,981,747	$ 4,192,047

[1] Includes our contractual payment obligations for social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that we agreed to pay in consideration for the Angolan government granting us the licenses to explore for and develop hydrocarbons offshore Angola.

[2] Annual payments required to maintain our U.S. Gulf of Mexico leases from year to year.

Our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligations at December 31, 2016 is $6.5 million.

Off–Balance Sheet Arrangements

As of December 31, 2016, we did not have any off–balance sheet arrangements.

RECENT ACCOUNTING STANDARDS

Please see “Item 8. Financial Statements and supplementary Data” contained herein for additional information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks refer to the risk of loss arising from changes in commodity prices, interest rates, foreign currency exchange rates and other relevant market risks. We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into various derivative instruments to manage or reduce market risk, but will not enter into derivative instruments for speculative purposes.

Commodity Price Risk

Our major market risk exposure is to prices for oil and natural gas. These prices have historically been volatile, and, as such, future earnings are subject to change due to changes in these prices. Realized prices are primarily driven by the prevailing worldwide price for oil and regional spot prices for natural gas production.

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 flows. 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.

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

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a–15 and 15d–15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Our disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes–Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10–K for the fiscal year ended December 31, 2016. Ernst & Young LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting. Management’s report and the independent registered public accounting firm’s attestation report are included in Item 8 under the caption entitled “Management’s Report on Internal Control Over Financial Reporting” and “Report of Independent Registered Public Accounting Firm” and are incorporated herein by reference.

Changes in Internal Controls Over Financial Reporting

During the third quarter of 2016, we identified a material weakness in the design of the controls related to the determination of the undiscounted cash flows used to test the recoverability of our proved oil and natural gas properties for purposes of evaluating whether or not an impairment loss should be recognized under the guidance in FASB Accounting Standards Codification Topic 360, *Property, Plant and Equipment*. Specifically, the review controls related to the inputs and calculations used to determine the undiscounted cash flows were not designed with a level of precision sufficient to identify errors that could lead to a material misstatement in our unaudited condensed consolidated financial statements. After the identification of the material weakness, management performed additional procedures to verify that the inputs and calculations used in the recoverability test performed at September 30, 2016 were appropriate.

To remediate this material weakness, we enhanced and revised the design of existing controls and procedures surrounding the inputs and calculations of the undiscounted cash flows used to test the recoverability of our proved oil and natural gas properties. During the fourth quarter of 2016, we were able to successfully remediate this material weakness.

Except as noted above, there have been no changes in our internal controls over financial reporting that occurred during the quarterly period ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

On March 10, 2017, Mr. Young advised us that he intends to retire from the Board of Directors (the "Board") at the end of his current term and will therefore not stand for re-election to the Board at our 2017 annual meeting of stockholders. Mr. Young has served as a director since 2009. Mr. Young's decision to retire and not stand for re-election was not related to any disagreement with us.

Effective as of March 10, 2017, the Board adopted and approved the Amended and Restated Cobalt International Energy, Inc. Executive Severance and Change in Control Benefit Plan (the "Plan") under which all of our current named executive officers, other than the Chief Executive Officer, participate. The Plan, as amended, increases the lump sum amount payable in a CIC Protection Period (as defined in the Plan) to a participant from an amount equal to the product of the participant's (i) Applicable Severance Multiple (as defined in the Plan) and (ii) base salary to an amount equal to the product of (i) the participant's Applicable Severance Multiple and (ii) the sum of the participant's (x) base salary plus (y) target bonus.

This description does not purport to be complete and is qualified in its entirety by reference to the description of the Cobalt International Energy, Inc. Executive Severance and Change in Control Benefit Plan in our Quarterly report on Form 10–Q as filed with the SEC on August 2, 2016 and the full text of the Plan, attached hereto as Exhibit 10.43, each of which is incorporated herein by reference.

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 for our 2017 annual stockholders meeting, which sections are incorporated by reference.

For information regarding our executive officers, see "Item 1. Business—Executive Officers" in this Annual Report on Form 10–K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference to our definitive Proxy Statement in connection with our 2017 annual stockholders meeting.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENTS AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference to our definitive Proxy Statement in connection with our 2017 annual stockholders meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference to our definitive Proxy Statement in connection with our 2017 annual stockholders meeting.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item is incorporated by reference to our definitive Proxy Statement in connection with our 2017 annual stockholders meeting.

GLOSSARY OF OIL AND NATURAL GAS TERMS

Appraisal well. A well drilled after an exploratory 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.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

BOE. One barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or natural gas liquids, and does not represent the sales price equivalency of natural gas to oil or natural gas liquids.

Boepd. One barrel of oil equivalent produced per day.

Completion. Installation of permanent equipment for production of oil or natural gas, or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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.

Developed oil and natural gas reserves. Reserves of any category that can be expected to be recovered:

- through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and

- through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines, and power lines, to the extent necessary in developing the proved reserves;

- drill, fracture, stimulate and equip development wells, development–type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- provide improve recovery systems.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or *well.* An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

DST. Drill stem test.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Farmout. 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 farmout, 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. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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 acres or *gross wells.* The total acres or wells, as the case may be, in which a working 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.

Leases. Full or partial interests in oil and 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.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrel of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million barrel of oil equivalent.

MMcf. One million cubic feet of natural gas.

Natural gas. A combination of light hydrocarbons that, in average pressure and temperature conditions, in 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 a gaseous state.

Natural gas liquids. The hydrocarbon liquids contained within natural gas.

Net acres or *net wells.* The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Net pay thickness. The vertical extent of the effective hydrocarbon–bearing rock (expressed in feet). The net pay thickness encountered by an exploratory well may differ from the mean net pay thickness of the prospect due to several factors, including the relative location of the exploratory well on the structure, potential thickness variations that may occur across the prospect and the extent to which potential reservoir horizons are penetrated.

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil and condensate.

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.

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.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and natural gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- severance taxes.

Productive well. An exploratory, development or extension well that is not a dry well.

Prospect. 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 to work and, if any of them fail, neither oil nor natural gas will be present, at least not in commercial volumes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Proved oil and natural gas 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 – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves ("PUDs"). Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

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.

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. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (the "SEC"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our standardized measure includes future obligations under the Texas gross margin tax, but it does not include future federal income tax expenses because we are a partnership and are not subject to federal income taxes.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Undeveloped oil and natural gas reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of Documents filed as part of this Annual Report on Form 10–K:

(1) Financial Statements

(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our consolidated financial statements and related notes.

(3) Exhibits

The exhibits listed below are filed or furnished as part of this Annual Report on Form 10–K:

Exhibit Number	Description of Document
3.1	Certificate of Incorporation of Cobalt International Energy Inc.'s (incorporated by reference from Exhibit 3.1 to Cobalt International Energy, Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
3.2	By-laws of Cobalt International Energy Inc.'s (incorporated by reference from Exhibit 3 to Cobalt International Energy, Inc.'s Registration Statement on Form 8–A filed with the SEC on December 11, 2009)
3.3	Amended and Restated Bylaws of Cobalt International Energy, Inc., effective as of October 27, 2016 (incorporated by reference from Exhibit 3.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on November 2, 2016)
4.1	Specimen stock certificate (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on November 27, 2009)
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on December 17, 2012)
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference from Exhibit 4.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on December 17, 2012)
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference from Exhibit 4.3 to Cobalt International Energy Inc.'s Current Report on Form 8-K filed with the SEC on December 17, 2012)
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 13, 2014)
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference from Exhibit 4.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 13, 2014)

Exhibit Number	Description of Document
10.1	Purchase and Sale Agreement, dated August 22, 2015, by and between Cobalt International Energy Angola Ltd. and Sociedade Nacional de Combustíveis de Angola—Empresa Pública (Sonangol E.P.) (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.2	Restated Overriding Royalty Agreement, dated February 13, 2009, by and between Whitton Petroleum Services Limited, CIE Angola Block 9 Ltd., CIE Angola Block 20 Ltd., CIE Angola Block 21 Ltd., and Cobalt International Energy, L.P. (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.3	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 from Exhibit 10.8 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
10.4	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 from Exhibit 10.20 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 21, 2012)
10.5	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference from Exhibit 10.5 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 29, 2009)
10.6	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference from Exhibit 10.6 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 29, 2009)
10.7	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference from Exhibit 10.7 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 9, 2009)
10.8	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference from Exhibit 10.8 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 9, 2009)
10.9	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on October 29, 2013)
10.10	Amendment No. 2 to the Drilling Contract for the Rowan Reliance, dated September 15, 2016, between Cobalt International Energy, L.P., Cobalt International Energy, Inc. and Rowan (UK) Reliance Limited (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on September 16, 2016)
10.11	Purchase and Exchange Agreement, dated December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and the Holders named in Schedule I thereto (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)
10.12	First Lien Indenture, dated as of December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent for the First Lien Notes (incorporated by reference from Exhibit 10.2 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)
10.13	Second Lien Indenture, dated as of December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent for the Second Lien Notes (incorporated by reference from Exhibit 10.3 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)

Exhibit Number	Description of Document
10.14	Exchange Agreement, dated January 30, 2017, among Cobalt International Energy, Inc., the Guarantors party thereto and the Holders named in Schedule I thereto (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on January 30, 2017)
10.15	First Supplemental Indenture, dated as of January 30, 2017, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association related to the 7.75% Second Lien Senior Secured Notes due 2023 (incorporated by reference from Exhibit 10.2 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on January 30, 2017)
10.16	Amended and Restated Stockholders Agreement, dated February 21, 2013, among Cobalt International Energy Inc. and the stockholders that are signatory thereto (incorporated by reference from Exhibit 10.36 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.17	Registration Rights Agreement, dated December 15, 2009, among Cobalt International Energy Inc. and the parties that are signatory thereto (incorporated by reference from Exhibit 10.31 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 21, 2012)
10.18	Form of Director Indemnification Agreements (incorporated by reference from Exhibit 10.19 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on November 27, 2009)
10.19†	Amended and Restated Long Term Incentive Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.15 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.20†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference from Exhibit 10.26 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 1, 2011).
10.21†	Form of Restricted Stock Unit Award Agreement (incorporated by reference from Exhibit 10.27 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 1, 2011).
10.22†	Deferred Compensation Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.35 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.23†	Annual Incentive Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.19 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
10.24†	Amended and Restated Non–Employee Directors Compensation Plan (incorporated by reference from Exhibit 99.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–8 filed with the SEC on May 3, 2016)
10.25†	Non–Employee Directors Deferral Plan (incorporated by reference from Exhibit 99.3 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on January 29, 2010)
10.26†	Form of Restricted Stock Unit Award Notification under the Non–Employee Directors Compensation Plan (incorporated by reference from Exhibit 99.4 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on January 29, 2010)
10.27†	Employment Agreement, dated November 3, 2014, between Cobalt International Energy Inc. and James W. Farnsworth (incorporated by reference from Exhibit 10.34 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.28†	Employment Agreement, dated November 3, 2014, between Cobalt International Energy Inc. and James H. Painter (incorporated by reference from Exhibit 10.35 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.29†	Form of Special Restricted Stock Award Agreement, dated January 15, 2015 (incorporated by reference from Exhibit 10.36 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)

Exhibit Number	Description of Document
10.30†	Form of Special Non–Qualified Stock Option Award Agreement, dated January 15, 2015 (incorporated by reference from Exhibit 10.37 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.31†	Form of Stock Appreciation Right Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.38 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.32†	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.39 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.33†	Form of Restricted Stock Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.40 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.34†	Severance Agreement, dated August 25, 2015, by and between Cobalt International Energy, Inc. and Shannon E. Young, III (incorporated by reference from Exhibit 10.4 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.35†	Cobalt International Energy, Inc. 2015 Long Term Incentive Plan (incorporated by reference from Exhibit 99.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–8 filed with the SEC on May 5, 2015)
10.36†	Form of Special Restricted Stock Award Agreement, dated January 15, 2016 (incorporated by reference from Exhibit 10.47 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)
10.37†	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2016 (incorporated by reference from Exhibit 10.48 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)
10.38†	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan (incorporated by reference from Exhibit 10.49 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)
10.39†	Offer Letter from Cobalt International Energy, Inc. to Timothy J. Cutt, dated May 30, 2016 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 31, 2016)
10.40†	Severance Agreement, dated May 30, 2016, between Cobalt International Energy, Inc. and Timothy J. Cutt (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 31, 2016)
10.41†	Offer Letter from Cobalt International Energy, Inc. to David D. Powell, dated July 6, 2016 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on July 7, 2016)
10.42†	Cobalt International Energy, Inc. Executive Severance and Change in Control Benefit Plan (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.43†*	Cobalt International Energy, Inc. Amended and Restated Executive Severance and Change in Control Benefit Plan
10.44†	Form of Participation Agreement under the Company's Executive Severance and Change in Control Benefit Plan (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.45†	Form of Performance Stock Unit Award Agreement (incorporated by reference from Exhibit 10.3 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)

Exhibit Number	Description of Document
10.46†	Offer Letter from Cobalt International Energy, Inc. to Rod Skaufel (incorporated by reference from Exhibit 10.4 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.47†	Separation and Consulting Agreement and General Release of Claims dated as of November 1, 2016 between Cobalt International Energy, Inc. and James W. Farnsworth (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on November 10, 2016)
10.48†*	Form of Performance Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan
10.49†*	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan
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*	Interactive Data Files

* Filed herewith.
** Furnished 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).

ITEM 16. FORM 10–K SUMMARY

None.

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/ TIMOTHY J. CUTT
Name:Timothy J. Cutt
Title: *Director and Chief Executive Officer*

Dated: March 14, 2017

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/ TIMOTHY J. CUTT Timothy J. Cutt	Director and Chief Executive Officer (Principal Executive Officer)	March 14, 2017
/s/ DAVID D. POWELL David D. Powell	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 14, 2017
/s/ WILLIAM P. UTT William P. Utt	Chairman of the Board of Directors	March 14, 2017
/s/ JACK E. GOLDEN Jack E. Golden	Director	March 14, 2017
/s/ JOHN E. HAGALE John E. Hagale	Director	March 14, 2017
/s/ KAY BAILEY HUTCHISON Kay Bailey Hutchison	Director	March 14, 2017
/s/ JON A. MARSHALL Jon A. Marshall	Director	March 14, 2017
/s/ KENNETH W. MOORE Kenneth W. Moore	Director	March 14, 2017
/s/ MYLES W. SCOGGINS Myles W. Scoggins	Director	March 14, 2017
/s/ D. JEFF VAN STEENBERGEN D. Jeff van Steenbergen	Director	March 14, 2017
/s/ VAN P. WHITFIELD Van P. Whitfield	Director	March 14, 2017
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Director	March 14, 2017

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, 2016. The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

/s/ TIMOTHY J. CUTT	/s/ DAVID D. POWELL
Timothy J. Cutt	David D. Powell
Chief Executive Officer	*Chief Financial Officer*

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, 2016 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, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2016 consolidated financial statements of Cobalt International Energy, Inc. and our report dated March 14, 2017 expressed an unqualified opinion thereon that included an explanatory paragraph regarding Cobalt International Energy, Inc.'s ability to continue as a going concern.

/s/ Ernst & Young LLP

Houston, Texas
March 14, 2017

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, 2016 and 2015, 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, 2016. 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, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has near–term liquidity constraints that raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 2 to the consolidated financial statements, the Company has changed its presentation of cash flows in the Consolidated Statements of Cash Flows as a result of the adoption of the amendments to the FASB Accounting Standards Codification resulting from Accounting Standards Update No. 2016–18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)."

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, 2016, 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 March 14, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 14, 2017

Cobalt International Energy, Inc.
Consolidated Balance Sheets
(In thousands, except number of shares and par value amounts)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 613,534	$ 80,171
Restricted cash	2,517	58,715
Joint interest and other receivables	167,573	211,308
Other current assets	23,149	134,434
Short-term investments	340,418	1,185,335
Total current assets	1,147,191	1,669,963
Oil and natural gas properties, net of accumulated depletion of $20,204 and $0 as of December 31, 2016 and 2015, respectively	1,078,885	2,359,033
Other property, net of accumulated depreciation and amortization of $8,426 and $12,859, as of December 31, 2016 and 2015, respectively	3,902	12,309
Other assets	500	19,914
Total assets	$ 2,230,478	$ 4,061,219
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Trade and other accounts payable	$ 36,954	$ 6,945
Accrued liabilities	227,418	369,692
Accrued contract amendment costs	19,582	—
Angolan preliminary consideration	250,000	250,000
Total current liabilities	533,954	626,637
Long-term debt	2,479,349	1,981,895
Long-term derivative liabilities	50,123	—
Asset retirement obligations	6,523	3,167
Other long-term liabilities	1,863	3,383
Commitments and contingencies		
Stockholders' Equity:		
Common stock, $0.01 par value per share; 2,000,000,000 shares authorized, 441,210,817 and 408,740,182 issued and outstanding as of December 31, 2016 and 2015, respectively	4,412	4,088
Additional paid-in capital	4,219,611	4,164,097
Accumulated deficit	(5,065,357)	(2,722,048)
Total stockholders' equity	(841,334)	1,446,137
Total liabilities and stockholders' equity	$ 2,230,478	$ 4,061,219

See accompanying notes to consolidated financial statements.

Cobalt International Energy, Inc.
Consolidated Statements of Operations
(In thousands, except per share data)

	Year Ended December 31,		
	2016	**2015**	**2014**
Oil, natural gas and natural gas liquids revenues	$ 16,805	$ —	$ —
Operating costs and expenses:			
Seismic and exploration costs	58,170	61,844	85,567
Dry hole costs and impairments	1,967,180	462,234	236,930
Loss on amendment of contract	95,908	—	—
Lease operating expenses	7,574	—	—
General and administrative expenses	127,860	110,634	114,860
Accretion expense	550	99	—
Depreciation, depletion and amortization	21,983	3,881	4,584
Total operating costs and expenses	2,279,225	638,692	441,941
Operating loss	(2,262,420)	(638,692)	(441,941)
Other (expense) income, net:			
Other (expense) income	(2,505)	1,555	(12)
Interest income	4,661	6,087	5,958
Interest expense	(83,045)	(63,376)	(74,768)
Total other expense, net	(80,889)	(55,734)	(68,822)
Net loss	$ (2,343,309)	$ (694,426)	$ (510,763)
Basic and diluted loss per share:	$ (5.69)	$ (1.70)	$ (1.25)
Weighted average common shares outstanding (basic and diluted)	412,080	408,535	407,116

See accompanying notes to consolidated financial statements.

Cobalt International Energy, Inc.
Consolidated Statements of Changes in Stockholders' Equity
(In thousands)

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Total
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 loss	—	—	(510,763)	(510,763)
Balance, December 31, 2014	4,085	4,137,803	(2,027,622)	2,114,266
Common stock issued for restricted stock	3	(3)	—	—
Equity-based compensation	—	26,297	—	26,297
Net loss	—	—	(694,426)	(694,426)
Balance, December 31, 2015	4,088	4,164,097	(2,722,048)	1,446,137
Common stock issued for restricted stock	24	(24)	—	—
Common stock issued in debt exchange	300	39,295		39,595
Equity-based compensation	—	16,243	—	16,243
Net loss	—	—	(2,343,309)	(2,343,309)
Balance, December 31, 2016	$ 4,412	$4,219,611	$ (5,065,357)	$ (841,334)

See accompanying notes to consolidated financial statements.

Cobalt International Energy, Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net loss	$ (2,343,309)	$ (694,426)	$ (510,763)
Adjustments to reconcile net loss to net cash used in operating activities:			
Dry hole costs and impairments	1,967,180	462,234	236,930
Equity-based compensation	14,889	26,297	31,742
Accretion expense	550	99	—
Depreciation and amortization	21,983	3,881	4,584
Loss on derivatives	2,505	—	—
(Accretion of discount) amortization of premium on investments	(242)	14,483	20,925
Amortization of debt discount	77,041	89,662	71,330
Other	(213)	(1,555)	12
Changes in operating assets and liabilities:			
Joint interest and other receivables	44,679	(151,334)	64,679
Other current assets	71,323	(27,528)	20,453
Trade and other accounts payable	20,138	2,681	(64,369)
Accrued liabilities	(62,058)	272,065	46,749
Accrued contract amendment costs	19,582	—	—
Other	287	1,795	15,968
Net cash flows used in operating activities	(165,665)	(1,646)	(61,760)
Cash flows from investing activities			
Additions to oil and natural gas properties	(687,892)	(915,861)	(748,656)
Capital expenditures for other property	(3,479)	(4,808)	(4,074)
Proceeds from maturity of investment securities	3,390,112	1,999,421	2,350,705
Purchase of investment securities	(2,545,911)	(1,192,873)	(2,739,134)
Net cash flows provided by (used in) investing activities	152,830	(114,121)	(1,141,159)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	490,000	—	—
Proceeds from debt offering, net of costs	—	—	1,269,778
Payment of debt issuance costs	—	(4,068)	—
Proceeds from exercise of stock options	—	—	33
Payments for common stock withheld for taxes on equity-based compensation	—	—	(631)
Net cash flows provided by (used in) financing activities	490,000	(4,068)	1,269,180
Increase (decrease) in cash, cash equivalents and restricted cash	477,165	(119,835)	66,261
Cash, cash equivalents and restricted cash, beginning of year	138,886	258,721	192,460
Cash, cash equivalents and restricted cash, end of year	$ 616,051	$ 138,886	$ 258,721

See accompanying notes to consolidated financial statements.

NOTE 1. ORGANIZATION AND NATURE OF BUSINESS

Cobalt International Energy, Inc., together with its wholly–owned subsidiaries (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. The Company operates in one reportable segment as its chief operating decision maker, the Chief Executive Officer, assesses performance and allocates resources based on the consolidated results of its business.

The Company no longer accounts for its Angolan operations as discontinued operations and has reclassified its consolidated financial statements for all periods presented to no longer reflect these operations as discontinued.

Liquidity and Going Concern

The accompanying consolidated financial statements have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The consolidated financial statements do not include any adjustments that might be necessary should the Company be unable to continue as a going concern. In 2016, the Company impaired its Angolan assets (see Note 3), which led to the Company reporting a net loss of $2,343.3 million, causing the Company to have a stockholders' deficit of $841.3 million.

Although the Company commenced initial production from its Heidelberg project in January 2016, the Company's ongoing capital and operating expenditures will vastly exceed the revenue it expects to receive from its oil and natural gas operations for the foreseeable future. In order to grow production, the Company needs to develop its discoveries into producing oil and natural gas properties, which will require that the Company raise substantial additional funding. If the Company is unable to raise substantial additional funding on a timely basis or on acceptable terms, the Company may be required to significantly curtail its exploration, appraisal and development activities.

The Company adopted Accounting Standards Update ("ASU") No. 2014–15, *Presentation of Financial Statements – Going Concern*, on December 31, 2016. This ASU required the Company to evaluate and disclose whether there is substantial doubt about its ability to continue as a going concern. The Company's assessment included the preparation of a detailed cash forecast that included all projected cash inflows and outflows as well as consideration of any cash related covenants associated with its financing structure.

In December 2016, the Company consummated a debt exchange and financing transaction (the "Transaction") as a part of obtaining new capital. The indentures governing the new debt obligations contain certain covenants including the maintenance of a minimum consolidated cash balance of at least $200.0 million. As the Company's detailed cash forecast shows that its projected cash balances would be out of compliance with the minimum consolidated cash balance covenant within one year after the date the consolidated financial statements are issued, the Company has concluded that there is substantial doubt about its ability to continue as a going concern.

The Company's ability to continue as a going concern is subject to, among other factors, its ability to monetize assets, its ability to obtain financing or refinance existing indebtedness, its ability to continue its cost cutting efforts for long–term rig and support services, the production rates achieved from the Heidelberg project, oil and natural gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed and cost with which the Company can bring such discoveries to production, whether and to what extent the Company invests in additional oil leases and concessional licenses, and the actual cost of exploration, appraisal and development of its prospects.

There can be no assurance that the Company will be able to obtain additional funding on satisfactory terms or at all. In addition, no assurance can be given that any such financing, if obtained, will be adequate to meet the Company's capital needs and support its growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then the Company's operations would be materially negatively impacted.

If the Company becomes unable to continue as a going concern, the Company may find it necessary to file a voluntary petition for reorganization under the Bankruptcy Code in order to provide it additional time to identify an appropriate solution to its financial situation and implement a plan of reorganization aimed at improving our capital structure.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its majority–owned subsidiaries ("we," "our" or "us"). All significant intercompany accounts and transactions have been eliminated in consolidation. In the Notes to Consolidated Financial Statements, all dollar and share amounts in tabulations are in thousands of dollars and shares, respectively, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We base our estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. While we believe that the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less at the time of purchase to be cash equivalents. All of our cash and cash equivalents are maintained with several major financial institutions in the United States. Deposits with these financial institutions may exceed the amount of insurance provided on such deposits; however, we regularly monitor the financial stability of these financial institutions and believe that we are not exposed to any significant default risk.

Restricted Cash

Restricted cash serves as collateral for certain of our obligations. These restricted funds are invested in interest–bearing accounts.

Joint Interest and Other Receivables

Joint interest receivables result from billing shared costs under the respective operating agreements to our partners. Accounts receivable from oil, natural gas and natural gas liquids sales are recorded at the invoiced amount and do not bear interest. We routinely assess the financial strength of our customers and partners and bad debts are recorded based on an account–by–account review after all means of collection have been exhausted, and the potential recovery is considered remote.

As of December 31, 2016, we have a $159.1 million receivable from Sonangol Pesquisa e Produção, S.A. ("Sonangol P&P") related to its share of costs incurred under the Block 21 Risk Services Agreement. Although this amount has been outstanding for over one year, Sonangol P&P has acknowledged that this amount is owed to us. We continue to work with them on resolution of this issue and have determined that we did not need to set up a reserve for doubtful accounts as of December 31, 2016.

As of December 31, 2016 and 2015, we did not have any reserves for doubtful accounts. We also did not have any off–balance sheet credit exposure related to our customers.

Investments

We have investments in marketable debt securities that are classified as held–to–maturity as we have the positive intent and ability to hold the investments until they mature. We classify investments with original maturities of greater than three months and remaining maturities of less than one year as short–term investments, and investments with maturities beyond one year as long–term investments.

Our debt securities are carried at amortized cost and the carrying value of these securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. As the estimated fair value of each investment approximates its amortized cost, there were no significant unrecognized holding gains or losses as of December 31, 2016 and 2015. Income related to these securities is reported as a component of interest income in our consolidated statements of operations.

Investments are considered to be impaired when a decline in fair value is determined to be other–than–temporary. We conduct a regular assessment of our debt securities with unrealized losses to determine whether these 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 we intend to sell or whether it is more likely than not that we will be required to sell the debt securities. As of December 31, 2016 and 2015, we have no OTTI in our debt securities.

Property and Depreciation, Depletion and Amortization

Our oil, natural gas and natural gas liquids producing activities are accounted for under the successful efforts method of accounting. Under this method, costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are charged to expense as incurred. For 2016, 2015 and 2014, we recorded dry hole costs of $213.5 million, $188.0 million and $165.5 million, respectively, to expense costs associated with the drilling of exploratory wells that did not find proved reserves.

Costs for unproved leasehold properties and exploratory wells that find reserves that cannot yet be classified as proved are capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or partner approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. For complex exploratory projects, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while additional appraisal drilling and seismic work is performed on the field or while we seek government or partner approval of development plans. Our assessment of suspended exploratory well costs is continuous until a determination is made to either sanction the project or to expense the well costs as dry hole costs as sufficient progress has not been made in assessing the reserves and the economic and operating viability of the project. In 2016, we recorded dry hole costs of $1,276.4 million to expense costs associated with our Angolan exploratory wells (see Note 3).

The capitalized costs of our producing oil and natural gas properties are depreciated and depleted by the units–of–production method based on the ratio of current production to estimated total net proved reserves as estimated by independent petroleum engineers. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves are used for depletion rates of leasehold costs.

Other property is stated at cost less accumulated depreciation, which is computed using the straight–line method based on estimated economic lives ranging from three to ten years. We expense costs for maintenance and repairs in the period incurred. Significant improvements and betterments are capitalized if they extend the useful life of the asset.

Impairment of Oil and Natural Gas Properties

We evaluate our proved oil and natural gas properties and related equipment and facilities for impairment whenever events or changes in circumstances indicate that the carrying amounts of such properties may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future net cash flows. The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related asset. For 2015, we recorded impairment charges of $256.8 million related to our proved oil and natural gas properties as the carrying amounts of such properties were determined not to be recoverable (see Note 5).

Oil and natural gas leases for unproved properties with a carrying value greater than $1.0 million are assessed individually for impairment based on our 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 over the terms of the leases at rates that provide for full amortization of leases upon lease expiration. These leases have expiration dates ranging from 2017 through 2026. For 2016, 2015 and 2014, we recorded impairment charges of $66.6 million, $26.9 million and $70.5 million, respectively, related to our leases for unproved oil and natural gas properties. In 2016, we also recorded an impairment charge of $353.4 million related to our Angolan leases in conjunction with the write-off of our Angolan exploratory well costs (see Note 3).

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the future abandonment costs of tangible assets, such as wells, service assets, and other facilities. We record an ARO and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit–of–production basis. If the ARO is settled for an amount other than the recorded amount, a gain or loss is recognized.

Embedded Derivatives

Our first lien senior secured notes due (the "First Lien Notes") and our second lien senior secured notes due 2023 (the "Second Lien Notes") include features which were determined to be embedded derivatives requiring bifurcation and accounting as separate financial instruments. The embedded derivatives were initially recorded at fair value and are subject to remeasurement as of each balance sheet date. We have elected not to designate our embedded derivatives as hedging instruments. Changes in the fair value of these embedded derivatives are recorded immediately to earnings in "Other (expense) income" in our consolidated statements of operations.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production. There were no significant natural gas imbalances at December 31, 2016.

Income Taxes

We use the liability method to determine our income tax provisions, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Concentration of Credit Risk

Our oil, natural gas and natural gas liquids revenues are derived principally from uncollateralized sales to customers in the oil and natural gas industry; therefore, our customers may be similarly affected by changes in economic and other conditions within the industry. We have experienced no credit losses on such sales in the past.

In 2016, one customer accounted for 96.5% of our consolidated oil, natural gas and natural gas liquids revenues. We believe that the loss of this customer would have a temporary effect on our revenues but, that over time, we would be able to replace this customer.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU No. 2014–09, *Revenue from Contracts with Customers*. This ASU superseded virtually all of the revenue recognition guidance in generally accepted accounting principles in the United States. The core principle of the five–step model is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. The provisions of ASU 2014–09 are applicable to annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. We plan to adopt ASU 2014-09 as of January 1, 2018 using the modified retrospective method with the cumulative effect, if any, of initial adoption to be recognized at the date of initial application. We are in the initial stages of our evaluation of the impact of adopting ASU 2014–09, but we do not expect the adoption to have a material impact on our consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014–15, *Presentation of Financial Statements – Going Concern*. This ASU amends the accounting guidance for the presentation and disclosure of uncertainties about an entity's ability to continue as a going concern. It requires management to evaluate and disclose whether there is substantial doubt about its ability to continue as a going concern. Management should consider relevant conditions or events that are known or reasonably known on the date the financial statements are issued. The provisions of ASU 2014–15 are applicable to the annual reporting period ending after December 15, 2016 and for annual periods and interim periods thereafter. We adopted ASU 2014–15 on December 31, 2016 (see Note 1).

In April 2015, the FASB issued ASU No. 2015–03, *Interest—Imputation of Interest*. This ASU changes the presentation of debt issuance costs in financial statements. Under ASU 2015–03, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. We adopted ASU 2015–03 on March 31, 2016, which required that we apply the guidance on a retrospective basis, wherein our consolidated balance sheets for all periods presented were adjusted to reflect the effects of applying the guidance. Accordingly, as of December 31, 2015, we reclassified $32.9 million of unamortized debt issuance costs previously reported in "Other assets" to "Long–term debt, net" on our consolidated balance sheet.

In July 2015, the FASB issued ASU No. 2015–11, *Accounting for Inventory*. This ASU requires entities to measure most inventory at lower of cost or net realizable value, which is defined as "the estimated selling prices in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation." We adopted ASU No. 2015–11 on December 31, 2016, and the adoption did not have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*. Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with lease terms of more than 12 months. Consistent with current accounting guidance, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily depends on its classification as a finance or operating lease. However, unlike current accounting guidance, which requires only capital leases to be recognized on the balance sheet, ASU 2016–02 will require both types of leases to be recognized on the balance sheet. ASU 2016-02 will also require disclosures to help investors and other financial statement users to better understand the amount, timing and uncertainty of cash flows arising from leases. Although ASU 2016–02 does not apply to leases for oil and natural gas properties, it does apply to equipment used to explore and develop oil and natural gas resources. ASU 2016–02 is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using the modified retrospective approach. We have not yet fully determined the effect that adopting ASU 2016-02 will have on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Subtopic 718)*. This ASU simplifies several aspects of the accounting for employee share–based payment transactions, including the accounting for income taxes, forfeitures and statutory withholding requirements, as well as classification in the statement of cash flows. The provision of ASU 2016–09 are applicable to annual reporting periods beginning after December 15, 2016 and interim period within those annual periods. Early adoption is permitted for financial statements that have not yet been previously issued. We have not yet fully determined or quantified the effect ASU 2016–09 will have on our consolidated financial statements.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments - Credit Losses*, which requires the measurement of expected credit losses for financial instruments held at the reporting date based on historical experience, current conditions and reasonable forecasts. The main objective of ASU 2016-13 is to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The provisions of ASU 2016-13 are effective for annual and interim periods beginning after December 15, 2019. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. We have not yet fully determined the effect that adopting ASU 2016-13 will have on our consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows*, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The provisions of ASU 2016-18 are effective for annual and interim periods beginning after December 15, 2017. We elected to early adopt the provisions of ASU 2016-18 on December 31, 2016, which required that we apply the guidance on a retrospective basis, wherein our consolidated statements of cash flows for all periods presented were adjusted to reflect the effects of applying the guidance. The following table shows the effects of applying the guidance:

	Prior to Adoption [1]	As Adjusted
Year ended December 31, 2015:		
(Accretion of discount) amortization of premium on investments	$ 14,207	$ 14,483
Accrued liabilities	22,453	272,065
Net cash flows used in operating activities	(251,942)	(1,646)
Change in restricted funds	(3,856)	—
Proceeds from maturity of investment securities	1,894,562	1,999,421
Purchase of investment securities	(892,577)	(1,192,873)
Net cash flows provided by (used in) investing activities	77,460	(114,121)
Increase (decrease) in cash, cash equivalents and restricted cash	(178,550)	(119,835)
Cash, cash equivalents and restricted cash, end of year	80,171	138,886
Year ended December 31, 2014:		
(Accretion of discount) amortization of premium on investments	18,159	20,925
Net cash flows used in operating activities	(64,526)	(61,760)
Change in restricted funds	43,667	—
Proceeds from maturity of investment securities	1,700,123	2,350,705
Purchase of investment securities	(2,129,453)	(2,739,134)
Net cash flows provided by (used in) investing activities	(1,138,393)	(1,141,159)

[1] Amounts are after reclassification of Angolan operations to no longer reflect these operations as discontinued.

No other new accounting pronouncements issued or effective during 2016 have had or are expected to have a material impact on our consolidated financial statements.

NOTE 3. ANGOLAN IMPAIRMENTS

In August 2015, we executed the Agreement with Sonangol for the sale by us to Sonangol of the entire issued and outstanding share capital of Cobalt Angola's indirect wholly–owned subsidiaries, CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold our 40% working interest in each of Block 20 and Block 21 offshore Angola. The requisite Angolan government approvals were not received within one year from the execution date and the Agreement terminated by its terms in August 2016. Since then, we have been working with Sonangol to understand and agree on the financial and operational implications of the termination of the Agreement. As part of these discussions, we have requested that Sonangol extend certain deadlines for exploration and development milestones under the agreements governing Blocks 20 and 21. Under the Agreement, we are entitled to be put back in our original position as if no agreement had been concluded, which we believe requires Sonangol to extend all such deadlines by, at a minimum, the one year period the Agreement was pending plus the period of time from the termination of the Agreement until this matter is resolved.

No extensions have been granted to date. Over six months have passed since the termination of the Agreement, and there can be no assurance that such extensions will be forthcoming, on favorable terms or at all. We reserve the right to and will vigorously enforce the provisions of the Agreement and our rights under international law if Sonangol does not grant the extensions we believe we are entitled to under the Agreement. The dispute resolution procedures of the Agreement require that any dispute be finally resolved under the Rules of Arbitration of the International Chamber of Commerce, with proceedings seated in London, England. In addition, prior to commencing arbitration proceedings, a party must provide the other party with a Notice of Dispute describing the nature of the dispute and the relief requested. Given Sonangol's delays and failure to date to grant the extensions, we submitted such a Notice of Dispute on March 8, 2017 to Sonangol under the Agreement. If Sonangol does not timely resolve this matter to our satisfaction, we intend to move forward with arbitration and at that time we will seek all available remedies at law or in equity. Further, our Angolan assets are indirectly held by a German subsidiary, and we therefore believe we are entitled to certain protections provided under international law under the bilateral investment treaty between Germany and Angola, dated October 30, 2003, including its substantive and procedural protections to investments of German investors.

In 2016, we recorded $1,629.8 million of dry hole costs and impairments to write off capitalized well costs and the underlying leases associated with our Angolan operations in accordance with Accounting Standards Codification ("ASC") 932, *Extractive Activities – Oil and Gas*, which requires, among other things, that "sufficient progress" be made with respect to oil and natural gas projects in order to avoid the requirement to expense previously capitalized exploratory or appraisal well costs. Given Sonangol's delays and failure to date to grant the extensions as well as the general investment climate in the Angolan oil and natural gas industry, the procedures of ASC 932 require us to record a full impairment of our Angolan assets at this time. The impairment is not associated with, nor is it indicative of, what we believe to be the intrinsic or fair market value of our Angolan assets. In addition, we also recorded $62.0 million of impairment charges related to inventory and other property in Angola.

Although we plan to continue to fulfill our obligations as operator, we do not plan to make any material additional investments in Angola until the financial and operational implications of the termination of the Agreement are resolved to our satisfaction. In addition, we are currently holding the $250.0 million initial payment that Sonangol made to us under the Agreement and do not plan to return any part of it until this matter, and the related matter concerning the payment of the joint interest receivable owed to us by Sonangol under the Block 21 Risk Services Agreement, is resolved.

NOTE 4. INVESTMENTS

Our investments in held–to–maturity securities consist of the following as of December 31:

	2016	2015
Corporate securities	$ 227,854	$ 492,955
Commercial paper	292,466	604,986
U.S. Treasury securities	161,778	105,064
Certificates of deposit	—	20,750
Total	$ 682,098	$ 1,223,755

These investments are recorded in our consolidated balance sheets as follows as of December 31:

	2016	2015
Cash and cash equivalents	$ 341,680	$ 38,420
Short-term investments [1]	340,418	1,185,335
	$ 682,098	$ 1,223,755

[1] As of December 31, 2016 and 2015, $9.1 million and $299.3 million, respectively, of these investments serve as collateral for certain of our obligations.

At December 31, 2016 and 2015, the contractual maturities of our investments were within one year. Actual maturities may differ from contractual maturities as some borrowers have the right to call or prepay obligations with or without call or prepayment penalties.

NOTE 5. FAIR VALUE MEASUREMENTS

The fair value hierarchy has three levels based on the reliability of the inputs used to determine fair value. Level 1 refers to fair values determined based on quoted prices in active markets for identical assets or liabilities. Level 2 refers to fair values determined based on quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration. Level 3 refers to fair values determined based on our own assumptions used to measure assets and liabilities at fair value.

Recurring Basis

The following table represents the fair value hierarchy for our liabilities required to be measured at fair value on a recurring basis:

		Fair Value Measurements at the End of the Reporting Period:		
	Fair Value	Level 1	Level 2	Level 3
As of December 31, 2016:				
Embedded derivative liabilities:				
First Lien Notes	$ 27,012	$ —	$ —	$ 27,012
Second Lien Notes	23,111	—	—	23,111
Total	$ 50,123	$ —	$ —	$ 50,123

The fair values of these embedded derivatives were estimated using the "with" and "without" method. Using this methodology, the First Lien Notes and Second Lien Notes were first valued with the embedded derivatives (the "with" scenario) and subsequently valued without the embedded derivative (the "without" scenario). The fair values of the embedded derivatives were estimated as the difference between the fair values of the First Lien Notes and Second Lien Notes in the "with" and "without" scenarios. The fair values of the First Lien Notes and Second Lien Notes in the "with" and "without" scenarios were estimated using a risk–neutral probability of default model. Significant Level 3 assumptions used in the valuation of the embedded derivatives were the fair values of our long–term debt, the expected recovery rates, the risk–neutral probability of default and the risk–free rates. The initial measurement of fair value for these embedded derivatives was at December 6, 2016, the date we entered into the First Lien Notes and Second Lien Notes (see Note 7).

The reconciliation of changes in the fair value of our embedded derivatives is as follows for the year ended December 31:

	2016
Beginning of period	$ —
Issuance of First Lien Notes and Second Lien Notes	47,618
Change in fair value	2,505
End of period	$ 50,123

Nonrecurring Basis

In 2015, as a result of a reduction in future net cash flows, we recognized a $256.8 million impairment charge to write down proved oil and natural gas properties to their fair value of $68.4 million. The fair value was determined using the income approach and was based on the expected present value of the future net cash flows from estimated reserves. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future prices, production costs, development expenditures, anticipated production of our estimated reserves, appropriate risk–adjusted discount rates and other relevant data.

Financial Instruments

The estimated fair values of our financial instruments have been determined at discrete points in time based on relevant market information. Our financial instruments consist of cash and cash equivalents, joint interest and other receivables, held–to–maturity investments, accounts payable and accrued liabilities. The carrying amounts of our financial instruments, other than held–to–maturity–investments and long–term debt, approximate fair value because of the short–term nature of the items.

There were no significant unrecognized holding gains or losses related to our held–to–maturity investments as of December 31, 2016 and 2015. Accordingly, the carrying value of our held–to–maturity investments approximates their fair value. Our held–to–maturity investments are not traded on a public exchange and the fair value of these investments is based on inputs using valuations obtained from independent brokers. As these valuations use readily observable market parameters that are actively quoted and can be validated through external sources, we have categorized these investments as Level 2.

The estimated fair value of our long–term debt is as follows as of December 31:

	2016	2015
10.75% first lien notes due 2021	$ 482,250	$ —
7.75% second lien notes due 2023	327,449	—
2.625% convertible senior notes due 2019	305,378	791,209
3.125% convertible senior notes due 2024	332,344	577,291
	$ 1,447,421	$ 1,368,500

The fair values of our long–term debt were estimated using quoted market prices. As these valuations use quoted prices in active markets for identical assets or liabilities, we have categorized the long–term debt as Level 1.

NOTE 6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consisted of the following as of December 31:

	2016	2015
Proved oil and natural gas properties:		
Well and development costs	$ 118,245	$ 71,463
Accumulated depletion	(20,204)	—
Total proved properties	98,041	71,463
Unproved oil and natural gas properties:		
Oil and natural gas leaseholds	651,295	738,852
Accumulated valuation allowance	(507,198)	(178,463)
	144,097	560,389
Exploratory wells in process	836,747	1,727,181
Total unproved properties	980,844	2,287,570
Total oil and natural gas properties, net	$ 1,078,885	$ 2,359,033

Capitalized Exploratory Well Costs

The following tables reflect the net changes in and the cumulative costs of capitalized exploratory well costs (excluding any related leasehold costs):

	2016	2015	2014
Beginning of period	$ 1,727,181	$ 1,186,464	$ 777,823
Additions to capitalized exploration			
Exploratory well costs	499,985	630,395	522,892
Capitalized interest	99,541	87,683	51,208
Amounts charged to expense [1]	(1,489,960)	(177,361)	(165,459)
End of period	$ 836,747	$ 1,727,181	$ 1,186,464

[2] Amounts represent dry hole costs related to exploratory wells which did not encounter commercial hydrocarbons or where it was determined that sufficient progress was not being made.

	2016	2015
Cumulative costs:		
Exploratory well costs	$ 582,115	$ 1,572,090
Capitalized interest	254,632	155,091
	$ 836,747	$ 1,727,181
Wells costs capitalized for a period greater than one year after completion after drilling (included in table above)	$ 609,893	$ 1,225,747

As of December 31, 2016, capitalized exploratory well costs that have been suspended longer than one year are associated with our Shenandoah, North Platte, Anchor, and Gabon discoveries. As of December 31, 2015, capitalized exploratory well costs that have been suspended longer that one year as associated with our Shenandoah, North Platte, Anchor, Gabon and Angolan discoveries. These well costs are suspended 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. We believe these discoveries exhibit sufficient indications of hydrocarbons to justify potential development and are 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.

NOTE 7. LONG–TERM DEBT, NET

Long–term debt, net consisted of the following as of December 31:

	2016	2015
10.75% first lien notes due 2021		
Principal outstanding	$ 500,000	$ —
Unamortized discount [1]	(34,416)	—
Carrying amount	465,584	—
7.75% second lien notes due 2023		
Principal outstanding	584,732	—
Unamortized discount [2]	(54,856)	—
Carrying amount	529,876	—
2.625% convertible senior notes due 2019:		
Principal outstanding	763,446	1,380,000
Unamortized discount [3]	(109,689)	(258,565)
Carrying amount	653,757	1,121,435
3.125% convertible senior notes due 2024:		
Principal outstanding	1,204,145	1,300,000
Unamortized discount [4]	(374,013)	(439,540)
Carrying amount	830,132	860,460
Total	$ 2,479,349	$ 1,981,895

[1] Effective interest rate of 12.6%

[2] Effective interest rate of 9.6%

[3] Effective interest rate of 8.4%

[4] Effective interest rate of 9.0%

On December 6, 2016, we consummated the Transaction with certain holders (the “Holders”) of our outstanding 2.625% Convertible Senior Notes due 2019 (the “2019 Notes”) and 3.125% Convertible Senior Notes due 2024 (the “2024 Notes”). The Transaction consisted of: (i) the issuance of $500.0 million aggregate principal amount of the First Lien Notes to Holders for cash at a price of 98% and (ii) the issuance of $584.7 million aggregate principal amount of the Second Lien Notes and 30.0 million shares of our common stock to Holders in exchange for $616.6 million aggregate principal amount of 2019 Notes and $95.9 million aggregate principal amount of 2024 Notes held by the Holders.

Both our First Lien Notes and Second Lien Notes have a requirement to pay an applicable premium upon a change in control or an event of default. In addition, our Second Lien Notes also have a put option in an asset sale. These requirements were determined to be embedded derivatives that require us to bifurcate and fair value the derivatives as of December 6, 2016 and to fair value the derivatives as of each subsequent reporting date (see Note 5). At December 6, 2016, we recognized derivative liabilities of $24.8 million and $22.8 million for our First Lien Notes and Second Lien Notes, respectively, which decreased the carrying value of these notes.

We accounted for the Transaction as a debt modification as we determined that the terms of the new debt instruments were not substantially different from the terms of the original instruments. We did not recognize any gain or loss on the Transaction and have prospectively adjusted the effective interest rates on the 2019 Notes and 2024 Notes. Costs related to the Transaction totaled $19.6 million and are included in “General and administrative expenses” in our consolidated statements of operations.

10.75% First Lien Notes

The 10.75% First Lien Notes were issued under an indenture dated December 6, 2016 (the "First Lien Indenture") and mature on December 1, 2021. Interest is payable semi–annually in arrears on each June 1 and December 1 of each year. The First Lien Notes are initially guaranteed by all of our wholly–owned domestic subsidiaries (the "Guarantors") and are secured, subject to certain exceptions, by a first priority lien on (i) substantially all of ours and the Guarantors' assets and (ii) 65% of the shares of capital stock of Cobalt International Energy Overseas Ltd., which indirectly owns our working interests in our blocks offshore Angola and offshore Gabon (collectively, the "Collateral").

The First Lien Indenture includes covenants including, without limitation, restrictions on our ability to incur additional indebtedness, create liens on our properties, pay dividends and make restricted payments or certain investments, in each case subject to certain exceptions. The First Lien Indenture also requires us to apply a portion of the proceeds from certain asset sales to offer to repay the obligations under the First Lien Indenture, limits the incurrence of indebtedness secured on a second lien basis (including additional Second Lien Notes), prohibits the issuance of additional First Lien Notes and requires us to maintain a cash balance of at least $200.0 million.

Prior to December 1, 2018, we may redeem the First Lien Notes, at our option, at a redemption price equal to 100% of the outstanding principal amount of such notes plus the applicable premium (as defined in the First Lien Indenture). On and after December 1, 2018, the First Lien Notes may be redeemed in multiples of $1,000 principal amount at a redemption price equal to 100% of the First Lien Notes to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date.

7.75% Second Lien Notes

The 7.75% Second Lien Notes were issued pursuant to an indenture dated December 6, 2016 (as amended or supplemented from time to time, the "Second Lien Indenture") and mature on December 1, 2023. Interest is payable semi–annually in arrears on each June 1 and December 1 of each year. The Second Lien Notes are guaranteed by the Guarantors and are secured, subject to certain exceptions, by a second priority lien on the Collateral.

The Second Lien Indenture includes covenants and redemption provisions substantially similar to those in the First Lien Indenture.

2.625% Convertible Senior Notes due 2019

The 2019 Notes were issued under an indenture dated December 17, 2012 (the "2019 Indenture") and mature December 1, 2019. Interest is payable semi–annually in arrears on June 1 and December 1 of each year. The 2019 Notes are senior unsecured obligations.

The 2019 Notes may be converted at the option of the holder on the second scheduled trading day immediately preceding the maturity date, in multiples of $1,000 principal amount. The 2019 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. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in 2019 Indenture, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. We can satisfy the conversion obligation, at our option, in either cash, shares of common stock or a combination thereof.

When the 2019 Notes were issued, we accounted for the debt and equity components of the 2019 Notes separately, as we have the option to settle the conversion obligation in cash. At the date of issuance, we calculated the fair value of the 2019 Notes, excluding the conversion feature, based on the fair value of similar non–convertible debt instruments. The difference between the cash proceeds and the estimated fair value represented the value which was assigned to the equity component and recorded as a debt discount. The debt discount is being amortized using the effective interest rate method over the period from issuance to the maturity date of December 1, 2019. The carrying amount of the equity component of the 2019 Notes reported in additional paid in capital was initially valued at $381.4 million, which is net of $9.1 million of debt issuance costs allocated to the equity component.

As the closing price of our common stock on December 31, 2016 was less than the initial conversion price for the 2019 Notes, the if–converted value of the 2019 Notes would be less than principal amount.

Holders of the 2019 Notes who convert their notes in connection with a "make–whole fundamental change", as defined in the 2019 Indenture, 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 2019 Indenture, holders of the 2019 Notes may require us 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 2019 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 2019 Indenture, the trustee or the holders of at least 25% in aggregate principal amount of the 2019 Notes then outstanding may declare 100% of the principal of, and accrued and unpaid interest on, all the 2019 Notes to be due and payable immediately.

3.125% Convertible Senior Notes due 2024

The 2024 Notes were issued under an indenture dated May 13, 2014 (the "2024 Indenture") and mature on May 15, 2024. Interest is payable semi–annually in arrears on May 15 and November 15 of each year. The 2024 Notes are senior unsecured obligations and ran equal in right of payment to the 2019 Notes.

Prior to November 15, 2023, the 3.125% Notes are convertible only under the following circumstances: (i) during any fiscal quarter commencing after March 31, 2015 (and only during such fiscal quarter), if the last reported sale price of our 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; (ii) during the five business day period after any five consecutive trading day period (the "2024 Notes Measurement Period") in which the trading price per $1,000 principal amount of notes for each trading day of the 2024 Notes Measurement Period was less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; (iii) if we call all or any portion of the 2024 Notes for redemption on the second scheduled trading day immediately preceding the related redemption date; or (iv) upon the occurrence of specified distributions or the occurrence of specified corporate events. As of December 31, 2016, none of the conditions allowing holders of the 2024 Notes to convert had been met.

On or after November 15, 2023, the 2024 Notes may be converted at the option of the holder at any time on the second scheduled trading day immediately preceding the stated maturity date, in multiples of $1,000 principal amount.

The 2024 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. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the 2024 Indenture, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. We can satisfy the conversion obligation, at our option, in either cash, shares of common stock or a combination thereof.

When the 2024 Notes were issued, we accounted for the debt and equity components of the 2024 Notes separately, as we have the option to settle the conversion obligation in cash. At the date of issuance, we calculated the fair value of the 2024 Notes, excluding the conversion feature, based on the fair value of similar non–convertible debt instruments. The difference between the cash proceeds and the estimated fair value represented the value which was assigned to the equity component and recorded as a debt discount. The debt discount is being amortized using the effective interest rate method over the period from issuance to the maturity date of May 15, 2024. The carrying amount of the equity component of the 2024 Notes reported in additional paid in capital was initially valued at $464.7 million, which is net of $11.1 million of debt issuance costs allocated to the equity component.

As the closing price of our common stock on December 31, 2016 was less than the initial conversion price for the 2024 Notes, the if–converted value of the 2024 Notes would be less than principal amount.

Holders of the 2024 Notes who convert their notes in connection with a "make– whole fundamental change", as defined in the 2024 Indenture, 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 2024 Indenture, holders of the 2024 Notes may require us 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 2024 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 2024 Indenture, 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 2024 Notes to be due and payable immediately.

Borrowing Base Facility Agreement

In 2015, Cobalt GOM #1 LLC, an indirect, wholly-owned subsidiary, entered into a Borrowing Base Facility Agreement (the "Facility Agreement") which provided for a limited recourse $150.0 million senior secured reserve–based term loan facility, with an amount available for borrowing at any time limited to a periodically adjusted borrowing base amount.

In 2016, we terminated the Facility Agreement because the borrowing base amount under the Facility Agreement was expected to be materially reduced to a level that would not justify the ongoing expense of maintaining the facility. In conjunction with the termination, we wrote off $3.3 million of debt issuance costs associated with the facility agreement.

We had no amounts outstanding under the Facility Agreement at any time it was in place.

Maturities of Long–Term Debt

The maturities of our long–term debt are as follows for the years ended December 31:

	Payments Due By Year					
	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Principal outstanding	$ —	$ —	$ 763,446	$ —	$ 500,000	$ 1,788,877

NOTE 8. ASSET RETIREMENT OBLIGATIONS

The changes in ARO are as follows for the years ended December 31:

	2016	**2015**
Beginning of period	$ 3,167	$ —
Liabilities incurred	—	3,068
Revisions	2,806	—
Accretion	550	99
End of period	$ 6,523	$ 3,167

NOTE 9. COMMITMENTS AND CONTINGENCIES

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.

In November 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, asserted 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.

In December 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 asserted 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.

In March 2015, the Court entered an order consolidating the Neuman lawsuit with the St. Lucie lawsuit (the "Consolidated Action") and also entered an order in the Consolidated Action appointing Lead Plaintiffs and Lead Counsel. Lead Plaintiffs filed their consolidated amended complaint in May 2015. Among other remedies, the Consolidated Action seeks damages in an unspecified amount, along with an award of attorney fees and other costs and expenses to the plaintiffs. We filed a motion to dismiss the consolidated amended complaint in June 2015, and the other defendants also filed motions to dismiss. The Court denied our motion to dismiss in January 2016, and, in March 2016, the Court also denied our motion requesting that the Court certify its order on the motions to dismiss so that we may seek interlocutory appellate review of the order. Lead Plaintiffs also have filed a motion for class certification, seeking to certify a class of all persons and entities who purchased or otherwise acquired our securities between March 1, 2011 and November 3, 2014. The matter remains ongoing.

In May 2016, Gaines, a purported stockholder, filed a derivative action in the 295th District Court in Harris County, Texas against us, as a nominal defendant, certain of our current and former officers and directors, and certain investment firms and funds. The lawsuit alleges that current and former officers and directors breached their fiduciary duties by making, and permitting us to make, alleged misrepresentations about two of our exploration wells offshore Angola; that certain officers received performance-based compensation in excess of what they were entitled; and that the investment firms and funds owed a fiduciary duty to us as controlling stockholders and breached that duty by engaging in insider trading. The lawsuit further alleges that demand was wrongfully refused. The plaintiff asserts claims for breach of fiduciary duty and unjust enrichment and seeks damages in an unspecified amount, disgorgement of profits, appropriate equitable relief, and an award of attorney fees and other costs and expenses. In July 2016, we filed our answer and special exceptions challenging the plaintiff's standing to bring such claims against us. The Court heard arguments on our special exceptions in December 2016. The matter remains ongoing.

In November 2016, McDonaugh, a purported stockholder, filed a derivative action in the 80th District Court in Harris County, Texas against us, as a nominal defendant, and certain of our current and former officers and directors. The lawsuit alleges that defendants breached their fiduciary duties by failing to maintain adequate internal controls and by permitting or failing to prevent alleged misrepresentations and omissions in our SEC filings and other public disclosures, including in relation to compliance with the FCPA in our Angolan operations and regarding the performance of certain wells offshore Angola. The lawsuit also alleges that defendants received compensation or other benefits in excess of what they were entitled and that certain officers and directors engaged in unlawful trading and misappropriation of information. The lawsuit further alleges that demand was wrongfully refused. The plaintiff asserts claims for breach of fiduciary duty and unjust enrichment and seeks damages in an unspecified amount, reform of our governance and internal controls, restitution and disgorgement of profits, and an award of attorney fees and other costs and expenses. We filed our answer and special exceptions challenging the plaintiff's standing to bring such claims against us in January 2017. The matter remains ongoing.

In May 2016, we filed suit against XL Specialty Insurance Company ("XL") in Harris County District Court in Houston, Texas. We assert XL improperly denied coverage for insurance claims made in July 2012 and other claims subsequently submitted to them in connection with our defending against the St. Lucie lawsuit, the Ogden derivative action, and other investigations and actions. In December 2016, we amended our petition to add Axis Insurance Company ("Axis"). Axis provides coverage in excess of the XL policy's limit of liability. We allege breach of contract, violation of the Texas Prompt Payment of Claims Act, and seek a declaratory judgment that XL and Axis are obligated to pay any additional loss suffered by us due to the circumstances, investigation, and claims described in the suit. In December 2016, we also amended our petition to add claims against Illinois National Insurance Company, an AIG subsidiary ("AIG"), which served as our insurer after XL Against AIG, we allege breach of contract, violation of the Texas Prompt Payment of Claims Act, violation of the Texas Deceptive Trade Practices-Consumer Protection Act, and seek a declaratory judgment that AIG is obligated to pay any additional loss suffered by us due to the circumstances, investigations, and actions related to the Lontra and/or Loengo wells. Discovery is ongoing in the case and trial is set for June 2017.

We are vigorously defending against the current lawsuits. It is not presently possible to determine whether any such matters will have a material adverse effect on our consolidated financial position, results of operations or liquidity.

At December 31, 2016, we had the following estimated contractual commitments for the years ending December 31:

	Payments Due By Year					
	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Drilling rig commitments	$ 85,269	$ —	$ —	$ —	$ —	$ —
Social payment obligations [1]	86,473	74	—	—	—	—
Delay rental payments [2]	5,243	3,388	3,575	3,595	3,595	7,492
Operating leases	2,309	2,369	2,405	2,454	2,501	671
Total	$179,294	$ 5,831	$ 5,980	$ 6,049	$ 6,096	$ 8,163

[1] Includes our contractual payment obligations for social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that we agreed to pay in consideration for the Angolan government granting us the licenses to explore for and develop hydrocarbons offshore Angola.

[2] Annual payments required to maintain our U.S. Gulf of Mexico leases from year to year.

We recorded $9.2 million, $12.4 million, and $12.8 million of office and delay rental expense in 2016, 2015 and 2014, respectively.

NOTE 10. EQUITY–BASED COMPENSATION

We have various long–term incentive plans for employees. These plans allow for the issuance of restricted stock awards (“RSAs”), non–qualified stock options (“NQSOs”), performance stock units (“PSUs”), stock appreciation rights (SARs”) and restricted stock units (“RSUs”). As of December 31, 2016, we have 25.7 million shares authorized for issuance under these plans, and 7.7 million shares remain available for grant.

We also have various long–term incentive plans for our non–employee directors. These plans allow for the issuance of NQSOs, RSUs or other equity–based awards as retainers. As of December 31, 2016, we have 1.5 million shares authorized for issuance under these plans, and 0.6 shares remain available for grant.

Our policy is to issue new shares when RSAs are granted, when NQSOs are exercised and, should we elect to settle our PSUs, SARs and RSUs in shares of our common stock, when PSUs, SARs and RSUs are vested.

Restricted Stock Awards

An RSA is an award of common stock with no exercise price. In 2016 and 2015, we granted 0.6 million and 0.4 million RSAs, respectively, with both a performance and a service condition, and the fair value was measured using the Monte Carlo simulation model. The remainder of the RSAs granted in 2016 and 2015 and all of the RSAs granted in 2014 had a service condition only, and the fair value was measured using the market price of our common stock on the grant date. RSAs generally vest in three equal annual installments.

The following weighted average assumptions were used to estimate the fair value of the RSAs for the year ended December 31:

	2016	2015
Expected volatility	55.02%	49.79%
Risk-free interest rate	2.03%	1.77%
Dividend yield	—%	—%
Expected life (years)	5.7	10.0

Volatility was estimated based on historical daily prices from January 1, 2010 to the grant date. The risk–free interest rate was based on the yield of a zero–coupon U.S. Treasury bill that is commensurate with the RSAs contractual term. The expected dividend yield was not taken into account as we have historically not paid any dividends. The expected life was based on the derived service period, which is the period between the grant date and the date the performance condition is met, as calculated by the Monte Carlo simulation model.

Activity related to RSAs is as follows:

	Number of RSAs	Weighted Average Grant Date Fair Value Per RSA
Nonvested at January 1, 2016	5,780,239	$ 11.59
Granted	3,898,052	1.43
Vested	(2,494,643)	11.33
Forfeited	(1,061,890)	12.70
Nonvested at December 31, 2016	6,121,758	$ 5.00
Exercisable at December 31, 2016	755,657	$ 6.73

The fair value of RSAs granted in 2016, 2015 and 2014 was $6.3 million, $30.5 million and $33.1 million, respectively, and the fair value of RSAs vested in 2016, 2015 and 2014 was $4.6 million, $1.4 million and $11.5 million, respectively.

The weighted average remaining contractual terms for RSAs outstanding and RSAs exercisable at December 31, 2016 were 5.4 years and 3.7 years, respectively.

As of December 31, 2016, there was $15.6 million of total unrecognized compensation cost related to unvested RSAs which is expected to be recognized over a weighted-average period of 1.6 years.

Non-Qualified Stock Options

We grant NQSOs to employees at an exercise price equal to the market value of our common stock on the grant date. The NQSOs have contractual terms of 10 years. The NQSOs granted in 2016 and 2015 vest after one year of service, subject to our common stock maintaining a minimum stock price for a specified period of time. The NQSOs granted in 2014 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.

As the NQSOs granted in 2016 and 2015 had both service and market conditions, we estimated the fair value of these NQSOs using the Monte Carlo simulation model. The fair values of the NQSOs granted in 2014 were determined using the Black–Scholes option pricing model. The following weighted average assumptions were used to estimate the fair value of the NQSOs for the years ended December 31:

	2016	2015	2014
Expected volatility	55.02%	54.97%	57.27%
Risk-free interest rate	2.03%	1.84%	1.69%
Dividend yield	—%	—%	—%
Expected life (years)	5.7	5.5	5.5

Volatility was estimated based on historical daily prices from January 1, 2010 to the grant date. The risk–free interest rate was based on the yield of a zero–coupon U.S. Treasury bill that is commensurate with the NQSOs contractual term. The expected dividend yield was not taken into account as we have historically not paid any dividends. The expected life was based on the derived service period, which is the period between the grant date and the date the performance condition is met, as calculated by the Monte Carlo simulation model.

Activity related to the NQSOs is as follows:

	Number of NQSOs	Weighted Average Exercise Price per NQSO
Outstanding at January 1, 2016	3,766,941	$ 17.23
Granted	1,129,944	3.50
Forfeited	(588,744)	19.69
Outstanding at December 31, 2016	4,308,141	$ 13.29
Exercisable at December 31, 2016	3,110,337	$ 16.75

The fair value of NQSOs granted in 2016, 2015 and 2014 was $4.0 million, $5.9 million and $14.2 million, respectively, and the fair value of NQSOs vested in 2016, 2015 and 2014 was $14.5 million, $12.3 million and $16.1 million, respectively.

The weighted average remaining contractual terms for NQSOs outstanding and NQSOs exercisable at December 31, 2016 were 6.7 years and 5.8 years, respectively. There was no intrinsic value for both NQSOs outstanding and NQSOs exercisable as the exercise prices exceeded the market price of our common stock as of December 31, 2016.

As of December 31, 2016, there was $0.4 million of total unrecognized compensation cost related to unvested NQSOs which is expected to be recognized over a weighted-average period of 0.8 years.

Performance Stock Units

A PSU is an award where each unit represents the right to receive, subject to our common stock attaining a specified return, the value of one share of our common stock at the date of vesting. The PSUs may be settled by, at our discretion, either the issuance of our common stock, cash or a combination thereof based on the fair market value of the common stock on the date of exercise. The PSUs vest in three equal installments subject to our common stock attaining a specified return each vesting date. The PSUs granted in 2016 had both service and performance conditions, and we estimated the fair value of these PSUs using the Monte Carlo simulation model.

The following weighted average assumptions were used to estimate the fair value of the PSUs for the year ended December 31:

	2016
Expected volatility	64.31%
Risk-free interest rate	0.80%
Dividend yield	—%

Expected volatility was calculated for the peer company based on historical volatility over the most recent three years using daily stock prices. The risk–free interest rate was based on the yield of a zero–coupon U.S. Treasury bill that is commensurate with the end date of the longest remaining period of three years. The expected dividend yield was not taken into account as we have historically not paid any dividends.

Activity related to the PSUs is as follows:

	Number of PSUs	Weighted Average Grant Date Fair Value Per PSU
Nonvested at January 1, 2016	—	$ —
Granted	283,750	0.75
Nonvested at December 31, 2016	283,750	$ 0.75
Exercisable at December 31, 2016	—	$ —

The weighted average remaining contractual term for PSUs outstanding at December 31, 2016 was 9.6 years.

As of December 31, 2016, there was $0.2 million of total unrecognized compensation cost related to unvested PSUs which is expected to be recognized over a weighted-average period of 2.6 years.

Restricted Stock Units

An RSU is an award where each unit represents the right to receive the value of one share of our common stock at the date of vesting. RSUs may be settled by, at our discretion, either the issuance of our common stock, cash or a combination thereof based on the fair market value of the common stock on the date of exercise. The RSUs granted in 2016 vest in three equal annual installments.

Activity related to the RSUs is as follows:

	Number of RSUs	Weighted Average Grant Date Fair Value Per RSU
Nonvested at January 1, 2016	—	$ —
Granted	3,491,352	2.44
Vested	(596,823)	2.44
Forfeited	(457,097)	2.44
Nonvested at December 31, 2016	2,437,432	$ 2.44
Exercisable at December 31, 2016	358,606	$ 2.44

The fair value of RSUs vested in 2016 and 2014 was $0.8 million and $0.7 million, respectively. No RSUs vested in 2015.

The weighted average remaining contractual terms for both RSUs outstanding and RSUs exercisable at December 31, 2016 was 9.1 years.

As of December 31, 2016, there was $4.1 million of total unrecognized compensation cost related to unvested RSUs which is expected to be recognized over a weighted–average period of 2.2 years.

Stock Appreciation Rights

An SAR represents a contractual right to receive an amount equal to the appreciation in the price of one share of our common stock from the grant date over the exercise price of the SAR. SARs may be settled by, at our discretion, either the issuance of our common stock, cash or a combination thereof based on the fair market value of the common stock on the date of exercise. We grant SARs to employees at an exercise price equal to the market value of our common stock on the grant date. The SARs have contractual terms of 10 years and vest in three equal annual installments.

We account for the SARs as liability awards, and the fair value of the SARs is remeasured at the end of each reporting period based on the current fair value of the SARs. We estimate the fair value of the SARs using the Black–Scholes option price model.

The following weighted average assumptions were used to estimate the fair value of the SARs for the year ended December 31:

	2015
Expected volatility	54.97%
Risk-free interest rate	1.84%
Dividend yield	—%
Expected life (years)	5.5

Activity related to the SARs is as follows:

	Number of SARs	Weighted Average Exercise Price Per SAR
Outstanding at January 1, 2016	1,452,332	$ 8.87
Forfeited	(595,566)	8.87
Outstanding at December 31, 2016	856,766	$ 8.87
Exercisable at December 31, 2016	698,424	$ 8.87

The weighted average grant date fair value of SARs granted in 2015 was $4.2 million. No SARs were granted in 2016 or 2014.

As of December 31, 2016, the weighted average remaining contractual term for both SARs outstanding and SARs exercisable was 8.1 years and there was no intrinsic value for both the SARS outstanding and the SARS exercisable as the exercise price exceeds the market price of our common stock as of December 31, 2016.

As of December 31, 2016, there was $10 thousand of total unrecognized compensation cost related to unvested SARs which is expected to be recognized over a weighted–average period of 1.1 years.

Non–Employee Director Grants

We granted a total of 0.3 million, 0.05 million and 0.03 million shares of our common stock to our non–employee directors as retainer awards in 2016, 2015 and 2014, respectively. The directors have elected to defer the issuance of this stock. Accordingly, we have recorded a liability for the future issuance of these shares. The weighted average fair value of the common stock granted in 2016, 2015 and 2014 was $1.89, $9.49 and $17.52 , respectively.

In addition, we granted 0.4 million RSUs to our non–employee directors. These RSUs will be settled by, at our discretion, either the issuance of our common stock, cash or a combination thereof. The fair value of these RSUs on the date of grant was $0.8 million.

Compensation Cost

Equity–based compensation cost is measured at the date of grant based on the calculated fair value of the award and is generally recognized on a straight–line basis over the requisite service period, including those with graded vesting. The compensation cost is determined based on awards ultimately expected to vest, and we have reduced the cost for estimated forfeitures based on historical forfeiture rtes. Forfeitures are estimated at the time of grant and revised, if necessary, in subsequent periods to reflect actual forfeitures.

The following table presents the compensation costs recognized for the years ended December 31:

	2016	2015	2014
Equity awards	$ 16,243	$ 26,297	$ 31,742
Liability awards	(1,354)	1,451	—
Total	$ 14,889	$ 27,748	$ 31,742

NOTE 11. EMPLOYEE BENEFIT PLAN

We have a defined contribution 401(k) plan (the “Plan”). All of our employees are eligible to participate in the Plan after three months of continuous employment. The plan is discretionary and provides a 6% employee contribution match as determined by our Board of Directors. For 2016, 2015 and 2014, we recorded $1.5 million, $1.7 million, and $1.0 million, respectively, in benefits contributions to the Plan, which are included in general and administrative expenses in our consolidated statements of operations.

NOTE 12. INCOME TAXES

The provision for income taxes is comprised of the following for the years ended December 31:

	2016	2015	2014
Current taxes:			
U.S.	$ —	$ —	$ —
Foreign	—	—	—
Deferred taxes:			
U.S	—	—	—
Foreign	—	—	—
Total	$ —	$ —	$ —

As we establish full valuation allowances against net deferred tax assets where we have determined that it is more likely than not that all of the deferred tax assets will not be realized, we have recognized no income taxes in our consolidated statements of operations for the years ended December 31, 2016, 2015 and 2014.

The geographic sources of our loss are as follows for the years ended December 31:

	2016	2015	2014
U.S.	$ (2,313,482)	$ (490,190)	$ (307,025)
Foreign	(29,827)	(204,236)	(203,738)
Net loss	$ (2,343,309)	$ (694,426)	$ (510,763)

The effective tax rate on our loss differs from the U.S. statutory rate as follows for the years ended December 31:

	2016	2015	2014
Income tax expense (benefit) at the federal statutory rate	35.0%	35.0%	35.0%
State income taxes, net of federal income tax benefit	0.1%	0.1%	0.2%
Foreign income tax	41.5%	13.5%	21.8%
Other	(4.0)%	(0.5)%	(1.8)%
Valuation allowance	(72.6)%	(48.1)%	(55.2)%
	—%	—%	—%

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 purposes. The tax effects of our temporary differences and net operating losses ("NOL") are as follows at December 31:

	2016	2015
Long-term deferred tax asset:		
Seismic and exploration costs	$ 2,227,489	$ 733,183
Stock based compensation	27,342	26,995
Domestic NOL carry forwards	695,434	568,050
Foreign NOL carry forwards	43,969	42,625
Other	11,522	(88,837)
Valuation allowance	(2,597,708)	(896,355)
Total long-term deferred tax asset	408,048	385,661
Long-term deferred tax liability:		
2019 Notes	(61,944)	(85,339)
2024 Notes	(107,629)	(148,279)
Oil and natural gas properties	(238,475)	(152,043)
Total long-term deferred tax liability	(408,048)	(385,661)
Net long-term deferred tax asset	$ —	$ —

As of December 31, 2016, we had NOL carryforwards for federal and state income tax purposes of approximately $2.0 billion and $82.8 million, respectively, which begin to expire in 2026 and 2025, respectively.

As of December 31, 2016, we had an NOL carryforward for foreign income tax purposes of approximately $85.6 million which began to expire in 2016.

The utilization of the NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period.

Our tax filings are subject to examination by federal and state tax authorities where we conduct our business. These examinations may result in assessments of additional tax that are resolved with the authorities or through the courts. We have evaluated whether any material tax position we have taken will more likely than not be sustained upon examination by the appropriate taxing authority. As we believe that all such material tax positions we have taken are supportable by existing laws and related interpretations, we believe there are no material uncertain tax positions to consider. There were no unrecognized tax benefits or accrued interest or penalties associated with unrecognized tax benefits as of December 31, 2016 and 2015.

NOTE 13. EARNINGS PER SHARE

A reconciliation of the number of shares used for the basic and diluted loss per share computations is as follows for the years ended December 31:

	2016	2015	2014
Weighted average common shares outstanding (basic and diluted)	412,080	408,535	407,116
Anti-dilutive shares excluded from diluted loss per share [1]	101,740	104,693	80,498

[1] Excludes RSAs, RSUs, NQSOs, PSUs, SARs and the shares underlying the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024 as their effect, if included, would have been anti–dilutive.

NOTE 14. OTHER SUPPLEMENTAL INFORMATION

Cash, cash equivalents and restricted cash are recorded in our consolidated balance sheets as follows as of December 31:

	2016	2015
Cash and cash equivalents	$ 613,534	$ 80,171
Restricted cash	2,517	58,715
	$ 616,051	$ 138,886

Supplemental cash flows and noncash transactions were as follows as of and for the years ended December 31:

	2016	2015	2014
Supplemental cash flows information:			
Cash paid for interest	$ 78,320	$ 78,410	$ 56,764
Cash paid for income taxes	—	—	—
Noncash transactions - changes in accrued capital expenditures	(69,667)	(47,580)	(56,129)

Accrued liabilities consisted of the following as of December 31:

	2016	2015
Accrued AFE costs	$ 73,808	$ 202,439
Social obligation payments	86,473	115,110
Funds from release of letter of credit on Block 9	18,375	—
Interest	13,793	7,843
Angolan consumption tax and withholding on services	9,796	13,421
Bonuses	8,900	12,300
General expenses	5,849	5,467
Seismic and other operating costs	5,625	9,782
Other	4,799	3,330
Total accrued liabilities	$ 227,418	$ 369,692

NOTE 15. OTHER MATTERS

In February 2016, we initiated a workforce reduction program in response to the pending sale of our Angola properties and prolonged commodity price weakness, which resulted in a reduction of our capital programs and other operations. In 2016, we recorded a charge for severance expense of $9.9 million. As of December 31, 2016, we had accrued severance of $0.9 million, which we expect will be paid in 2017.

In September 2016, we announced that we entered into an amendment to our drilling contract with Rowan (UK) Reliance Limited and recorded a charge of $95.9 million, of which $76.3 million was paid in 2016. This amendment provided for the early termination of our long–term drilling contract for one of their drillships. The drilling contract was originally scheduled to terminate in February 2018, but the amendment provides for a contract termination date in March 2017. This charge is recorded in “Loss on amendment of contract” in our consolidated statements of operations. As of December 31, 2016, we had accrued costs of $19.6 million, which will be paid in March 2017.

NOTE 16. QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2016				
Revenues	$ 1,636	$ 3,173	$ 4,228	$ 7,768
Gross profit [1]	680	1,470	1,856	5,225
Net loss [2]	(46,615)	(205,549)[2]	(218,205)[3]	(1,872,940)[4]
Basic and diluted loss per share	$ (0.11)	$ (0.50)	$ (0.53)	$ (4.47)
2015				
Revenues	$ —	$ —	$ —	$ —
Gross profit	—	—	—	—
Net loss	(81,617)	(66,810)	(59,164)	(486,835)[5]
Basic and diluted loss per share	$ (0.20)	$ (0.16)	$ (0.14)	$ (1.19)

(1) Represents oil, natural gas and natural gas liquids revenues less lease operating expenses.

(2) Includes dry hole costs and impairments of $155.8 million, of which $149.9 million relates to the Goodfellow exploratory well and underlying leases.

(3) Includes a $95.9 million charge related to the amendment of a drilling contract in the U.S. Gulf of Mexico.

(4) Includes dry hole costs and impairment of $1,761.4 million, of which $1,691.8 million relates to our Angolan assets.

(5) Includes dry hole costs and impairments of $422.4 million, of which $256.8 million relates to our proved oil and natural gas properties and $151.4 million relates to the Lontra exploratory well.

NOTE 17. SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GAS ACTIVITIES (UNAUDITED)

Oil and Natural Gas Properties

Capitalized costs relating to oil and natural gas producing activities are as follows at December 31:

	2016	2015
Proved oil and natural gas properties	$ 118,245	$ 71,463
Unproved oil and natural gas properties, net	980,844	2,287,570
	1,099,089	2,359,033
Accumulated depreciation, depletion and amortization	(20,204)	—
Net capitalized costs	$ 1,078,885	$ 2,359,033

Costs incurred in oil and natural gas property development activities are as follows for the years ended December 31:

	2016	2015	2014
Acquisition of unproved oil and natural gas properties	$ 3,715	$ 35,993	$ 27,784
Exploration costs:			
Capitalized	599,526	718,078	574,100
Expensed	58,170	61,844	85,567
Development costs	39,111	145,021	90,642
Total	$ 700,522	$ 960,936	$ 778,093

Estimated Proved Oil, Natural Gas and Natural Gas Liquids Reserves

Our estimated proved reserves are all located within the U.S. Gulf of Mexico. We caution that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are expected to change as further information becomes available. Material revisions of reserve estimates may occur in the future, development and production of the oil, natural gas and natural gas liquids reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in these estimates. The estimates of our proved reserves as of December 31, 2016, 2015 and 2014 have been prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), independent petroleum consultants.

The following table sets forth changes in estimated proved and estimated proved developed reserves for the periods indicated.

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	MMBOE
Proved developed and undeveloped reserves:				
As of December 31, 2013	7.9	3.4	—	8.5
Extensions and discoveries	0.5	0.3	—	0.5
As of December 31, 2014	8.4	3.7	—	9.0
Revisions of previous estimates	(2.8)	(1.9)	0.3	(2.8)
As of December 31, 2015	5.6	1.8	0.3	6.2
Revisions of previous estimates	(2.2)	(0.5)	(0.2)	(2.5)
Production	(0.4)	(0.1)	—	(0.4)
As of December 31, 2016	3.0	1.2	0.1	3.3
Proved developed reserves:				
December 31, 2013	—	—	—	—
December 31, 2014	—	—	—	—
December 31, 2015	—	—	—	—
December 31, 2016	1.9	0.8	0.1	2.1
Proved undeveloped reserves:				
December 31, 2013	7.9	3.4	—	8.5
December 31, 2014	8.4	3.7	—	9.0
December 31, 2015	5.6	1.8	0.3	6.2
December 31, 2016	1.1	0.4	—	1.2

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

The following tables present a standardized measure of discounted future net cash flows and changes therein relating to estimated proved oil, natural gas and natural gas liquids reserves. In computing this data, assumptions other than those required by the Securities and Exchange Commission ("SEC") could produce different results. Accordingly, the data should not be construed as representative of the fair market value of our estimated proved oil, natural gas and natural gas liquids reserves. The following assumptions have been made:

- Future cash inflows were based on prices used in estimating our proved oil, natural gas and natural gas liquids reserves. Future price changes were included only to the extent provided by existing contractual agreements.

- Future development and production costs were computed using year end costs assuming no change in present economic conditions.

- No provisions for future federal income taxes were computed as the tax basis of our oil and natural gas properties in the United States and net operating losses attributable to oil and natural gas operations exceed the future net revenues.

- Future net cash flows were discounted at an annual rate of 10%.

The standardized measure of discounted future net cash flows relating to estimated proved oil, natural gas and natural gas liquids reserves is as follows at December 31:

	2016	2015	2014
Future cash inflows	$ 123,889	$ 288,705	$ 814,394
Future production and development costs	(86,103)	(186,053)	(257,016)
Future net cash flows	37,786	102,652	557,378
10% annual premium (discount) for estimated timing of cash flows	1,164	(45,077)	(192,094)
Standardized measure of discounted future net cash flows	$ 38,950	$ 57,575	$ 365,284

As specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were the average prices during the year determined using the price of the first day of each month, except for volumes subject to fixed price contracts. The prices utilized in calculating our total estimated proved reserves at December 31, 2016, 2015 and 2014 were $40.32, $50.78 and $95.24 per barrel of oil, $19.23, $15.23 and $0.00 per barrel of natural gas liquids, and $2.056, $(0.182) and $4.770 per Mcf of natural gas, respectively.

The principal sources of changes in the standardized measure of future net cash flows are as follows for the years ended December 31:

	2016	2015	2014
Standardized measure at beginning of year	$ 57,575	$ 365,284	$ 276,633
Sales and transfers of oil, natural gas and natural gas liquids produced, net of production costs	(9,231)	—	—
Net changes in prices and production costs	(31,738)	(314,367)	(36,869)
Development costs incurred during the period	45,611	—	—
Revisions and other	(23,579)	(122,584)	17,351
Accretion of discount	5,757	36,528	27,663
Changes in estimated future development costs	(822)	99,964	49,700
Changes in timing and other	(4,623)	(7,250)	30,806
Standardized measure, ending	$ 38,950	$ 57,575	$ 365,284

NOTE 18. SUBSEQUENT EVENTS (UNAUDITED)

In January 2017, we consummated a follow–on debt exchange transaction with certain of the Holders whereby we issued an aggregate principal amount of $139.2 million in additional second lien notes due 2023 in exchange for $137.8 million aggregate principal amount of the 2019 Notes and $60.0 million aggregate principal amount of the 2024 Notes held by the Holders.

In February 2017, we received a letter from the Department of Justice ("DOJ") advising us that the DOJ has closed its investigation into our operations in Angola. This formally concluded the DOJ investigation, which was the last investigation by any U.S. regulatory agency into our Angolan operations. No regulatory action has been taken against us as a result of these investigations.

In March 2017, the SEC informed us by telephone that it had initiated an informal inquiry regarding the Company related to the Sonangol Research and Technology Center (the "Technology Center"). As background, in December 2011, we executed the Block 20 Production Sharing Contract under which we and BP Exploration Angola (Kwanza Benguela) Limited are required to make certain social contributions to Sonangol, including for the Technology Center. In March 2017, we also received a voluntary request for information regarding such inquiry. We believe our activities in Angola have complied with all applicable laws, including the Foreign Corrupt Practices Act, and we will cooperate with the SEC's inquiry.

We evaluated subsequent events for appropriate accounting and disclosure through the date these consolidated financial statements were issued and determined that there were no other material items that required recognition or disclosure in our consolidated financial statements.

Exhibit Index

Exhibit Number	Description of Document
3.1	Certificate of Incorporation of Cobalt International Energy Inc.'s (incorporated by reference from Exhibit 3.1 to Cobalt International Energy, Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
3.2	By-laws of Cobalt International Energy Inc.'s (incorporated by reference from Exhibit 3 to Cobalt International Energy, Inc.'s Registration Statement on Form 8–A filed with the SEC on December 11, 2009)
3.3	Amended and Restated Bylaws of Cobalt International Energy, Inc., effective as of October 27, 2016 (incorporated by reference from Exhibit 3.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on November 2, 2016)
4.1	Specimen stock certificate (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on November 27, 2009)
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on December 17, 2012)
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference from Exhibit 4.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on December 17, 2012)
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference from Exhibit 4.3 to Cobalt International Energy Inc.'s Current Report on Form 8-K filed with the SEC on December 17, 2012)
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference from Exhibit 4.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 13, 2014)
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference from Exhibit 4.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 13, 2014)
10.1	Purchase and Sale Agreement, dated August 22, 2015, by and between Cobalt International Energy Angola Ltd. and Sociedade Nacional de Combustíveis de Angola—Empresa Pública (Sonangol E.P.) (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.2	Restated Overriding Royalty Agreement, dated February 13, 2009, by and between Whitton Petroleum Services Limited, CIE Angola Block 9 Ltd., CIE Angola Block 20 Ltd., CIE Angola Block 21 Ltd., and Cobalt International Energy, L.P. (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.3	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 from Exhibit 10.8 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
10.4	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 from Exhibit 10.20 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 21, 2012)
10.5	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference from Exhibit 10.5 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 29, 2009)
10.6	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference from Exhibit 10.6 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 29, 2009)

Exhibit Number	Description of Document
10.7	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference from Exhibit 10.7 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 9, 2009)
10.8	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference from Exhibit 10.8 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on October 9, 2009)
10.9	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on October 29, 2013)
10.10	Amendment No. 2 to the Drilling Contract for the Rowan Reliance, dated September 15, 2016, between Cobalt International Energy, L.P., Cobalt International Energy, Inc. and Rowan (UK) Reliance Limited (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on September 16, 2016)
10.11	Purchase and Exchange Agreement, dated December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and the Holders named in Schedule I thereto (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)
10.12	First Lien Indenture, dated as of December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent for the First Lien Notes (incorporated by reference from Exhibit 10.2 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)
10.13	Second Lien Indenture, dated as of December 6, 2016, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent for the Second Lien Notes (incorporated by reference from Exhibit 10.3 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on December 7, 2016)
10.14	Exchange Agreement, dated January 30, 2017, among Cobalt International Energy, Inc., the Guarantors party thereto and the Holders named in Schedule I thereto (incorporated by reference from Exhibit 10.1 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on January 30, 2017)
10.15	First Supplemental Indenture, dated as of January 30, 2017, among Cobalt International Energy, Inc., the Guarantors party thereto and Wilmington Trust, National Association related to the 7.75% Second Lien Senior Secured Notes due 2023 (incorporated by reference from Exhibit 10.2 to Cobalt International Energy, Inc.'s Current Report on Form 8–K filed with the SEC on January 30, 2017)
10.16	Amended and Restated Stockholders Agreement, dated February 21, 2013, among Cobalt International Energy Inc. and the stockholders that are signatory thereto (incorporated by reference from Exhibit 10.36 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.17	Registration Rights Agreement, dated December 15, 2009, among Cobalt International Energy Inc. and the parties that are signatory thereto (incorporated by reference from Exhibit 10.31 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 21, 2012)
10.18	Form of Director Indemnification Agreements (incorporated by reference from Exhibit 10.19 to Cobalt International Energy Inc.'s Registration Statement on Form S–1/A filed with the SEC on November 27, 2009)
10.19†	Amended and Restated Long Term Incentive Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.15 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.20†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference from Exhibit 10.26 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 1, 2011).

Exhibit Number	Description of Document
10.21†	Form of Restricted Stock Unit Award Agreement (incorporated by reference from Exhibit 10.27 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 1, 2011).
10.22†	Deferred Compensation Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.35 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 26, 2013)
10.23†	Annual Incentive Plan of Cobalt International Energy Inc. (incorporated by reference from Exhibit 10.19 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on March 30, 2010)
10.24†	Amended and Restated Non–Employee Directors Compensation Plan (incorporated by reference from Exhibit 99.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–8 filed with the SEC on May 3, 2016)
10.25†	Non–Employee Directors Deferral Plan (incorporated by reference from Exhibit 99.3 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on January 29, 2010)
10.26†	Form of Restricted Stock Unit Award Notification under the Non–Employee Directors Compensation Plan (incorporated by reference from Exhibit 99.4 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on January 29, 2010)
10.27†	Employment Agreement, dated November 3, 2014, between Cobalt International Energy Inc. and James W. Farnsworth (incorporated by reference from Exhibit 10.34 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.28†	Employment Agreement, dated November 3, 2014, between Cobalt International Energy Inc. and James H. Painter (incorporated by reference from Exhibit 10.35 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.29†	Form of Special Restricted Stock Award Agreement, dated January 15, 2015 (incorporated by reference from Exhibit 10.36 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.30†	Form of Special Non–Qualified Stock Option Award Agreement, dated January 15, 2015 (incorporated by reference from Exhibit 10.37 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.31†	Form of Stock Appreciation Right Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.38 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.32†	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.39 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.33†	Form of Restricted Stock Award Agreement under Cobalt International Energy Inc.'s Long Term Incentive Plan (incorporated by reference from Exhibit 10.40 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 23, 2015)
10.34†	Severance Agreement, dated August 25, 2015, by and between Cobalt International Energy, Inc. and Shannon E. Young, III (incorporated by reference from Exhibit 10.4 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on November 3, 2015)
10.35†	Cobalt International Energy, Inc. 2015 Long Term Incentive Plan (incorporated by reference from Exhibit 99.1 to Cobalt International Energy Inc.'s Registration Statement on Form S–8 filed with the SEC on May 5, 2015)
10.36†	Form of Special Restricted Stock Award Agreement, dated January 15, 2016 (incorporated by reference from Exhibit 10.47 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)

Exhibit Number	Description of Document
10.37†	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2016 (incorporated by reference from Exhibit 10.48 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)
10.38†	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan (incorporated by reference from Exhibit 10.49 to Cobalt International Energy Inc.'s Annual Report on Form 10–K filed with the SEC on February 22, 2016)
10.39†	Offer Letter from Cobalt International Energy, Inc. to Timothy J. Cutt, dated May 30, 2016 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 31, 2016)
10.40†	Severance Agreement, dated May 30, 2016, between Cobalt International Energy, Inc. and Timothy J. Cutt (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on May 31, 2016)
10.41†	Offer Letter from Cobalt International Energy, Inc. to David D. Powell, dated July 6, 2016 (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on July 7, 2016)
10.42†	Cobalt International Energy, Inc. Executive Severance and Change in Control Benefit Plan (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.43†*	Cobalt International Energy, Inc. Amended and Restated Executive Severance and Change in Control Benefit Plan
10.44†	Form of Participation Agreement under the Company's Executive Severance and Change in Control Benefit Plan (incorporated by reference from Exhibit 10.2 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.45†	Form of Performance Stock Unit Award Agreement (incorporated by reference from Exhibit 10.3 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.46†	Offer Letter from Cobalt International Energy, Inc. to Rod Skaufel (incorporated by reference from Exhibit 10.4 to Cobalt International Energy Inc.'s Quarterly Report on Form 10–Q filed with the SEC on August 2, 2016)
10.47†	Separation and Consulting Agreement and General Release of Claims dated as of November 1, 2016 between Cobalt International Energy, Inc. and James W. Farnsworth (incorporated by reference from Exhibit 10.1 to Cobalt International Energy Inc.'s Current Report on Form 8–K filed with the SEC on November 10, 2016)
10.48†*	Form of Performance Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan
10.49†*	Form of Restricted Stock Unit Award Agreement under Cobalt International Energy Inc.'s 2015 Long–Term Incentive Plan
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

Exhibit Number	Description of Document
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*	Interactive Data Files

* Filed herewith.
** Furnished 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).

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CORPORATE INFORMATION

COMMON STOCK
Listed New York Stock Exchange (ticker symbol: CIE)

ANNUAL MEETING
The Annual Meeting of Shareholders will be held on Tuesday, May 2, 2017.

AVAILABLE DOCUMENTS
Copies of this Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request to Investor Relations or through the company's website at www.cobaltintl.com. Quarterly reports, Corporate Governance documents and press release information may also be accessed through the website.

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.

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 in this Annual Report on Form 10-K, 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. Because of these uncertainties, you should not place undue reliance on these forward looking statements.

Photo courtesy of Anadarko Petroleum Corporation

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