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: 1-32167

VAALCO Energy, Inc.
(Exact name of registrant as specified on its charter)

Delaware	**76-0274813**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

9800 Richmond Avenue
Suite 700
Houston, Texas 77042
(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Name of exchange on which registered
Common Stock, $.10 par value	**New York Stock Exchange**

Securities registered under Section 12(g) of the Exchange 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 15d of the 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 website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐	Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 201 6 was approximately $61.1 million based on a closing price of $1.06 on June 30, 201 6.

As of February 28, 2017, t here were outstanding 58,554,470 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Definitive proxy statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which is incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

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Gl ossary of Terms

Terms used to describe quantities of oil and natural gas

- *Bbl* — One stock tank barrel, or 42 United States ("U.S.") gallons liquid volume, of crude oil or other liquid hydrocarbons.

- *BOE* — One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil. 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 natural gas to oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids. Currently, the sales price of a Bbl of oil or natural gas liquids is significantly higher than the sales price of six Mcf of natural gas.

- *BOPD* — One barrel of oil per day.

- *MBbl* — One thousand Bbls.

- *MBOE*— One thousand barrels of oil equivalent.

- *Mcf* — One thousand cubic feet of natural gas.

- *MMbtu* — One million British thermal units, a measure commonly used for natural gas pricing.

- *MMcf* — One million cubic feet of natural gas.

- *MMBbl* — One million Bbls.

Terms used to describe legal ownership of oil and natural gas properties, and other terms applicable to our operations

- *Carried interest* — Working interest owners (defined below) whose share of costs are paid by the non-carried working interest owners and whose share of revenues are paid to non-carried working interest owners until such owners costs have been repaid.

- *Consortium* –A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under a Production Sharing Contract with the Republic of Gabon.

- *PSC* — A production sharing contract; Etame PSC is the Etame Production Sharing Contract, as amended, and as it may be further amended, that we have entered into with the Republic of Gabon, related to the Etame Marin block located offshore Gabon.

- *FPSO* — A floating, production, storage and offloading vessel.

- *Participating interest* — Working interest (as defined below) attributable to non-carried interest owner adjusted to include its relative share of the benefits and obligations attributable to carried working interest owners.

- *Royalty interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas.

- *Working interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe interests in wells and acreage

- *Gross oil and natural gas wells or acres* — Gross wells or gross acres represent the total number of wells or acres in which a working interest is owned, before consideration of the ownership percentage.

- *Net oil and natural gas wells or acres* — Determined by multiplying "gross" wells or acres by the owned working interest.

Terms used to classify reserve quantities

- *Developed oil and natural gas reserves* — Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered:

  (i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

- *Proved oil and natural gas 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- *Reserves* — Reserves are 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.

- *Undeveloped oil and natural gas reserves* — Undeveloped oil and natural gas reserves are 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.

(i) Reserves on undrilled acreage shall be 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.

(ii) 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable 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.

- *Unproved properties* — Properties with no proved reserves.

Terms used to assign a present value to reserves

- *Standardized measure* — Standardized measure is the present value, discounted at an annual rate of 10%,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 ("SEC"), using the 12-month unweighted average of first-day-of-the-month Brent price adjusted for historical marketing differentials, (the "12-month average"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service, derivatives or to depreciation, depletion and amortization.

Terms used to describe seismic operations

- *Seismic data* — Oil and natural gas companies use seismic data as their principal source of information to locate oiland natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

- *2-D seismic data.* — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

- *3-D seismic data* — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, (the "Exchange Act") which are intended to be covered by the safe harbors created by those laws.We have based these forward-looking statements on our current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of our operations. All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements regardingour financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures and plans and objectives of management for future operations are forward-looking statements. Whenwe use words such as "anticipate," "believe," "estimate," "expect," "intend," "forecast," "outlook," "aim," "target," "will," "could," "should," "may," "likely," "plan," "probably" or similar expressions, we are making forward-looking statements. Many risks and uncertainties that could affectour future results and could cause results to differ materially from those expressed in our forward-looking statements include, but are not limited to:

- declines, volatility of and weakness in oil and natural gas prices;
- our ability to maintain liquidity in view of current oil and natural gas prices;
- our ability to meet the financial covenants of our loan agreement;
- the resolution of matters related to our exit from Angola;
- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- timing and amount of future production of oil and natural gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate companies and properties that we acquire;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- changes in customer demand and producers' supply;

- future capital requirements and our ability to attract capital;
- currency exchange rates;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit;
- actions of operators of our oil and natural gas properties;
- our ability to meet the continued listing standards of the New York Stock Exchange ("NYSE") or to cure any deficiency in meeting the listing standards; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Item 1A. Risk Factors," identifies additional factors that could cause our results or performance to differ materially from those we express in forward-looking statements. Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements which are included in this report, our inclusion of this information is not a representation by us or any other person that our objectives and plans will be achieved. When you consider our forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this report.

Our forward-looking statements speak only as of the date made, and we will not update these forward-looking statements unless the securities laws require us to do so. Our forward-looking statements are expressly qualified in their entirety by this cautionary statement. In light of these risks, uncertainties and assumptions, any forward-looking events discussed in this report may not occur.

PART I

Item 1. Business

BACKGROUND

VAALCO Energy, Inc. is a Delaware corporation, incorporated in 1985 and headquartered at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. Our telephone number is (713) 623-0801 and our website address is www.vaalco.com. As used in this Annual Report on Form 10-K, the terms, "we", "us", "our", and "VAALCO" refer to VAALCO Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires.

We are an independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. Our primary source of revenue has been from our Etame Production Sharing Contract ("Etame PSC") related to the Etame Marin block located offshore the Republic of Gabon ("Gabon") in West Africa. We also currently own interests in an undeveloped block offshore Equatorial Guinea, West Africa and undeveloped leasehold acreage in Montana. As discussed further in Note 5 to the audited consolidated financial statements included in Part III, Item 8 – "Financial Statements and Supplementary Data"("Financial Statements"), we have discontinued operations associated with our activities in Angola, West Africa.

Our consolidated subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited and VAALCO Energy (USA), Inc.

STRATEGY

Our strategy is to utilize our technical expertise and operational infrastructure, with a focus on extending our existing license in Gabon, further developing our Gabon resources and expanding into new development opportunities in West Africa. Crude oil prices began their rapid and significant decline in 2014 as the global oil supply began to outpace demand. In 2015 and 2016, this global oil oversupply condition continued, resulting in a prolonged period of low realized prices for our crude oil production. During this period, we scaled back our global operations, divested non-core assets, amended our credit agreement and focused on reducing costs and maximizing our cash flows. North America is not a core area for us, and we sold substantially all of our U.S. properties over the past several years. Exploration is not a growth strategy for VAALCO at this time, so in 2016 we discontinued our operations in Angola. See " — *Discontinued Operations-Angola*."

We conducted no drilling activities in 2016, and we do not intend to drill any development wells in 2017. As of December 31, 2016 and 2015, we had no proved undeveloped reserves on our books. We recorded significant impairment charges in 2014 and 2015, but impairment losses were immaterial in 2016. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Impairment*."

Prices for crude oil did improve during the second half of 2016; Intercontinental Exchange Brent crude oil prices increased from approximately $36 per Bbl in early January 2016 to approximately $55 per Bbl at the end of 2016. However, the prolonged period of low prices adversely affected our results of operations and financial condition in 2015 and 2016. As a result, we have substantially altered our strategic focus.

At December 31, 2016, we had proved developed reserves of 2.6 million barrels of oil equivalent. For 2016, our reserves replacement amount was equal to 87% of our 2016 Gabon production, based on the reserves report issued by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc., despite the decline in the average of the first-day-of-the-month pricesadjusted for quality, transportation fees and market differentialsrequired by Securities and Exchange Commission rules to determine reserves, from $49.36 for 2015 to $40.35 in 2016.

Assuming oil and natural gas prices continue at current levels (and holding other variables constant), we believe that through March 31, 2018 we will be able generate cash flows sufficient to cover our operating expenses. However, an unfavorable resolution of our current obligations or a return to the levels of depressed oil and natural gas prices seen in the first quarter of 2016 that continues for an extended period of time would have a material adverse effect on our liquidity, financial condition and results of operations. To fund any potential growth opportunities going forward, we are considering multiple alternatives, including, but not limited to, additional debt or equity financing through traditional sources or strategic partnerships (see "— *Strategic Alternatives and Operating Strategies*" below). There can be no guarantee of future capital acquisition or fundraising success. Our current cash position and our ability to access additional capital may limit our available opportunities.

By the end of 2016, ourreserves were positively affected by (i) our acquisition in November 2016 of an additional 3.23% participating interest in the Etame Marin field; (ii) our cost-cutting efforts; (iii) deploying lower-cost hydraulic workover units to conduct workovers in the Etame field in 2016; and (iv) production optimization which resulted in better-than-forecasted results from our 2015 development program.These favorable impacts were somewhat offset by the effects of an 18% reduction in the average realized price used for determining our reserves. While we believe that these circumstances have favorable implications for our company's cash flows, potential access to capital, liquidity and financial condition, we are planning to make very limited capital expenditures in 2017 and will need access to capital from additional sources in order for us grow our revenues from operations and ultimately accomplish our business plan.

Strategic Alternatives and Operating Strategies. In January 2016, our Board of Directors formed a strategic committee to oversee the evaluation of our strategic alternatives, including those discussed below. We can give no assurances that any of these strategic alternatives can be completed, and if so, on reasonable terms that are acceptable to us.

Our strategic growth alternatives are as follows:

- Identify viable acquisition targets and/or merger opportunities;
- Consider joint ventures that allow us to leverage our operating capabilities and proven West Africa experience;
- Exit non-core exploration assets to focus on development opportunities; and
- Obtain external funding necessary for growth opportunities and maintaining our liquidity.

Our operating strategies for 2017 are financially-driven, and are as follows:

- Maximize our cash flow and preserve our cash balances;
- Manage our capital expenditures and improve our liquidity position:
  - Identify new sources of liquidity to strengthen our balance sheet and fund new opportunities;
  - Limit capital expenditures to those required to maintain the integrity of our facilities;
  - Undertake activities in 2017 to prepare for the next Etame Marin block drilling program
- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in prices:
  - Continue our focus on operating safely and complying with environmental operating standards;
  - Optimize production through careful management of wells and infrastructure;
  - Further reduce field-level costs;
  - Minimize administrative costs; and
  - Protect downside, while preserving upside related to oil price changes through put options.

We believe that we have strong management and technical expertise specific to West Africa, and that our strengths include the following:

- Our reputation as a West Africa operator;
- Our history of establishing favorable operating relationships with host governments and local partners;
- Our subsurface knowledge of key plays and risks in the broader regional framework of discoveries and fields;
- Our operational capacity to take on new development projects;

· Our familiarity with local practices and infrastructure; and

· Our market intelligence to provide insight into available opportunities early.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic financial information, see Note 15 to the Financial Statements. Our only reportable operating segments are Gabon, Equatorial Guinea and the United States.

Gabon Segment

Offshore – Etame Marin Block

Our most significant asset, which accounts for nearly 100% of our current revenues, is the Etame PSC, which we signed in 1995, relating to the Etame Marin block located offshore Gabon. The Etame Marin block covers an area of approximately 28,700 gross acres and consists of subsalt reservoirs that lie 20 miles offshore in water depths of approximately 250 feet. The Etame, Avouma/South Tchibala, Ebouri, Southeast Etame and North Tchibala fields are included in the block. Our working interest in the Etame Marin block is now 31.1%, and we operate it on behalf of a consortium of four companies (which we refer to as the "consortium"). The development is subject to a 7.5% back-in interest by the government of Gabon, which they have assigned to a third party.

Etame Field. In 2001, the Government of Gabon awarded to us and our consortium partners a 12,000 gross acre exploitation area for development of the Etame field. The exploitation area has a term of 20 years through June 2021, and includes the Southeast Etame field. There are currently five wells producing in the Etame field.

Avouma/South Tchibala Field. We and our consortium partners have rights to a 13,000-gross acre exploitation area for the joint development of Avouma/South Tchibala field, which expire in March 2025, and includes the North Tchibala field. Currently, two wells in the Avouma/South Tchibala field are producing.

Ebouri field. We and our consortium partners have rights to a 3,700-gross acre exploitation area for the joint development of the Ebouri field, which expire in July 2026. Currently, we have one producing well in the Ebouri field.

Southeast Etame. We drilled one well in the Southeast Etame field in 2015, and this well is continuing to produce.

North Tchibala field. We drilled two wells in the North Tchibala field in 2015. These wells targeted the Dentale formation, and are producing currently.

Development. Following the installation of platforms in the Etame and Southeast Etame/North Tchibala fields, we commenced drilling the first well, the Etame 8-H, in November 2014. We determined to shut in this well in December 2014 after determining that it was producing high levels of hydrogen sulfide ("H_2S"). See "— *Hydrogen Sulfide Impact*" below. In 2015, two new development wells were drilled in the Etame field and brought on production, and three new development wells were drilled and brought on production in the Southeast Etame field and the North Tchibala field. All the wells brought online subsequent to the Etame 8-H have not produced H_2S.

The Constellation II drilling rig that we had contracted in 2014 and 2015 for these operations performed workover operations in late 2015. In February 2016, due to the continuing low commodity price regime, we released the rig and incurred expenses of $7.9 million in 2016, net to us, related to its demobilization and early release. These expenses are reflected in "Other operating expenses" in the Financial Statements. See also Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Rig commitment*."

During the first quarter of 2016, we conducted workover operations on two Avouma field wells. An Electrical Submersible Pump ("ESP") system was replaced successfully in one well, but the second workover was suspended due to operational problems. During the second and third quarters of 2016, the ESPs in the South Tchibala 2-H well and the Avouma 2-H well also failed. These wells were temporarily shut-in, but through our utilizing a lower-cost hydraulic workover unit to replace these failed ESP systems, the two wells were back on production in December 2016 and January 2017, respectively.

As a result of our addition of these two workover wells, our current net production is averaging 4,600 barrels of oil per day (BOEPD), up from a 4,200 barrels of oil equivalent per day (BOEPD) average for fiscal 2016.

For 2016, our total proved reserves replacement was an amount equal to 87% of our 2016 total net production in Gabon. See "—*Reserve Information*" below. These results occurred primarily due to (i) our acquisition in November 2016 of an additional 3.23% participating interest in the Etame Marin field, which added approximately 11% to our total interest in Etame: (ii) our cost-cutting efforts had the effect of driving down operating cost projections and extending economic limits; (iii) the effectiveness of our deploying lower-cost hydraulic workover units to conduct workovers in the Etame field during 2016; and (iv) better-than-forecasted results from our 2015 development program.

Production. Production operations in the Etame Marin block include eight platform wells, plus three subsea wells across all fields tied back by pipelines to deliver oil and associated natural gas through a riser system to allow for delivery, processing, storage and ultimately offloading the oil from a leased Floating, Production, Storage and Offloading vessel ("FPSO") anchored to the seabed on the block. The FPSO has production limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day. For the years ended December 31, 2016, 2015 and 2014, aggregate production from the block was approximately 6.2 MMBbls (1.5 MMBbls net to us), 6.8 MMBbls (1.7 MMBbls net to us) and 5.8 MMBbls (1.4 MMBbls net to us), respectively. Our net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13%.

Hydrogen Sulfide Impact

Four of our wells are currently shut-in for safety and marketability reasons because of high levels of H_2S found in their initial production. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including the construction of one or more processing facilities capable of removing H_2S, the recompletion of the temporarily abandoned wells and the potential drilling of additional wells. There are no alternatives deemed economic at current forecasted oil prices, but we believe economic alternatives are available should oil prices recover sufficiently. As of December 31, 2016, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2016, we had no undeveloped leasehold costs related to the Etame Marin block. The sixth extension period of the exploration acreage on the Etame Marin block expired at the end of July 2014, with the Consortium having fully met all of the obligations under its terms.

Abandonment Costs

As part of securing the first of two five-year extensions to the Etame field production license to which we were entitled from the government of Gabon, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. The agreement was finalized in 2014, but effective for 2011 forward, providing for annual funding over a period of ten years at 12.14% of the total abandonment estimate for the first seven years, with the remaining unfunded estimated costs spread over the last three years of the production license.

We are required under the Etame PSC to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. In January 2016, we completed a new abandonment study, resulting in an increase of $7.1 million in the estimated costs to be necessary to fund these abandonment obligations. The estimated abandonment costs utilized for this study was approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2016, $27.4 million ($8.5 million net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $2.3 million in 2017 and 2018, and $1.6 million per year for each year from 2019 to 2021. Amounts paid are reimbursable through the cost account and are non-refundable. Our estimated liabilities for the abandonment of these Gabon offshore facilities as of December 31, 2016 and 2015 were $18.6 million and $16.2 million, included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2016 and 2015. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Other noncurrent assets" in the line item "Abandonment funding" on our consolidated balance sheets as of December 31, 2016 and 2015.

Onshore – Mutamba Iroru Block

We have a 50% working interest (41% net working interest assuming the Republic of Gabon exercises its back-in rights) and have been designated as the operator of the Mutamba Iroru block located onshore Gabon. Because of the lower projected oil price data in 2015, we wrote off our investment in this block in 2015, charging all costs, including capitalized exploratory well costs, to exploration expense. The government of Gabon believes that our production sharing contract for this block expired in mid-2014. While we maintain that the PSC is still valid, we expect that a new PSC would be required in order to pursue development, and we would only enter into a new PSC in the event that the project becomes economic. We can provide no assurances as to either the approval of a new PSC, or any subsequent approval of a development plan by the Government of Gabon.

Equatorial Guinea Segment

We have a 31% working interest in an undeveloped portion of a block offshore Equatorial Guinea that we acquired in 2012. It is currently unlikely that we will be making any near-term expenditures with respect to any development of this property. Before beginning exploration, we and our partners will need to evaluate the timing and budgeting for development and exploration activities under a development and production area in the block, including the approval of a development and production plan. Our production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

United States Segment

In December 2016, we completed the sale of our interests in two producing wells in the Hefley field (Granite Wash formation) in North Texas for $830,000, resulting in an immaterial loss. We currently own leasehold interests in undeveloped acreage in Montana.

Organization of Petroleum Exporting Countries ("OPEC") Production Reductions

In November 2016, OPEC reached a decision to reduce its level of production effective January 1, 2017. Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. As a result, we expect our production reduction to be approximately 548.9 Bbl per day (170.5 Bbl per day net to VAALCO). We anticipate being able to reduce our production by these amounts, by delaying certain workover activities until later in 2017, and through natural production declines. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – 2016 Highlights*."

DRILLING ACTIVITY

The table below reports the results of our drilling activity for each of the last three years. The "International" geographic designation for the prior three years was comprised solely of Gabon.

	International						United States					
	Gross			Net			Gross			Net		
	2016	2015	2014	2016	2015	2014	2016	2015	2014	2016	2015	2014
Exploratory wells												
Productive	-	-	-	-	-	-	-	-	-	-	-	-
Dry	-	1.0 (1)	1.0	-	0.5	0.4	-	-	-	-	-	-
In progress	-	-	-	-	-	-	-	-	-	-	-	-
Development wells												
Productive	-	6.0 (2)	1.0	-	1.8	0.3	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-	-	-	-	-	-
In progress	-	-	1.0	-	-	0.3	-	-	-	-	-	-
Total wells	-	7.0	3.0	-	2.3	1.0	-	-	-	-	-	-

(1) N'Gongui No. 2 discovery well, which had been suspended since being drilled onshore Gabon in 2012 and was deemed to be unsuccessful in 2015. Excludes an unsuccessful well associated with discontinued operations in Angola.

(2) Includes the Etame 8-H well that was in progress at December 31, 2014, evaluated for H_2S in 2015 and then shut-in when the presence of high levels of H_2S was confirmed.

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease and the total number of productive oil and natural gas wells as of December 31, 2016:

	International		United States	
	Gross	Net	Gross	Net
(Acreage in thousands)				
Developed acreage	28.7	8.9	-	-
Undeveloped acreage	327.0	128.0 (1)	21.9	10.7
Productive natural gas wells	-	-	-	-
Productive oil wells	11.0 (2)	3.7	-	-

(1) We have net undeveloped acreage of 110,000 acres onshore Gabon and 18,000 acres in Equatorial Guinea.

(2) Excludes the Etame 8-H and three Ebouri field wells shut-in due to the presence of high levels of H_2S.

RESERVE INFORMATION

Net Proved Reserves

In accordance with the current guidelines of the SEC, estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2016, the average realized price after adjustments used for our reserve estimates was $40.35 per Bbl for crude oil from Gabon. This compares to the average realized price for 2015 of $49.36 per Bbl.

Reserves are reported by geographic area. International consists solely of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa. We have no proved reserves related to our other international ventures and as a result of the sale of the Hefley wells in December 2016, we have no proved reserves in the United States. There have been no estimates of total proved net oil or gas reserves filed with or included in reports to any federal authority or agency other than the SEC since the beginning of the last fiscal year. Natural gas volumes include natural gas liquid ("NGL") barrels which were converted to Mmcf using the relative prices of the products. The table below sets forth our estimated net proved reserve quantities for the years ended December 31, 2016, 2015, and 2014 as prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers.

	As of December 31,		
	2016	**2015**	**2014**
Crude oil			
Proved developed reserves (MBbls)			
International	**2,642**	2,840	3,197
United States	**-**	15	27
Total proved developed reserves (MBbls)	**2,642**	2,855	3,224
Proved undeveloped reserves (MBbls)			
International	**-**	-	5,036
United States	**-**	-	-
Total proved undeveloped reserves (MBbls)	**-**	-	5,036
Total proved reserves (MBbls)			
International	**2,642**	2,840	8,233
United States	**-**	15	27
Total proved reserves (MBbls)	**2,642**	2,855	8,260
Natural gas			
Proved developed reserves (MMcf)			
International	**-**	-	-
United States	**-**	1,053	1,406
Total proved developed reserves (MMcf)	**-**	1,053	1,406
Total proved reserves (MMcf)			
International	**-**	-	-
United States	**-**	1,053	1,406
Total proved reserves (MMcf)	**-**	1,053	1,406
Total proved reserves (MBOE)	**2,642**	3,031	8,494
Standardized measure of discounted future net cash flows *(in thousands)*	**$ 9,441**	$ 27,141	$ 149,387

Changes in Proved Reserves

The following table shows changes intotal proved reserves for all presented years

	Proved Reserves		
	Crude Oil (MBbls)	**Natural Gas (MMCF)**	**Oil Equivalent (MBOE)**
Balance at January 1, 2014	7,232	1,333	7,454
Production	(1,351)	(227)	(1,389)
Revisions of previous estimates	2,312	300	2,362
Extensions and discoveries	67	-	67
Balance at December 31, 2014	8,260	1,406	8,494
Production	(1,659)	(181)	(1,688)
Revisions of previous estimates	(3,746)	(172)	(3,775)
Balance at December 31, 2015	**2,855**	1,053	3,031
Production	**(1,518)**	(124)	(1,539)
Purchases of minerals in place	**308**	-	308
Sales of minerals in place	**(12)**	(929)	(167)
Revisions of previous estimates	**1,009**	-	1,009
Balance at December 31, 2016	**2,642**	-	2,642

The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in preceding years' estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place at the end of the contract remain the property of the Gabon government.

We do not book proved reserves on discoveries until such time as a development plan has been prepared and approved by our partners and the government, where applicable.

The upward revision of the previous estimates in 2016 was primarily a result of improved well performance and lower costs. Purchases of minerals in place in 2016 was related to the additional 2.98% working interest in the Etame Marin block we acquired from Sojitz Etame Limited ("Sojitz") in November 2016. The lower average realized crude oil price used for 2016 estimates only partially offset the favorable impacts of well performance, operating cost reductions, and the other factors described in "— *Strategy*" above. Sales of minerals in place in 2016 is related to the sale of the Hefley field in the U.S. in December 2016.

The net negative revisions of previous estimates in 2015 were primarily a result of the loss of 3.5 years of production due to lower oil and natural gas prices (2,705 MBOE) and the removal of sour oil reserves (1,440 MBbl), partially offset by positive revisions due to the performance of wells drilled in the 2014-2015 drilling campaign exceeding expectations (370 MBbl). The average realized oil price used to value reserves for 2015 was $49.36 per Bbl, which is almost 50% lower than the $98.88 per Bbl used for 2014 reserves. This price decrease accelerated the economic cutoff date for the Etame Marin block reserves from December 2021 as of the end of 2014 to May 2018 as of the end of 2015. Investigations into the cause of the crude souring indicate that the effect is not as widespread as previously projected and the volume of sour resources is less than earlier estimates. As discussed in "Hydrogen Sulfide Impact" above, crude sweetening options were uneconomic in the depressed commodity price environment.

The net positive revisions of previous estimates in 2014 were primarily due to better reservoir performance at the Avouma/South Tchibala field (1,507 MBbls) and a combination of better reservoir performance from existing wells at Etame, and revisions to proved undeveloped reserves at Etame (1,122 MBbls). The Ebouri field proved undeveloped reserves were revised downward (300 MBbls) due to higher costs of developing the reserves rendering them uneconomic. In 2014, the extensions and discoveries were associated with the booking of the Southeast Etame and North Tchibala reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flows should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties.

Proved Undeveloped Reserves

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. Declines in oil and natural gas prices in 2014 through early 2016 caused our PUDs to become uneconomic to develop at prices calculated in accordance with SEC guidelines. Accordingly, we had no PUDs recorded at December 31, 2016 and 2015, compared with 5,036 MBbls of PUDs December 31, 2014. Reserves related to the successful wells drilled in 2015 were transferred to proved developed producing reserves during the year ended December 31, 2015. The remaining PUD reserves were reclassified to unproved during the year ended December 31, 2015 due to lower oil prices.

Controls over Reserve Estimates

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with SEC regulations and generally accepted accounting principles in the U.S. ("GAAP"). Compliance with these rules and regulations with respect to our reserves is the responsibility of a reservoir engineer, who is our principal engineer. Our principal engineer has over 20 years of experience in the oil and natural gas industry, including over 10 years as a reserve evaluator and trainer, and is a qualified reserves estimator, as defined by the Society of Petroleum Engineers' standards. Further professional qualifications include a Bachelor's degree in mechanical engineering and Master's degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers. The Audit Committee of the Board of Directors meets periodically with management to discuss matters and policies related to reserves.

Our controls over reserve estimation include retaining Netherland, Sewell & Associates, Inc. ("NSAI") as our independent petroleum and geological firm for all years presented. We provide information to NSAI about our oil and natural gas properties which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. NSAI prepares its own estimates of the reserves attributable to our properties. The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. He graduated from Rice University in 2004 with a Bachelor of Science Degree in Chemical Engineering and from University of Texas at Austin in 2008 with a Master of Business Administration Degree. Mr. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. He graduated from University of Louisiana at Lafayette in 2003 with a Bachelor of Science Degree in Geology and from Texas A&M University in 2005 with a Master of Science Degree in Geophysics.

NET VOLUMES SOLD, PRICES, AND PRODUCTION COSTS

Net volumes sold, average sales prices per unit, and production costs per unit for our 2016, 2015, and 2014 operations are shown in the tables below.

	Year Ended December 31,								
	2016			2015			2014		
	Oil Equivalent *(MBOE)*	Oil and Condensate *(MBbl)*	Natural Gas *(MMcf)*	Oil Equivalent *(MBOE)*	Oil and Condensate *(MBbl)*	Natural Gas *(MMcf)*	Oil Equivalent *(MBOE)*	Oil and Condensate *(MBbl)*	Natural Gas *(MMcf)*
Net production sold									
International	**1,485**	**1,485**	**-**	1,679	1,679	-	1,348	1,348	-
United States	**24**	**3**	**124**	33	3	181	41	3	227
Total production sold	**1,509**	**1,488**	**124**	1,712	1,682	181	1,389	1,351	227

	Year Ended December 31,								
	2016			2015			2014		
	Oil Equivalent *($/BOE)*	Oil and Condensate *($/Bbl)*	Natural Gas *($/Mcf)*	Oil Equivalent *($/BOE)*	Oil and Condensate *($/Bbl)*	Natural Gas *($/Mcf)*	Oil Equivalent *($/BOE)*	Oil and Condensate *($/Bbl)*	Natural Gas *($/Mcf)*
Average sales price									
International	**$ 40.17**	$ **40.17**	$ **-**	$ 47.87	$ 47.87	$ -	$ 93.68	$ 93.68	$ -
United States	**13.50**	**23.54**	**1.95**	15.09	32.67	2.21	32.40	85.89	4.57
Overall average sales price	**39.62**	**40.13**	**1.95**	47.24	47.85	2.21	91.86	93.66	4.57

	Year Ended December 31,		
	2016	2015	2014
Average production expense per MBOE			
International	$ **25.22**	$ 23.79	$ 23.01
United States	**5.58**	4.67	9.88
Overall average production expense	**24.91**	23.42	22.62

DISCONTINUED OPERATIONS-ANGOLA

On September 30, 2016, we notified Sonangol P&P, our joint venture partner, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have taken actions to begin closing our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Discontinued Operations - Angola*."

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. Our SEC filings are also available to the public at the SEC's website at www.sec.gov.

You may also obtain copies of our annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from our website at www.vaalco.com. No information from the either the SEC's or our website is incorporated by reference herein. We have placed on our website copies of our Audit Committee Charter, Code of Business Conduct and Ethics, and Code of Ethics for the Chief Executive Officer and Chief Financial Officer. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, VAALCO Energy, Inc., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042.

CUSTOMERS

Prior to the second quarter of 2014, we sold oil from Gabon under contracts with Mercuria Trading NV ("Mercuria") beginning with the calendar year 2011. Beginning in the second quarter of 2014 and through April 2015, we switched to an agency model by contracting with a third party, The Vitol Group, to sell our crude oil on the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA ("Total") for May through July of 2015 and Glencore Energy UK Ltd. ("Glencore") beginning in August of 2015. The contract with Glencore expires in January of 2018. Sales of oil to Glencore were 99.9% of total revenues for 2016, with less than 1% related to U.S. production.

EMPLOYEES

As of December 31, 2016, we had 104 full-time employees, 78 of whom were located in Gabon and two of whom were located in Angola. We are not subject to any collective bargaining agreements, although most of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. We believe relations with employees are satisfactory.

COMPETITION

The oil and natural gas industry is highly competitive. Competition is particularly intense from other independent operators and from major oil and natural gas companies with respect to acquisitions and development of desirable oil and natural gas properties and licenses, and contracting for drilling equipment**.** There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of oil and natural gas is affected by a number of factors beyond our control which may delay drilling, increase prices and have other adverse effects which cannot be accurately predicted.

Our competition for acquisitions, exploration, development and production includes the major oil and natural gas companies in addition to numerous independent oil companies, individual proprietors, investors and others. Many of these competitors have financial and technical resources and staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of properties and licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of lower commodity prices, unsuccessful wells, volatility in financial markets and generally adverse global and industry-wide economic conditions. These companies may also be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position. Our ability to generate reserves in the future will depend on our ability to select and acquire suitable producing properties and/or developing prospects for future drilling and exploration.

INSURANCE

For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, and worker's compensation and employer's liability. We maintain insurance at levels we believe to be customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances in to the environment. Such insurance might not cover the complete claim amount and would not cover fines or penalties for a violation of environmental law. We are not fully insured against all risks associated with our business either because such insurance is unavailable or because premium costs are considered uneconomic. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows.

REGULATORY

General

Our operations and our ability to finance and fund our operations and growth are affected by political developments and laws and regulations in the areas in which we operate. In particular, oil and natural gas production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on oil and natural gas production;
- tax, environmental, safety and other laws relating to the petroleum industry;
- changes in laws relating to the petroleum industry;
- changes in administrative regulations and the interpretation and application of administrative rules and regulations; and
- changes in contract interpretation and policies of contract adherence.

In any country in which we may do business, the oil and natural gas industry legislation and agency regulation are periodically changed, sometimes retroactively, for a variety of political, economic, environmental and other reasons. Numerous governmental departments and agencies issue rules and regulations binding on the oil and natural gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and our potential for economic loss.

Gabon

Our exploration and production activities offshore Gabon are subject to Gabonese regulations. 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 is a summary of certain applicable regulatory frameworks in Gabon.

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

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

Furthermore, under Article 260 of the 2014 Hydrocarbons Law, all oil and 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. Under Article 260, oil and gas companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities at the Banque des Etats de l’Afrique Centrale or at a Gabonese banking or financial institution.

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

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—Société Nationale des Hydrocarbures du Gabon—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to Article 4 of 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, under Article 86 of the Hydrocarbons Law, the national oil company may also acquire participating interests of up to 15%, at market value.

In addition to general labor regulations, which require that the workforce of any company in Gabon complies with a 90/10 ratio of Gabon national to foreign expatriate workers, pursuant to the Hydrocarbons Law, subcontracting activities are awarded in priority to Gabonese companies in which at least 80% of the workforce consists of Gabonese nationals. In this respect, only technically qualified license holders may be hired as subcontractors.

Under the 2014 Hydrocarbons Law, assignment of interests in production sharing contracts is subject to the Ministry of Hydrocarbons’ consent and to 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 of entry into force of the Hydrocarbons Law under its Article 254.

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

Hydrocarbons agreements entered into prior to the Hydrocarbon 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 production sharing contract governing our rights to the Etame Marin block offshore Gabon was entered into before the publication of the Hydrocarbon Law. The PSC contains a stabilization clause, which provides for the stability of the legal, tax, economic and financial conditions in force at the signing of the PSC. Pursuant to the PSC, these conditions may not be adversely altered during the term of the agreement; however, we can make no assurance that the Hydrocarbon Law will not adversely affect our operations or assets in Gabon.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, our business and financial results could be adversely affected.

In addition, a number of governmental bodies have introduced or are contemplating regulatory changes in response to various climate change non-governmental organizations and the potential impact of climate change. Legislation and increased regulation regarding climate change could impose significant costs on us, our venture partners, and our suppliers, including costs related to increased energy requirements, capital equipment, environmental monitoring and reporting, and other costs to comply with such regulations. Given the political significance and uncertainty around the impact of climate change and how it should be dealt with, we cannot predict how legislation and regulation will affect our financial condition and operating performance. In addition, increased awareness and any adverse publicity in the global marketplace about potential impacts on climate change by us or other companies in our industry could harm our reputation. The potential physical impacts of climate change on our operations are highly uncertain and would be particular to the geographic circumstances in areas in which we operate. These may include changes in rainfall and storm patterns and intensities, water shortages, changing sea levels, and changing temperatures. These impacts may adversely impact the cost, production, and financial performance of our operations.

Our activities have been subject to federal, state and local laws and regulations governing environmental quality and pollution control in Gabon and the U.S., and will be subject to the laws and regulations of Equatorial Guinea if exploration drilling occurs in that country. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

In part because they are developing countries, it is unclear how quickly and to what extent Gabon or Equatorial Guinea will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental issues by Gabon or Equatorial Guinea could have a material effect on us. Developing countries, in certain instances, have patterned environmental laws after those in the U.S., which are discussed below. However, the extent to which any environmental laws are enforced in developing countries varies significantly.

With regards to our development operations offshore West Africa, we are a member of Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London. OSRL has aircraft and equipment available for dispersant application or equipment transport, including active recovery boom systems and other booms that can be used for offshore or shoreline responses. In addition, OSRL can provide communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, generators, boats and vessels and oiled wildlife equipment.

See Item 1A "*Risk Factors*" for further discussion on the impact of these and other regulations relating to environmental protection.

Environmental Regulations in the United States

Currently, we conduct no operations in the U.S. and own no producing U.S. properties. We currently own only non-producing leasehold acreage in the U.S. However, our prior operations in the U.S., and any future operations we may conduct in the U.S., may subject us to certain liabilities under U.S. federal, state and local environmental regulations. In the U.S., environmental laws and regulations are administered by the U.S. Environmental Protection Agency ("EPA") and counterpart state agencies in the various states where operations are conducted. The more significant of these existing U.S. environmental health and safety laws and regulations that have affected us, and may affect us in the future, include the following:

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas emissions;
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;

- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories; and
- The U.S. Endangered Species Act, which protects endangered and threatened species.

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law.

Some of our prior operations on U.S. onshore properties involved hydraulic fracturing activities associated with drilling in shale formations. Hydraulic fracturing has been increasingly the subject of significant focus among many non-governmental organizations and regulators. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment and, potentially, the general public health, have been raised at local, state and federal levels of government in the US. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of both water supply sources and disposal methods.

Superfund

We have previously owned or leased properties in the U.S. used for the exploration and production of oil and natural gas, and we currently own interests in a non-producing property in Montana. Although we may have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for disposal. In addition, some of these properties are or have been operated by third parties. We have no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We could, in the future, be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination or mitigate existing contamination.

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the 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 ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of Hazardous Substances found at a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action.

Although CERCLA generally exempts "petroleum" from the definition of a Hazardous Substance, in the course of our prior U.S. operations, we may have generated substances that may fall within CERCLA's definition of a "Hazardous Substance" and may have disposed of these substances at disposal sites owned and operated by others. Also, properties that we own and properties that we may have owned or operated may have been sites on which Hazardous Substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties. States such as Texas have comparable statutes which may cover substances (including petroleum) in addition to those covered under CERCLA. In the event contamination is discovered at a site on which we have been an owner or operator or to which we sent regulated substances, we could be liable for costs of investigation and remediation and damages to natural resources.

Solid and Hazardous Waste Handling

In the past, we may have generated wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under RCRA and comparable state statutes ("Hazardous Wastes"). Although most oil and natural gas wastes are exempt from regulation as a hazardous waste at the federal level, not all comparable state statutes may have provided the same exemption, and certain wastes that we previously generated may have been subject to RCRA or comparable state statutes.

Clean Water Act

The Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes, into state waters and waters of the U.S., a term broadly defined. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or other pollutants. The CWA also prohibits the discharge of fill materials to regulated waters, including wetlands, without a permit. The EPA has issued final rules outlining its position on the federal jurisdictional reach over waters of the United States. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other pollutants, into state waters.

The Oil Pollution Act of 1990

The Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the CWA, 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 U.S. waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. 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. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages. The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted in the future and could cause us to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the 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 past legislative sessions, both houses of the U.S. Congress have considered legislation to reduce emissions of greenhouse gases without any ultimate resolution and many states have taken or considered legal measures to reduce GHG emissions, including, in a few locations, the consideration of a cap and trade program. Most cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how federal and state regulation of GHGs will unfold and how it may impact our industry. Moreover, the federal, regional, state and local regulatory initiatives could adversely affect the marketability of the oil and natural gas that we produce.

Air Emissions

Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. At the federal level, the Clean Air Act is the primary statute governing air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forego construction, modification or operation of certain air emission sources.

Endangered Species Act

The Endangered Species Act ("ESA") 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 adversely affecting that species' habitat. A critical habitat or suitable habitat designation by the U.S. Fish and Wildlife Service could also result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it may adversely impact the value of our affected leases.

It em 1A. Risk Factors

Our business faces many risks. You should carefully consider the following risk factors in addition to the other information included in this report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Any risks discussed elsewhere in this Form 10-K and in our other SEC filings could also have a material impact on our business, financial position or results of operations. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us.

Oil and natural gas prices are highly volatile, and a return to a very depressed price regime for a prolonged period of time will negatively affect our financial results.

Our revenues, cash flow, profitability, oil and natural gas reserves value and future rate of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on reasonable terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and decreased further in 2015 and early 2016. During 2014, based on New York Mercantile Exchange ("NYMEX") pricing, the spot price per Bbl of Brent crude oil ranged from a high of $115.19 to a low of $55.27, and the Henry Hub spot price per Mcf of natural gas ranged from a high of $6.00 to a low of $3.48. During 2015, the spot price per Bbl of Brent crude oil ranged from a high of $66.33 to a low of $35.26, and the Henry Hub spot price per Mcf of natural gas ranged from a high of $2.99 to a low of $1.93. During 2016, the spot price per Bbl of Brent crude oil ranged from a high of $54.96 to a low of $26.01, and the Henry Hub spot price per Mcf of natural gas ranged from a high of $3.80 to a low of $1.49.

As a result of the decline in oil and natural gas prices since 2014, our revenues, operating income, cash flows and borrowing capacity have been materially and adversely affected and have required reductions in the carrying value of our oil and natural gas properties and our planned level of capital expenditures. The average price at which we sold our crude oil in 2016 was $40.13 per Bbl compared to $47.85 per Bbl in 2015, and $93.66 per Bbl in 2014. Because the oil price we are required to use by the SEC to estimate our future net cash flows is the average price over the 12 months prior to the date of determination of future net cash flows, the full effect of increasing or falling prices may not be reflected in our estimated net cash flows for several quarters. We review the carrying value of our properties on a quarterly basis and once incurred, a write-down in the carrying value of our properties is not reversible at a later date, even if oil and natural gas prices increase.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, increases in supplies from U.S. shale production, international political conditions, including uprisings and political unrest in the Middle East and Africa, the domestic and foreign supply of oil and natural gas, actions by OPEC member countries and other state-controlled oil companies to agree upon and maintain oil price and production controls, the level of consumer demand due to slowing economic growth in China and continued weak economic growth in Europe, weather conditions, domestic and foreign governmental regulations and taxes, the price and availability of alternative fuels, the health of international economic and credit markets, and general economic conditions. In addition, various factors, including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our oil and natural gas production.

Unless we are able to replace the proved reserve quantities that we have produced, our cash flows and production will decrease over time.

At December 31, 2016 and 2015, we had no proved undeveloped reserves. We expect to make minimal capital expenditures for our development activities during 2017.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced.

There can be no assurance that our development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including declines in oil or natural gas prices, title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, prolonged periods of historically low oil and natural gas prices, failure of wells drilled in similar formations, equipment failures (such as our experience with our electronic submersible pumps in 2016 – see Item 1. "Business – Segment and Geographic Information – Gabon Segment – Development"), delays in the delivery of equipment and availability of drilling rigs. Our Equatorial Guinea property is operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain.

We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. Offshore drilling and development operations require capital-intensive techniques. If we do not replace the reserves we produce, our reserves revenues and cash flow will decrease over time, which will have an adverse effect on our business.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Our exploration and development activities are capital intensive. To replace and grow our reserves, we must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and natural gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations, debt, asset sales, and private sales of equity. We are the operator of the Etame Marin block offshore Gabon, and are thus responsible for contracting on behalf of all the remaining parties participating in the project. We rely on the timely payment of cash calls by our partners to pay for 66.43% of the offshore Gabon budget. The continued economic health of our partners could be adversely affected by low oil prices, thereby adversely affecting their ability to make timely payment of cash calls.

If low oil and natural gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may be unable to obtain or expend the capital necessary to undertake or complete future drilling programs. Our ability to secure additional or replacement financing is currently limited. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet our capital requirements. The outstanding indebtedness under our term loan with the IFC matures in June 2019. Interest is due quarterly, and we must begin repaying the principal amounts of this outstanding indebtedness in March 2017. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under any financing sources is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our properties. Such a curtailment in operations could lead to a possible expiration of our PSCs and a decline in our estimated net proved reserves, and would likely adversely affect our business, financial condition and results of operations.

Our amended loan agreement imposes significant restrictions on our current and future operations. If we default under the amended loan agreement, the lender may act to accelerate our indebtedness, which would impact our ability to conduct our business and results of operations.

The current $15 million outstanding indebtedness under our amended term loan agreement matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding commencing on March 31, 2017 and continuing through June 30, 2019.

The amended agreement contains a number of restrictive covenants that impose significant operating and financial restrictions on us, which may limit our ability to engage in acts that may be in our best interests. These covenants include restrictions on our ability to:

- incur additional indebtedness, guarantee debt or enter into any arrangement to assume or become obligated for financial or other obligations of another (except pursuant to a joint operating agreement);
- pay dividends on or make other distributions in respect of, or purchase or redeem, shares of our capital stock;
- prepay, redeem or repurchase certain debt;
- make loans, investments and other restricted payments;
- sell, transfer or otherwise dispose of assets;
- create or incur liens;
- sell, transfer or lease all or a substantial part of our assets (other than inventory or depleted or obsolete assets in the ordinary course of business);
- enter into non-arm's-length transactions;
- incur or commit to make certain expenditures for fixed or other non-current assets;
- enter into lease agreements or arrangements, other than the FPSO contract and leases necessary to carry on our business;
- form any subsidiary;
- terminate, amend or grant consents or waivers with respect to certain material contracts;
- use the proceeds of loans other than as permitted by the credit agreement;
- reduce certain of our working interests;
- modify our organizational documents;
- alter the business we conduct;
- undertake or permit any merger, spin-off, consolidation or reorganization; and
- enter into any derivative transaction without prior approval.

In addition, the amended loan agreement includes certain financial ratios, including;

- a debt service coverage ratio of (i) net cash flows (plus a balance in an operating account) to (ii) debt service obligations, of at least 1.2:1at each quarter end; and
- a ratio of (i) net debt as of the end of a fiscal quarter to (ii) earnings before interest, tax, depreciation and amortization, and exploration expenses (EBITDAX) for the trailing 12 months ended on the most recent quarter end, at less than 3.0:1, except the quarter-end limitation has been raised to 5.0:1 for periods through December 31, 2016.

As of December 31, 2016, we were in compliance with all of our financial covenants under our amended loan agreement. However, we can make no assurance that we will be able to continue to comply with these financial covenants in the future. Failure to maintain these covenants or otherwise negotiate amendments to the amended loan agreement could require us to immediately pay down any outstanding amounts.

These covenants have the effect of restricting our ability to engage in certain actions, including potentially limiting our ability to sell assets or incur other additional indebtedness. Our ability to meet our net debt to EBITDAX ratio and our different coverage ratio requirements can be affected by events beyond our control, including changes in commodity prices. There can be no assurance that we will be able to comply with these covenants in future periods. In addition, if we receive any additional waivers or amendments to our amended loan agreement, the lender may impose additional operating and financial restrictions on us.

A breach of the covenants under our amended loan agreement could result in an event of default under the agreement. Such a default may allow the lender to accelerate payment of the indebtedness under the amended loan agreement. Furthermore, if we were unable to repay the amounts due and payable under the amended loan agreement, the lender could proceed against the collateral granted to it to secure that indebtedness.

All of the value of our production and proved reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.

The Etame Marin block consists of five fields with 11 producing wells. Production from these fields constituted approximately 99% of our total production for the year ended December 31, 2016. In addition, at December 31, 2016, 100% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations, financial condition, and cash flows could be materially adversely affected.

Because the PSCs relating to these properties are concentrated in the same geographic area, many of our rights under the PSCs will be affected by the same conditions at the same time, resulting in a relatively greater impact on our results of operations than with respect to companies that have a more diversified portfolio of licenses and properties located across diverse geographic areas.

Increases in U.S. oil production from unconventional resources coupled with slower economic growth in economies around the world and prior actions taken by OPEC members have led to a dramatic reduction in oil prices. While lower oil prices may have the effect of escalating global economic growth rates, and thereby increase demand for oil supplies, a prolonged period of low oil prices will adversely affect our results of operations.

The increase in world oil supplies being produced, due to increased U.S. shale production and OPEC's past decisions not to reduce production to support higher oil prices occurred at the same time as reduced economic activity associated with slower economic growth in China, Europe and other global economies reduced demand for, and the prices we receive for, our oil and natural gas production. The U.S. federal government in December 2015 lifted its decades-old prohibition of exports of crude oil produced in the lower 48 states of the U.S.; it is uncertain what impact this regulatory change will have on our operations or our sales of crude oil. A reduction in the prices we receive for our oil and natural gas production will have a material adverse effect on our results of operations and the borrowing base under our credit facility.

Other governmental actions, including the recent accord by OPEC members to reduce production, may impact oil prices, although it is uncertain as to whether this accord will continue, or whether it will continue to be honored by OPEC member countries. In addition, it is uncertain what impact the recent election of President Trump will have on the exploration for and production of oil, natural gas and NGLs in the U.S. Increased domestic oil and natural gas production in a changing regulatory environment could impact the price of oil.

If oil and natural gas prices remain at low levels for extended periods of time, we may be required to take further write-downs in the value of our oil and natural gas properties.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using the un-weighted average price received for oil and natural gas based on closing prices on the first day of each month during the twelve-month period prior to the end of the reporting period As a result of declines in prices and increased development well costs, during 2015, we recorded additional impairments totaling $81.3 million related to the Etame Marin block and to various fields in the U.S. During 2016, no impairments were necessary related to the Etame Marin block. The sale of our interests in two wells in North Texas caused us to perform an impairment test, resulting in a $0.1 million impairment charge taken during the third quarter of

2016. Sustained lower prices will cause the estimated quantities and present values of our reserves to be reduced, which may necessitate further write-downs.

We rely on a single purchaser of our Gabon production, which could have a material adverse effect on our results of operations.

We currently sell our crude oil production from Gabon under a term contract with Glencore at pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors, that ends in January 2018.

In January 2016, we announced the formation of a strategic committee of our board of directors to oversee the consideration of various strategic alternatives potentially available to us in order to maximize our value.

A strategic committee of our directors formed by our board of directors in January 2016 is authorized to explore strategic options for VAALCO, including, but not limited to, securing additional investment to support existing projects and growth opportunities, joint ventures, asset sales or farm-outs, our potential sale or merger, or continuing to pursue our existing operating plan. We will continue to pursue ways to increase our liquidity. However, we can give no assurances that any of these strategic alternatives can be completed, and if so, on reasonable terms that are acceptable to us.

The formation of the strategic committee was not in response to any proposal we received or any approach by a third party.

No decision has been made to engage in any particular transaction or transactions. There can be no assurance that the strategic committee or our board of directors will authorize the pursuit of any strategic alternative. Moreover, there can be no assurance with respect to the terms or the timing of any transaction, or whether any transaction will ultimately occur. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, the interest of third parties in our areas of operation and the availability of financing to potential buyers on reasonable terms.

Until the fourth quarter of 2016, prevailing market conditions, including commodity prices, were unfavorable for our business, and constrained our ability to move forward with any possible transactions. There can be no assurances that we will be able to identify or complete any strategic transactions on commercially reasonable terms or at all, or that any such transaction would be favorable to our stockholders or lenders, or our business.

Our offshore operations involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment. Our production facilities are subject to hazards such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Exploration and development operations offshore Africa often lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between an offshore discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Offshore drilling operations generally require more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks of which we are currently unaware. For example, the production of hydrogen sulfide at our Etame 8-H well, which caused us to shut in the well in December 2014, created unexpected production losses and delays in our development plans; see Item 1. “Business – Segment and Geographic Information – Hydrogen Sulfide Impact.” The development of new subsea infrastructure and use of floating production systems to transport oil from producing wells, may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays.

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 drilling activities require us to risk significant amounts of capital that may not be recovered.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, equipment failures or accidents, elevated pressure or irregularities in geologic formations, compliance with governmental requirements and shortages or delays in the delivery of equipment and services.

We have less control over our investments in foreign properties than we would have with respect to domestic investments,and added risk in foreign countries may affect our foreign investments.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. For example, the Gabonese government has recently audited the accounts of a number of energy companies, including ours, that has led to disputes. The Gabonese government has formed a new oil company that may seek to participate in oil and natural gas projects in a manner that could be dilutive to the interest of current license holders and the Gabonese government is under pressure from the Gabonese labor union to require companies to hire a higher percentage of Gabonese citizens. In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. While we do not anticipate that we will be subject to assessments for 2013 through 2014 that will have significant, if any, negative impact on our reported earnings or cash flows, we can make no assurances that this will be the case. In addition, if a dispute arises with our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the U.S.

Private ownership of oil and natural gas reserves under oil and natural gas leases in the U.S. differs distinctly from our rights in foreign reserves where the state generally retains ownership of the minerals, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the U.S. may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. Gabon has indicated an interest in taking their oil in kind rather than our continuing to market their share of production on their behalf, which could cause fluctuations in the timing of and realized prices for oil sales.

All of our proved reserves are related to the Etame Marin block located offshore Gabon. We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

Our operations may be adversely affected by violent acts such as from civil disturbances, terrorist acts, regime changes, cross-borderviolence, war, piracy, or other conflicts that may occur in regions that encompass our operations.

Violent acts resulting in loss of life, destruction of property, environmental damage and pollution occur around the world. Many incidents are driven by civil, ethnic, religious or economic strife. In addition, the number of incidents attributed to various terrorist organizations has increased significantly. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred.

We monitor the economic and political environments of the countries in which we operate. However, we are unable to predict the occurrence of disturbances such as those noted above. In addition, we have limited ability to mitigate their impact.

Civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- inability to deliver our production due to disruption or closing of transportation routes;
- reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our commodity purchasers leading to interruption of deliveries, claims of force majeure, and/or termination of commodity sales contracts, resulting in a reduction in our revenues;
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;
- lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- capital market reassessment of risk and reduction of available capital making it more difficult for us and our partners to obtain financing for potential development projects.

Loss of property and/or interruption of our business plans resulting from civil unrest could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Cyber-attacks targeting systems and infrastructure used by the oil and natural gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and natural gas distribution systems, which are necessary to transport our production to market. A cyber-attack directed at oil and natural gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. While we have not experienced significant cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks 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 vulnerability to cyber-attacks.

Competitive industry conditions may negatively affect our ability to conduct operations.

The oil and natural gas industry is intensely competitive. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in oil and natural gas properties. These properties include exploration prospects as well as properties with proved reserves. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to retain and hire experienced personnel, especially for our engineering, geoscience and accounting departments; and;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and natural gas production.

Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do. These companies may be able to pay more for oil and natural gas properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit, and may be better able than we are to continue drilling during periods of low oil and natural gas prices, to contract for drilling equipment and to secure trained personnel. Our competitors may also use superior technology which we may be unable to afford or which would require costly investment by us in order to compete.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our oil and natural gas activities.

The oil and natural gas business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures and discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids including chemical additives, the occurrence of any of which could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In interpretive guidance on climate change disclosure, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities because of climate-related damages to our facilities and our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects.

Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

We may not have enough insurance to cover all of the risks we face and operators of prospects in which we participate may not maintain or may fail to obtain adequate insurance.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalization, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and natural gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including non-escalated prices and costs and capital expenditures subsequent to December 31, 2016, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and natural gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing oil and natural gas prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and natural gas industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and natural gas for the preceding twelve months. Future reductions in prices below the average calculated for 2016 would result in the estimated quantities and present values of our reserves being reduced.

Our proved reserves are in foreign countries and are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and natural gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of oil and natural gas, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors could affect the estimates of proved reserves in foreign jurisdictions.

Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by changes in currency exchange rates.

We are exposed to foreign currency risk from our foreign operations. While oil sales are denominated in U.S. dollars, portions of our costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in recent years in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control. Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by such fluctuations in currency exchange rates.

Fluctuations in currency exchange rates may negatively impact our earnings, which are subject to financial covenants under our amended loan agreement Failure to maintain these covenants could preclude us from borrowing under our amended loan agreement and require us to immediately pay down any outstanding amounts under the agreement, which could affect cash flows or restrict business. As of December 31, 2016, we were in compliance with all financial covenants under our amended loan agreement.

Acquisitions and divestitures of properties and businesses subject our company to addiional risks and uncertainties. We may be unable to integrate successfully the operations of any acquisitions with our operations, and we may not realize all the anticipated

benefits of any future acquisitions. Any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sale or divestment.

Failure to successfully exploit any acquisitions we engage in could adversely affect our financial condition and results of operations.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

In the case of sales or divestitures of our properties, we may become exposed to future liabilities that arise under the terms of those sales or divestitures. Under such terms, sellers typically are required to retain certain liabilities for matters with respect to their sold properties. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could result in material liabilities and adversely affect our financial condition.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and employer liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every potential liability on each individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the reserves, future production and revenues, or future operating or development costs with respect to the acquired properties, as well as future prices of oil and natural gas;
- decreased liquidity as a result of using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- significant increases in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- an increase in our costs or a decrease in our revenues associated with any claims or disputes with governments or other interest owners;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- losses of key employees at the acquired businesses;
- operating a significantly larger combined organization and adding operations;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

We have been, and in the future may become, involved in legal proceedings with governmental and private litigants, and, as a result, may incur substantial costs in connection with those proceedings.

Our business subjects us to liability risks from litigation or government actions.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our net income, net cash flows and financial condition. Adverse litigation decisions or rulings may also damage our business reputation.

Often, our operations are conducted through joint ventures over which we may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

The laws and regulations of the U.S., Gabon, and Equatorial Guinea regulate our current business.These laws and regulations may require that we obtain permits for our development, limit or prohibit drilling activities in certain protected or sensitive areas, or restrict the substances that can be released in connection with our operations. Our operations could result in liability for personal injuries, property damage, natural resource damages, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators of properties that we purchase or lease. Some environmental laws provide for joint and several strict liabilities for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and use of hydraulic fracturing fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity. Additionally, more stringent GHG regulation could impact demand for oil and natural gas.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

If our assumptions underlying accruals for abandonment costs are too low, we could be required to expend greater amounts than expected.

Almost all of our producing properties are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and capitalize the related costs as part of the carrying amount of the long-lived assets. The estimated liability is reflected as Asset retirement obligation in the consolidated balance sheets.

As part of the Etame field production license, we are subject to an agreed upon cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the abandonment study completed in January 2016, the abandonment cost estimate used for this purpose is approximately $61.1 million ($19.0 million net to our company) on an undiscounted basis.On an annual basis over the remaining life of the production license, we must fund a portion of these estimated abandonment costs. See “Item 1. Business – Segment and Geographic Information –Gabon Segment—Etame Marin Block—Abandonment,” for further information. Future changes to the anticipated abandonment cost estimates could change our asset retirement obligations and increase the amount of future abandonment funding payments we are obligated to make.

We operate in international jurisdictions and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.

The U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws generally prohibit companies and their intermediaries from making improper payments to government and other officials for the purpose of obtaining or retaining business. Our internal policies mandate compliance with these anti-corruption laws. Despite our training and compliance programs, we cannot be assured that our internal control policies and procedures will always protect us from acts of corruption committed by our employees or agents. Any additional expansion outside the U.S., including in developing countries, could increase the risk of such violations in the future. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our financial condition, results of operations and cash flows.

During 2016, we were not in compliance with the New York Stock Exchange's average minimum market capitalization and minimum share price requirements, and have been at risk of the NYSE delisting our common stock, which could materially impair the liquidity and value of our common stock.

Our common stock is currently listed on the NYSE. On August 9, 2016, we were notified by the NYSE that the average closing price of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price required by the NYSE. In addition, we received a notification from the NYSE on November 30, 2016 that our market capitalization had fallen below the NYSE’s continued listing standard because our average market capitalization had fallen below $50 million over a trailing 30 trading-day period and our last reported stockholders’ equity was less than $50 million.

On February 1, 2017, we announced that the NYSE had accepted our plan for compliance for continued listing, which extends 18 months through May 2018. As a result, our common stock will continue to be listed on the NYSE, subject to quarterly reviews by the NYSE's Listing and Compliance Committee to ensure our progress toward our plan to restore compliance with the continued listing standards.

Our stock price has remained above $1.00 per share since December 14, 2016 and we regained compliance with the $1.00 requirement as of January 31, 2017. While our market capitalization has exceeded $50 million since December 5, 2016, we understand that we must maintain a market capitalization in excess of this requirement for at least two consecutive quarters prior to being deemed eligible for the NYSE to consider the company for an accelerated return to compliance.

If we are ultimately unable to regain compliance, the NYSE will commence suspension and delisting procedures. In the event that our common stock price falls below the $1.00 per share threshold and falls to a point where the NYSE considers the stock price to be "abnormally low," the NYSE has the discretion to begin delisting procedures immediately. There is no formal definition of "abnormally low" in the NYSE rules.

A delisting of our common stock could negatively impact us by, among other things, reducing the liquidity and market price of our common stock, reducing the number of investors willing to hold or acquire our common stock, and limiting our ability to issue additional securities or obtain additional financing in the future.

Commodity derivatives transactions we enter into may fail to protect us from declines in commodity prices.

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we may enter into derivatives arrangements with respect to a portion of our expected production. Our derivatives contracts consist of a series of put derivative instruments and are limited in duration. Our derivatives program may be inadequate to protect us fromsignificant and prolonged declines in the price of crude oil.

The distressed financial conditions of one or more hedge providers could have an adverse impact on us in the event these hedge providers are unable to pay us amounts owed to us under one or more financial hedge transactions by which we have hedged our exposure to commodity price volatility.

From time to time, wemay enter into financial hedge transactions to hedge or mitigate our exposure to the risks of commodity price volatility with respect to the crude oil or natural gas we produce and sell. Similarly, some credit agreement facilities will require that we enter into financial hedges with creditworthy hedge providers for a percentage of our anticipated oil and natural gas production in order to ensure that we are able to make debt service payments under such credit facilities if oil and natural gas prices fall. In such instances, the hedge provider will be obligated to make payments to us under such financial hedge transactions to the extent that the floating (market) price is below an agreed fixed (strike) price. Hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. This risk of counterparty performance is of particular concern given the disruptions that have occurred in the financial markets that led to sudden changes in counterparty's liquidity and hence their ability to perform under their hedging contracts with us. We are unable to predict sudden changes in counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The enactment of derivatives legislation and the adoption of regulations thereunder could have an adverse effect on our ability to use derivative instruments to reduce (hedge, manage or mitigate) the effect of commodity price, interest rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), enacted in 2010, requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, including swap clearing and trade execution requirements. While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed position limits rule, remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time.

The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity-price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, and (iii) reduce the availability and use of derivatives to protect against risks we encounter. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, those transactions may become subject to such regulations. At this time, the impact of such regulations is not clear. Title VII of the Dodd-Frank Act establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the CFTC and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

***Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation*.**

In recent years, the U.S. government's budget proposals and other proposed legislation have included the elimination of certain key US. federal income tax incentives currently available to oil and natural gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and natural gas within the U.S. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. While the passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively impact our future taxable income in the U.S., we are currently not paying taxes in the U.S. as a result of tax benefits from foreign tax credits and net operating losses.

We may incur a significant penalty for failing to drill all the commitment wells under our production sharing contract in Angola.

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. Under a production sharing agreement, we and our working interest partner, Sonangol P&P, the Angolan national oil company, were obligated to perform exploration activities in Angola that would result in drilling or commencing four wells by November 30, 2017; one well was drilled in 2015. Under the contract, we are required to pay a $5.0 million penalty for each of the three wells not completed. However, the penalty amounts may be reduced by exploration expenses incurred, and we believe that a substantial portion of the penalty amount may be reduced due to prior exploration expenditures. Support for our determination has been presented to Angola government authorities, and we anticipate further discussions on this matter.

Due to the uncertainties as to the ultimate outcome, we have accrued a $15.0 million liability for the penalty, which represents what we believe to be the maximum potential amount due under the agreement. However, an unfavorable result on the resolution of the ultimate amount of the penalty could have a material adverse effect on our financial position, results of operations, or cash flows.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

As described in the Annual Report on Form 10-K for the year ended December 31, 2015, our management concluded that control deficiencies in aggregate constituted a material weakness in our internal control over financial reporting. We determined that we did not maintain effective internal control over financial reporting due to the failure to maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. We did not identify that the change in the complement of corporate accounting and finance personnel resulted in elevated risk that impacted our system of internal control, which in aggregate resulted in a material weakness. Controls were not operating effectively over the review and preparation of the financial statements. This material weakness resulted in adjustments prior to the issuance of the financial statements that, if not corrected, would have resulted in a material misstatement of the financial statements.

In 2016 management undertook a number of steps to remediate the material weakness. Implementation of these steps was adversely impacted by cost cutting and cost containment measures undertaken in the first half of 2016 in response to liquidity constraints resulting from an extended period of low oil prices. As disclosed in Note 2 to the Financial Statements, management determined that there was substantial doubt about our ability to continue as a going concern in the 2015 Form 10-K filed on March 16, 2016. Events and conditions improved during the year to such an extent that management concluded, as of March 13, 2017, that current events and conditions do not raise a substantial doubt about our ability to continue as a going concern through March 31, 2018. As a result of our focus on controlling costs and minimizing cash outlays, most of the actions taken in 2016 to remediate the material weakness (as described in "Remediation of Material Weakness" below), did not occur until the third and fourth quarters of 2016. These actions included replacement of accounting personnel in key positions and augmentation of the staff with additional professional resources. At December 31, 2016, management determined that the effectiveness and timeliness of the performance of controls related to the review of financial reports, the review of account reconciliations and the evaluation and reporting of significant and unusual transactions was not adequate to ensure that the material weakness in internal control identified in 2015 had been fully remediated. Management also determined that as of December 31, 2016 there is a material weakness related to the execution of the control for the physical observation of equipment which is performed annually to validate its existence.

Our management, including our Chief Executive Officer and Principal Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our business could suffer if we lose the services of, or fail to attract, key personnel.

We are highly dependent upon the efforts of our senior management and other key employees. Our former chief executive officer, and former chief financial officer, resigned effective September 1, 2016 and June 2, 2016, respectively. On December 29, 2016, our Board of Directors appointed Cary Bounds, our Chief Operating Officer and Interim Chief Executive Officer, as our permanent Chief Executive Officer. Also on August 1, 2016, the Board designated Elizabeth Prochnow, our Controller and Chief Accounting Officer, as the Company's Principal Financial Officer. In addition, we have engaged a third-party consultant to serve as an interim Chief Financial Officer. The loss of the services of our chief executive officer and chief financial officer, as well as any loss of the services of one or more other members of our senior management, could delay or prevent the achievement of our objectives. We do not maintain any "key-man" insurance policies on any of our senior management, and do not intend to obtain such insurance. In addition, due to the specialized nature of our business, we are highly dependent upon our ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas from proved properties and maximizing production from oil and natural gas properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

Item 1B. Un resolved Staff Comments

None.

Item 2. Pr operties

The location and general character of our principal oil and natural gas assets, production facilities, and other important physical properties have been described by segment under Item 1. "Business." Information about oil and natural gas reserves, including the basis for their estimation, is discussed in Item 1. "Business."

It em 3. Legal Proceedings

Butcher settlement

On October 3, 2016, the Court approved a Stipulation and Order of Dismissal entered into by the parties in a stockholder class action lawsuit against the Company and all of its directors alleging that a previously terminated shareholder rights agreement, no longer in effect, and certain provisions of the former Chief Executive Officer's and former Chief Financial Officer's employment agreements securing change-in-control severance benefits were invalid under Delaware law, case number C.A. No. 12277-VCL, filed on April 29, 2016, in the Court. After the Company and its directors moved to dismiss the lawsuit, the Plaintiff Daniel Butcher agreed to dismiss the lawsuit as moot, and the Company agreed to settle Plaintiff's application for an award of attorneys' fees, all of which were covered by our directors and officers insurance as a covered claim.

McDonough litigation

On December 7, 2016, a lawsuit was filed against the Company alleging that a former worker on the Company's oil and gas platforms off the coast of Gabon was terminated because of his age in violation of the Age Discrimination in Employment Act and the Texas Commission on Human Rights Act. The Plaintiff seeks damages for lost wages and benefits as well as attorneys' fees. The case is pending in the U.S. District Court for the Southern District of Texas and is styled as *McDonough v. VAALCO Energy, Inc.*, No. 4:17-cv-00361. In a February 2017 demand letter, the plaintiff made a demand for $361,000 to settle this claim. We intend to defend the claim vigorously, and we do not expect that this claim will have a material effect on our financial condition, results of operations or liquidity.

Ite m 4. Mine Safety Disclosures

Not applicable.

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

GENERAL

Our common stock is traded on the New York Stock Exchange under the symbol EGY. The following table sets forth the range of high and low sales prices of the common stock for the periods indicated.

Period	High	Low
2016:		
First Quarter	$ 1.69	$ 0.87
Second Quarter	1.26	0.76
Third Quarter	1.10	0.79
Fourth Quarter	1.26	0.71
2015:		
First Quarter	$ 6.20	$ 2.45
Second Quarter	2.60	2.00
Third Quarter	2.12	1.28
Fourth Quarter	2.30	1.34

On February 28, 2017, the last reported sale price of the common stock on the New York Stock Exchangewas $1.12 per share.

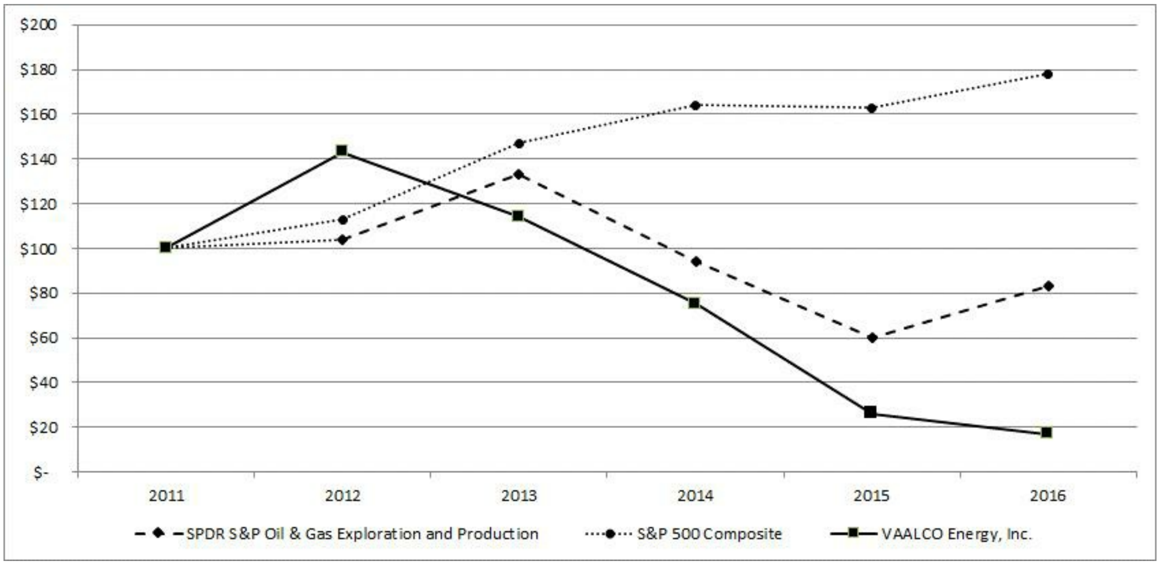
As of February 28, 2017, based upon information received from our transfer agent and brokers and nominees, there were approximately 50 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in “street” names.

Dividends

We have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future

Performance Graph

The following graph compares the annual percentage change in our cumulative total stockholder return on common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. The graph assumes $100 was invested on December 31, 2011 in our common stock and in each index (based on prices from the close of trading on January 1, 2011), and that all dividends are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.



	2011	2012	2013	2014	2015	2016
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 104	$ 133	$ 94	$ 60	$ 83
S&P 500 Composite	$ 100	$ 113	$ 147	$ 164	$ 163	$ 178
VAALCO Energy, Inc.	$ 100	$ 143	$ 114	$ 75	$ 26	$ 17

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2016 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 12 to the Financial Statements for additional information on stock-based compensation.

Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)**
Equity compensation plans approved by security holders	2,127,114	$ 2.78	2,692,605
Equity compensation plans not approved by security holders	516,500	$ 8.63	118,000
Total	2,643,614	$ 3.92	2,810,605

Issuer Purchases of Equity Securities for Year Ended December 31, 2016

During 2016, we did not acquire any shares.

It em 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information. The financial information for each of the five years ended December 31, 2016, 2015, 2014, 2013 and 2012 has been derived from the consolidated financial statements filed in the Annual Report on Form 10-K for each year. The information should be read in conjunction with "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Financial Statements and Notes thereto. The following information is not necessarily indicative of future results.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
(In thousands, except per share amounts)					
Total revenues	$ 59,784 (1)	$ 80,445 (1)	$ 127,691 (1)	$ 169,277	$ 195,287
Income (loss) from continuing operations	(18,267) (2)	(120,554) (2)	(73,753) (2)	46,094	8,637
Income (loss) from continuing operations attributable to VAALCO Energy, Inc.	(18,267) (2)	(120,554) (2)	(73,753) (2)	46,094	3,929 (3)
Basic income (loss) from continuing operations per share attributable to VAALCO Energy, Inc. common shareholders	(0.31)	(2.07)	(1.29)	0.80	0.07
Diluted income (loss) from continuing operations per share attributable to VAALCO Energy, Inc. common shareholders	(0.31)	(2.07)	(1.29)	0.79	0.07
Net property, plant and equipment	28,019	33,357 (4)	93,479 (4)	126,984	95,670
Total assets	81,032	123,958 (4)	248,849 (4)	308,167	267,956
Total debt	15,000 (5)	15,000 (5)	15,000 (5)	-	-

(1) The decrease in total revenues is tied to the decrease in oil and natural gas prices that began in the second half of 2014 and continued through 2016. See Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations below for discussion of how price decreases and sales volume increases impacted revenues.

(2) Net loss from continuing operations in 2016 was primarily impacted by decreased revenues due to prevailing low oil and natural gas prices . Net losses from continuing operations in 2014 and 2015 were primarily impacted by decreased revenues and oil and natural gas property impairments.

(3) We acquired the noncontrolling interest in VAALCO Energy (International), Inc. in October 2012.

(4) Net property, plant and equipment and Total assets decreased substantially in 2014 and 2015 due to impairments. See Note 6 to the Financial Statements for discussion of impairments.

(5) Not inclusive of deferred financing costs of $0.6 million, $1.7 million and $2.0 million as of December 31, 2016, 2015 and 2014, respectively.

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

INTRODUCTION

VAALCO is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We participate in exploration and development activities as a non-operator in Equatorial Guinea, West Africa. VAALCO currently holds undeveloped leasehold acreage in Montana, United States, which is being held for sale. As discussed further in Note 5 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa, have sold our interests in North Texas, and have entered into a letter of intent to sell our interests in Montana.

A significant component of our results of operations is dependent upon the difference between prices received for our offshore Gabon oil production and the costs to find and produce such oil. Oil and natural gas prices have been and are expected in the future to be volatile and subject to fluctuations based on a number of factors beyond our control. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through 2015 and into early 2016. Current prices, while higher than those in early 2016, are significantly less than they were in the several years prior to mid-2014. Sustained low oil and natural gas prices or further decreases in oil and natural gas prices could have a material adverse effect on our financial condition and the carrying value of our proved oil and natural gas properties and undeveloped leasehold interests.

CURRENT DEVELOPMENTS

During 2015 and 2016, the global oil supply continued to outpace demand, resulting in continuing lower realized prices for oil production. Prices for crude oil improved during the second half of 2016 (ICE Brent crude oil prices increased from approximately $36 per Bbl in early January 2016 to approximately $55 per Bbl at the end of 2016). These low prices relative to previous years have affected our business in numerous ways, including causing:

- a material reduction in our revenues, cash flows and liquidity;
- lower valuations for our proved reserves, contributing to the possibility that some of our existing wells may become uneconomic; and

- an increased possibility that the purchaser of our oil and natural gas production, or some of the companies that provide us with services, may experience financial difficulties.

Price declines also adversely affected our borrowing capacity based mainly on the value of our oil and natural gas reserves. Our borrowing base was reduced from $65.0 million to $20.1 million effective December 31, 2015. On June 29, 2016, we executed a Supplemental Agreement with the IFC, the lender under our revolving credit facility, which among other things, amended and restated our loan agreement to convert $20 million of the revolving portion of the credit facility into a term loan. Currently $15 million is outstanding as a term loan. See Note 8 to the Financial Statements and "—Capital Resources and Liquidity—Liquidity—Credit Facility" below for additional details about the loan agreement.

In January 2016, our Board of Directors formed a strategic committee to oversee the evaluation of our strategic alternatives including those described below. We can give no assurances that any of these strategic alternatives can be completed, and if so, on reasonable terms that are acceptable to us:

- identify viable acquisition targets and/or merger opportunities;
- consider joint ventures that allow us to leverage our operating capabilities and proven West Africa experience;
- exit non-core exploration assets to focus on development opportunities; and
- obtain external funding necessary for growth opportunities and maintaining our liquidity.

In light of the depressed levels of oil prices, we intend to focus on maintaining oil production and lowering operating costs with respect to current production in our Etame Marin block located offshore Gabon. In early 2016, we determined that additional development drilling is uneconomic at then current commodity prices. In January 2016, we began demobilizing our contracted drilling rig and did not drill any wells in 2016 on the Etame Marin block. In June 2016, we reached an agreement with the drilling contractor to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We paid this amount, plus the demobilization charges, in seven equal monthly installments beginning in July 2016.

Although prices continue to be low, if oil and natural gas prices continue at current levels (and holding other variables constant), we believe that through March 31, 2018 we will generate cash flows sufficient to cover our operating expenses.

2016 HIGHLIGHTS

As further discussed in Notes 5 and 6 to the Financial Statements:

- We recorded impairments on our proved oil and natural gas properties in periods prior to 2016. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, and reserve additions and adjustments. Our impairment calculations have been based upon reserve economics using forecasted future prices, adjusted for specifics related to our production. We may experience additional write-downs in the future. If the per barrel prices used in the impairment calculation made as of December 31, 2016 had been $10.00 lower, there would still have been no impairment charges incurred for 2016. Given the uncertainty associated with the factors used in these calculations, these estimates should not be construed as indicative of our future financial results.

- On September 30, 2016, we notified Sonangol P&P, our joint venture partner in Block 5, that we were withdrawing from the Block 5 joint operating agreement effective October 31, 2016. In addition to the withdrawal, we have taken actions to begin closing our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been reflected as discontinued in our Financial Statements.

- On March 14, 2016, we received payment of $19.0 million from Sonangol P&P for the full amount owed us as of December 31, 2015, including the $7.6 million of pre-assignment costs. The $7.6 million recovery is reflected in the "Bad debt expense and other" line of our summarized results of discontinued operations. Default interest of $3.2 million was received and is shown in the Interest income line of our summarized results of discontinued operations. While this payment improved our liquidity in the short-term, we are continuing to pursue alternatives for increasing our liquidity.

- In November 2016, OPEC reached a decision to reduce its level of production effective January 1, 2017. Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. As a result, we expect our production reduction to be approximately 548.9 Bbl per day (170.5 Bbl per day net to VAALCO). We anticipate being able to reduce our production by these amounts by delaying certain workover activities until later in 2017 and by natural production declines.

- On November 22, 2016, we closed on the purchase of an additional 2.98% working interest (3.23% Participating interest) in the Etame Marin block located offshore the Republic of Gabon from Sojitz, which represents all interest owned by Sojitz in the concession. The acquisition has an effective date of August 1, 2016. The transaction was funded from our cash on hand.

- In December 2016, we completed the sale of our interests in two wells in the Hefley field in North Texas for $30,000 resulting in a minimal loss, and on October 17, 2016, we signed a letter of intent to sell our interests in the East Poplar Dome field in Montana for $250,000. As we had fully impaired the book value for the East Poplar Dome assets, we expect a small gain if the sale is completed. As a result of signing the letter of intent to sell our interests in the two wells in North Texas in Q3 2016, we performed an impairment test and determined that a $0.1 million impairment was required during the third quarter. As of December 31, 2016, no proved reserves remained in the United States. U.S. sales volumes for the year ended December 31, 2016 were 24 MBOE.

DISCONTINUED OPERATIONS-ANGOLA

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. The four year primary term, with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and our partner to drill two additional exploration wells. Our working interest is 40% and we carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P, our joint venture partner, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have taken actions to begin closing our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented.

Drilling Obligation

Under the production sharing agreement for Block 5, we and our working interest partner, Sonangol P&P, were obligated to perform exploration activities in Angola that would result in drilling or commencing four wells by November 30, 2017. With the drilling of the Kindele #1 in 2015, the obligation was reduced to three wells. Under the contract, VAALCO is required to pay a $5.0 million penalty for each of the three wells not completed; however, the penalty amounts may be reduced by exploration expenses previously incurred. Prior to 2016, we classified the $15.0 million commitment for drilling these wells as long term restricted cash on our balance sheet. As a result of our decision to terminate the contract, we are no longer reflecting the $15.0 million as restricted cash. We believe that a substantial portion of the penalty amount may be reduced due to prior exploration expenditures. Support for our determination has been presented to Angola government authorities, and we anticipate further discussions on this matter. However, due to the uncertainties as to the ultimate outcome, we have accrued a $15.0 million liability for the penalty as of December 31, 2016, which represents what we believe to be the maximum potential amount due under the agreement.

Other Matters – Partner Receivable

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and was removed from the production sharing contract in 2010 by a governmental decree. Efforts to collect from the defaulted partner were abandoned in 2012. The available 40% working interest in Block 5, offshore Angola was assigned to Sonangol P&P effective on January 1, 2014. We invoiced Sonangol P&P for the unpaid delinquent amounts from the defaulted partner plus the amounts incurred during the period prior to assignment of the working interest totaling $7.6 million plus interest in April 2014. Because this amount was not paid and Sonangol P&P was slow in paying monthly cash call invoices since their assignment, we placed Sonangol P&P in default in the first quarter of 2015.

On March 14, 2016, we received a $19.0 million payment from Sonangol P&P for the full amount owed us as of December 31, 2015, including the $7.6 million of pre-assignment costs and default interest of $3.2 million. The $7.6 million recovery and default interest of $3.2 million is included in Income (loss) from discontinued operations, net of tax for 2016.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2016, 2015 and 2014 are as follows:

	Year Ended December 31,			Increase (Decrease) in the Year	
(in thousands)	2016	2015	2014	2016 Over (Under) 2015	2015 Over (Under) 2014
Net cash provided by (used in) operating activities	$ (3,452)	$ 38,875	$ 23,390	$ (42,327)	$ 15,485
Net cash used in continuing investing activities	(1,287)	(83,010)	(101,398)	81,723	18,388
Net cash provided by (used in) continuing financing activities	(144)	441	16,530	(585)	(16,089)
Net change in cash and cash equivalents	$ (4,883)	$ (43,694)	$ (61,478)	$ 38,811	$ 17,784

Net cash provided by operations decreased by $42.3 million between 2015 and 2016. Working capital related changes contributed $42.8 million of the decrease. Net cash provided by operations increased by $15.5 million between 2014 and 2015. Working capital related changes contributed to a $64.4 million increase while the offsetting decrease of $48.6 million was primarily the result of lower revenues between the periods.

Property and equipment expenditures were not as significant in 2016 as in previous years where they were our most significant investing activities. During 2016, these expenditures on a cash basis (including expenditures attributable to discontinued operations) were $8.7 million compared to $88.9 million and $92.2 million in 2015 and 2014, respectively. These cash property and equipment expenditures are included in capital expenditures. See "—*Capital Expenditures*" below for further discussion. Other significant investing activities in 2016 included $5.7 million for the November 2016 acquisition of Sojitz' interest in the Etame Marin block and $2.9 million to purchase oil puts used to mitigate the potential impact of price declines in 2016 and 2017, as discussed further in Note 10 to the Financial Statements. In addition, restricted cash inflows of $15.2 million in 2016 are primarily a result of us withdrawing from the joint operating agreement for Block 5 offshore Angola. Under the production sharing agreement for Block 5, we and our working interest partner, Sonangol P&P, were obligated to perform exploration activities in Angola. Prior to the September 30, 2016 quarterly reporting period, we classified the $15.0 million commitment for drilling these wells as long term restricted cash on our balance sheet. As a result of our decision to terminate the contract, we are no longer reflecting the $15.0 million as restricted cash. Restricted cash decreased by $5.5 million in 2015 because one commitment well, the Kindele #1, was drilled in Angola. Restricted cash increased $9.2 million in 2014 when funds for two additional Angola well commitments were designated as restricted due to drilling plans.

Net cash used in financing activities in 2016 was due to $0.1 million of debt issuance costs related to the Supplemental Agreement with the IFC. Net cash provided by financing activities included $0.4 million and $5.7 million related to stock option exercises in 2015 and 2014, respectively, and the $15.0 million in borrowings under the IFC facility in 2014. Uses of cash in 2014 included $2.3 million of debt issuance costs related to the IFC facility and treasury stock purchases of $1.9 million.

Capital Expenditures

At December 31, 2016, we had no material commitments for capital expenditures to be made in 2017 and in future years. We expect any capital expenditures made during 2017 will be funded by cash on hand and cash flow from operations.

During 2016, we had negative accrual basis capital expenditures of $4.1 million compared to $66.4 million and $84.0 million accrual basis capital expenditures in 2015 and 2014, respectively, including dry hole costs ("Capital Expenditures") expended in 2014. The difference between capital expenditures and the property and equipment expenditures reported in the consolidated statements of cash flows is attributable to changes in accruals for costs incurred but not yet invoiced or paid on the report dates. Capital Expenditures in 2016 were mainly for equipment and enhancements. Capital Expenditures in 2015 were primarily associated with the drilling of five development wells offshore Gabon. Capital Expenditures in 2014 were primarily associated with the construction of the two new platforms offshore Gabon. In addition, 2014 Capital Expenditures included $9.2 million in dry hole costs related to one unsuccessful exploratory well drilled offshore Gabon.

In early January 2016, we determined that additional development drilling was uneconomic at the then prevailing commodity prices and initiated the demobilization of a drilling rig we had under contract as we determined we would not drill any wells on the Etame Marin block in 2016. In June 2016, we reached an agreement with the drilling contractor to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We paid this amount, including the demobilization charges, in seven equal monthly installments beginning in July 2016 and ending in January 2017.

In 2017, we plan to review drilling opportunities with our partners in advance of the next drilling program in the Etame Marin block. Any drilling program we enter into would require approval of our partners and the government of Gabon.

Liquidity

Liquidity and Going Concern

As discussed above, our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and will likely continue to be volatile. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and have remained low through 2016. Revenues have decreased from $127.7 million for the year ended December 31, 2014 to $59.8 million for the year ended December 31, 2016.

As discussed further in Note 2 to the Financial Statements, in the financial statements included in our Annual Report on Form 10-K for December 31, 2015 filed with the Securities and Exchange Commission on March 16, 2016 ("2015 Form 10-K"), we concluded that at the date of filing our cash position and our ability to access additional capital may limit our available opportunities, or not provide sufficient cash available for our operations, which raised substantial doubt about our ability to continue as a going concern at such date.

Subsequent to the filing of the 2015 Form 10-K, events and conditions have improved. Oil and gas prices stabilized at prices which are adequate to generate cash flows from operations beginning in the fourth quarter of 2016 and continuing through March 13, 2017, the date of filing of these financial statements. As discussed in Note 8, in June 2016, we modified our revolving credit facility with the IFC converting $20 million of the revolving portion of the credit facility into a $15 million term loan. Although our available liquidity continues to be limited, we expect to have adequate cash flows to meet our principal and interest obligations under the Term Loan, and we expect we will be able to meet our financial covenants. We and our partners have approved a budget which limits the amount of capital expenditures for 2017. As discussed in Note 10 to the Financial Statements, we have put contracts in place at December 31, 2016 which limit our exposure to a decline in oil prices through December 31, 2017. Based on our forecasts which consider these and other relevant factors, management believes that events and conditions as of March 13, 2017, considered in the aggregate, do not raise substantial doubt about VAALCO's ability to continue as a going concern through March 31, 2018.

At December 31, 2016, we had 2.6 MMBOE of proved reserves, all of which are related to the Etame Marin block offshore Gabon. The current term for exploitation of the reserves in the Etame Marin block ends in June 2021, and as discussed in Item 1. "Business – Strategy" above, we are focused on extending the license for the block, and this could favorably improve our long-term liquidity. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. While both short-term and long-term liquidity are impacted by crude oil prices, our long-term liquidity also depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable.

Credit Facility

Historically, our primary sources of capital have been cash flows from operating activities, borrowings under the credit facility with the IFC and cash balances on hand. The current $15.0 million in outstanding indebtedness under our Term Loan matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding commencing on March 31, 2017 and continuing through June 30, 2019. Interest accrues on the unpaid balance at the per annum rate of LIBOR plus 5.75%. Approximately $7.5 million of the outstanding debt was classified as a current liability on our audited consolidated balance sheet as of December 31, 2016. As of that date, we had a working capital deficit of $17.1 million.

On June 29, 2016, we executed a Supplemental Agreement with the IFC which, among other things, amended and restated the existing loan agreement to convert $20 million of the revolving portion of the credit facility, to the Term Loan having $15 million outstanding.

The indebtedness under our amended loan agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A. and is guaranteed by VAALCO as the parent company.

Our credit agreement contains a number of restrictive covenants that impose significant operating and financial restrictions on us. These covenants include restrictions on our ability to:

- incur additional indebtedness, guarantee debt or enter into any arrangement to assume or become obligated for financial or other obligations of another (except those pursuant to a joint operating agreement);
- pay dividends on or make other distributions in respect of, or purchase or redeem, shares of our capital stock;
- prepay, redeem or repurchase certain debt;
- make loans, investments and other restricted payments;
- sell, transfer or otherwise dispose of assets;
- create or incur liens;
- sell, transfer or lease all or a substantial part of our assets, other than inventory or depleted or obsolete assets in the ordinary course of our business;
- enter into non-arm's-length transactions;
- incur or commit to make certain expenditures for fixed or other non-current assets;
- enter into lease agreements or arrangements, other than the FPSO contract and leases necessary to carry on our business;
- form any subsidiary;
- terminate, amend or grant consents or waivers with respect to certain material contracts;
- use the proceeds of loans other than as permitted by the credit agreement;
- reduce certain of our working interests;
- modify our organizational documents;
- alter the business we conduct;
- undertake or permit any merger, spin-off, consolidation or reorganization; and
- enter into any derivative transaction without prior approval.

These covenants restrict our ability to engage in certain transactions, including potentially limiting our ability to sell assets, make future borrowings or incur other additional indebtedness. Our ability to meet our quarter-end net debt to EBITDAX ratio and our debt service coverage ratio can be affected by events beyond our control, including changes in commodity prices.

Under the amended loan agreement, quarter-end net debt to EBITDAX (as defined in the loan agreement) must be no more than 3.0 to 1.0. However, the quarter-end net debt to EBITDAX limitation was raised to 5.0 to 1.0 for all periods through the end of 2016. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at each quarter end. Forecasting our compliance with these and other financial covenants in future periods is inherently uncertain. Factors that could impact our quarter-end financial covenants in future periods include future realized prices for sales of oil and natural gas, estimated future production, returns generated by our capital program, and future interest costs, among others. We are in compliance with all financial covenants as of December 31, 2016, and we expect to be in compliance with these covenants through maturity. However, there can be no assurance that we will be able to comply with these covenants in future periods. In addition, if we receive any waivers or amendments to our amended loan agreement, the lender may impose additional operating and financial restrictions on us or modify the terms of the loan agreement.

A breach of the covenants under our amended loan agreement could result in an event of default under the agreement. Such a default may allow the lender to accelerate payment of the indebtedness under the agreement and may result in the acceleration of any other indebtedness to which a cross-acceleration or cross-default provision applies. Furthermore, if we were unable to repay the amounts due and payable under the Term Loan the lender could proceed against the collateral granted to it to secure that indebtedness.

Cash on Hand

At December 31, 2016, we had unrestricted cash of $20.5 million. In connection with discontinuing operations in Angola, we have accrued $15 million for the penalty which we believe represents the maximum potential amount due under the agreement. As operator of the Etame Marin and Mutamba Iroru blocks in Gabon, we enter into project related activities on behalf of our working interest partners. We generally obtain advances from partners prior to significant funding commitments.

We currently sell our crude oil production from Gabon under a term contract that ends in January 2018. Pricing under the contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Contractual Obligations

Cash Obligations

The table below provides aggregated information on our net share of cash obligations and commitments at December 31, 2016:

	2017	2018	2019	2020	2021	Thereafter	Total
				(in thousands)			
IFC Credit Facility[1]	$ 7,500	$ 5,000	$ 2,500	$ -	$ -	$ -	$ 15,000
Operating leases [2]	12,831	10,754	10,126	7,369	-	-	41,080
Drilling rig[3]	1,007	-	-	-	-	-	1,007
Abandonment funding [4]	2,298	2,298	1,641	1,641	1,641	-	9,519
Total cash obligations	$ 23,636	$ 18,052	$ 14,267	$ 9,010	$ 1,641	$ -	$ 66,606

(1) See complete discussion of the facility above under "—Credit Facility". Interest estimated to be paid on the IFC credit facility in each of 2017 through 2019 is $0.8 million, $0.4 million and $0.1 million.

(2) Included in these figures is our net share of charter payments for the FPSO used on the Etame Marin block. See "*FPSO Charter*" in Note 9 to the Financial Statements and "—Rig Commitment" below for further information.

(3) Represents final payment to be made for unused rig days and demobilization charges for a rig released under a long-term drilling rig contract. See *"Rig commitment"* in Note 9 to the Financial Statements for further information about the long-term drilling rig contract.

(4) See *"Abandonment funding"* in Note 9 to the Financial Statements for further information.

Impairment

In 2014, we recorded an impairment loss of $98.3 million to write down our investment in certain fields comprising the Etame Marin block to fair value as a result of the declines in the forecasted oil prices used in the impairment testing and calculation. We recorded impairments totaling $81.3 million in 2015 to write down our investment in all fields comprising the Etame Marin block, as well as various U.S. fields, primarily as a result of lower forecasted oil prices as well as higher costs for planned development wells used in the impairment evaluation. Impairments of proved properties were $0.1 million in the year ended December 31, 2016 (all related to U.S. properties). See " — Results of Operations" below and Note 6 to the Financial Statements for further discussion of impairments.

Commitments and Uncertainties

McDonough litigation

On December 7, 2016, a lawsuit was filed against the Company alleging that a former worker on the Company's oil and gas platforms off the coast of Gabon was terminated because of his age in violation of the Age Discrimination in Employment Act and the Texas Commission on Human Rights Act. The Plaintiff seeks damages for lost wages and benefits as well as attorneys' fees. The case is pending in the U.S. District Court for the Southern District of Texas and is styled as *McDonough v. VAALCO Energy, Inc.*, No. 4:17-cv-00361. In a February 2017 demand letter, the plaintiff made a demand for $361,000 to settle this claim. We intend to defend the claim vigorously, and we do not expect that this claim will have a material effect on our financial condition, results of operations or liquidity.

Rig commitment

In 2014, we entered into a long-term contract for a jackup drilling rig for the multi-well development drilling campaign offshore Gabon. The campaign included the drilling of development wells and workovers of existing wells in the Etame Marin block. We began demobilization in January 2016 and released the drilling rig in February 2016, prior to the original July 2016 contract termination date, because we no longer intended to drill any wells in 2016 on our Etame Marin block offshore Gabon. In June 2016, we reached an agreement with the drilling contractor to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We are paying this amount, plus the demobilization charges, in seven equal monthly installments which began in July 2016. As of December 31, 2016, the remaining amount to pay was $1.0 million net to VAALCO's interest. The related expense is reported in the "Other operating expense" line of our consolidated statements of operations.

Gabon

Abandonment

We have an agreed cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the abandonment study completed in January 2016, the abandonment cost estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. The obligation for abandonment of the Gabon offshore facilities is included in the "Asset retirement obligations" line on our consolidated balance sheet. Through December 31, 2016, $27.4 million ($8.5 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on our consolidated balance sheet. The next funding is expected to be $7.4 million ($2.3 million net to VAALCO) and paid in December 2017; however, future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Audits

We are subject to periodic routine audits by various government agencies in Gabon, including audits of our petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements.

As of December 31, 2016, we had accrued $1.1 million net to VAALCO in "Accrued liabilities and other" on our consolidated balance sheet for certain payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor. While the payroll taxes were for individuals who were not our employees, we were deemed liable for these expenses as the end user of the services provided. These liabilities were substantially resolved at the accrued amount by January 2017.

OFF BALANCE SHEET ARRANGEMENTS

For a discussion of off balance sheet arrangements associated with our guarantee of the FPSO charter payments and the remaining maximum gross potential obligation, see *"FPSO charter"* in Note 9 to the Financial Statements.

RESULTS OF OPERATIONS

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

We reported a net loss for the year ended December 31, 2016 of $26.6 million compared to a net loss of $158.7 million for the same period of 2015. These losses are inclusive of losses from discontinued operations for the years ended December 31, 2016 and 2015 of $8.3 million and $38.1 million, respectively. The 2016 losses from continuing operations are primarily attributable to lower revenues resulting from lower oil prices, expenses associated with the demobilization and early release of a contracted drilling rig. The 2015 losses from continuing operations are primarily attributable to non-cash proved property impairments and decreased revenues resulting from the severe decline in oil prices that began in 2014. The write-off of suspended well costs related to the N'Gongui No. 2 well and provisions for bad debt of $2.7 million also adversely impacted 2015. Further discussion of results by significant line item follows:

Oil and natural gas revenues decreased $20.7 million during the year ended December 31, 2016 compared to the same period of 2015. Based on the average realized oil prices in the table below, the decrease in revenue is primarily related to 16% lower realized oil prices due to decreases in the Dated Brent market price which were experienced in the first half of the year and 12% lower oil sales volume due to temporarily shut-in wells, two of which were worked over and returned to production in December 2016 and January 2017.

The revenue changes between the years ended December 31, 2016 and 2015 identified as related to changes in price or volume are shown in the table below:

(in thousands)		
Price	$	(11,518)
Volume		(9,409)
Other		266
	$	(20,661)

The table below shows net production, sales volumes and realized prices for both years.

	Year Ended December 31,	
	2016	2015
Gabon net oil production (MBbls)	1,515	1,656
Gabon net oil sales (MBbls)	1,485	1,679
U.S. net oil sales (MBbls)	3	3
Net oil sales (MBbls)	1,488	1,682
Net natural gas sales (MMcf)	124	181
Net oil equivalents (MBOE)	1,509	1,712
Average realized oil price ($/Bbl)	$ 40.13	$ 47.85
Average realized natural gas price ($/Mcf)	1.95	2.21
Weighted average realized price ($/BOE)	39.62	47.24
Average Dated Brent spot* ($/Bbl)	43.67	52.32

*Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil sales are a function of the number and size of crude oil liftings from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given period. We made 12 and 11 liftings in the years ended December 31, 2016 and 2015, respectively. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 46,700 and 34,000 barrels at December 31, 2016 and 2015, respectively.

Production expenses decreased $2.5 million in 2016 compared to 2015. Production expenses included workover costs to replace ESPs which were $6.8 million in 2016 and $4.2 million in 2015. 2015 production expenses are higher because they include $1.9 million related to studies to evaluate solutions for a centralized processing facility to remove H_2S from the sour production on the block.Excluding workovers and H_2S studies, the overall decrease in production expense was $3.2 million, which reflects some success in ongoing cost cutting efforts.

Exploration expense was minimal in 2016 compared to $10.4 million in 2015. During 2015, we charged to dry hole costs $9.2 million of exploratory well costs incurred in 2012 related to the N'Gongui No. 2 discovery that had been capitalized pending the determination of proved reserves. Also in 2015, we recorded impairments of $1.3 million related to undeveloped leasehold costs associated with Poplar Dome in the U.S. The following table shows exploration expense in detail.

	Year Ended December 31,	
(in thousands)	2016	2015
Exploration expenses:		
Dry hole costs	$ -	$ 8,994
Unproved leasehold impairment	-	1,250
Seismic	-	61
Other	5	104
Total exploration expenses	$ 5	$ 10,409

Depreciation, depletion and amortization ("DD&A") expenses decreased $26.1 million in 2016 compared to 2015. DD&A per BOE rates were lower in 2016 reflecting the impact of impairments in 2015, particularly the $52.1 million impairment made in the fourth quarter of 2015.

General and administrative expenses decreased $2.7 million in 2016 compared to 2015. This is primarily a result of a $3.6 million decrease in stock-based compensation expense reflecting forfeitures related to employee departures. In addition, we took steps beginning in 2015 to reduce overall general and administrative costs, with decreases realized in personnel costs, services and various other cost categories. However, the amount of overhead we were able to recover from our partners in 2016 has decreased and more than offset the benefits from reductions in personnel and other costs. Under our operating agreements the amount of overhead recoverable is larger when capital spending is higher, as it was in 2015 with the development program in Gabon and the exploratory drilling in Angola.

Impairment of proved properties is discussed in detail in Note 6 to the Financial Statements. Declining forecasted oil prices in 2015 caused us to record an impairment of $81.3 million.

Other operating loss, net in 2016 includes $2.8 million, net to VAALCO, of expense associated with the demobilization, $5.1 million related to the early release of the contracted drilling rig and $1.0 million accrued for certain payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor. In June 2016, we reached an agreement with the drilling contractor to pay less than our originally estimated maximum day rate, plus demobilization costs, in seven equal monthly installments beginning in July 2016.

General and administrative related to shareholder matters for 2016 and 2015 reflects costs incurred related to shareholder litigation that was settled in 2016. For 2016, the amounts also include the offsetting insurance proceeds related to these matters.

Bad debt expense and other for both the years ended December 31, 2016 and 2015 includes baddebt expense related to Value Added Tax (“VAT”) which the government of Gabon is required to reimburse but has not yet paid.

Other operating income (loss), net decreased by $0.8 million in 2016 compared to 2015. Both years consisted primarily of impairments of capitalized equipment inventory located in Gabon. Equipment inventory in Gabon related to Mutamba was written off because further drilling in the prospect was uneconomic, while equipment inventory related to the Etame Marin block was reduced in value due to obsolescence of some items.

Interest expense increased $1.3 million in 2016 compared to 2015 primarily due to the write-off of previously deferred financing costs in June 2016 upon conversion of our credit facility to the term loan and a decrease in capitalized interest as none of the interest expense incurred in 2016 was capitalized versus $0.8 million capitalized in 2015. See Note 8 to the Financial Statements for further discussion of our loan agreement and interest expense.

Other, net consists primarily of derivative instrument gains (losses) as discussed in Note 10 to the Financial Statements and foreign currency gains (losses).

Income tax expense decreased $5.3 million in 2016 compared to 2015. Income tax expense in both periods is primarily attributable to our operations in Gabon and is lower in 2016 than income tax for the comparable 2015 period as a result of lower revenues. Income taxes paid to the government of Gabon are a function of taxation on the remaining profit oil value after deducting the royalty and the cost oil values.

Loss from discontinued operations is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. Results for discontinued operations for 2016 were primarily attributable to the $15.0 million accrual of the maximum potential drilling penalty connected with our exit from Angola, income tax expense and other exploration expense, partially offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest. Results for 2015 were primarily attributable to dry hole costs for the Kindele #1 well, higher general and administrative expense and impairments of equipment inventory, offset by higher foreign exchange gains.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

We reported a net loss for the year ended December 31, 2015 of $158.7 million compared to a net loss of $77.6 million for the same period of 2014. These losses are inclusive of loss from discontinued operations for the years ended December 31, 2015 and 2014 of $38.1 million and $3.8 million, respectively. The 2015 and 2014 losses from continuing operations are primarily attributable to non-cash proved property impairments and decreased revenues resulting from the severe decline in oil prices that began in 2014. 2015 was also impacted by the write-off of suspended well costs related to the N’Gongui No. 2 well and provisions for bad debt of $2.7 million. Further discussion of results by significant line item follows:

Oil and natural gas revenues decreased $47.2 million in 2015 compared to 2014 primarily as a result of significantly lower realized oil prices. Prices were impacted by the decrease in the Dated Brent market price and an adverse increase in marketing differentials for our crude.Offsetting the decrease from prices was an increase as a result of higher volumes sold reflecting production from the wells drilled in the 2014 and 2015 drilling campaign.

The revenue changes between the years ended December 31, 2015 and 2014 identified as related to changes in price or volume are shown in the table below:

(in thousands)	
Price	$ (62,458)
Volume	15,735
Other	(523)
	$ (47,246)

The table below shows net production, sales volumes and realized prices for both years.

	2015	2014
Gabon net oil production (MBbls)	1,656	1,417
Gabon net oil sales (MBbls)	1,679	1,348
U.S. net oil sales (MBbls)	3	3
Net oil sales (MBbls)	1,682	1,351
Net natural gas sales (MMcf)	181	227
Net oil equivalents (MBOE)	1,712	1,389
Average realized oil price ($/Bbl)	$ 47.85	$ 93.66
Average realized natural gas price ($/Mcf)	2.21	4.57
Weighted average realized price ($/BOE)	47.24	91.86
Average Dated Brent spot* ($/Bbl)	52.32	98.97

*Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil sales are a function of the number and size of crude oil liftings from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given period. We made 11 liftings in both years. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 34,000 and 84,000 barrels at December 31, 2015 and 2014, respectively.

Production expenses increased $8.4 million in the year ended December 31, 2015 compared to the same period of 2014. Production expenses included workover costs to replace ESPs of $4.2 million in 2015 and $2.1 million in 2014. While the impact of cost reduction efforts began to be apparent in the latter part of 2015, overall production expenses are higher because they include $1.9 million related to studies to evaluate solutions for a centralized processing facility to remove H2S from the sour production on the block. Costs in 2015 were also impacted by increased production volumes. A decrease in the domestic market obligation for 2015 partially offset the cost increases.

Exploration expense decreased $3.2 million in 2015 compared to 2014. Included in 2015 were $9.2 million of exploratory well costs incurred in 2012 related to the N'Gongui No. 2 discovery which was determined to be a dry hole expense in the third quarter of 2015. Included in 2014 was one exploratory dry hole drilled offshore Gabon. Also in 2015, we recorded impairments of $1.3 million related to undeveloped leasehold costs associated with Poplar Dome in the U.S. The following table shows exploration expense in detail.

(in thousands)	2015	2014
Exploration expenses:		
Dry hole costs	$ 8,994	$ 9,214
Unproved leasehold impairment	1,250	3,880
Seismic	61	185
Other	104	372
Total exploration expenses	$ 10,409	$ 13,651

Depreciation, depletion and amortization ("DD&A") expenses increased $12.9 million in 2015 compared to 2014 as a result of several factors. Oil sales volumes were higher in 2015 versus 2014. Depletion rates increased with the completion of the Etame 12-H, the Southeast Etame 2-H and the North Tchibala 1-H and 2-H wells, and the addition of the remaining Etame and SEENT platform costs. In addition, the reduction in proved reserves previously discussed increased our rate of depletion per barrel for the fourth quarter of 2015.

General and administrative expenses increased $0.2 million in the year ended December 31, 2015 compared to the same period of 2014. The increase in general and administrative expense was primarily due to increased stock-based compensation expense and professional fees.

General and administrative related to shareholder matters for 2015 reflects costs incurred in connection to shareholder actions by Group 42, Inc., Bradley L. Radoff and certain other participants (collectively, the "Group 42-BLR Group"), which beneficially owns approximately 11.1% of the Company's outstanding stock and is related to shareholder litigation filed in Delaware as discussed further in Note 8 to the Financial Statements. In December 2015, we reached an agreement with the Group 42-BLR Group.

Bad debt expense and other for both 2015 and 2014 is primarily comprised of bad debt expense related to Value Added Tax ("VAT") which the government of Gabon is required to reimburse but has not paid.

Impairment of proved properties is discussed in detail in Note 6 to the Financial Statements. Declining forecasted oil prices in 2015 and 2014 caused us to record impairments of $81.3 million and $98.3 million, respectively.

Other operating loss, net in 2015 consists primarily of impairments of capitalized equipment inventory located in Gabon. Equipment inventory in Gabon related to Mutamba was written off because further drilling in the prospect was uneconomic, while equipment inventory related to the Etame Marin block was reduced in value due to obsolescence of some items.

Interest expense increased $1.3 million in 2015 compared to 2014. All interest expense incurred on the IFC credit facility was capitalized in 2014, while only a portion of the interest expense incurred could be capitalized in 2015. Costs associated with projects in progress and which are subject to capitalization of interest were significantly higher in 2014 as we had two platforms under construction during the period. See Note 8 to the Financial Statements for further discussion of interest expense.

Other, net for both 2015 and 2014 consists primarily of foreign currency gains (losses).

Income tax expense decreased $7.9 million in 2015 compared to 2014. Income tax for 2015 includes $1.4 million deferred expense associated with valuation allowance provided on Alternative Minimum Tax ("AMT") credit carryforwards. The remaining income tax expense of $13.2 million is for income tax in Gabon and compares to income tax expense of $22.5 million in 2014, all of which was attributable to income tax expense in Gabon. Income tax expense for Gabon was lower in 2015 as a result of the decrease in revenue.

Loss from discontinued operations is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. Loss from discontinued operations increased $34.3 million in 2015 compared to 2014. Results for 2015 were primarily attributable to dry hole costs for the Kindele #1 well. In addition, 2015 included general and administrative expenses and foreign exchange gains. Results for the 2014 comparable period were primarily attributable to exploration expenses related to seismic activities and general and administrative expenses.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used. Further, in some cases, GAAP allows more than one alternative accounting method for reporting. In those cases, our reported results of operations would be different should we employ an alternative accounting method. See Note 3 to the Financial Statements for our accounting policy elections.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

We use the successful efforts method to account for our oil and natural gas activities Management believes that this method is preferable, as we have focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results. Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including dry exploration well costs, geological and geophysical expenses applicable to undeveloped leaseholds, leasehold expiration costs and delay rentals are expensed as incurred.

We review our oil and natural gas producing properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. This may occur if a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. The fair value measurement used in the impairment test is generally calculated with a discounted cash flow model using several Level 3 inputs which are based upon estimates, the most significant of which is the estimate of net proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates.

Impairment of Unproved Property

We evaluate our undeveloped oil and natural gas leases for impairment on at least a quarterly basis by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts and future plans for exploration or development. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to undeveloped acreage in Equatorial Guinea. See "Item 1—Business—Segment and Geographic Information—Equatorial Guinea Segment" for further information on our exploration plans in Equatorial Guinea.

Asset Retirement Obligations ("ARO")

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oiland natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for AROis recognized in the period in which thelegal obligations are incurred if a reasonable estimate of fair value can be made.The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. 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. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to oil and natural gas properties.To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. 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 to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

NEW ACCOUNTING STANDARDS

See Note 4 to the Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices, foreign exchange rates and interest rates as described below.

Foreign Exchange Risk

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our costs in Gabon and Angola are denominated in the respective local currency and our VAT receivable in Gabon is also denominated in the Gabon local currency. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing costs. For our VAT receivable in Gabon, a strengthening U.S. dollar will have the effect of decreasing the value of this receivable resulting in foreign exchange losses and vice versa. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has historically fluctuated widely in response to international political conditions, general economic conditions and other factors beyond our control. The exchange rate between the Angola local currency and the U.S. dollar has fluctuated for similar reasons, with the Angola local currency devaluing in 2015 and 2016. As a result of discontinuing operations in Angola, our exposure to the Angola local currency has declined significantly.

Interest Rate Risk

The floating rate on our amended loan agreement exposes us to risks associated with changes in interest rates (LIBOR). At December 31, 2016 and 2015, we had $15.0 million in borrowings outstanding with the IFC. Our deferred financing costs totaled $0.6 million and $1.7 million at December 31, 2016 and 2015. Fluctuations in floating interest rates will cause our interest costs to fluctuate. During years ended December 31, 2016, 2015 and 2014, the average effective interest rate on our debt, excluding commitment fees, was 5.52%, 4.09% and 4.35%, respectively. If the balance of the debt at December 31, 2016 were to remain constant, a 1% change in market interest rates would impact our cash flow by an estimated $150,000 per year. As future quarterly payments reduce the principal of the term loan, our cash flow becomes less sensitive to fluctuations in interest rate.

Counterparty Risk

We are exposed to market risk on our open derivative instruments related to potential nonperformance by our counterparty. To mitigate this risk, we enter into such derivative contracts with creditworthy financial institutions deemed by management as competent and competitive market makers.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our oil and natural gas production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for oil and natural gas have been volatile and unpredictable in recent years, and this volatility is expected to continue. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through 2016. Current prices remain significantly lower than they were in the years prior to 2015. Sustained low oil and natural gas prices or further decreases in oil and natural gas prices could have a material adverse effect on our financial condition, the carrying value of our proved reserves, our undeveloped leasehold interests and our ability to borrow funds and to obtain additional capital on attractive terms. Were oil sales to remain constant at the most recent quarterly sales volumes of 326 MBbls, a $5 per Bbl decrease in oil price would be expected to cause a $1.6 million decrease per quarter ($6.5 million annualized) in revenues and operating income (loss) and a $1.4 million increase per quarter ($5.5 million annualized) in net loss.

As of December 31, 2016, we had unexpired oil puts with a fair value asset position of $1.2 million. A ten percent increase in oil prices would reduce the asset by approximately $0.6 million, while a ten percent decrease in prices would increase the asset by approximately $1.2 million. These fair value changes assume volatility based on prevailing market parameters as of December 31, 2016. While these crude oil derivative contracts are intended to be an economic hedge, they are not designated as hedges for accounting purposes. The contracts are measured at fair value at the end of each quarter, with changes in value flowing through net income. See Note 10 to the Financial Statements for further information about these contracts, their fair value and their impact on our net loss. We had no commodity price derivatives outstanding as of and during the years ended December 31, 2015 and 2014.

Item 8. Financial Statements and Supplementary Data

The information required here begins on page F-1 as described in "Item 15. Exhibits and Financial Statement Schedules—Index to Consolidated Financial Information".

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

Effective June 20, 2016, the Audit Committee of the Board of Directors of VAALCO Energy, Inc. approved the engagement of BDO USA, LLP ("BDO") as our independent registered public accounting firm for the year ending December 31, 2016. In connection with the selection of BDO, also on June 20, 2016, the Audit Committee informed Deloitte & Touche LLP ("Deloitte") that it was to be dismissed as our independent registered public accounting firm effective June 20, 2016. The Audit Committee made its decision after soliciting proposals from several accounting firms.

During the years ended December 31, 2015 and 2014, and through June 20, 2016, neither VAALCO nor anyone on its behalf has consulted with BDO with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered onour consolidated financial statements, and neither written nor oral advice was provided tous that BDO concluded was an important factor considered by us in reaching a decision as to any accounting, auditing or financial reporting issue; (ii) any matter that was either the subject of disagreement (as defined in Item 304(a)(l)(iv) of Regulation SK and the related instructions to Item 304 of Regulations S-K) or a reportable event (as defined by Item 304(a)(l)(v) of Regulation S-K).

The reports of Deloitte on our consolidated financial statements for the years ended December 31, 2015 and 2014 did not contain an adverse opinion or disclaimer of an opinion, and were not qualified or modified as to uncertainty, audit scope, or accounting principles, except that the December 31, 2015 report contained an explanatory paragraph regarding substantial doubt about our ability to continue as a going concern.

During the years ended December 31, 2015 and 2014 and through June 20, 2016, there were no disagreements (as defined in Item 304(a)(l)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) with Deloitte on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Deloitte, would have caused Deloitte to make reference to the matter in its report on the consolidated financial statements for such year.

Except for the material weaknesses in our internal control over financial reporting as described by the Company in Item 9A ofour Annual Reports on Form 10-K for the years ended December 31, 2014 (the “2014 Form 10-K”) and December 31, 2015 (the “2015 Form 10-K”), each as filed with the SEC on March 16, 2015 and March 16, 2016, respectively, and the material weakness in our internal control over financial reporting that has not been remediated as described by us in Item 4 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 (“Q1 2016 Form 10-Q”), as filed with the SEC on May 10, 2016, there were no “reportable events,” as defined in Item 304(a)(1)(v) of Regulation S-K that occurred during our two most recent fiscal years or during the subsequent interim period through June 20, 2016, when Deloitte was dismissed. The material weaknesses in internal control over financial reporting identified in the 2014 Form 10-K related to (i) internal control over the preparation and review of the impairment evaluation of oil and gas properties and (ii) the control environment, risk assessment and internal controls over financial reporting due to insufficient financial reporting resources. The material weakness in internal control over financial reporting identified in the 2015 Form 10-K and in the Q1 2016 Form 10-Q related to the control environment and internal controls over financial reporting due to insufficient financial reporting resources.

Because of these weaknesses, our management concluded, as reported in the 2014 Form 10-K, the 2015 Form 10-K and the Q1 2016 Form 10-Q, that we did not maintain effective internal control over financial reporting as of December 31, 2014, December 31, 2015 and March 31, 2016. Deloitte, in its attestation reports in the 2014 Form 10-K and 2015 Form 10-K also reported that, in its opinion, we did not maintain in all material respects, effective internal control over financial reporting as of December 31, 2014 and December 31, 2015, respectively. The Audit Committee has discussed these matters with Deloitte, and we have authorized Deloitte to respond fully to inquiries by BDO regarding these reportable events.

It em 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Accounting Officer (who is our principal financial officer), to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Management, including our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below, two material weaknesses were identified in our internal control over financial reporting. As a result of the material weaknesses, the Company’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures were not effective at December 31, 2016. Notwithstanding the identified material weaknesses, management believes the Financial Statements included in this Annual Report on Form 10-K fairly represent in all material respects our financial condition, results of operations and cash flows at and for the periods presented in accordance with U.S. GAAP.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including our Chief Executive Officer and our Chief Accounting Officer (who is our principal financial officer), is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of its internal control over financial reporting using the criteria set forth in the *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework").

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.

As described in the Annual Report on Form 10-K for the year ended December 31, 2015, our management concluded that control deficiencies in aggregate constituted a material weakness in our internal control over financial reporting. We determined that we did not maintain effective internal control over financial reporting due to the failure to maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. Controls were not operating effectively over the review and preparation of the financial statements, which in aggregate resulted in a material weakness. This material weakness resulted in adjustments prior to the issuance of the financial statements that, if not corrected, would have resulted in a material misstatement of the financial statements.

As discussed further in "Remediation of Material Weaknesses" section below, in 2016 management undertook a number of steps to remediate the material weakness. Implementation of these steps was adversely impacted by cost cutting and cost containment measures undertaken in the first half of 2016 in response to liquidity constraints resulting from an extended period of low oil prices. As disclosed in Note 2 to the Financial Statements, management determined that there was substantial doubt about the ability of the Company to continue as a going concern in the 2015 Form 10-K filed on March 16, 2016. While events and conditions improved during the year such that management concluded as of March 13, 2017 that events and conditions at such date do not raise substantial doubt about VAALCO's ability to continue as a going concern through March 31, 2018, these improvements occurred over a number of months. As a result of the focus on controlling costs and minimizing cash outlays, most of the actions taken in 2016 to remediate the material weakness (as described in "Remediation of Material Weakness" below), did not occur until the third and fourth quarters of 2016. These actions included replacement of accounting personnel in key positions and augmentation of the staff with additional professional resources.

At December 31, 2016, management determinedthat the effectiveness and timeliness of the performance of controls related to the review of financial reports, the review of account reconciliations and the evaluation and reporting of significant and unusual transactions was not adequate to ensure that the material weakness in internal control identified in 2015 had been fully remediated. Management also determined that as of December 31, 2016 there is a material weakness related to the execution of the control for the physical observation of equipment which is performed annually to validate its existence.

Based on our evaluation of the material weaknesses described above, our principal executive officer and principal financial officer have concluded that the Company's internal control over financial reporting was not effective as of December 31, 2016 as a result of the material weaknesses.

BDO, the independent registered public accounting firm, has issued their report on our internal control over financial reporting as of December 31, 2016, which is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REMEDIATION OF MATERIAL WEAKNESSES

As described above, at December 31, 2015,our management concluded that control deficiencies in aggregate constituted amaterial weakness in our internal control over financial reporting due to the failure to maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. In response to the identified material weakness at December 31, 2015, our management, with oversight from our Audit Committee, undertook the following actions to remediate the material weakness described above:

- Made improvements to refine certain controls, specifically, key controls related to accruals, account balance reconciliations, account analyses and analytical reviews;
- Improved the timing of the periodic financial close and reporting process through the use of a detail financial close plan and expanded reporting of financial data to senior management;

- Management upgraded the permanent accounting personnel and augmented the resources for accounting activities with qualified professionals; and
- For unfilled positions, management retained highly qualified consultants.

As described in "Management's Annual Report on Internal Control Over Financial Reporting" above, these efforts were largely undertaken in the third and fourth quarters of 2016 as liquidity constraints required the Company to undertake cost cutting and cost containment measures during the first half of the year. As a result, adequate time has not passed for the remediation efforts discussed above to be fully implemented and tested. Furthermore, additional permanent hires in key unfilled positions need to be made and then time is needed to allow those newly hired individuals to become fully trained in the controls for which they are responsible.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Except for the remediation procedures detailed above for the previously identified material weaknesses, there have been no other changes in our internal control over financial reporting during the three months ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

MANAGEMENT'S PLAN FOR REMEDIATION OF THE MATERIAL WEAKNESSES

In response to the identified material weaknesses at December 31, 2016, our management, with oversight from our Audit Committee, is taking the following actions to remediate the material weakness described above:

- Hiring additional permanent employees for key roles in accounting and finance which are currently being performed by professional consultants.
- Continue to improve the timing of the periodic financial close, reporting process and analysis of results through the use of a detailed financial close plan and expanded reporting of financial data to senior management.
- Training of personnel and development of policies and procedures related to the periodic validation of equipment used in operations.

Management is committed to improving our internal control processes and believes that the measures described above should remediate the material weakness identified and strengthen internal control over financial reporting. As we continue to evaluate and improve internal control over financial reporting, additional measures to remediate the material weaknesses or modifications to certain of the remediation procedures described above may be necessary. We expect to complete the required remedial actions during 2017. While senior management and our Audit Committee are closely monitoring the implementation of these remediation plans, we cannot provide any assurance that these remediation efforts will be successful or that internal control over financial reporting will be effective as a result of these efforts. Until the remediation steps set forth above are fully implemented and operating for a sufficient period of time, the material weaknesses that exists at December 31, 2016 will continue to exist.

RE PORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
VAALCO Energy, Inc.
Houston, Texas

We have audited the internal control over financial reporting of VAALCO Energy, Inc. and subsidiaries (the "Company) as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A, 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment: the effectiveness and timeliness of the performance of controls related to the review of financial reports, the review of account reconciliations and the evaluation and reporting of significant and unusual transactions was not adequate. Also, the controls over the physical observation of equipment to validate its existence were not adequate. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2016 consolidated financial statements, and this report does not affect our report dated March 13, 2017 on those consolidated financial statements.

In our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We do not express an opinion or any other form of assurance on management's statements referring to any corrective actions taken by the company after the date of management's assessment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of VAALCO Energy, Inc. and subsidiaries as of December 31, 2016, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the year then ended and our report dated March 13, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 13, 2017

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the proxy statement for our 2017 annual meeting, which will be filed with the Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2017 annual meeting, which will be filed with the Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

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

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the Company's proxy statement for its 2017 annual meeting, which will be filed with the Commission within 120 days of December 31, 2016, and which is incorporated herein by reference. Please see "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities" for information on securities that may be issued under our stock incentive plans.

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

Information required by this item will be included in the proxy statement for our 2017 annual meeting, which will be filed with the Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item will be included in the proxy statement for our 2017 annual meeting, which will be filed with the Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. The following is an index to the financial statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES

(a) 2. Other schedules are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

3.1	Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on September 28, 2015, and incorporated herein by reference).
3.3	First Amendment to the Second Amended and Restated Bylaws of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
3.4	Certificate of Elimination of Series A Junior Participating Preferred Stock of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
4.1	Form of Senior Debt Indenture (filed as Exhibit 4.1 to the Company’s Registration Statement on Form S-3 filed on May 13, 2014, and incorporated herein by reference).
4.2	Form of Subordinated Debt Indenture (filed as Exhibit 4.2 to the Company’s Registration Statement on Form S-3 filed on May 13, 2014, and incorporated herein by reference).
10.1	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as an exhibit to the Company’s Form 10-QSB for the quarterly period ended September 30, 1995, and incorporated by herein by reference).
10.2	Addendum No. 1 to Exploration and Production Sharing Contract, dated July 7, 2001, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.2 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.3	Addendum No. 2 to Exploration and Production Sharing Contract, dated July 7, 2006, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.3 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.4	Addendum No. 3 to Exploration and Production Sharing Contract, dated November 26, 2009, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.4 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.5	Addendum No. 4 to Exploration and Production Sharing Contract, dated January 5, 2012, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.5 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.6	Trustee and Paying Agent Agreement, dated June 26, 2002, by and among VAALCO Gabon (Etame), Inc., J.P. Morgan Trustee and Depositary Company Limited and JPMorgan Chase Bank, London Branch (filed as Exhibit 10.3 to the Company’s Quarterly Report on Form 10-QSB filed on August 19, 2002, and incorporated herein by reference).
10.7	Production Sharing Agreement, dated November 1, 2006, between Sonangol, E.P. and VAALCO Angola (Kwanza), Inc. (filed as Exhibit 10.8 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.8	Supplemental Loan Agreement, dated June 29, 2016, between VAALCO Gabon (Etame), Inc. and International Finance Corporate (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on July 6, 2016, and incorporated herein by reference).
10.10*	Indemnity Agreement entered into among the Company and certain of its officers and directors listed therein (filed as an exhibit to the Company’s Form 10 (File No. 0-20928) filed on December 3, 1992, as amended by Amendment No. 1, filed as an exhibit to the Company’s Form 8 on January 7, 1993, and Amendment No. 2 filed as an exhibit to the Company’s Form 8 filed on January 25, 1993, and hereby incorporated by reference herein).
10.11*	VAALCO Energy, Inc. 2001 Stock Incentive Plan (filed as Exhibit 99.1 to the Company’s Registration Statement on Form S-8 filed on August 17, 2001, and incorporated herein by reference).

10.12*	Form of Award Agreement under the VAALCO Energy, Inc. 2001 Stock Incentive Plan(filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.17*	VAALCO Energy, Inc. 2012 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 30, 2012, and incorporated herein by reference).
10.18*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2012 Long Term Incentive Plan(filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.19*	VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 17, 2014, and incorporated herein by reference).
10.20*	Form of Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan(filed as Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.21*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan(filed as Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.22*	Form of Restricted Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan(filed as Exhibit 10.22 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.25*	Employment Agreement between the Company and Cary Bounds (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 29, 2016, and incorporated herein by reference).
10.31	Settlement Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Group 42, Inc. Mr. Paul A. Bell, Michael Keane, BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff Stockholder Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Kornitzer Capital Management, Inc. and John C. Kornitzer (filed as Exhibit 10.12 to the Company's Current Report on Form 8-K filed onDecember 23, 2015, and incorporated herein by reference).
10.32	Stockholder Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Kornitzer Capital Management, Inc. and John C. Kornitzer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.33	VAALCO Energy, Inc. 2016 Stock Appreciate Rights Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.34	Form of Stock Appreciation Rights Agreement under the VAALCO Energy, Inc. 2016 Stock Appreciate Rights Plan(filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company
23.1(a)	Consent of BDO USA, LLP
23.2 (a)	Consent of Deloitte & Touche LLP
23.3(a)	Consent of Netherland, Sewell & Associates, Inc. —Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Schema Document.

101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Label Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith
(b) Furnished herewith
* Management contract or compensatory plan or arrangement

Item 16. Form 10-K Summary

None.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By /s/ CARY BOUNDS
Cary Bounds

Chief Executive Officer

Dated March 13, 2017

In accordance with the Exchange Act, this report has been signed below on the13th day of March, 2017, by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
By: /s/ CARY BOUNDS Cary Bounds	Chief Executive Officer (Principal Executive Officer) and Director
By: /s/ ELIZABETH D. PROCHNOW Elizabeth D. Prochnow	Chief Accounting Officer (Principal Financial and Accounting Officer)
By: /s/ ANDREW L. FAWTHROP Andrew L. Fawthrop	Chairman of the Board and Director
By: /s/ MICHAEL KEANE Michael Keane	Vice Chairman and Director
By: /s/ A. JOHN KNAPP, JR. A. John Knapp, Jr.	Director
By: /s/ JOHN J. MYERS, JR. John J. Myers, Jr.	Director
By: /s/ STEVEN J. PULLY Steven J. Pully	Director

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
VAALCO Energy, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheet of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2016, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the year then ended. In connection with our audit of the consolidated financial statements, we have also audited the financial statement schedule listed in Item 15(a)(1) as of and for the year ended December 31, 2016. These consolidated financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and schedule based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries at December 31, 2016, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Also in our opinion, the related financial statement schedule as of and for the year ended December 31, 2016, when considered in relation to the basic consolidated financial statements, taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 4 to the consolidated financial statements, the Company has changed its method of accounting for stock compensation forfeitures on a modified retrospective basis in the consolidated financial statements as of and for the year ended December 31, 2016 due to the early adoption of Financial Accounting Standards Board, Accounting Standards Update No. 2016-09 *Compensation – Stock Compensation*.

We also have audited the adjustments to the 2015 and 2014 consolidated financial statements to retrospectively reflect the operations attributable to the Company's activities in Angola as discontinued operations as described in Note 5. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2015 and 2014 consolidated financial statements of VAALCO Energy, Inc. and subsidiaries other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2015 and 2014 consolidated financial statements taken as a whole.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 13, 2017 expressed an adverse opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 13, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:

We have audited, before the effects of the retrospective adjustments for the discontinued operations as discussed in Note 5 to the consolidated financial statements, the consolidated balance sheet of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2015, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the years ended December 31, 2015 and 2014 (the 2015 and 2014 consolidated financial statements before the effects of the retrospective adjustments discussed in Note 5 to the consolidated financial statements are not presented herein). Our audit also includes the financial statement schedule listed in the index at item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, such 2015 and 2014 consolidated financial statements, before the effects of the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements, present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2015, and the results of their operations and their cash flows for the years ended December 31, 2015 and 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic 2015 and 2014 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

The accompanying consolidated financial statements for the year ended December 31, 2015 have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company's recurring losses from operations and insufficient liquidity due to depressed oil and gas prices, raise substantial doubt about its ability to continue as a going concern. Management's plans concerning these matters are also discussed in Note 2 to the financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We were not engaged to audit, review, or apply any procedures to the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 16, 2016

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
ASSETS	*(in thousands)*	
Current assets:		
Cash and cash equivalents	**$ 20,474**	$ 25,357
Restricted cash	**741**	1,048
Receivables:		
Trade	**6,751**	5,353
Accounts with partners, net of allowance of $0.5 million and no allowance at December 31, 2016 and 2015, respectively	**3,297**	19,765
Other	**120**	42
Crude oil inventory	**913**	639
Materials and supplies	**84**	194
Prepayments and other	**3,956**	2,975
Current assets - discontinued operations	**2,139**	8,369
Total current assets	**38,475**	63,742
Property and equipment - successful efforts method:		
Wells, platforms and other production facilities	**389,231**	412,593
Undeveloped acreage	**10,000**	10,000
Equipment and other	**9,779**	10,805
	409,010	433,398
Accumulated depreciation, depletion, amortization and impairment	**(380,991)**	(400,041)
Net property and equipment	**28,019**	33,357
Other noncurrent assets:		
Restricted cash	**918**	15,830
Value added tax and other receivables, net of allowance of $4.7 million and $4.2 million at December 31, 2016 and 2015, respectively	**5,110**	4,221
Deferred finance costs	**-**	1,655
Abandonment funding	**8,510**	5,137
Noncurrent assets - discontinued operations	**-**	16
Total assets	**$ 81,032**	$ 123,958
LIABILITIES AND SHAREHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	**$ 19,096**	$ 44,140
Accrued liabilities and other	**10,506**	18,447
Current portion of long term debt	**7,500**	-
Current liabilities - discontinued operations	**18,452**	4,129
Total current liabilities	**55,554**	66,716
Asset retirement obligations	**18,612**	16,166
Other long term liabilities	**284**	-
Long term debt, excluding current portion	**6,940**	15,000
Total liabilities	**81,390**	97,882
Commitments and contingencies (Note 9)		
Shareholders' equity (deficit):		
Preferred stock, none issued, 500,000 shares authorized, $25 par value	**-**	-
Common stock, 66,109,565 and 66,041,338 shares issued $0.10 par value, 100,000,000 shares authorized	**6,611**	6,604
Additional paid-in capital	**70,268**	69,118
Less treasury stock, 7,555,095 and 7,514,169 shares at cost	**(37,933)**	(37,882)
Accumulated deficit	**(39,304)**	(11,764)
Total shareholders' equity (deficit)	**(358)**	26,076
Total liabilities and shareholders' equity (deficit)	**$ 81,032**	$ 123,958

See notes to consolidated financial statements.

VA ALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2016	**2015**	**2014**
Revenues:			
Oil and natural gas sales	**$ 59,784**	$ 80,445	$ 127,691
Operating costs and expenses:			
Production expense	**37,586**	40,096	31,718
Exploration expense	**5**	10,409	13,651
Depreciation, depletion and amortization	**6,926**	32,998	20,074
General and administrative expense	**9,561**	12,294	12,112
Impairment of proved properties	**88**	81,322	98,341
Other operating expense	**8,853**	-	-
General and administrative related to shareholder matters	**(332)**	2,372	-
Bad debt expense and other	**1,222**	2,968	2,400
Total operating costs and expenses	**63,909**	182,459	178,296
Other operating income (loss), net	**(266)**	(1,092)	-
Operating loss	**(4,391)**	(103,106)	(50,605)
Other income (expense):			
Interest income	**3**	12	75
Interest expense	**(2,616)**	(1,337)	-
Other, net	**(2,015)**	(1,536)	(737)
Total other income (expense)	**(4,628)**	(2,861)	(662)
Loss from continuing operations before income taxes	**(9,019)**	(105,967)	(51,267)
Income tax expense	**9,248**	14,587	22,486
Loss from continuing operations	**(18,267)**	(120,554)	(73,753)
Loss from discontinued operations, net of tax	**(8,283)**	(38,102)	(3,797)
Net loss	**$ (26,550)**	$ (158,656)	$ (77,550)
Basic net loss per share:			
Loss from continuing operations	**$ (0.31)**	$ (2.07)	$ (1.29)
Loss from discontinued operations	**(0.14)**	(0.65)	(0.07)
Net loss	**$ (0.45)**	$ (2.72)	$ (1.36)
Basic weighted average shares outstanding	**58,384**	58,289	57,229
Diluted net loss per share:			
Loss from continuing operations	**$ (0.31)**	$ (2.07)	$ (1.29)
Loss from discontinued operations	**(0.14)**	(0.65)	(0.07)
Net loss	**$ (0.45)**	$ (2.72)	$ (1.36)
Diluted weighted average shares outstanding	**58,384**	58,289	57,229

See notes to consolidated financial statements

VA ALCO ENERGY, INC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (DEFICIT)
(in thousands)

	Common Shares	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance at January 1, 2014	64,013	(7,163)	$ 6,408	$ 55,455	$ (35,431)	$ 224,442	$ 250,874
Shares issued - stock-based compensation	1,182	-	111	5,574	-	-	5,685
Stock-based compensation expense	-	-	-	3,322	-	-	3,322
Treasury stock acquired	-	(231)	-	-	(1,868)	-	(1,868)
Net income	-	-	-	-	-	(77,550)	(77,550)
Balance at December 31, 2014	65,195	(7,394)	6,519	64,351	(37,299)	146,892	180,463
Shares issued - stock-based compensation	846	-	85	957	-	-	1,042
Stock-based compensation expense	-	-	-	3,810	-	-	3,810
Treasury stock acquired	-	(120)	-	-	(583)	-	(583)
Net loss	-	-	-	-	-	(158,656)	(158,656)
Balance at December 31, 2015	66,041	(7,514)	6,604	69,118	(37,882)	(11,764)	26,076
Cumulative effect adjustment for adoption of ASU 2016-09	(420)	-	(42)	1,032	-	(990)	-
Balance at January 1, 2016 after cumulative effect adjustments	65,621	(7,514)	6,562	70,150	(37,882)	(12,754)	26,076
Shares issued - stock-based compensation	489	(41)	49	(49)	(51)	-	(51)
Stock-based compensation expense	-	-	-	167	-	-	167
Net loss	-	-	-	-	-	(26,550)	(26,550)
Balance at December 31, 2016	66,110	(7,555)	$ 6,611	$ 70,268	$ (37,933)	$ (39,304)	$ (358)

See notes to consolidated financial statements

V AALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Year Ended December 31, 2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	**$ (26,550)**	$ (158,656)	$ (77,550)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Loss from discontinued operations	**8,283**	38,102	3,797
Depreciation, depletion and amortization	**6,926**	32,998	20,074
Other amortization	**1,424**	304	328
Deferred taxes	**-**	1,349	-
Unrealized foreign exchange loss	**(32)**	(5,243)	(59)
Dry hole costs and impairment of unproved leasehold	**-**	10,244	13,272
Stock-based compensation	**192**	3,810	3,321
Commodity derivatives loss	**1,711**	-	-
Bad debt provision	**1,222**	2,699	2,400
Other operating (income) loss, net	**266**	1,092	-
Impairment of proved properties	**88**	81,322	98,341
Change in operating assets and liabilities:			
Trade receivables	**(1,050)**	14,174	(2,556)
Accounts with partners	**16,284**	(13,816)	(8,910)
Other receivables	**(18)**	(609)	(1,230)
Crude oil inventory	**(192)**	1,266	(1,747)
Materials and supplies	**125**	92	(122)
Value added tax and other receivables	**(1,937)**	(2,286)	-
Other long term assets	**(2,827)**	(1,566)	(3,537)
Prepayments and other	**392**	3,037	(3,957)
Accounts payable	**(15,459)**	30,187	(8,999)
Accrued liabilities and other	**(4,586)**	3,034	(874)
Net cash provided by (used in) continuing operating activities	**(15,738)**	41,534	31,992
Net cash provided by (used in) discontinued operating activities	**12,286**	(2,659)	(8,602)
Net cash provided by (used in) operating activities	**(3,452)**	38,875	23,390
CASH FLOWS FROM INVESTING ACTIVITIES:			
Decrease in restricted cash	**15,219**	5,536	(9,218)
Acquisitions	**(5,692)**	-	-
Property and equipment expenditures	**(8,705)**	(68,067)	(89,493)
Proceeds from sales of oil and gas properties	**830**	398	-
Premiums paid	**(2,939)**	-	-
Net cash used in continuing investing activities	**(1,287)**	(62,133)	(98,711)
Net cash used in discontinued investing activities	**-**	(20,877)	(2,687)
Net cash used in investing activities	**(1,287)**	(83,010)	(101,398)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**-**	441	5,685
Debt issuance costs	**(93)**	-	(2,287)
Borrowings	**-**	-	15,000
Purchases of treasury stock	**(51)**	-	(1,868)
Net cash provided by (used in) continuing financing activities	**(144)**	441	16,530
Net cash (used in) provided by discontinued financing activities	**-**	-	-
Net cash (used in) provided by financing activities	**(144)**	441	16,530
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(4,883)**	(43,694)	(61,478)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**25,357**	69,051	130,529
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 20,474**	$ 25,357	$ 69,051
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	**$ 1,326**	$ 1,337	$ -
Income Taxes paid	**$ 9,210**	$ 15,163	$ 23,041
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at period end	**$ 2,282**	$ 15,132	$ 18,553
Asset retirement cost capitalized	**$ 1,543**	$ 542	$ 2,662

See notes to consolidated financial statements.

1. ORGANIZATION

VAALCO Energy, Inc. and its consolidated subsidiaries ("VAALCO" or the "Company") is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. As non-operator, we participate in exploration and development activities in Equatorial Guinea, West Africa. In the United States, VAALCO holds undeveloped leasehold acreage in Montana. As discussed further in Note 5 below, we have discontinued operations associated with our activities in Angola, West Africa.

Our consolidated subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon),Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited and VAALCO Energy (USA), Inc.

2. LIQUIDITY

Our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on satisfactory terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and will likely continue to be volatile. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and have remained low through 2016. Revenues have decreased from $127.7 million for the year ended December 31, 2014 to $59.8 million for the year ended December 31, 2016.

Our financial statements for the years ended December 31, 2016, 2015 and 2014 and as of December 31, 2016 and 2015 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. The financial statements do not include any adjustments relating to the recoverability and classification of assets or the amounts and classification of liabilities that might be necessary should we be unable to continue as a going concern. In the financial statements included in our Annual Report on Form 10-K for December 31, 2015 filed with the Securities and Exchange Commission on March 16, 2016 ("2015 Form 10-K"), we concluded that at the date of filing our cash position and our ability to access additional capital may limit our available opportunities, or not provide sufficient cash available for our operations, which raised substantial doubt about our ability to continue as a going concern at such date.

Subsequent to the filing of the 2015 Form 10-K, events and conditions have improved. Oil and natural gas prices stabilized at prices which are adequate to generate cash flows from operations beginning in the fourth quarter of 2016 and continuing through March 13, 2017, the date of filing of these financial statements. As discussed in Note 8, in June 2016, we modified our revolving credit facility with the International Finance Corporation (the "IFC") converting $20 million of the revolving portion of the credit facility into a $15 million term loan (the "Term Loan"). Although our available liquidity continues to be limited, we expect to have adequate cash flows to meet our principal and interest obligations under the Term Loan, and we expect we will be able to meet our financial covenants. We and our partners have approved a budget which limits the amount of capital expenditures for 2017. As discussed in Note 10 below, we have put contracts in place at December 31, 2016 which limit our exposure to a decline in oil prices through December 31, 2017. Based on our forecasts which consider these and other relevant factors, management believes that events and conditions as of March 13, 2017, considered in the aggregate, do not raise substantial doubt about VAALCO's ability to continue as a going concern through March 31, 2018.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation – The accompanying consolidated financial statements include the accounts of VAALCO and its wholly owned subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications did not affect our consolidated financial results.

Use of estimates – The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Our consolidated financial statements include amounts that are based on management's best estimates and judgments. Actual results could differ from those estimates.

Estimates of oil and natural gas reserves used in the consolidated financial statements to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures.

We consider our estimates to be reasonable; however, due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

Correction of error – Accounts with partners and allowance for bad debts – Subsequent to the issuance of our 2015 financial statements, we identified an error in the presentation on our consolidated balance sheet of the accounts with partners and the associated allowance for bad debts. These accounts incorrectly included a fully reserved receivable of $7.6 million which should have been charged off against the reserve in 2012 when efforts to collect from a removed partner were no longer viable and had been abandoned. To correct this error, we removed the reference to the $7.6 million allowance from the caption. This correction had no impact on our consolidated balance sheet or the consolidated results of operations.

Cash and cash equivalents — Cash and cash equivalent includes deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase.

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and time duration. Current amounts in restricted cash at December 31, 2016 and 2015 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long term amounts at December 31, 2016 and 2015 include a charter payment escrow for the Floating Production Storage and Offloading tanker ("FPSO") offshore Gabon as discussed in Note 9. We also have funds restricted for the purposes of satisfying the asset retirement obligation on the Etame Marin block in Gabon. These funds are reflected under Abandonment funding on the consolidated balance sheet. Restricted cash at December 31, 2015 included funds designated for our drilling commitment in Angola Block 5 as discussed in Note5.

We invest restricted and excess cash in certificates of deposit and commercial paper issued by banks with maturities typically not exceeding 90 days.

Accounts with partners – Accounts with partners represent the excess of charges billed over cash calls paid by the partners for exploration, development and production expenditures made by us as operator.

Bad debts – Quarterly, we evaluate our accounts receivable balances to confirm collectability. When collectability is in doubt, we record an allowance against the accounts receivable and a corresponding income charge for bad debts which appears in the "Bad debt expense and other" line of the consolidated statements of operations. The majority of our accounts receivable balances are with our joint venture partners, purchasers of our production and the government of Gabon for reimbursable Value-Added Tax ("VAT"). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed us. In June 2016, we entered into an agreement with the government of Gabon to receive payments related to the outstanding VAT receivable balance of XAF 16.3 billion (XAF 4.9 billion, net to VAALCO), representing the outstanding balance as of December 31, 2015, in thirty-six monthly installments of $0.2 million net to VAALCO. We received one monthly installment payment in July 2016; however, no further payments have been received. The Gabonese government has informed us that they are temporarily delaying further payments

In 2016, 2015 and 2014, we recorded allowances of $0.7 million, $2.7 million and $2.4 million related to VAT which the government of Gabon has not reimbursed. The receivable amount, net of allowances, is reported as a long-term item in the Value added tax receivable line at December 31, 2016 in the consolidated balance sheet. Because both the VAT receivable and the related allowance are denominated in the local currency of Gabon, the revaluation of these balances into U.S. dollars at each period end also has an impact on profit/loss. Such foreign currency gains/(losses) are reported separately in the Other, net, operating income (expense) line of the consolidated statements of operations.

The table provides a rollforward of the aggregate allowance:

	Year Ended December 31,		
Allowances for bad debts	**2016**	**2015**	**2014**
		(in thousands)	
Balance at January 1	**$ (4,221)**	$ (2,400)	$ -
Charged to costs and expenses	**(1,222)**	(2,699)	(2,400)
Foreign currency gain (loss)	**232**	878	-
Balance at December 31	**$ (5,211)**	$ (4,221)	$ (2,400)

Crude oil inventory — Crude oil inventories are carried at the lower of cost or market and represent our share of crude oil produced and stored on the FPSO, but unsold at the end of the period.

Materials and supplies – Materials and supplies, which are primarily used for production related activities, are valued at the lower of cost, determined by the weighted-average method, or market.

Property and equipment – We use the successful efforts method of accounting for oil and natural gas producing activities.

Capitalization – Leasehold acquisition costs are initially capitalized. Costs to drill exploratory wells are initially capitalized until a determination as to whether proved reserves have been discovered. If an exploratory well is deemed to not have found proved reserves, the associated costs are charged to exploration expense at that time. Exploration costs, other than the cost of drilling exploratory wells, which can include geological and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are charged to exploration expense as incurred. All development costs, including developmental dry hole costs, are capitalized.

Impairment – We review our oil and natural gas producing properties for impairment on a field-by-field basisquarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. We evaluate our undeveloped oil and natural gas leases for impairment periodically by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts, lease expiration terms and future plans for exploration or development. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Capitalized equipment inventory is reviewed regularly for obsolescence. We identified equipment inventory in Gabon that we do not expect to use and charged $0.3 million and $1.5 million to Other operating loss, net in the years ended December 31, 2016 and 2015, respectively.

Depreciation, depletion and amortization – Depletion of wells, platforms, and other production facilities are calculated on a field basis under the unit-of-production method based upon estimates of proved developed reserves. Depletion of developed leasehold acquisition costs are provided on a field basis under the unit-of-production method based upon estimates of proved reserves. Support equipment and leasehold improvements related to oil and natural gas producing activities, as well as property, plant and equipment unrelated to oil and natural gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which are typically five years for office and miscellaneous equipment and five to seven years for leasehold improvements.

Capitalized interest – Interest costs from external borrowings are capitalized on major projects. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

Asset retirement obligations ("ARO") – We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. 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. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to oil and natural gas properties. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. See Note 7 for disclosures regarding our asset retirement obligations.

Revenue recognition – We recognize oil and natural gas revenues when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances. We recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property, and we would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. As of December 31, 2016 and 2015, we had no recorded oil and natural gas imbalances.

Major maintenance activities – Costs for major maintenance are expensed in the period incurred and can include the costs of workovers of existing wells, contractor repair services, materials and supplies, equipment rentals and our labor costs.

Stock based compensation - We measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. Grant date fair value for options is estimated using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. For restricted stock, grant date fair value is determined using the market value of our common stock on the date of grant. The fair value of stock appreciation rights ("SARs") is based on a Monte Carlo simulation at grant date and at each subsequent reporting date. The Monte Carlo simulation to value our SARs uses the following inputs: (i) the quoted market price of our common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term which is based on the contractual term, (iv) the expected volatility which is based on the historical volatility of the our stock for the length of time corresponding to the expected term of the SARs, (v) the expected dividend yield is based on our anticipated dividend payments, (vi) the risk-free interest rate which is based on the U.S. treasury yield curve in effect as of the reporting date for the length of time corresponding to the expected term of the SARs.

Our stock-based compensation expense is recognized based on the awards as they vest, using the straight-line attribution method over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

As discussed in Note 4, in the fourth quarter of 2016, we adoptedASU No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). As a result, previously recognized expense related to forfeitures is reversed in the period in which the forfeiture occurs. Prior to the adoption of this accounting standard, we recognized stock-based compensation expense based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature rather than accounting for forfeitures as they occur.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries Gains and losses on foreign currency transactions are included in income. Within the consolidated statements of operations line Other income (expense)—Other, net, we recognized gains on foreign currency transactions of $0.5 million and $1.5 million in 2016 and 2015, respectively, and losses on foreign currency transactions of $0.7 million in 2014.

Income taxes – We account for income taxes under an asset and liability approach that recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the financial statements and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized. We classify interest related to income tax liabilities as Interest expense and penalties as Other, net on the consolidated statements of operations.

Derivative Instruments and Hedging Activities – We use derivative financial instruments to achieve a more predictable cash flow from oil production by reducing our exposure to price fluctuations. Our derivative instruments at December 31, 2016 consisted of fixed price oil puts, which give us the option to sell a contracted volume of oil at a contracted price on a contracted date in the future. As of December 31, 2016, all of our unexpired oil put contracts provide for settlement based upon reported Brent prices.

We record balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented within "Other, net" located in Other income (expense) in the consolidated statements of operations. There were no cash settlements during the year ended December 31, 2016.

Fair Value – Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1 – Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – Inputs that are not observable from objective sources, such as internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in our internally developed present value of future cash flows model that underlies the fair-value measurement).

Fair value of financial instruments – Our current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets and accounts payable. As discussed further in Note 10, derivative assets and liabilities are measured and reported at fair value each period with changes in fair value recognized in net income. With respect to our other financial instruments included in current assets and liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments. The carrying value of our long-term debt approximates fair value, as the interest rates are adjusted based on market rates currently in effect.

General and administrative related to shareholder matters – Amounts related to shareholder matters for the years ended December 31, 2016 and 2015 relate to costs incurred related to shareholder litigation that was settled in 2016. For 2016, the amounts also include the offsetting insurance proceeds related to these matters.

4. NEW ACCOUNTING STANDARDS

Not Yet Adopted

In November 2016, the Financial Accounting Standards Board ("FASB") issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash ("ASU 2016-18"), which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, 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. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. We are currently evaluating the provisions of this guidance and are assessing its potential impact on our cash flows and related disclosures. Due to the nature of this accounting standards update, this may have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15") related to how certain cash receipts and payments are presented and classified in the statement of cash flows. These cash flow issues include debt prepayment or extinguishment costs, settlement of zero-coupon debt, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, beneficial interests in securitization transactions, and separately identifiable cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. We are currently evaluating the provisions of this guidance and are assessing its potential impact on our cash flows and related disclosures. Due to the nature of this accounting standards update, this may have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including our trade and partner receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date which is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model which increases the allowance when losses are probable. This change is effective for all public companies for fiscal years beginning after December 31, 2019, including interim periods within those fiscal years and will be applied with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We are currently evaluating the provisions of ASU 2016-13 and are assessing its potential impact on our financial position, results of operations, cash flows and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases (ASC 842) ("ASU 2016-02"), which amends the accounting standards for leases. ASU 2016-02 retains a distinction between finance leases and operating leases. The primary change is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Certain aspects of lease accounting have been simplified and additional qualitative and quantitative disclosures are required along with specific quantitative disclosures required by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. We are required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period presented in the financial statements. Early adoption is allowed.Assuming adoption January 1, 2019, we expect that leases in effect on January 1, 2017 and leases entered into after such date will be reflected in accordance with the new standard in the audited consolidated financial statements included in our Annual Report on Form 10-K for 2019, including comparative financial statements presented in such report. We are in the preliminary stages of our gap assessment, but we expect that leases treated as operating leases will be capitalized. We expect adoption of this standard to result in the recording of a right of use asset related to our operating leases with a corresponding lease liability. This is expected to result in a material increase in total assets and liabilities as certain of our operating leases are significant as disclosed in Note 9. We do not expect there will be a material overall impact on results of operations or cash flows; however, cash flows from operations will increase and cash from financing activities will decrease as a result of reflecting a significant portion of lease payments as payments on the lease liabilities rather than rental expense. We are continuing to evaluate the impact of this new standard, and are in the process of developing our implementation plan.

In July 2015, the FASB issued guidance to simplify the measurement of inventory. This simplification applies to all inventory other than that measured using last-in, first out ("LIFO") or the retail inventory method and requires measurement of inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation. This guidance is to be applied prospectively effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. We do not expect the application of this guidance to have a significant impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09").The new standard will replace most existing revenue recognition guidance in U.S. GAAP. The core principle of ASU 2014-09 requires companies to reevaluate when revenue is recorded on a transaction based upon newly defined criteria, either at a point in time or over time as goods or services are delivered. The ASU requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and estimates, and changes in those estimates. In early 2016, the FASB issued additional guidance: ASU No. 2016-10, 2016-11 and 2016-12 (and together with ASU 2014-09, "Revenue Recognition ASU"). These updates provide further guidance and clarification on specific items within the previously issued ASU 2014-09. The Revenue Recognition ASU becomes effective for the Company as of January 1, 2018, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016, and allows for both retrospective and modified-retrospective methods of adoption. The Company does not plan to early adopt the standard. We have preliminarily concluded that we will adopt the Revenue Recognition ASU via the modified retrospective transition method, taking advantage of the allowed practical expedients. We are substantially complete with our gap assessment and have determined that we will qualify for point in time recognition for essentially all of our sales. As such, the Company does not expect adoption of this standard to result in a change in the timing of revenue recognition compared to current practices, and therefore we do not expect adoption of this standard to have a material impact on our financial position or results of operations. We do expect that we will have expanded disclosures around the nature of our sales contracts and other matters related to revenues and the accounting for revenues. We are continuing to evaluate the impact of this new standard, and are in the process of developing our implementation plan.

Adopted

In March 2016, the FASB issued ASU No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09") that changes several aspects of accounting for share-based payment transactions, including a requirement to recognize all excess tax benefits and tax deficiencies as income tax expense or benefit in the income statement, classification of awards as either equity or liabilities, and classification on the statements of cash flows. This standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 31, 2016, with early adoption permitted. Varying transition methods (modified retrospective, retrospective or prospective) are applicable to different provisions of the standard. We adopted ASU 2016-09 during the fourth quarter of 2016. Upon early adoption of ASU 2016-09, the Company elected to change its accounting policy to account for forfeitures as they occur. The change was applied on a modified retrospective basis with a cumulative effect adjustment to retained earnings of $1.0 million as of January 1, 2016.The amendments related to accounting for excess tax benefits have been adopted prospectively, resulting in no impact on either retained earnings at January 1, 2016 or net loss for 2016 as the Company is in a net operating loss position with a full valuation allowance. Additionally, excess tax benefits for stock-based compensation is now included in cash flows from operating activities rather than cash flows from financing activities in the Statements of Cash Flows and will be applied prospectively in accordance with the ASU.

In April 2015, the FASB issued ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03) that requires the presentation of debt issuance costs in financial statements as a direct reduction of the related debt liabilities, with amortization of debt issuance costs reported as interest expense. Under prior GAAP, debt issuance costs were reported as deferred charges (i.e., as an asset). We adopted ASU 2015-03 in the first quarter of 2016. As discussed in Note 8 below, in the second quarter of 2016, our loan agreement was modified into a term loan. At that time, a portion of deferred debt issuance costs related to the revolving credit facility were charged to expense. The remaining unamortized deferred financing costs plus the incremental costs of converting the revolver into a term loan was presented as a direct reduction of Long-term debt on our consolidated balance sheet.

In August 2014, the FASB issued an update to accounting standards that requires management to assess an entity's ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. More specifically, in connection with preparing financial statements for each annual and interim reporting period, an entity's management shall evaluate whether there are conditions and events, considered in the aggregate, that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Substantial doubt exists when conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued. We adopted this guidance in the fourth quarter of 2016. As a result of the adoption of this standard, we made an evaluation of the events and conditions as of the date of these financial statements to determine whether in the aggregate these raised substantial doubt about our ability to continue as a going concern. We concluded that this was not the case. See Note 2 for further discussion. Except for the additional disclosures, the adoption of this standard did not have any impact on our consolidated financial statements.

5. ACQUISITIONS AND DISPOSITIONS

Sojitz Acquisition

On November 22, 2016, we closed on the purchase of an additional 2.98% working interest (3.23% Participating interest) in the Etame Marin block located offshore the Republic of Gabon from Sojitz Etame Limited ("Sojitz"), which represents all interest owned by Sojitz in the concession. The acquisition has an effective date of August 1, 2016 and was funded with cash on hand

The following amounts represent the preliminary estimates of the fair value of identifiable assetsacquired and liabilities assumed in the Sojitz acquisition. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained. These amounts will be finalized as soon as possible, but no later than one year from the date of the acquisition.

		November 22, 2016 (in thousands)
Assets acquired:		
Wells, platforms and other production facilities	$	5,754
Equipment and other		684
Value added tax and other receivables		297
Abandonment funding		546
Accounts receivable - trade		888
Other current assets		220
Liabilities assumed:		
Asset retirement obligations		(1,731)
Accrued liabilities and other		(747)
Total identifiable net assets and consideration transferred	$	5,911

All assets and liabilities associated with Sojitz's interest in Etame Marin block, including oil and gas properties, asset retirement obligations and working capital items were recorded at their fair value. In determining the fair value of the oil and gas properties, we prepared estimates of oil and natural gas reserves. We used estimated future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at the estimates of future net revenues. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates. Other significant estimates were used by management to calculate fair value of assets acquired and liabilities assumed. We may record purchase price adjustments as a result of changes in such estimates. These assumptions represent Level 3 inputs, as further discussed in Note 3.

The actual impact of the Sojitz Acquisition was an increase to "Total revenues" in the consolidated statement of operations of $0.2 million for the year ended December 31, 2016 and a minimal decrease to "Net loss" in the consolidated statement of operations for the year ended December 31, 2016. The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2016 and 2015 as if it had been consummated on January 1, 2015. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31,			
	2016		2015	
	(in thousands)			
Pro forma (unaudited)				
Oil and gas sales	$	65,427	$	88,940
Operating loss		(4,295)		(101,494)
Loss from continuing operations		(19,232)		(120,546)
Basic and diluted net loss per share:				
Loss from continuing operations	$	(0.33)	$	(2.07)
Net loss	$	(0.47)	$	(2.72)

Sale of Certain U.S. Properties

In December 2016, we completed the sale our interests intwo wells in the Hefley field in North Texas for$830,000 resulting in a minimal loss.On October 17, 2016, we signed a letter of intent to sell our interests in the East Poplar Dome field in Montana for $250,000, which is held for sale as of December 31, 2016. Based on the fully impaired net book value for these assets as of December 31, 2016, we expect any gain/loss to be insignificant.

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. Thefour year primary term, with an optionalthree year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drilltwo exploratory wells. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and our partner to drill two additional exploration wells. Our working interest is 40% and we carry the Angolan national oil company, Sonangol P&P, for10% of the work program. On September 30, 2016, we notified

Sonangol P&P, our joint venture partner, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have taken actions to begin closing our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, we classified all the related assets and liabilities as those of discontinued operations in the consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in our consolidated statements of operations. We segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in our consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment's operations as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

Summarized Results of Discontinued Operations

	Year Ended December 31,		
	2016	**2015**	**2014**
		(in thousands)	
Operating costs and expenses:			
Exploration expense	**$ 15,137**	$ 36,044	$ 1,707
Depreciation, depletion and amortization	**9**	12	12
General and administrative expense	**1,269**	2,535	2,082
Bad debt expense (recovery) and other	**(7,629)**	-	-
Total operating costs and expenses	**8,786**	38,591	3,801
Other operating loss, net	**(172)**	(1,856)	-
Operating loss	**(8,958)**	(40,447)	(3,801)
Other income:			
Interest income	**3,201**	-	-
Other, net	**552**	2,345	4
Total other income	**3,753**	2,345	4
Loss from discontinued operations before income taxes	**(5,205)**	(38,102)	(3,797)
Income tax expense	**3,078**	-	-
Loss from discontinued operations	**$ (8,283)**	$ (38,102)	$ (3,797)

Assets and Liabilities Attributable to Discontinued Operations

	December 31,	
	2016	**2015**
	(in thousands)	
ASSETS		
Current assets:		
Accounts with partners	**$ 2,138**	$ 8,091
Prepayments and other	**1**	278
Total current assets	**2,139**	8,369
Property and equipment - successful efforts method:		
Equipment and other	**-**	143
	-	143
Accumulated depreciation, depletion, amortization and impairment	**-**	(127)
Net property and equipment	**-**	16
Total assets	**$ 2,139**	$ 8,385
LIABILITIES		
Current liabilities:		
Accounts payable	**$ 77**	$ 2,708
Foreign taxes payable	**3,078**	-
Accrued liabilities and other	**15,297**	1,421
Total current liabilities	**$ 18,452**	$ 4,129

Drilling Obligation

Under the production sharing agreement for Block 5, we and our working interest partner, Sonangol P&P, were obligated to performexploration activities in Angola that would result in drilling or commencing four wells by November 30, 2017. With the drilling of theKindele #1 in 2015, the obligation was reduced to three wells. Under the contract, VAALCO is required to pay a $5.0 million penalty for each of the three wells not completed; however, the penalty amounts may be reduced by exploration expenses incurred. Prior to theSeptember 30, 2016 quarterly reporting period, we classified$15.0 million as long term restricted cash on our balance sheet to guarantee the commitment for drilling these wells. On September 30, 2016, we reclassified this amount from restricted cash to cash and cash equivalents. As a result of our decision to terminate the contract, we are no longer reflecting the $15.0 million as restricted cash. We believe that a substantial portion of the penalty amount may be reduced due to prior exploration expenditures. Support for our determination has been presented to Angola government authorities, and we anticipate further discussions on this matter. However, due to the uncertainties as to the ultimate outcome, we have accrued a $15.0 million liability for the penalty as of December 31, 2016, which represents what we believe to be the maximum potential amount due under the agreement.

Other Matters – Partner Receivable

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and was removed from the production sharing contract in 2010 by a governmental decree. Efforts to collect from the defaulted partner were abandoned in 2012. The available 40% working interest in Block 5, offshore Angola was assigned to Sonangol P&P effective on January 1, 2014. We invoiced Sonangol P&P for the unpaid delinquent amounts from the defaulted partner plus the amounts incurred during the period prior to assignment of the working interest totaling $7.6 million plus interest in April 2014. Because this amount was not paid and Sonangol P&P was slow in paying monthly cash call invoices since their assignment, we placed Sonangol P&P in default in the first quarter of 2015.

On March 14, 2016, we received a $19.0 million payment from Sonangol P&P for the full amount owed us as of December 31, 2015, including the $7.6 million of pre-assignment costs and default interest of $3.2 million. The $7.6 million recovery is reflected in the “Bad debt expense and other” line of our summarized results of discontinued operations. Default interest of $3.2 million is shown in the “Interest income” line of our summarized results of discontinued operations.

6. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Proved Properties

We review our oil and natural gas producing properties for impairment quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When an oil and natural gas property’s undiscounted estimated future net cash flows are not sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount of the asset to its fair value. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs into the undiscounted future net cash flows. The undiscounted estimated future net cash flows used in our impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers’ report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results.

During 2016, our negative price differential to Brent narrowed and we incurred no significant capital spending. We considered these and other factors and determined that there were no events or circumstances triggering an impairment evaluation for most of our fields, with the exception of the Avouma field in the Etame Marine block offshore Gabon. Recently, at the Avouma field, the electrical submersible pumps (“ESPs”) in the South Tchibala 2-H well and the Avouma 2-H well failed, and these wells were temporarily shutin. After utilizing a hydraulic workover unit to replace the failed ESP systems, the South Tchibala 2-H and the Avouma 2-H wells resumed production in December 2016 and January 2017, respectively. The reserves used in our impairment evaluation of the Avouma field prior to the fourth quarter of 2016 were revised to reflect the impact of this lost production for several months and the impact of the forward price curve. The undiscounted future net cash flows for the Avouma field were in excess of the field’s carrying value. As a result, no impairment was required for the Avouma field, or any of our other fields in Gabon, for 2016.

Prior to selling our interests in the two wells in North Texas for $830,000, we performed an impairment test and determined that a $0.1 million impairment was required in the third quarter of 2016.

Declining forecasted oil prices in 2015 caused us to perform impairment reviews of our proved properties in each quarter of 2015 for all fields in the Etame Marin block offshore Gabon and the Hefley field in North Texas. For the Etame Marin fields, we recorded an aggregate impairment charge of $78.1 million for 2015, reducing the aggregate carrying value of these fields to an aggregate fair value of $12.7 million. For the U.S. fields, we recorded an impairment charge of $3.2 million for 2015 reducing the aggregate carrying value of the field to $1.2 million.

The substantial decline in oil prices that began in the third quarter of 2014, triggered an impairment review at December 2014. Accordingly, impairment testing was performed using the year end 2014 independently prepared reserve report. The measurement of these assets at fair value was calculated using a discounted cash flow model based on estimates of future revenues and costs associated with the fields of the Etame Marin block. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include our estimate of future crude oil and natural gas prices, production costs, and anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. For crude oil, estimates were based on NYMEX Brent Ice Intermediate prices, adjusted for quality, transportation fees, and market differential. An aggregate impairment loss of $98.3 million was recorded in 2014 to write down Etame, Ebouri, Southeast Etame and North Tchibala fields to their fair value of $41.1 million.

Undeveloped Leasehold Costs

In September 2011, we acquired an interest in the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Exploratory drilling required by terms of the acquisition was unsuccessful. Due to the sustained low oil prices and forward oil prices, we charged the full $1.2 million undeveloped leasehold to exploration expense in 2015.

Capitalized Exploratory Well Costs

The following table provides information about exploratory well costs capitalized pending the determination of proved reserves as of December 31, 2016, 2015 and 2014.

	December 31,		
(in thousands, except number of projects)	**2016**	**2015**	**2014**
Exploratory well costs capitalized for less than one year	**$ -**	$ -	$ -
Exploratory well costs capitalized for greater than one year	**-**	-	8,900
Total capitalized exploratory well costs	**$ -**	$ -	$ 8,900
Number of projects capitalized for greater than a year	**-**	-	1

At December 31, 2014, the drilling costs of the N'Gongui No. 2 discovery that was drilled in the third and fourth quarters of 2012 in the Mutamba Iroru block onshore Gabon were capitalized pending the determination of proved reserves.

Since this discovery, we have performed quarterly evaluations of the capitalized exploratory well costs for the N'Gongui No. 2 discovery to determine whether sufficient progress had been made towards development, as well as the economic and operational viability of the project. The evaluation of economic viability takes into account a number of factors, including alternative development scenarios, estimated reserves, projected drilling and development costs and projected oil price data. As a result of lower projected oil price data at September 30, 2015, the results from the economic modeling indicated that the costs for this well did not continue to meet the criteria for suspended well costs. Accordingly, all capitalized costs related to the project, including capitalized exploratory well costs were charged to exploration expense in the third quarter of 2015.

Capitalized Equipment Inventory

Capitalized equipment inventory in Gabon related to Mutamba was written off in 2015 because further drilling in the prospect is uneconomic, while equipment inventory related to the Etame Marin block was reduced in value due to obsolescence of some items.

7. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in our asset retirement obligations:

(in thousands)	**2016**	**2015**	**2014**
Balance at January 1	**$ 16,166**	$ 14,846	$ 11,464
Accretion	**903**	778	720
Additions	**-**	1,085	2,526
Acquisitions and dispositions	**1,544**	-	-
Revisions	**(1)**	(543)	136
Balance at December 31	**$ 18,612**	$ 16,166	$ 14,846

Accretion is recorded in the line item "Depreciation, depletion and amortization" on our consolidated statements of operations.

We are required under the Etame PSC to conduct regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. In January 2016, we completed a new abandonment study. The final results of the abandonment study resulted in an increase in the costs necessary to fund future abandonment obligations. During 2014, we added asset retirement obligations related to two new platforms and two wells on the Etame Marin block, based upon baseline costs from the prior study.

8. DEBT

In January 2014, we executed a loan agreement with the International Finance Corporation ("IFC credit facility") for a $65.0 million revolving credit facility, which was secured by the assets of our Gabon subsidiary, VAALCO Gabon (Etame), Inc. The borrowing base under the IFC credit facility was last re-determined effective December, 31, 2015 at $20.1 million, with $15.0 million drawn at December 31, 2015.

On June 29, 2016, we executed a Supplemental Agreement with the IFC which, among other things, amended and restated our existing loan agreement to convert the $20 million revolving portion of the credit facility, to the Term Loan with $15 million outstanding. The amended loan agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A. and is guaranteed by VAALCO as the parent company. The amended loan agreement provides for quarterly principal and interest payments on the amounts currently outstanding through June 30, 2019, with interest accruing at a rate of LIBOR plus 5.75%. The amended loan agreement also provided for an additional $5 million (the "Additional Term Loan"), which could be requested in a single draw, subject to the IFC's approval through March 15, 2017. As of the date of this filing, no borrowings have been made of the Additional Term Loan.

Compared to the $15.0 million carrying value of debt, the estimated fair value of the term loan is $15.0 million when measured using a discounted cash flow model over the life of the current borrowings at forecasted interest rates. The inputs to this model are Level 3 in the fair value hierarchy.

Covenants

Under the amended loan agreement, quarter-end net debt to EBITDAX (as defined in the loan agreement) must be no more than 3.0 to 1.0. However, the quarter-end net debt to EBITDAX limitation was raised to 5.0 to 1.0 for all periods through the end of 2016. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at each quarter end. Certain of VAALCO's subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our IFC Term Loan, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Term Loan. Forecasting our compliance with these and other financial covenants in future periods is inherently uncertain; therefore, we can make no assurance that we will be able to comply with our term loan covenants in future periods. Factors that could impact our quarter-end financial covenants in future periods include future realized prices for sales of oil and natural gas, estimated future production, returns generated by our capital program, and future interest costs, among others. We were in compliance with all financial covenants as of December 31, 2016 and 2015.

Interest

Until June 29, 2016, under the terms of the original revolving credit facility, we paid commitment fees on the undrawn portion of the total commitment. Commitment fees were equal to 1.5% of the unused balance of the senior tranche of $50.0 million and 2.3% of the unused balance of the subordinated tranche of $15.0 million when a commitment was available for utilization. With the execution of the Supplemental Agreement with the IFC on June 29, 2016, from June 29, 2016 through March 15, 2017, commitment fees are 2.3% of the undrawn Additional Term Loan of $5 million.

We capitalize interest and commitment fees related to expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest and commitment fees are capitalized only for the period that activities are in progress to bring these projects to their intended use.

The table below shows the components of the Interest expense line of our consolidated statements of operations and the average effective interest rate, excluding commitment fees, on our borrowings:

	Year Ended December 31,		
	2016	**2015**	**2014**
		(in thousands)	
Interest incurred, including commitment fees	**$ 1,353**	$ 1,496	$ 1,161
Deferred finance cost amortization	**319**	304	-
Deferred finance cost write-off due to loan modification	**869**	-	-
Capitalized interest	**-**	(771)	(1,161)
Other interest not related to debt	**75**	308	-
Interest expense	**$ 2,616**	$ 1,337	$ -
Average effective interest rate, excluding commitment fees	**5.52%**	4.09%	4.32%

9. COMMITMENTS AND CONTINGENCIES

Litigation

Butcher settlement

On October 3, 2016, the Court approved a Stipulation and Order of Dismissal entered into by the parties in a stockholder class action lawsuit against the Company and all of its directors alleging that a previously terminated shareholder rights agreement, no longer in effect, and certain provisions of the former Chief Executive Officer's and former Chief Financial Officer's employment agreements securing change-in-control severance benefits were invalid under Delaware law, case number C.A. No. 12277-VCL, filed on April 29, 2016, in the Court. After the Company and its directors moved to dismiss the lawsuit, the Plaintiff Daniel Butcher agreed to dismiss the lawsuit as moot, and the Company agreed to settle Plaintiff's application for an award of attorneys' fees, all of which were covered by our directors and officers insurance as a covered claim.

McDonough litigation

On December 7, 2016, a lawsuit was filed against the Company alleging that a former worker on the Company's oil and gas platforms off the coast of Gabon was terminated because of his age in violation of the Age Discrimination in Employment Act and the Texas Commission on Human Rights Act. The Plaintiff seeks damages for lost wages and benefits as well as attorneys' fees. The case is pending in the U.S. District Court for the Southern District of Texas and is styled as *McDonough v. VAALCO Energy, Inc.*, No. 4:17-cv-00361. In a February 2017 demand letter, the plaintiff made a demand for $361,000 to settle this claim. We intend to defend the claim vigorously, and we do not expect that this claim will have a material effect on our financial condition, results of operations or liquidity.

FPSO charter

In connection with the charter of the FPSO, we, as operator of the Etame Marin block, guaranteed the full charter payments through contract term, which goes until September 2020. At our election, the charter may be extended for two one-year periods beyond September 2020. We obtained guarantees from each of our partners for their shares of the charter payment. Our net share of the charter payment is 31.1%. Although, we believe the need for performance under the charter guarantee is remote, we have recorded a liability of $0.7 million and $1.0 million at December 31, 2016 and 2015, respectively, representing the guarantee's fair value.

Estimated future minimum obligations through the end of the FPSO charter are as follows:

(in thousands)	Full Charter Payment	VAALCO Net
Year		
2017	$ 31,294	$ 9,719
2018	31,294	9,719
2019	31,294	9,719
2020	22,634	7,029
Total	$ 116,516	$ 36,186

The charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of oil per day. VAALCO's net share of payments was $11.2 million, $10.9 million and $11.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Other lease obligations

In addition to the FPSO, we have operating lease obligations, as follows:

(in thousands)	Gross Obligation	VAALCO Net
Year		
2017	$ 8,918	$ 3,112
2018	2,419	1,035
2019	407	407
2020	340	340
2021	-	-
Thereafter	-	-
Total	$ 12,084	$ 4,894

We incurred rent expense of $4.5 million, $4.3 million and $3.9 million under operating leases for 2016, 2015 and 2014.

Rig commitment

Not included in the lease obligations for 2017 above are the remaining costs for the Constellation II drilling rig that was under a long-term contract for the multi-well development drilling campaign offshore Gabon. The campaign included the drilling of several development wells and workovers of existing wells in the Etame Marin block. As of December 31, 2015, the remaining rig commitment was $32.2 million ($9.8 million net to VAALCO). We began demobilization in January 2016 and released the drilling rig in February 2016, prior to the original July 2016 contract termination date because we no longer intended to drill any wells in 2016 on our Etame Marin block offshore Gabon. In June 2016, we reached an agreement with the drilling contractor to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We are paying this amount, plus the demobilization charges, in seven equal monthly installments which began in July 2016. As of December 31, 2016, the remaining amount to pay was $1.0 million net to VAALCO's interest. The full expense is reported in the "Other operating expense" line of our consolidated statements of operations in the year ended December 31, 2016

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC, effective in April 2016, the consortium is required to provide to the local government refinery a volume of crude at a 15% discount to market price (the "Gabon DMO"). Prior to April 2016, the discount was 25%. The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of oil refined by the refinery per year. In 2016, we paid $1.7 million for our share of the 2015 obligation. In 2015, we paid $2.3 million for our share of the 2014 obligation. In 2014, we paid $3.3 million for our share of the 2013 obligation. We accrue an amount for the Gabon DMO based on management's best estimate of the volume of crude required, because the refinery does not publish throughput figures. The amount accrued at December 31, 2016, for our share of the 2016 obligation was $1.1 million. The amount accrued at December 31, 2015, for our share of the 2015 obligation was $1.8 million. These costs are cost recoverable under the terms of the Etame PSC. Also, beginning in April 2016, the consortium is required to pay an additional 1% of revenues for provisions for diversified investments ("PID") and for investments in hydrocarbons ("PIH"). The amount accrued at December 31, 2016, for our share of the 2016 obligation was $0.4 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

Abandonment funding

As part of securing the first of two five-year extensions to the Etame field production license to which we are entitled from the government of Gabon, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over a period of ten years at 12.14% of the total abandonment estimate for the first seven years and 5.0% per year for the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2016, $27.4 million ($8.5 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on our consolidated balance sheet. Future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Audits

We are subject to periodic routine audits by various government agencies in Gabon, including audits of our petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements.

As of December 31, 2016, we had accrued $1.0 million net to VAALCO in "Accrued liabilities and other" on our consolidated balance sheet for certain payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor. While the payroll taxes were for individuals who were not our employees, we could be deemed liable for these expenses as the end user of the services provided. These liabilities were substantially resolved at the accrued amount by January 2017.

In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. We do not anticipate that the ultimate outcome of this audit will have a material effect on our financial condition, results of operations or liquidity.

Employment agreements

Our Chief Executive Officer and certain other officers have employment agreements which provide for payments of annual salary, incentive compensation and certain other benefits if their employment is terminated without cause. We have also entered into change of control agreements with certain officers providing for additional payments in the event that their employment is terminated without cause just for a specified period after a change of control of the Company.

10. DERIVATIVES AND FAIR VALUE

Throughout the year ended December 31, 2016, we executed crude oil put contracts as market conditions allowed in order to economically hedge anticipated 2016 and 2017 cash flows from crude oil producing activities. Premiums totaling $2.9 million were paid during 2016 as a result of these option agreements. While these crude oil puts are intended to be an economic hedge to mitigate the impact of a decline in oil prices, we have not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. These changes in fair value have no cash flow impact. The impact to cash flow occurs upon settlement of the underlying contract. We do not enter into derivative instruments for speculative or trading proposes.

As of December 31, 2016, we had unexpired oil puts covering 792,000 barrels of anticipated sales volumes for the period from January 2017 through December 31, 2017 at a weighted average price of $48.46. Our put contracts are subject to agreements similar to a master netting agreement under which we have the legal right to offset assets and liabilities. At December 31, 2016, the fair value of all of the put contracts were assets. We had neither derivative instruments outstanding as of December 31, 2015 nor derivative instrument activity during 2015 or 2014.

The following table sets forth, by level within the fair value hierarchy and location on our consolidated balance sheets, the reported values of derivative instruments accounted for at fair value on a recurring basis:

		Balance at December 31, 2016			
		Carrying	Fair Value Measurements Using		
Derivative Item	**Balance Sheet Line**	**Value**	**Level 1**	**Level 2**	**Level 3**

			(in thousands)		
Crude oil puts	Prepayments and other	$ 1,227	$ -	$ 1,227	$ -

The crude oil put contracts are measured at fair value using the Black's option pricing model. Level 2 observable inputs used in the valuation model include market information as of the reporting date, such as prevailing Brent crude futures prices, Brent crude futures commodity price volatility and interest rates. The determination of the put contract fair value includes the impact of the counterparty's non-performance risk.

To mitigate counterparty risk, we enter into such derivative contracts with creditworthy financial institutions deemed by management as competent and competitive market makers.

The following table sets forth the gain (loss) on derivative instruments on our consolidated statements of operations:

		Gain (Loss)		
		Year Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2016**	**2015**	**2014**
			(in thousands)	
Crude oil puts	Other, net	**$ (1,711)**	$ -	$ -

Subsequent to December 31, 2016 through March 13, 2017, we have not entered into additional derivative contracts.

11. SHAREHOLDERS' EQUITY (DEFICIT)

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2016 or 2015.
Treasury stock – In the years ended December 31, 2016, 2015 and 2014, we withheld 40,926, 120,455 and 231,142 shares, respectively, in cashless stock option exercises and to satisfy tax withholding obligations related to stock option exercises.

12. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

Our stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of our Board of Directors to issue various types of incentive compensation. Currently, we have issued stock options, restricted shares and SARs from the 2014 Long-Term Incentive Plan ("2014 Plan"). At December 31, 2016, 2,810,605 shares were authorized for future grants under this plan.

For each stock option granted, the number of authorized shares under the 2014 Plan will be reduced on a one-for-one basis. For each restricted share granted, the number of shares authorized under the 2014 Plan will be reduced by twice the number of restricted shares. We have no set policy for sourcing shares for option grants. Historically the shares issued under option grants have been new shares.

We record non-cash compensation expense related to stock-based compensation as general and administrative expense. For the years ended December 31, 2016, 2015 and 2014, non-cash compensation expense was $0.2 million, $3.8 million and $3.3 million, related to the issuance of stock options and restricted stock. Because we do not pay significant United States federal income taxes, no amounts were recorded for tax benefits.

Stock options

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors, which in the past has been a five year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. There were no cash proceeds from the exercise of stock options in 2016 and 2015. For 2014 there were cash proceeds from the exercise of stock options of $5.7 million. A portion of the stock options granted in the years ended December 31, 2016, 2015 and 2014 were vested immediately with the remainder vesting over a two-year or three-year period.

We use the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the vesting period of the option. During 2016, 2015 and 2014, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because we have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future, no expected dividend yield was input to the Black-Scholes model.

	2016	2015	2014
Weighted average exercise price - ($/share)	**$ 1.14**	$ 4.41	$ 7.05
Expected life in years	**3.0 years**	2.5 years	2.5 years
Average expected volatility	**71%**	61%	58%
Risk-free interest rate	**1.10%**	0.88%	0.52%
Weighted average grant date fair value - ($/share)	**$ 0.49**	$ 1.65	$ 2.43

Stock option activity for the year ended December 31, 2016 is provided below:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2016	4,144	$ 6.41		
Granted	1,894	1.14		
Forfeited/expired	(3,394)	5.52		
Outstanding at December 31, 2016	2,644	3.92	2.98	$ -
Exercisable at December 31, 2016	1,622	5.35	2.18	$ -

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.There were no exercises of stock options in 2016 and the intrinsic value of stock options exercised in 2015 and 2014 was $0.3 million and $4.1 million.

As of December 31, 2016, unrecognized compensation cost related to stock optionswas $0.3 million which is expected to be recognized over a weighted average period of 1.1 years.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee which is generally a three-year period, vesting in three equal parts on the first three anniversaries of the date of the grant. Share grants to directors vest immediately and are not restricted. The following is a summary of activity in unvested restricted stock in 201 6.

	Restricted Stock	Weighted Average Grant Price
Non-vested shares outstanding at January 1, 2016	419,888	$ 3.83
Awards granted	542,330	1.11
Awards vested	(488,115)	2.05
Awards forfeited	(222,250)	3.95
Non-vested shares outstanding at December 31, 2016	251,853	1.31

In the year ended December 31, 2016,40,926 shares were added to treasury due to tax withholding on vesting restricted shares.

The total vest-date fair value of restricted stock awards which vested during2016, 2015 and 2014 was $0.6 million, $0.7 million and $0.4 million, respectively. The weighted average grant date fair value per share of restricted stock awards was $1.11, $3.34 and $6.98 for the years ended December 31, 2016, 2015 and 2014, respectively.

As of December 31, 2016, unrecognized compensation cost related to restricted stocktotaled $0.3 million and is expected to be recognized over a weighted average period of 1.8 years.

Stock appreciation rights ("SARs")

SARs are granted under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan. A SAR is the right to receive a cash amount equal to the spread with respect to a share of common stock upon the exercise of the SAR. The spread is the difference between the SAR price per share specified in a SAR award on the date of grant (which may not be less than the fair market value of our common stock on the date of grant) and the fair market value per share on the date of exercise of the SAR. SARs granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of our Board of Directors.

The 815,355 SARs granted in the three months ended March 31, 2016 vest over athree-year period with a life of5 years and have a maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. Compensation payable related to these awards through December 31, 2016 is not significant.

SAR activity for the year ended December 31, 2016 is provided below:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2016	-	$ -		
Granted	815,355	1.04		
Forfeited/expired	(635,775)	1.04		
Outstanding at December 31, 2016	179,580	1.04	4.21	$ -
Exercisable at December 31, 2016	-	-	-	$ -

Other benefit plans

We sponsor a 401(k) plan, with a company match feature, for our employees. Costs incurredin the years ended December 31,2016, 2015 and 2014 for administering the plan, including the company match feature, were approximately $316,000, $444,000 and $464,000, respectively.

13. INCOME TAXES

VAALCO and its domestic subsidiaries file a consolidated United States income tax return. Certain subsidiaries' operations are also subject to foreign income taxes.

Provision for income taxes related to income (loss) from continuing operationsconsists of the following:

	Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
U.S. Federal:			
Current	**$ -**	$ -	$ -
Deferred	**-**	1,349	-
Foreign:			
Current	**9,248**	13,238	22,486
Deferred	**-**	-	-
Total	**$ 9,248**	$ 14,587	$ 22,486

The primary differences between the financial statement and tax bases of assets and liabilities resulted in deferred tax assetsassociated with continuing operations at December 31, 2016 and 2015 are as follows:

(in thousands)	2016	2015
Deferred tax assets:		
Basis difference in fixed assets	**$ 89,016**	$ 98,890
Foreign tax credit carryforward	**50,339**	58,290
Alternative minimum tax credit carryover	**1,349**	1,349
U.S. federal net operating losses	**30,230**	13,878
Foreign net operating losses	**25,543**	29,182
Asset retirement obligations	**6,514**	5,658
Basis difference in receivables	**1,824**	4,148
Other	**6,952**	(648)
Total deferred tax assets	**211,767**	210,747
Valuation allowance	**(211,767)**	(210,747)
Net deferred tax assets	**$ -**	$ -

Foreign tax credits will start to expire betweenthe years 2017 and 2024. The alternative minimum tax credits do not expire, and foreign net operating losses (“NOLs”) are not subject to expiry dates. The NOL for our United Kingdom subsidiary can be carried forward indefinitely, while the NOLs for our Gabon subsidiaries are included in the respective subsidiaries’ cost oil accounts, which will be offset against future taxable revenues. The U.S federal NOL can be carried forward until 2036. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. We do not anticipate utilization of the foreign tax credits prior to expiration nor do we expect to generate sufficient taxable income to utilize other deferred tax assets. On the basis of this evaluation, valuation allowances of $211.8 million, $210.7 million and $147.7 million have been recorded as of December 31, 2016, 2015 and 2014. Valuation allowances reduce the deferred tax asset to the amount that is more likely than not to be realized.

As a result of activity in the U.S. in 2015, a full valuation allowance was recorded related to AMT credits and our expectationis that these credits will not be utilized in the foreseeable future.

The Company recognizes the financial statement benefit of a tax position only after determining that they are more likely than not to sustain the position following an audit. The Company believes that its income tax positions and deductions will be sustained on audit and therefore no reserves for uncertain tax positions have been established. Accordingly, no interest or penalties have been accrued as of December 31, 2016 and 2015. The Company’s policy is to include interest and penalty related to unrecognized tax benefits as a component of income tax expense.

Income (loss) from continuing operations before income taxes is attributable as follows:

	Year Ended December 31,		
(in thousands)	2016	2015	2014
United States	**$ (9,893)**	$ (15,177)	$ (6,349)
Foreign	**874**	(90,790)	(44,918)
	$ (9,019)	$ (105,967)	$ (51,267)

The reconciliation of income tax expense attributable to income (loss) from continuing operationsto income tax on income (loss) from continuing operations at the U.S. statutory rate is as follows:

	Year Ended December 31,		
(in thousands)	2016	2015	2014
Tax provision computed at U.S. statutory rate	**$ (3,156)**	$ (37,089)	$ (17,944)
Foreign taxes not offset in U.S. by foreign tax credits	**6,319**	(394)	6,331
Effect of change in foreign statutory rates	**2,394**	3,014	12
Permanent differences	**4,505**	1,803	135
Foreign tax credit adjustments	**-**	-	8,417
Increase/(decrease) in valuation allowance	**(802)**	47,253	25,535
Other	**(12)**	-	-
Total income tax expense	**$ 9,248**	$ 14,587	$ 22,486

At December 31, 2016, 2015 and 2014, we were subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

Jurisdiction	Years
United States	2009-2016
Gabon	2007-2016

14. EARNINGS PER SHARE

Basic earnings per share is calculated using the average number of shares of common stock outstanding during each period. For the calculation of diluted shares, we assume that restricted stock is outstanding on the date of vesting, and we assume the issuance of shares from the exercise of stock options using the treasury stock method.

A reconciliation from basic to diluted shares follows:

	Year Ended December 31,		
	2016	2015	2014
		(in thousands)	
Basic weighted average shares outstanding	**58,384**	58,289	57,229
Effect of dilutive securities	**-**	-	-
Diluted weighted average shares outstanding	**58,384**	58,289	57,229
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**4,363**	5,586	2,329

Because we recognized net losses for the years ended December 31, 2016, 2015 and 2014, there were no dilutive securities for these years.

15. SEGMENT INFORMATION

Our operations are based in Gabon, Equatorial Guinea and the U.S. Each of our three reportable operating segments is organized and managed based upon geographic location. Our Chief Executive Officer, who is the chief operating decision maker, and management review and evaluate the operation of each geographic segment separately primarily based on Operating income (loss). The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. Revenues are based on the location of hydrocarbon production. Corporate and other is primarily corporate and operations support costs which are not allocated to the reportable operating segments.

Segment activity of continuing operations for the years ended December 31, 2016, 2015 and 2014 and long-lived assets and segment assets at December 31, 2016 and 2015 are as follows:

	Year Ended December 31, 2016				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 59,460	$ -	$ 324	$ -	$ 59,784
Depreciation, depletion and amortization	6,531	-	151	244	6,926
Impairment of proved properties	-	-	88	-	88
Bad debt expense and other	1,222	-	-	-	1,222
Operating income (loss)	3,901	(384)	(72)	(7,836)	(4,391)
Interest income (expense), net	(2,614)	-	-	1	(2,613)
Income tax expense	9,248	-	-	-	9,248
Additions to property and equipment	(4,242)	-	-	181	(4,061)

	Year Ended December 31, 2015				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 79,947	$ -	$ 498	$ -	$ 80,445
Depreciation, depletion and amortization	32,125	-	633	240	32,998
Impairment of proved properties	78,080	-	3,242	-	81,322
Bad debt expense and other	2,968	-	-	-	2,968
Operating income (loss)	(87,243)	(1,342)	(4,366)	(10,155)	(103,106)
Interest income (expense), net	(1,144)	-	-	(181)	(1,325)
Income tax expense	13,238	-	-	1,349	14,587
Additions to property and equipment	66,269	-	-	150	66,419

	Year Ended December 31, 2014				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 126,322	$ -	$ 1,369	$ -	$ 127,691
Depreciation, depletion and amortization	19,079	-	901	94	20,074
Impairment of proved properties	98,341	-	-	-	98,341
Bad debt expense and other	2,400	-	-	-	2,400
Operating income (loss)	(42,105)	(1,525)	(119)	(6,856)	(50,605)
Interest income (expense), net	42	-	-	33	75
Income tax expense	22,486	-	-	-	22,486
Additions to property and equipment	83,170	-	8	816	83,994

(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Long lived assets from continuing operations:					
as of December 31, 2016	$ 17,291	$ 10,000	$ -	$ 728	$ 28,019
as of December 31, 2015	21,329	10,000	1,234	794	33,357
Total assets from continuing operations:					
as of December 31, 2016	$ 64,478	$ 10,122	$ 382	$ 3,911	$ 78,893
as of December 31, 2015	98,858	10,200	1,470	5,045	115,573

Information about our most significant customers

Prior to the second quarter in 2014, we sold oil from Gabon under contracts with Mercuria Trading NV (“Mercuria”) beginning with the calendar year 2011. Beginning in the second quarter of 2014 and through April 2015, we switched to an agency model by contracting with a third party, The Vitol Group, to sell our crude oil on the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA (“Total”) for May through July of 2015 and Glencore Energy UK Ltd. (“Glencore”) for August of 2015 through December of 2016. The contract with Glencore U.K. ends in January 2018. Sales of oil to Glencore were 99.9% of total revenues for 2016, with less than 1% related to U.S. production.

SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Our unaudited quarterly results for years ended December 31, 2016 and 2015 were prepared in accordance with accounting principles generally accepted in the United States of America, and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature. Quarterly income per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands of dollars except per share information)			
2016:				
Total revenues	$ 10,976	$ 18,847	$ 14,635	$ 15,326
Total operating costs and expenses	24,509 (1)	14,232 (1)	10,919 (1)	14,249
Operating income (loss)	(13,515) (1)	4,615 (1)	3,690 (1)	819
Income (loss) from continuing operations	(15,430) (1)	(498) (1)	1,016 (1)	(3,355)
Income (loss) from discontinued operations	7,806 (1)	(20) (1)	(15,783) (1)	(286)
Net income (loss)	(7,624) (1)	(518) (1)	(14,767) (1)	(3,641)
Basic net income (loss) per share	$ (0.13) (1)	$ (0.01) (1)	$ (0.25) (1)	$ (0.06)
Diluted net income (loss) per share	$ (0.13) (1)	$ (0.01) (1)	$ (0.25) (1)	$ (0.06)
2015:				
Total revenues	$ 18,239	$ 27,137	$ 17,546	$ 17,523
Total operating costs and expenses	25,997 (2)	27,241 (2)	48,497 (2)	80,724 (2)
Operating income (loss)	(7,418)	(46)	(30,951)	(64,691)
Income (loss) from continuing operations	(11,146)	(4,379)	(34,521)	(70,508)
Income (loss) from discontinued operations	(27,859)	(825)	853	(10,271)
Net income (loss)	(39,005)	(5,204)	(33,668)	(80,779)
Basic net income (loss) per share	$ (0.67)	$ (0.09)	$ (0.58)	$ (1.38)
Diluted net income (loss) per share	$ (0.67)	$ (0.09)	$ (0.58)	$ (1.38)

(1) As discussed in Note 4, in the fourth quarter of 2016 we adopted ASU 2016-09 related to stock-based compensation. Stock-based compensation expense for the three months ended March 31, 2016, June 30, 2016 and September 30, 2016 have been increased (decreased) by ($0.4) million, $0.3 million and ($0.8) million, respectively, from the amounts previously reported.

(2) Significant cost and expense items that caused total operating costs and expenses to vary among the quarters are impairments of proved properties and undeveloped leasehold costs, dry hole costs, bad debt expense and inventory write-offs.

- Impairments of proved properties for the first through fourth quarters of 2015 were of $5.4 million, $5.8 million, $18.0 million, and $52.1 million. Impairments of undeveloped leasehold costs for the first through fourth quarters of 2015 were $2.7 million, $0.6 million, zero and $8.8 million.
- Dry hole costs were $9.0 million in the third quarter of 2015.
- Bad debt expense was $2.7 million in the third quarter of 2015.
- Equipment write-offs were $1.5 million in the fourth quarter of 2015.

SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

This supplemental information is presented in accordance with certain provisions of ASC Topic 932 –*Extractive Activities- Oil and Natural Gas.* The geographic areas reported are the United States (North America), which includes our producing properties in the state of Texas, and International, which includes our producing properties offshore Gabon (Africa).

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
Costs incurred during the year:	2016	2015	2014
International:		*(in thousands)*	
Exploration - capitalized	$ -	$ -	$ -
Exploration - expensed	5	170	13,666
Acquisition	5,754	-	-
Development	-	60,397	79,722
Total	$ 5,759	$ 60,567	$ 93,388
United States:			
Exploration - capitalized	$ -	$ -	$ -
Exploration - expensed	-	-	-
Acquisition	-	-	-
Development	-	-	8
Total	$ -	$ -	$ 8

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

Capitalized costs pertain to our producing activities in Gabon and the U.S and to undeveloped leasehold in Gabon, Equatorial Guinea and the U.S.

	December 31,	
	2016	2015
Capitalized costs:	*(in thousands)*	
Properties not being amortized	$ 10,000	$ 10,000
Properties being amortized (1)	399,010	423,398
Total capitalized costs	$ 409,010	$ 433,398
Less accumulated depreciation, depletion, and amortization	(380,991)	(400,041)
Net capitalized costs	$ 28,019	$ 33,357

(1) Includes $10.3 million and $8.7 million asset retirement cost in 2016 and 2015.

Results of Operations for Oil and Natural Gas Producing Activities

	International			United States		
	Year Ended December 31,			Year Ended December 31,		
	2016	2015	2014	2016	2015	2014
			(in thousands)			
Crude oil and natural gas sales	$ 59,460	$ 79,947	$ 126,322	$ 324	$ 498	$ 1,369
Production and other expense (1)	(38,160)	(42,399)	(33,755)	(166)	(171)	(467)
Depreciation, depletion and amortization	(6,531)	(32,125)	(19,079)	(151)	(633)	(901)
Exploration expenses	(5)	(9,159)	(13,594)	-	(1,250)	-
Impairment of proved properties	-	(78,080)	(98,341)	(88)	(3,242)	-
Other operating expense	(8,853)	-	-	-	-	-
Bad debt expense	(1,222)	(2,700)	(2,400)	-	-	-
Income tax	(9,248)	(13,238)	(22,486)	-	(1,349)	-
Results from oil and natural gas producing activities	$ (4,559)	$ (97,754)	$ (63,333)	$ (81)	$ (6,147)	$ 1

(1) Includes local general and administrative expenses, but excludes corporate general and administrative expenses and allocated corporate overhead.

Estimated Quantities of Proved Reserves

The estimation of net recoverable quantities of crude oil and natural gas is a highly technical process which is based upon several underlying assumptions that are subject to change. See "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates – Estimated Quantities of Net Reserves". For a discussion of our reserve estimation process, including internal controls, see "Item 1. Business – Reserves".

Proved reserves:	**Oil (MBbls)**	**Natural Gas (MMCF)**
Balance at January 1, 2014	7,232	1,333
Production	(1,351)	(227)
Revisions of previous estimates	2,312	300
Extensions and discoveries	67	-
Balance at December 31, 2014	8,260	1,406
Production	(1,659)	(181)
Revisions of previous estimates	(3,746)	(172)
Balance at December 31, 2015	2,855	1,053
Production	(1,518)	(124)
Purchases of minerals in place	308	-
Sales of minerals in place	(12)	(929)
Revisions of previous estimates	1,009	-
Balance at December 31, 2016	2,642	-

* The natural gas reserves shown as of December 31, 2016 include natural gas liquids ("NGL") expressed as gas volumes using a ratio of 4.9 MMcf to 1 MBbl of NGL.

Proved developed reserves:	**Oil (MBbls)**	**Natural Gas (MMCF)**
Balance at January 1, 2014	3,505	1,333
Balance at December 31, 2014	3,224	1,406
Balance at December 31, 2015	2,855	1,053
Balance at December 31, 2016	2,642	-

Our proved developed reserves are located offshore Gabon. In 2016, reserves increased as a result of estimated proved reserve quantities related to our acquisition of the Sojitz working interest in Etame Marin block (308 MBbl) as well as upward revisions to our estimated proved reserve quantities as a result of cost cutting efforts that had the impact of driving down operating cost projections and extending economic limits, demonstration of the effectiveness of deploying lower cost hydraulic workover units to conduct workovers during 2016 and success in production optimization produced better-than-forecasted results from the prior year's development program (1,575 MBbl). These positive developments were somewhat offset by the effects of an 18% reduction in the average realized price used to determine reserves in 2016 versus 2015 (566 MBbl). The net negative revisions of previous estimates in 2015 were primarily a result of the loss of 3.5 years of production due to lower oil prices (2,705 MBOE) and the removal of sour reserves (1,440 MBbl), partially offset by positive revisions due to the performance of wells drilled in the 2014-2015 drilling campaign exceeding expectations (370 MBbl). The net positive revisions in 2014 were primarily due to better reservoir performance at the Avouma/South Tchibala field (1,500 MBbls) and a combination of better reservoir performance from existing wells at Etame, and revisions to proved undeveloped reserves at Etame (1,100 MBbls). Ebouri proved undeveloped reserves were revised downward (300 MBbls) due to higher costs of developing the reserves rendering them uneconomic. In 2014, the extensions and discoveries were associated with the booking of the Southeast Etame/North Tchibala reserves.

We maintain a policy of not booking proved reserves on discoveries until such time as a development plan has been prepared for the discovery. Additionally, the development plan is required to have the approval of our partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

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

The information that follows has been developed pursuant to procedures prescribed U.S. GAAP and uses reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating us or our performance.

In accordance with the guidelines of the SEC, our estimates of future net cash flow from our properties and the present value thereof are made using oil and natural gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. All future development costs related to future abandonment when the wells become uneconomic to produce.

	International			United States			Total		
(In thousands)	2016	2015	2014	2016	2015	2014	2016	2015	2014
Future cash inflows	$ 106,583	$ 140,190	$ 814,059	$ -	$ 3,086	$ 9,598	$ 106,583	$ 143,276	$ 823,657
Future production costs	(71,260)	(81,973)	(307,331)	-	(1,644)	(1,475)	(71,260)	(83,617)	(308,806)
Future development costs [1]	(10,887)	(10,900)	(136,137)	-	(259)	-	(10,887)	(11,159)	(136,137)
Future income tax expense	(16,346)	(21,598)	(177,924)	-	-	(359)	(16,346)	(21,598)	(178,283)
Future net cash flows	8,090	25,719	192,667	-	1,183	7,764	8,090	26,902	200,431
Discount to present value at 10% annual rate	1,351	491	(47,528)	-	(252)	(3,516)	1,351	239	(51,044)
Standardized measure of discounted future net cash flows	$ 9,441	$ 26,210	$ 145,139	$ -	$ 931	$ 4,248	$ 9,441	$ 27,141	$ 149,387

[1] Includes costs expected to be incurred to abandon the properties.

International income taxes represent amounts payable to the Government of Gabon on profit oil as final payment of corporate income taxes, and domestic income taxes (including other expenses treated as taxes), and domestic income taxes represent amounts payable for severance and ad-valorem taxes in Texas.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

	2016	2015	2014
		(in thousands)	
Balance at beginning of period	$ 27,141	$ 149,387	$ 137,436
Sales of oil and natural gas, net of production costs	(22,198)	(40,349)	(95,973)
Net changes in prices and production costs	(25,958)	(146,536)	(28,098)
Revisions of previous quantity estimates	19,558	(104,158)	74,497
Purchases	3,400	-	2,188
Divestitures of reserves	(835)	-	-
Changes in estimated future development costs	-	(15,604)	31,686
Development costs incurred during the period	-	60,004	-
Accretion of discount	4,657	27,312	24,163
Net change of income taxes	4,052	104,303	(15,609)
Change in production rates (timing) and other	(376)	(7,218)	19,097
Balance at end of period	$ 9,441	$ 27,141	$ 149,387

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place at the end of the contract period remain the property of the Gabon government.

In accordance with the current guidelines of the SEC, estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2016, such average realized prices after adjustments used for our reserve estimates reflected consistently low prices during the year and were $40.35 per Bbl for crude oil from Gabon. Further declines in prices could result in the estimated quantities and present values of our reserves being reduced.

Under the PSC in Gabon, the Gabonese government is the owner of all oil and natural gas mineral rights. The right to produce the oil and natural gas is stewarded by the Directorate Generale de Hydrocarbures and the Production Sharing Contract was awarded by a decree from the State. Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, we were authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in 2016, the Gabonese government elected to take physical delivery of its allocated production and royalty volumes.

The consortium maintains a Cost Account, which entitles it to receive 70% of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). At December 31, 2016, there was $105.8 million in the cost account net to our interest. As payment of corporate income taxes, the consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, we only recover ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also because of the nature of the Cost Account, decreases in oil prices result in a higher number of barrels required to recover costs, therefore at higher oil prices, our net reserves after taxes would decrease, but at lower prices our Cost Recovery barrels increase.

The Etame PSC allows for the carve-out of development areas which include all producing fields in the Etame Marin block. The Etame development area has a term of 20 years and will expire in 2021. The Avouma/South Tchibala field development area has a term of 20 years and will expire in 2025. The Ebouri field development area has a term of 20 years and will expire in 2026. The balance of the Etame Marin block comprises the exploration area, which expired in July 2014. This compares to the economic end date of reserves under the current reserve report prepared by our independent reserve engineering firm of January 2019.

The Mutamba Iroru PSC entitles us to receive 70% of any future production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. The Mutamba Iroru PSC provides for all commercial discoveries to be reclassified into a development area with a term of twenty years. At December 31, 2016, we have no proved reserves related to the Mutamba Iroru block.

The PSC for Block P in Equatorial Guinea entitles us to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 10% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2016, we have no proved reserves related to Block P in Equatorial Guinea.

SCH EDULE I — PARENT COMPANY FINANCIAL STATEMENTS

VAALCO ENERGY, INC.

CONDENSED UNCONSOLIDATED BALANCE SHEETS

(in thousands of dollars, except number of shares and par value amounts)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,038	$ -
Receivables:		
Other	21	-
Prepayments and other	1,696	741
Total current assets	2,755	741
Property and equipment - successful efforts method:		
Equipment and other	1,225	1,222
	1,225	1,222
Accumulated depreciation, depletion and amortization	(497)	(428)
Net property and equipment	728	794
Other noncurrent assets:		
Restricted cash	-	1,582
Investment in subsidiaries	-	26,781
Total assets	$ 3,483	$ 29,898
LIABILITIES AND EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 310	$ 968
Accrued liabilities and other	1,024	2,854
Total current liabilities	1,334	3,822
Losses in excess of investment in subsidiaries	2,507	-
Total liabilities	3,841	3,822
Commitments and contingencies		
VAALCO Energy Inc. shareholders' equity (deficit):		
Preferred stock, none issued, 500,000 shares authorized, $25 par value	-	-
Common stock, 66,109,565 and 66,041,338 shares issued, $0.10 par value, 100,000,000 shares authorized	6,611	6,604
Additional paid-in capital	70,268	69,118
Less treasury stock, 7,555,095 and 7,514,169 shares at cost	(37,933)	(37,882)
Accumulated deficit	(39,304)	(11,764)
Total equity (deficit)	(358)	26,076
Total liabilities and equity (deficit)	$ 3,483	$ 29,898

See accompanying notes to the unconsolidated financial statements.

VAALCO ENERGY, INC.
STATEMENTS OF CONDENSED UNCONSOLIDATED OPERATIONS
(in thousand dollars)

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil and gas sales	$ -	$ -	$ -
Operating costs and expenses:			
Depreciation, depletion and amortization	244	240	94
General and administrative expense	7,935	7,550	6,740
Shareholder matters	(332)	2,372	-
Total operating costs and expenses	7,847	10,162	6,834
Other operating income, net	16	-	-
Operating loss	(7,831)	(10,162)	(6,834)
Other income (expense):			
Interest income (expense), net	(2)	(181)	33
Other, net	(1,985)	(469)	450
Equity in subsidiary earnings (losses)	(16,732)	(146,495)	(71,199)
Total other income (expense)	(18,719)	(147,145)	(70,716)
Loss before income taxes	(26,550)	(157,307)	(77,550)
Income tax expense	-	(1,349)	-
Net loss	$ (26,550)	$ (158,656)	$ (77,550)

VAALCO ENERGY, INC.
STATEMENTS OF CONDENSED UNCONSOLIDATED CASH FLOWS
(in thousands of dollars)

	Year Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net loss	$ (26,550)	$ (158,656)	$ (77,550)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	244	240	94
Deferred tax asset	-	1,349	-
Stock-based compensation	192	3,810	3,322
Equity in (earnings) losses from subsidiaries	16,732	146,495	71,199
Change in operating assets and liabilities:			
Other receivables	(21)	293	(257)
Prepayments and other	(955)	(236)	(416)
Accounts payable	(658)	753	(34)
Accrued liabilities and other	(1,855)	517	187
Net cash used in operating activities	(12,871)	(5,435)	(3,455)
CASH FLOWS FROM INVESTING ACTIVITIES			
Investment in subsidiaries	-	(7,044)	(4,371)
Return of investment in subsidiaries	12,556	-	-
Decrease in restricted cash	1,582	8,418	-
Property and equipment expenditures	(178)	(160)	(816)
Net cash provided by (used in) investing activities	13,960	1,214	(5,187)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuances of common stock	-	441	5,685
Purchases of treasury stock	(51)	-	(1,868)
Net cash provided by financing activities	(51)	441	3,817
NET CHANGE IN CASH AND CASH EQUIVALENTS	1,038	(3,780)	(4,825)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	-	3,780	8,605
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 1,038	$ -	$ 3,780

See accompanying notes to the unconsolidated financial statements.

Notes to Condensed Unconsolidated Financial Statements

Note 1- The condensed financial statements of VAALCO Energy, Inc. (the "Parent Company") have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended, because certain of VAALCO's subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our IFC Term Loan, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Term Loan. The restricted net assets associated with each of these entities exceed 25% of the consolidated net assets of VAALCO Energy, Inc. as of December 31, 2016 and 2015.

For purposes of these financial statements, the Parent Company's investments in wholly owned subsidiaries are accounted for under the equity method. Under this method, the accounts of the subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded in the unconsolidated balance sheets. The Parent Company's share of income (loss) from operations of the subsidiaries is reported as equity in subsidiary earnings, net of tax, in its unconsolidated statements of operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto, included in Part II, Item 8 of in this Annual Report on Form 10-K.

The Parent Company and certain of its subsidiaries file a consolidated tax returnfor U.S. federal income taxes. The amount of income tax expense for the Parent Company financial statements represents the amount attributable to the U.S. federal and state tax jurisdictions. Income tax expense for foreign jurisdictions has been included in the applicable subsidiary's results.

Exhibit 21.1

Subsidiary Name	Business	Ownership	Date and Place of Incorporation	
VAALCO Energy (USA), Inc.	Energy	100 %	10/16/96	Delaware
VAALCO International, Inc	Energy	100 %	7/31/02	Delaware
VAALCO Gabon (Etame), Inc.	Energy	100 %	6/14/95	Delaware
VAALCO Production (Gabon), Inc.	Energy	100 %	6/14/95	Delaware
VAALCO Angola (Kwanza), Inc.	Energy	100 %	5/15/06	Delaware
VAALCO UK (North Sea), Limited	Energy	100 %	5/22/06	England
VAALCO Energy (EG), Inc.	Energy	100 %	7/3/12	Delaware
VAALCO Energy Mauritius (EG), Limited	Energy	100 %	11/23/12*	Mauritius
VAALCO Gabon S.A.	Energy	100 %	6/4/14	Gabon

* Date of Certificate of Incorporation on Change of Name

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

VAALCO Energy, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8(No. 333-197180, 333-183515 and 333-67858) of VAALCO Energy, Inc. and subsidiaries (the “Company”) of our reports dated March 13, 2017, relating to the consolidated financial statements, financial statement schedule and the effectiveness of the Company’s internal control over financial reporting, which appear in this Form 10-K. Our report on the effectiveness of internal control over financial reporting expresses an adverse opinion on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2016.

/s/ BDO USA, LLP
Houston, Texas
March 13, 2017

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-197180, 333-183515 and 333-67858 on Form S-8 of our report dated March 16, 2016, relating to the consolidated financial statements (before retrospective adjustments to the consolidated financial statements) (not presented herein) and financial statement schedule of VAALCO Energy, Inc. and subsidiaries (the "Company"), (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's recurring losses from operations and insufficient liquidity due to depressed oil and gas prices, raising substantial doubt about its ability to continue as a going concern), appearing in this Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 13, 2017

[Letterhead of Netherland, Sewell & Associates, Inc.]

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2016. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from VAALCO Energy, Inc.'s oil and gas reserves as of December 31, 2016, 2015, and 2014 and to the inclusion of our report dated February 15, 2017, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2016. We further consent to the incorporation by reference thereof into VAALCO Energy, Inc.'s Registration Statements on Forms S-8 (Nos. 333-197180, No. 333-183515, and No. 333-67858).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons, P.E.
Danny D. Simmons P.E.
President and Chief Operating Officer

Houston, Texas
March 13, 2017

Exhibit 31.1

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cary Bounds, certify that:

(1) I have reviewed this annual report on Form 10-K of VAALCO Energy, Inc.;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date March 13, 2017

/s/ Cary Bounds
Cary Bounds
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Elizabeth D. Prochnow, certify that:

(1) I have reviewed this Annual Report on Form 10-K of VAALCO Energy, Inc.;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

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

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

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

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

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

Date March 13, 2017

/s/ Elizabeth D. Prochnow
Elizabeth D. Prochnow
Controller and Chief Accounting Officer
(Principal Financial Officer)

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of VAALCO Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Cary Bounds, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

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

Dated: March 13, 2017

/s/ Cary Bounds

Cary Bounds, Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of VAALCO Energy, Inc. (the ‘Company”) on Form 10-K for the annual period ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Elizabeth D. Prochnow, Controller and Chief Accounting Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

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

Dated: March 13, 2017

/s/ Elizabeth D. Prochnow
Elizabeth D. Prochnow, Controller and Chief
Accounting Officer

[Letterhead of Netherland, Sewell & Associates, Inc.]

Exhibit 99.1

February 15, 2017

Mr. Cary Bounds
VAALCO Gabon S.A.
9800 Richmond Avenue, Suite 700
Houston, Texas 77042

Dear Mr. Bounds:

In accordance with your request, we have estimated the proved developed reserves and future revenue, as of December 31, 2016, to the VAALCO Gabon S.A. (VAALCO) interest in certain oil properties located in the Etame Marin permit area, offshore Gabon. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by VAALCO Energy, Inc. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO Energy, Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 201 6, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net[(1)]	Total	Present Worth at 10%
Proved Developed Producing	9,068.0	2,450.1	5,250.5	6,636.1
Proved Developed Non-Producing	709.1	191.6	2,839.7	2,804.9
Total Proved Developed	9,777.1	2,641.7	8,090.2	9,441.0

(1) Net reserves are prior to deductions for "income tax barrels".

The oil volumes shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates shown in this report are for proved developed reserves. Our study indicates that there are no proved undeveloped reserves for these properties at this time. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Etame Marin permit area. Included are determinations of cost oil incorporating the unrecovered cost pool, as of December 31, 2016, and estimated cost-recoverable items scheduled to be purchased in the future. Also included are determinations of profit oil based on estimated future oil production rates.

As requested, our estimates of net reserves are prior to deductions for the portion of the government's share of the profit oil required for payment of VAALCO's Gabon income taxes, referred to as "income tax barrels". These income tax barrels have been calculated as the government's share of profit oil multiplied by VAALCO's working interest, net of government participation.

Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting all production sharing revenue paid to the Gabon government. Future net revenue is after deductions for these amounts and VAALCO's share of abandonment costs, operating expenses, and production taxes and credits for VAALCO's share of state reimbursement but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month U.S. Energy Information Administration Brent spot price for each month in the period January through December 2016. The average price of $42.90 per barrel is adjusted for quality, transportation fees, and market differentials. The average adjusted oil price weighted by production over the remaining lives of the properties is $40.35 per barrel of oil.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. As requested, operating costs are limited to direct permit- and field-level costs and VAALCO's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. It is our understanding that VAALCO has established escrow accounts for abandonment liability and expects these accounts to be fully funded by December 31, 2021. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by December 31 of the year after the economic limit date. Abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ John R. Cliver
John R. Cliver, P.E. 107216
Vice President

Date Signed: February 15, 2017

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 15, 2017

JRC:BWG

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4 10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is 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.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves -- Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and 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:

- (i) 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, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill 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.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *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 gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *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. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) 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 gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated

ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30: A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year.

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b . Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B).

a . Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c . Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are 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.

(i) Reserves on undrilled acreage shall be 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.

(ii) 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.