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, 2018

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

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

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of June 30, 2018, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $160.0 million based on a closing price of $2.73 on June 30, 2018.

As of February 27, 2019, there were outstanding 59,595,742 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Portions of the 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 are incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

TABLE OF CONTENTS

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.
- *BOPD* — One barrel of oil per day.
- *MBbl* — One thousand Bbls.
- *MBOE*— One thousand barrels of oil equivalent.
- *MBOPD* — One thousand barrels of oil per day.
- *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 (as described below) where the carried interest owner's share of costs are paid by the non-carried working interest owners. The carried costs are repaid to the non-carried working interest owners from the revenues of the carried working interest owner.
- *Gabon* — Republic of Gabon.
- *Consortium* –A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under a Production Sharing Contract with 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 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 a 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

- *Proved 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.

- *Proved undeveloped oil and natural gas reserves* — Proved undeveloped oil and natural gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(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 proved 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 proved 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* — The standardized measure of discounted future net cash flows ("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 prices 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 oil and 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.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Annual Report") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), 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 Annual Report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements regarding our 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. When we use words such as "anticipate," "believe," "estimate," "expect," "intend," "forecast," "outlook," "aim," "target," "will," "could," "should," "may," "likely," "plan," "probably," the negative of such terms or similar expressions, we are making forward-looking statements. Many risks and uncertainties that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include, but are not limited to:

- volatility of, and declines and weaknesses in oil and natural gas prices;
- the discovery, acquisition, development and replacement of oil and natural gas reserves;
- future capital requirements;
- our ability to maintain sufficient liquidity in order to fully implement our business plan;
- our ability to generate cash flows that, along with our cash on hand, will be sufficient to support our operations and cash requirements;
- our ability to attract capital;
- our ability to resolve satisfactorily matters related to our exit from Angola, including our obligations to pay the amount, as it is ultimately determined, of our liabilities to Sonangol E.P. with respect to our production sharing contract;
- our ability to pay the expenditures required in order to develop certain of our properties offshore Equatorial Guinea;
- 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;
- the impact of competition;
- weather conditions;
- the uncertainty of estimates of oil and natural gas reserves;
- currency exchange rates and regulations;
- unanticipated issues and liabilities arising from non-compliance with environmental regulations;

- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- 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 assets and properties that we acquire into our operations;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- our ability to enter into new customer contracts;
- changes in customer demand and producers' supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our joint venture owners;
- 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; and
- actions of operators of our oil and natural gas properties.

The information contained in this Annual 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 Annual 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 Annual Report.

Our forward-looking statements speak only as of the date made, and reflect our best judgment about future events and trends based on the information currently available to us. Our results of operations can be affected by inaccurate assumptions we make or by risks and uncertainties known or unknown to us. Therefore, we cannot guarantee the accuracy of the forward-looking statements. Actual events and results of operations may vary materially from our current expectations and assumptions. Our forward-looking statements, express or implied, are expressly qualified in their entirety by this "Special Note Regarding Forward-Looking Statements," which constitute cautionary statements. These cautionary statements should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances occurring after the date of this Annual Report.

EXPLANATORY NOTE-RESTATEMENT OF FINANCIAL INFORMATION

This Annual Report on Form 10-K for the year ended December 31, 2018 includes a restated balance sheet as of September 30, 2018. See Item 8, "Financial Statements and Supplementary Data" and Item 9A, "Controls and Procedures," in Part II of this Annual Report on Form 10-K, including Notes 2 and 16 of the notes to the Consolidated Financial Statements, for more information concerning this restatement. We do not plan to amend our previously filed Form 10-Q for the quarter ended September 30, 2018 in connection with this restatement. The financial information that has been previously filed or otherwise reported for this period is superseded by the information included in this Annual Report on Form 10-K.

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, the terms, "we," "us," "our," the "Company" and "VAALCO" refer to VAALCO Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires.

We are a Houston, Texas-based independent energy company engaged in the acquisition, exploration, development and production of crude oil. Our primary source of revenue has been from the Etame PSC related to the Etame Marin block located offshore Gabon in

West Africa. We also currently own interests in an undeveloped block offshore Equatorial Guinea, 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

We own producing properties and conduct operating activities offshore West Africa with a focus on maximizing the value of our Gabon resources and expanding into new development opportunities across Africa. Our financial results are heavily dependent upon the margins between prices received for our offshore Gabon oil production and the costs to find and produce such oil. In light of the volatility of oil prices over the past several years, we have focused on maximizing our margins by reducing costs, paying off debt, divesting non-core assets, minimizing capital expenditures and maintaining our existing production at optimal levels. On September 25, 2018, the term of the Etame PSC with Gabon related to the Etame Marin block located offshore Gabon was extended through 2028 with options to extend up to an additional ten years ("PSC Extension"). The PSC Extension provides us with the extended time horizon necessary to pursue developing the resources we have identified at Etame. As a result of these efforts, our financial position has improved, and we believe that we have working capital sufficient to sustain current operations and fund development projects on our Etame license in Gabon. In combination with improved oil pricing and positive production performance, the PSC Extension enabled us to increase proved reserves during 2018 by 76% to 5.4 MMBbls at December 31, 2018 which include reserves for wells we are drilling in 2019. We are seeking to further increase production and reserves by pursuing accretive growth opportunities where we can leverage our proven technical and operational capabilities in areas where we have established favorable relationships with host governments and local joint venture owners.

Our strategy is to create long-term value for all stakeholders by focusing on profitable growth from low-risk reserve development while maintaining financial discipline. Specifically, we seek to:

- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in prices;
- Manage capital expenditures related to our Etame 2019 drilling program so that expenditures can be funded by cash on hand and cash from operations;
- Continue our focus on operating safely and complying with internationally accepted environmental operating standards;
- Optimize production through careful management of wells and infrastructure, including minimizing downtime;
- Maximize our cash flow and income generation;
- Continue planning for additional development in Etame as well as future exploration and development in Equatorial Guinea;
- Preserve a strong balance sheet by maintaining conservative leverage ratios and exhibiting financial discipline;
- Opportunistically hedge against exposures to changes in oil prices; and
- Actively pursue strategic, value-accretive mergers and acquisitions of similar properties to diversify our portfolio of producing assets.

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

- Our reputation as a safe and efficient operator in Africa;
- Our history of establishing favorable operating relationships with host governments and local joint venture owners;
- 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 early insight into available opportunities.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic financial information, see Note 5 to the Financial Statements. Our only reportable operating segments are Gabon and Equatorial Guinea.

Gabon Segment

Offshore – Etame Marin Block

Our most significant asset, which accounts for approximately 100% of our current revenues, is the Etame PSC related to the Etame Marin block located offshore Gabon. The Etame Marin block covers an area of approximately 46,200 gross acres located 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 31.1%, and we are designated as the operator on behalf of a consortium of four companies (which we refer to as the "Consortium"). The fields are subject to a 7.5% back-in carried interest by the government of Gabon, which they have assigned to a third party. Our working interest decreases to 30.3% in June 2026 when the back-in carried interest increases to 10%.

Fields in the Etame Marin block There are currently five producing fields in the Etame Marin block: the Etame field which currently has five producing wells; the Avouma/South Tchibala field which currently has three producing wells; the Ebouri field which currently has one producing well; the Southeast Etame field which currently has one producing well and the North Tchibala field which has two wells producing from the Dentale formation.

Development. Following the installation of the platform for the Etame field and the platform for the Southeast Etame/North Tchibala fields in 2014, we commenced a multi-well drilling campaign which brought on five new wells in 2015. In February 2016, due to the continuing low commodity prices, 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 – Results of Operations – Year Ended December 31, 2017 Compared to Year Ended December 31, 2016*."

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 from Sojitz Etame Limited ("Sojitz"), which had an effective date of August 1, 2016. See Note 4 of the Financial Statements for further discussion.

Periodically, we perform workovers on our wells to maintain or restore production. In May 2018 we mobilized a hydraulic workover unit to the Avouma platform to replace the electronic submersible pump ("ESP") systems in the Avouma 2-H and the South Tchibala 1-HB wells and restored production to both wells in June 2018. While the hydraulic workover unit was on location, we decided to pro-actively replace the ESPs in the South Tchibala 2-H well to upgrade the system to those just installed in the other two wells. Since completion of the Avouma workovers in 2018, the new ESP systems have operated continuously as designed. Excluding the Avouma platform wells, the wells with ESPs on our three other platforms have operated without incident for up to four years.

As discussed in Note 9, the PSC Extension requires the Consortium to drill two wells and two appraisal well bores by September 16, 2020. The Consortium is planning to drill the two wells and two appraisal well bores during the second half of 2019. The Consortium may drill a third well as part of this drilling campaign.

Our current net production is averaging approximately 3,752 BOPD, up from a 3,500 BOPD average for fiscal year 2017 as a result of the workovers performed in 2018.

At December 31, 2018, we had estimated net proved reserves of 5.4 MMBbls. For 2018, our proved reserve additions of 3.7 MMBbl were equal to 270% of our 2018 Gabon production, as reflected in the reserve report issued by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). We added 1.1 MMBbls of reserves through reservoir performance additions and proved undeveloped reserves, 2.2 MMBO as a result of the PSC Extension and 0.4 MMBbls through positive pricing revisions. The increase in the average of the first-day-of-the-month prices adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was from $53.49 for the 2017 year-end report to $70.83 for the 2018 year-end report.

For 2018, our total proved reserves replacement was270% of our 2018 total net production in Gabon. See "—*Reserve Information*" below. These results occurred primarily due to (i) better-than-forecasted results for production and (ii) increased crude oil prices.

Production. Production operations in the Etame Marin block includenine 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 FPSO vessel anchored to the seabed on the block. Production from seven of our wells is aided by ESPs. We currently have twelve producing wells. 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, 2018, 2017 and 2016, aggregate production from the block was approximately 5.1 MMBbls (1.4 MMBbls net to us), 5.6 MMBbls (1.5 MMBbls net to us) and 6.2 MMBbls (1.5 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 hydrogen sulfide ("H_2S"). These wells have been excluded from the above-referenced well count. 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. Previously, these identified processing facilities were not economic; however, the Consortium will be re-evaluating this during 2019. As of December 31, 2018, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2018, we had $13.7 million in undeveloped leasehold costs related to the Etame Marin block. These costs are associated with the exploitation area expansion related to the PSC Extension.

Abandonment Costs

Under the PSC terms, the Consortium has agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. 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. The current abandonment study was completed in November 2018 resulting in estimated gross abandonment costs of approximately $61.8

million ($19.2 million, net to VAALCO) on an undiscounted basis. Through December 31, 2018, $37.4 million ($11.6 million, net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $0.8 million for 2019 through 2028. 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, 2018 and 2017 were $14.8 million and $20.2 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2018 and 2017. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Property and equipment – successful efforts method" in the line item "Wells, platforms and other production facilities" on our consolidated balance sheets as of December 31, 2018 and 2017.

Equatorial Guinea Segment

We have a 31% working interest in an undeveloped portion of a block offshore Equatorial Guinea that we acquired in 2012 (the "Block P interest"). For a number of years, the Block P interest was in suspension; however, in September 2018, the Ministry of Mines and Hydrocarbons lifted the suspension. We are awaiting the Ministry of Mines and Hydrocarbons (the "EG MMH") to approve our appointment as technical operator for Block P. Compania Nacional de Petroleos de Guinea Equatorial ("GEPetrol") will act as the administrative operator. Under the terms of lifting of the suspension, a new joint owner is expected to assume GEPetrol's working interest obligations and be presented to the EG MMH by March 28, 2019. Once the joint owner is approved, we are required to drill one exploration well within one year. While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, we would lose our interest in the license, and the associated capitalized unproved leasehold costs of $10.0 million as of December 31, 2018 would become impaired. We and our joint venture owners are evaluating 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.

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

During 2017 and 2018, Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. As a result of natural production declines, production in 2017 and 2018 was not impacted by this agreement. In December 2018, OPEC decided to further reduce overall production by 0.8 MBOPD for the first six months of 2019 versus the October 2018 levels. We have not been advised whether this will require us to reduce production for 2019. We do not expect our production or drilling plans will be impacted by the agreement because of natural declines in production and because production from the new wells would not occur until later in 2019. Nevertheless, there can be no assurance that this agreement or future agreements would not result in limitations on our production.

DRILLING ACTIVITY

We have had no drilling activity during the period from January 1, 2016 through December 31, 2018. As discussed above, we are planning to drill up to two to three wells, and two appraisal well bores during 2019 at the Etame Marin block.

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the PSC and the total number of productive oil and natural gas wells as of December 31, 2018:

	International	
Acreage in thousands	**Gross**	**Net**
Developed acreage	28.7	8.9
Undeveloped acreage	74.5	23.1 (1)
Total acreage	103.2	32.0
Productive oil wells	12.0 (2)	3.7

(1) We have net undeveloped acreage of 5,400 acres offshore Gabon and 17,700 acres offshore Equatorial Guinea.

(2) Excludes the Etame 8-H, the Etame 5-H and two Ebouri field wells shut-in due to the presence of high levels of H_2S.

RESERVE INFORMATION

Estimated Reserves and Estimated Future Net Revenues

Reserve Data

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

2018, the average of such price used for our reserve estimates was $70.83 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2017 of $53.49 per Bbl.

Reserves reported below consist of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa. There have been no estimates of total proved net oil or natural 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. The table below sets forth our estimated net proved reserve quantities for the years ended December 31, 2018, 2017, and 2016 as prepared by NSAI, independent petroleum engineers.

	As of December 31,		
	2018	2017	2016
		(in thousands)	
Crude oil			
Proved developed reserves (MBbls)	3,388	3,049	2,642
Proved undeveloped reserves (MBbls)	1,982 —	—	—
Total proved reserves (MBbls)	5,370	3,049	2,642

Standardized Measure and Changes in Proved Reserves

The following table shows changes in total proved reserves for all presented years:

	Proved Reserves		
	Crude Oil (MBbls)	Natural Gas (MMCF)	Oil Equivalent (MBOE)
		(in thousands)	
Balance at January 1, 2016	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
Production	(1,518)	—	(1,518)
Revisions of previous estimates	1,925	—	1,925
Balance at December 31, 2017	3,049	—	3,049
Production	(1,369)	—	(1,369)
Additions associated with PSC extension	2,235	—	2,235
Revisions of previous estimates	1,455	—	1,455
Balance at December 31, 2018	5,370	—	5,370
Standardized measure of discounted future net cash flows as of December 31, 2018	$ 80,057	$ 22,490	$ 9,441

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 an increase or decrease in the projected economic life of such properties resulting from changes in product prices. Crude oil amounts shown for Gabon are recoverable under a PSC, and the reserves in place at the end of the contract remain the property of the Gabon government. The reserves at the end of the contract are not included in the table above.

We do not reflect proved reserves on discoveries in our reserve estimates until such time as a development plan has been prepared and approved by our joint owners and the government, where applicable. The proved undeveloped reserves at December 31, 2018 in the table above are related to the two wells which the Consortium plans to drill in 2019.

In 2018, we replaced 270% of production by adding a total of 3.7 MMBbls of proved reserves including 2.2 MMBbls of proved reserves additions as a result of extending the Etame PSC in Gabon. VAALCO also added 1.1 MMBbls of proved reserves as a result of improved reservoir performance and another 0.4 MMBbls of proved reserves as a result of higher oil pricing.

The upward revision of the previous estimates of proved reserves in 2017 were primarily a result of improved well performance and to a lesser degree the higher average crude oil prices.

The upward revision of the previous estimates of proved reserves 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 in November 2016. The lower average crude oil price used for 2016 estimates only partially offset the favorable impacts of well performance, operating cost reductions, and the other factors. Sales of minerals in place in 2016 was related to the sale of the Hefley field in the U.S. in December 2016.

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.

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. At December 31, 2018, we had PUDs associated with the two wells which the Consortium plans to drill in 2019. As a result of crude oil prices in 2017 and 2016, our PUDs were uneconomic to develop at prices calculated in accordance with SEC guidelines. Accordingly, we had no PUDs recorded at December 31, 2017 and 2016.

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 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 the 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 2018, 2017, and 2016 operations are shown in the tables below. There were no natural gas sales in 2018 and 2017.

	Year Ended December 31,				
	2018	2017	2016		
	Oil and Condensate (MBbl)	Oil and Condensate (MBbl)	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)
Net production sold					
International	1,442	1,423	1,485	1,485	—
U.S.	—	—	24	3	124
Total production sold	1,442	1,423	1,509	1,488	124

	Year Ended December 31,				
	2018	2017	2016		
	Oil and Condensate ($/Bbl)	Oil and Condensate ($/Bbl)	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)
Average sales price					
International	$ 70.32	$ 52.58	$ 40.17	$ 40.17	$ —
U.S.	—	—	13.50	23.54	1.95
Overall average sales price	70.32	52.58	39.62	40.13	1.95

	Year Ended December 31,		
	2018	2017	2016
Average production expense per MBOE			
International	$ 28.03	$ 27.90	$ 25.22
U.S.	—	—	5.58
Overall average production expense	28.03	27.90	24.91

DISCONTINUED OPERATIONS-ANGOLA

On September 30, 2016, we notified Sonangol P&P, our joint venture owners, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have closed 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. Our SEC filings are 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 charters for our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee as well as our Code of Business Conduct and Ethics, Corporate Governance Principles and Code of Ethics for the CEO and Senior Financial Officers. 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

For the years ended December 31, 2018, 2017 and 2016, 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 purchaser was Glencore Energy UK Ltd. ("Glencore") for these periods and through January 2019. Sales of oil to Glencore were approximately 100% of revenues sold to customers for 2018. We have signed a new contract with Mercuria Energy Trading SA which covers sales from February 2019 through January 2020.

The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of "Profit Oil" determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. Prior to February 1, 2018, the government of Gabon did not take any of its share of Profit Oil in-kind. Beginning February 1, 2018, the government of Gabon elected to take its Profit Oil in-kind with the only lifting made in September 2018.

EMPLOYEES

As of December 31, 2018, we had 108 full-time employees, 75 of whom were located in Gabon. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. We believe relations with our 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 various operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, 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 into 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 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 Gabon 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 Gabon. Pursuant to Article 4 of the Hydrocarbons Law, Gabon 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 Gabon 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 Gabon'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 the entry into force of the Hydrocarbons Law under its Article 254.

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

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 Etame 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 Etame PSC. Pursuant to the Etame PSC, these conditions may not be adversely altered during the term of the agreement; however, we can make no assurance that the interpretation of the Hydrocarbon Law will not adversely affect our operations or assets in Gabon.

As discussed in *"— Segment and Geographic Information—Gabon Segment—Offshore – Etame Marin Block—Production*," production from the Etame block is stored in an FPSO which we lease from a third party. Over the past 15 years, this vessel was imported under a temporary import license. In November 2018, a permanent import license for the FPSO was issued.

Equatorial Guinea

Our exploration and production activities in Equatorial Guinea are subject to the applicable regulations of the country. 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 Equatorial Guinea.

All hydrocarbons existing in Equatorial Guinea's onshore territory, as well as in its sovereign and jurisdictional waters, are Gabon property and part of the public domain. The monetization of such hydrocarbons is to be pursued exclusively by Gabon under its constitution, which reserves the exploitation of mineral and hydrocarbons resources exclusively to Gabon and the public sector. However, the constitution also provides that Gabon can delegate to, grant a concession to or associate itself with private parties for purposes of exploration and production activities in the manner and cases set forth by law.

Private oil companies have been allowed to conduct petroleum operations in Equatorial Guinea through PSCs signed by the minister responsible for petroleum operations on behalf of Gabon. PSCs are subject to ratification by the President of the Republic and become effective only on the date the contractor is notified of presidential ratification. The powers to sign and amend PSCs and supervise their performance belong to the ministry responsible for petroleum operations. In addition, GEPetrol, holds, manages and takes participations in petroleum activities on behalf of Gabon.

In 2006, the Parliament of Equatorial Guinea passed a new hydrocarbons law ("2006 Hydrocarbons Law") which superseded the previous 1981 Hydrocarbons Law, as amended in 2000, incorporating not only the regime applicable to the exploration, appraisal, development and production of hydrocarbons, but also rules on their transportation, distribution, storage, preservation, decommissioning, refining, marketing, sale and other disposal. The 2006 Hydrocarbons Law contains provisions on a number of aspects concerning exploration and production operations and contracts, such as national content obligations, unitization, transfers and abandonment. The 2006 Hydrocarbons Law has increased the Gabon's benefits under exploration and production contracts and, to a certain extent, has reduced the ability of the minister responsible for petroleum operations to negotiate some contractual terms (e.g. by imposing minimum royalties of 13%).

The 2006 Hydrocarbons Law expressly repeals any conflicting provisions of equal or lower standing, in particular the 1981 Hydrocarbons Law, and provides that all petroleum operations are subject thereto. However, the 2006 Hydrocarbons Law does not amend any conflicting clauses of existing PSCs which continue to govern the performance of petroleum operations. In 2013, the 2006 Hydrocarbons Law was complemented by the Petroleum Regulations, which address in further detail a broad range of matters concerning upstream, midstream and downstream activities.

The Block P PSC was entered into before the publication of the 2006 Hydrocarbons Law and Petroleum Regulations. The Etame PSC contains a stabilization clause, whereby in case the economic balance of Gabon or the contractor under the Etame PSC is materially altered as a result of any change in laws, orders or regulations in Equatorial Guinea, the parties should make the necessary adjustments to the relevant provisions to the Etame PSC, observing the principle that the affected party should be restored to substantially the same economic conditions if such changes had not occurred. However, we can make no assurance that the interpretation of the 2006 Hydrocarbons Law or Petroleum Regulations will not adversely affect our operations or assets in Equatorial Guinea.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations, including laws and regulations in Gabon and Equatorial Guinea, governing the discharge of materials into the environment or otherwise relating to environmental protection or pollution control. 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 for 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. 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, however, what effect future environmental regulation or legislation, enforcement policies, or claims for damages to property, employees, other persons, the environment or natural resources could have on us.

In addition, a number of governmental bodies have adopted, have introduced or are contemplating regulatory changes in response to the potential impact of climate change and to the lobbying effects of various climate change non-governmental organizations. Legislation and increased regulation regarding climate change could impose significant costs on us, our venture joint owners, 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 or impact the marketability of oil and natural gas. 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.

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 U.S.

Currently, we conduct no operations in the U.S. and have only inconsequential interests in two U.S. properties. 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 laws and regulations. In the U.S., environmental laws and regulations are administered by the U.S. Environmental Protection Agency ("EPA") and counterpart state agencies.

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; 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. 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

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 soil or groundwater 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.

The Oil Pollution Act of 1990

The Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the Clean Water Act ("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.

Other Environmental Regulation in the U.S.

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 which may limit disposal options. Although most oil and natural gas wastes are exempt from regulation as a hazardous waste under RCRA at the federal level, not all comparable state statutes have provided the same exemption, and certain wastes that we previously generated may have been subject to RCRA or comparable state statutes.

The 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 as well as fill materials, into state waters and waters of the U.S., a term broadly defined but which remains subject to litigation and rulemaking over its scope.

The Clear Air Act and analogous state laws govern emissions from sources of air pollution. These laws may require new and modified sources of air pollutants to obtain permits prior to commencing construction and may require the installation of stringent control methods.

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.

Most environmental laws and regulations provide for fines, penalties and injunctive relief for violations of their requirements. Some laws and regulations also provide for citizen suits, which allow a private citizen to sue to enforce the requirements of the applicable regulatory program.

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 Annual 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 Annual Report 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 2016, the spot price per Bbl of Brent crude oil ranged from a high of $55 to a low of $26. During 2017, the spot price per Bbl of Brent crude oil ranged from a high of $67 to a low of $44. During 2018, the spot price per Bbl of Brent crude oil ranged from a high of $86 to a low of $51. The average price at which we sold our crude oil in 2018 was $70.32 per Bbl compared to 2017 was $52.58 per Bbl and $40.13 per Bbl in 2016. 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 which is impacted by economic growth rates, 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, 2018, we had 2.0 MBbl of PUDs while we had no PUDs at December 31, 2017. As discussed above in "Item 1. Business– *Segment and Geographic Information — Gabon Segment*", we are planning to drill two wells and two appraisal well bores in the second half of 2019.

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 natural 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 natural 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 and/or prolonged periods of historically low oil and 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, failure of wells drilled in similar formations, equipment failures (such as ESPs), delays in the delivery of equipment and availability of drilling rigs.

All of the value of our production and 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 12 producing wells. Production from these fields constituted 100% of our total production for the year ended December 31, 2018. In addition, at December 31, 2018, 100% of our total 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 our properties are concentrated in the same geographic area, many of our rights under the Etame PSC 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.

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 could have a material effect on our business, financial condition, results of operations and liquidity.

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 joint owners to pay for 66.43% of the offshore Gabon budget. With respect to Block P, we are awaiting approval by the EG MMH of our appointment as technical operator. Once we are appointed, we will rely on the timely payment of cash calls by our joint owners to pay for 61% of the Equatorial Guinea budget. The continued economic health of our joint owners 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 joint owners 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. 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 decline in our estimated net proved reserves, and would likely adversely affect our business, financial condition and results of operations.

If oil and natural gas prices decline materially, we may be required to take 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. During 2016, 2017 and 2018, no impairments were necessary with respect to the Etame Marin block. Material declines in crude oil prices will cause the estimated quantities and present values of our reserves to be reduced, which may necessitate write-downs. Material declines in crude oil prices could also cause a decline in the estimated fair value and/or the economic viability of projects associated with our undeveloped leasehold costs for the Etame Marin block and the Equatorial Guinea Block P resulting in write-downs of these costs.

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 certain of our Etame Marin block wells create 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, decisions of international financial institutions such as the International Monetary Fund and the Banking Commission of Central Africa, changes in laws and regulations relating to banking institutions and deposit accounts, requirements to hold funds in government-owned banks and the risk of foreign banking institution failure, possible changes in government personnel, the development of new administrative policies, practices and political conditions that may affect the enforcement or administration of laws and regulations, adoption of new or amendments to regulatory regimes for foreign investment, uncertainties as to whether the laws and regulations will be applicable in any particular circumstance, uncertainty as to whether VAALCO will be able to demonstrate to the satisfaction of the applicable governing authorities, compliance with governmental or contractual requirements 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's oil company 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. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are working with the current representatives to resolve the audit findings. While we do not anticipate that we will be subject to assessments related to this audit that 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.

Additionally, on February 28, 2019, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account advised that the bank regulator required transfer of the funds to the Central Bank for "CEMAC" (the Central African Economic and Monetary Community), of which Gabon is one of the six member states, for conversion to local currency with a credit back to the Gabonese branch in local currency. See risk factor, "*Our results of operations, financial conditions and cash flows could be adversely affected by changes in currency exchange rates and regulations*." Amendment 5 to the PSC provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Contractor shall no longer be held liable for the obligation to remediate the sites.

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.

Beginning in February 2018, Gabon elected to take the portion of their oil attributable to Profit Oil in-kind rather than our continuing to market their share of production on their behalf. Gabon took their Profit Oil in-kind with the September 2018 lifting. We anticipate that this will continue to 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-border violence, 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. For example, in January 2019, there was a failed military coup attempt in Gabon. While the disruption from this event was minimal and was suppressed quickly, these types of events can expand quickly into more serious and costly ones and could adversely affect Gabon's economy and government.

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, coups, wars, 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 joint owners 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.

Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.

As an oil producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows.

Cybersecurity attacks in particular are becoming more sophisticated. We rely extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our technologies systems and networks, and those of our business associates may become the target of cybersecurity attacks, including without limitation malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems and materially and adversely affect us in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on our ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- unauthorized access to and release of personal identifying information of employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations; and
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

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, among other things:

- 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 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 better able to: competitively bid for and purchase oil and natural gas properties; evaluate, bid for and purchase a greater number of properties than our financial or human resources permit; continue drilling during periods of low oil and natural gas prices; contract for drilling equipment; and 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.

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, 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, 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 provedoil 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, 2018, 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 2018 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 and cash flows could be adversely affected by changes in currency exchange rates and by currency regulations.

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 financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk.In addition, currency devaluation can result in a loss to us for any deposits of that currency, such as our deposits in the Etame PSC abandonment account which have been converted from U.S. dollar to Gabon local currency. See the risk factor "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." Hedging foreign currencies can be difficult, especially if the currency is not actively traded.

We are also subject to risks relating to governmental regulation of foreign currency, which may limit our ability to:

- Transfer funds from or convert currencies in certain countries;
- Repatriate foreign currency received in excess of local currency requirements; and
- Repatriate funds held by our foreign subsidiaries to the US. at favorable tax rates.

Acquisitions and divestitures of properties and businesses subject us to additional 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 or divestitures. 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 and businesses, 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 or businesses. 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 activities, 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 the 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.

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 properties which have future abandonment obligations 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 in the “Asset retirement obligation” line item of our 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 most recent abandonment study completed in November 2018, the abandonment cost estimate used for this purpose is approximately $61.8 million ($19.2 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 —Abandonment Costs*,” 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.

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 (“PSA”), we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We are currently engaged in discussions with newly appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be substantially less than the accrued amount.

Due to the uncertainties as to the ultimate outcome, we have reflected an accrual of $15.0 million for a potential payment as of December 31, 2018 and 2017, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. 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.

We could incur substantial penalties for not fulfilling our work commitment under the terms of the PSC Extension.

We, along with the Consortium, are required within a period of two years from September 17, 2018, to drill two wells and two appraisal well bores. We plan to fulfill this commitment with the wells and appraisal well bores planned in connection with the 2019 drilling campaign at an estimated cost of $61.2 million ($20.5 million, net to VAALCO). If we are unable to do so, we will be required to pay within thirty days of the expiration date of such period, an indemnity equal to the cost of works not carried out, as required with the work commitment.

We could lose our interest in Block P if the terms for lifting the suspension are not met.

Under the terms of lifting of the suspension, a new joint owner is expected to assume GEPetrol's working interest obligations and be presented to the EG MMH by March 28, 2019. Once the joint owner is approved, we are required to drill one exploration well within one year. While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, we would lose our interest in the license, and the associated capitalized unproved leasehold costs of $10.0 million as of December 31, 2018 would become impaired.

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 have entered into derivatives arrangements with respect to a portion of our expected production. Our derivative contracts consist of a series of commodity swap contracts and are limited in duration. Our derivatives program may be inadequate to protect us from significant 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, we may 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. 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.

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 *"Item 9A. Controls and Procedures. Management's Annual Report on Internal Control over Financial Reporting"*, our management concluded that a control deficiency constituted a material weakness in our internal control over financial reporting. Wedetermined that we did not maintain effective internal control over financial reporting with respect to the effectiveness and timeliness of the performance of a control related to the evaluation and reporting of the income tax effects related to significant, unusual and infrequent transactions This material weakness resulted in a correction of an error in the condensed consolidated financial statements included in our quarterly report on Form 10-Q for September 30, 2018.

Our management, including our Chief Executive Officer and Chief 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. 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

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are currently involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Ite m 4. Mine Safety Disclosures

Not applicable.

PA RT II

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.

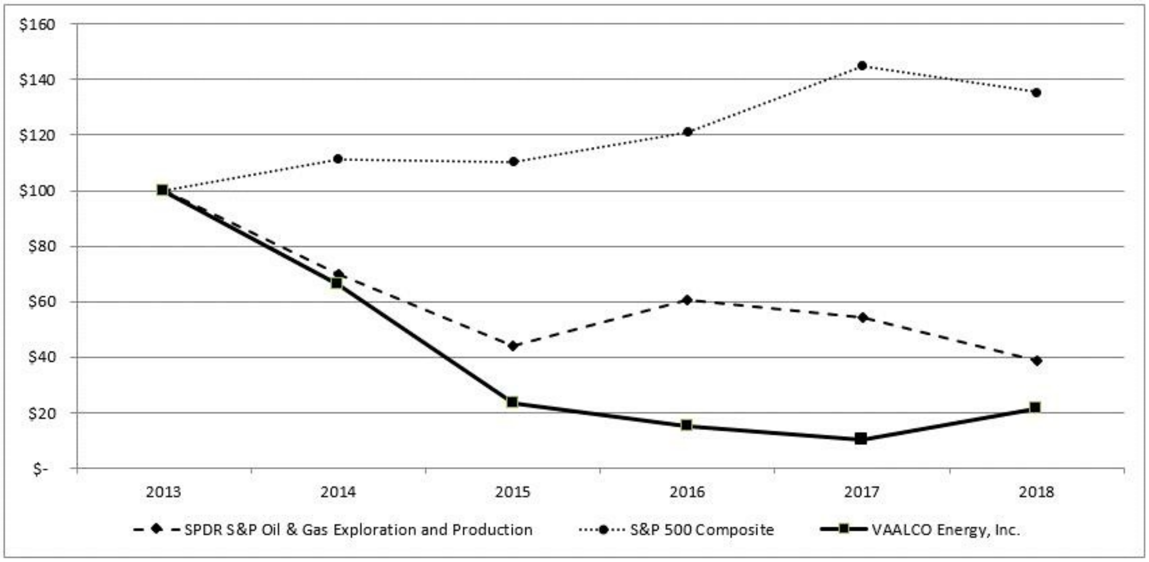
As of February 27, 2019, based upon information received from our transfer agent and brokers and nominees, there were approximately44 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in "street" names.

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, 2013 in our common stock and in each index, and that all dividends are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.



	2013	2014	2015	2016	2017	2018
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 70	$ 44	$ 60	$ 54	$ 39
S&P 500 Composite	$ 100	$ 111	$ 110	$ 121	$ 145	$ 136
VAALCO Energy, Inc.	$ 100	$ 66	$ 23	$ 15	$ 10	$ 21

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2018 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 15 to the Financial Statements for additional information on stock-based compensation.

Plan Category	Number of security 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 issues under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	2,414,448	$ 1.58	1,112,527
Equity compensation plans not approved by security holders	186,706	0.96	—
Total	2,601,154	$ 1.54	1,112,527

Issuer Purchases of Equity Securities for Year Ended December 31, 2018

During 2018, we acquired 26,421 shares to satisfy tax withholding obligations related to restricted stock vestings.

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, 2018, 2017, 2016, 2015 and 2014 has been derived from the 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 accompanying notes. The following information is not necessarily indicative of future results.

	Years Ended December 31,				
	2018	2017	2016	2015	2014
(In thousands, except per share amounts)					
Total revenues	$ 104,943	$ 77,025	$ 59,784 (1)	$ 80,445 (1)	$ 127,691
Income (loss) from continuing operations	98,728 (2)	10,272	(18,267) (2)	(120,554) (2)	(73,753) (2)
Basic income (loss) from continuing operation per share attributable to common shareholders	1.65	0.17	(0.31)	(2.07)	(1.29)
Diluted income (loss) from continuing operations per share attributable to common shareholders	1.63	0.17	(0.31)	(2.07)	(1.29)
Net property, plant and equipment	52,724	23,221	28,019	33,357 (3)	93,479
Total assets	166,312 (3)	79,633	81,032	123,958 (3)	248,849 (3)
Total long-term liabilities	15,441	22,756	25,836	31,166	29,846

(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) Income from continuing operations in 2018 was primarily impacted by a $56.9 million deferred tax benefit primarily related to the re-evaluation of the realizability of certain tax assets. Losses from continuing operations in 2016 was primarily impacted by decreased revenues due to prevailing low oil and natural gas prices. Losses from continuing operations in 2014 and 2015 were primarily impacted by decreased revenues and oil and natural gas property impairments.

(3) Total assets increased substantially in 2018 due to the recognition of certain deferred tax benefits. Net property, plant and equipment and Total assets decreased substantially in 2014 and 2015 due to impairments.

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

The following management's discussion and analysis describes the principal factors affecting our capital resources, liquidity, and results operations. This management's discussion and analysis should be read in conjunction with the accompanying consolidated financial statements and related notes, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this Annual Report. Our website address is www.vaalco.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Annual Report.

INTRODUCTION

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 4 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa.

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 volatile and subject to fluctuations based on a number of factors beyond our control. Over the past few years, we have focused on reducing costs and maximizing cash flow as well as divesting non-core assets. To preserve our cash flow, during 2016, 2017 and 2018, we conducted no drilling activities and extinguished our debt. As a result of improved commodity prices and the PSC Extension, we currently intend to drill two to three wells and two appraisal well bores during 2019 at the Etame Marin block in Gabon.

CURRENT DEVELOPMENTS

During 2017 through the third quarter of 2018, the global oil supply and demand were close to being balanced; however, late in the fourth quarter of 2018, prices were adversely impacted by concerns about oversupplies in the markets. ICE Dated Brent crude oil prices fluctuated between $44 and $67 per Bbl from January 2017 through December 2017. During year ended December 31, 2018, ICE Dated Brent crude oil prices have fluctuated between $51 and $86 per Bbl with the December 31, 2018 price of $51 per Bbl, 24% lower than the December 31, 2017 price of $67 per Bbl.

On May 22, 2018, we terminated the amended term loan agreement with theInternational Finance Corporation (the "IFC") ("Amended Term Loan Agreement") by prepaying the outstanding principal and accrued interest. We did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

On September 17, 2018, the PSC Extension to the Etame PSC providing for the extension of our three Exclusive Exploitation Authorizations for the Etame Marin block through September 16, 2028, with the right for two additional five-year extension periods, was executed. See *"Item 1. Business – Segment and Geographic Information – Gabon Segment."*

At December 31, 2018, we reported a 76% increase in estimates for proved reserves over reserves reported at December 31, 2017. See "*Item 1. Business – Reserve Information"* for further discussion.

We are preparing for a drilling program for the second half of 2019 on the Etame Marin block which will include two to three wells and two appraisal well bores.

Effective as of September 2018, the suspension of the license for Block P offshore Equatorial Guinea has been lifted and we are awaiting the EG MMH to approve our appointment as technical operator for Block P.

DISCONTINUED OPERATIONS-ANGOLA

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). Our working interest is 40%, and it carries Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to our decision to withdraw from Angola, we have closed 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 consolidated financial statements for all periods presented.

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of September 30, 2018 and December 31, 2017, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. We are engaged in discussions with representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be less than the accrued amount.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2018, 2017 and 2016 are as follows:

	Year Ended December 31,			Increase (Decrease) in the Year	
	2018	**2017**	**2016**	**2018 Over (Under) 2017**	**2017 Over (Under) 2016**
			(in thousands)		
Net cash provided by (used in) operating activities before change in operating assets and liabilities	**$ 44,342**	$ 19,312	$ (6,470)	$ 25,030	$ 25,782
Net change in operating assets and liabilities	**(6,114)**	(5,932)	(5,895)	(182)	(37)
Net cash provided by (used in) continuing operating activities	**38,228**	13,380	(12,365)	24,848	25,745
Net cash provided by (used in) discontinued operating activities	**(1,052)**	(4,423)	12,286	3,371	(16,709)
Net cash provided by (used in) operating activities	**37,176**	8,957	(79)	28,219	9,036
Net cash used in continuing investing activities	**(14,127)**	(1,499)	(16,506)	(12,628)	15,007
Net cash used in discontinued investing activities	—	—	—	—	—
Net cash used in investing activities	**(14,127)**	(1,499)	(16,506)	(12,628)	15,007
Net cash used in financing activities	**(8,680)**	(5,815)	(144)	(2,865)	(5,671)
Net change in cash, cash equivalents and restricted cash	**$ 14,369**	$ 1,643	$ (16,729)	$ 12,726	$ 18,372

The increase in net cash provided by our operating activities for the year ended December 31, 2018 compared to the same period of 2017 includes a $25.0 million increase in cash generated by continuing operations before change in operating assets and liabilities which in large part was the result of higher 2018 crude oil prices and lower operating costs and other expenses. The decrease in net cash provided by our operating assets and liabilities was $0.2 million lower than the decrease for 2017. The net change in operating assets and liabilities of $ (6.1) million for the year ended December 31, 2018 included a $7.7 million increase in trade and other receivables, a decrease in "Accounts payable" of $3.4 million, offset primarily by a $2.5 million decrease in crude oil inventory and a $2.8 million increase in foreign taxes payable. The net change in operating assets and liabilities of $(5.9) million for the year ended December 31, 2017 included a reduction of "Accounts payable" of $7.3 million, an increase in VAT receivable of $3.0 million and an increase crude oil inventory of $2.4 million offset by a reduction in trade receivables of $3.2 million, an increase in "Accrued liabilities and other" of $2.0 million, and a reduction in prepayments and other of $1.6 million.

The increase in net cash provided by our operating activities for 2017 compared to 2016 was primarily related to a $25.8 million increase in cash generated by continuing operations before changes in operating assets and liabilities which in large part was the result of higher 2017 crude oil prices and lower operating costs and expenses. Net cash provided by our operating assets and liabilities increased by $1.0 million from 2016 to 2017. This overall improvement was offset by a reduction in cash generated by our discontinued operation from 2016 to 2017 of $16.7 million. The decrease in cash generated by discontinued operations was the result of a benefit received in 2016 of $19.0 million from our Angolan joint interest owner in payment of joint owner receivables.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. These expenditures were significantly lower in 2016 and 2017. No drilling activities were conducted during these two years as we conserved cash during the recent period of low crude oil prices. For 2018, the cash basis expenditures of $14.1 million, were primarily related to the $11.8 million signing bonus paid in connection with the PSC Extension and $2.3 million paid for equipment and enhancements. For 2017, the cash basis expenditures of $1.8 million for property and equipment was primarily related to equipment and other enhancements. During 2016, these expenditures on a cash basis (including expenditures attributable to discontinued operations) were $8.7 million. See "—*Capital Expenditures*" below for further discussion.

There were no other significant investing activities in 2018 and 2017. For 2016, other significant investing activities included $5.7 million for the November 2016 acquisition of Sojitz's 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 joint venture owner, Sonangol P&P, were obligated to perform exploration activities in Angola.

Net cash used in financing activities during the year ended December 31, 2018 included $9.2 million in principal payments on debt which was extinguished in May 2018. With respect to cash flows related to financing activities, for 2017, we had cash increases from $4.2 million of borrowings and cash decreases from $10.0 million of debt repayments under the Amended Term Loan Agreement. There were no significant financing activities in 2016.

Capital Expenditures

At December 31, 2018, pursuant to the PSC Extension, we had commitments for capital expenditures related to the drilling of two wells and two appraisal well bores at an estimated cost of approximately $61.2 million ($20.5 million, net to VAALCO), by September 16, 2020. We anticipate drilling these wells and a possible third well in the second half of 2019. The third well is subject to approval by the joint venture owners and the government of Gabon. We expect any capital expenditures made during 2019 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances.

During 2018, we had accrual basis capital expenditures attributable to continuing operations of $20.0 million compared to $1.7 million and $(4.1) million accrual basis capital expenditures in 2017 and 2016, respectively. 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 2018 were attributable to the PSC Extension signing bonus, equipment and enhancements. Capital Expenditures in 2017 and 2016 were mainly for equipment and enhancements.

Contractual Obligations

The table below provides aggregated information on our net share of cash obligations and commitments at December 31, 2018:

	2019	2020	2021	2022	2023	Thereafter	Total
Operating leases and other obligations (1)	10,345	7,479	—	—	—	—	17,824
Drilling and other commitments (2)	20,500	400	—	—	—	—	20,900
Abandonment funding (3)	763	763	763	763	763	3,818	7,633
Total cash obligations	$ 31,608	$ 8,642	$ 763	$ 763	$ 763	$ 3,818	$ 46,357

(1) 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 12 to the Financial Statements for further information.
(2) Associated with the execution of the PSC Extension. See Note 12 to the Financial Statements for further information.
(3) See "Abandonment funding" in Note 12 to the Financial Statements for further information.

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 November 2018, the abandonment cost estimate used for this purpose is approximately $61.8 million ($19.2 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 item on our consolidated balance sheet. Through December 31, 2018, $37.4 million ($11.6 million, net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of our consolidated balance sheet. The next funding is expected to be $2.5 million ($0.8 million, net to VAALCO) and paid in December 2019; however, future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

In connection with the PSC Extension, the Consortium is committed to drill two wells and two appraisal well bores by September 16, 2020. The estimated cost for these wells is approximately $61.2 million ($20.5 million, net to VAALCO). In addition to the drilling commitment, the Consortium is required to pay $5.0 million ($1.7 million, net to VAALCO) in cash to the government of Gabon following the end of these drilling activities. We have accrued for our $1.7 million share of this obligation as of December 31, 2018. See "*Item 1. Business – Segment and Geographic Information – Gabon Segment*" from above for further discussion.

Under the terms of lifting of the suspension, a new joint owner is expected to assume GEPetrol's working interest obligations and be presented to the EG MMH by March 28, 2019. Once the joint owner is approved, we are required to drill one exploration well within one year. While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, we would lose our interest in the license, and the associated capitalized unproved leasehold costs of $10.0 million as of December 31, 2018 would become impaired.

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each of the three exploration wells for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2018 and 2017, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. We are currently engaged in discussions with recently appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be less than the accrued amount.

Regulatory and Joint Interest 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, 2018, we had accrued $1.3 million, net to VAALCO, in "Accrued liabilities and other" on our consolidated balance sheet for these various audits by governmental agencies in Gabon. See Note 12 to the Financial Statements for further discussion.

Commodity Price Hedging

The price we receive for our oil significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Oil commodities and, therefore their prices can be subject to wide fluctuations in response to relatively minor changes in supply and demand. We believe these prices will likely continue to be volatile in the future.

Due to the inherent volatility in oil prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a significant portion of our anticipated oil production. These instruments allow us to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The instruments provide only partial protection against declines in oil prices and may limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge physical production by individual hydrocarbon product in order to protect returns. The counterparty to our derivative transactions is a major oil company's trading subsidiary, and our derivative positions are generally reviewed on a monthly basis. We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in net income (loss). We record such derivative instruments as assets or liabilities in the consolidated balance sheet. We do not anticipate any substantial changes in our hedging policy.

For the period from January to June 2019, we have commodity swap contracts for approximately 172,000 barrels of oil. As of December 31, 2018, the estimated mark-to-market value of our commodity price swaps in 2019 was an asset of $3.5 million, which is recorded on the "Prepayments and other" line item on our consolidated balance sheet.

Capital Resources

Credit Facility

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 $20.0 million of the revolving portion of the credit facility, to an Amended Term Loan Agreement with $15.0 million outstanding at that date. Historically, our primary sources of capital have been cash flows from operating activities, borrowings under the Amended Term Loan Agreement with the IFC and cash balances on hand. On May 22, 2018, we terminated the Amended Term Loan Agreement by prepaying the outstanding principal and accrued interest. The Company did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

Cash on Hand

At December 31, 2018, we had unrestricted cash of $33.4 million.The unrestricted cash balance included $0.3 million of cash attributable to non-operating joint venture owner advances. As operator of the Etame Marin and Mutamba Iroru blocks in Gabon, we enter into project related activities on behalf of our working interest joint owners. We generally obtain advances from joint owners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations for the foreseeable future.

We currently sell our crude oil production from Gabon under a term contract that began in February 2019 and ends in January 2020. Pricing under the contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Liquidity

As discussed above, our revenues, cash flow, profitability, oil and gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices. After a period of low commodity prices, oil and natural gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and natural gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. As discussed above, we are committed to drill two wells and two appraisal well bores in the Etame block by September 16, 2020 and one exploration well in Block P by September 2020. We expect any capital expenditures made during 2019 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances. We believe that at current prices, cash generated from continuing operations, together with cash on hand at December 31, 2018, are adequate to support our operations and cash requirements during 2019 and through March 31, 2020.

At December 31, 2018, we had 5.4 MMBbls of estimated net 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 September 2028 with rights for two five-year extension periods. 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.

OFF BALANCE SHEET ARRANGEMENTS

In connection with the charter of the FPSO (*see "FPSO charter" in* Note 12 to the Financial Statements), we, as operator of the Etame Marin block, guaranteed all of the lease payments under the charter through its contract term, which expires in 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 joint owners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.3 million and $0.5 million as of December 31, 2018 and 2017, respectively, representing the guarantee's fair value. The guarantee of the offshore Gabon FPSO lease has $53.9 million in remaining gross minimum obligations for the total amount of charter payments at December 31, 2018. There have been no other material off-balance sheet arrangements entered into since December 31, 2018.

RESULTS OF OPERATIONS

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

We reported net income for the year ended December 31, 2018 of $98.2 million, compared to a net income of $9.7 million for the same period of 2017. These amounts of income were inclusive of our loss from discontinued operations for the year ended December 31, 2018 of $0.5 million, and loss from discontinued operations for the year ended December 31, 2017 of $0.6 million. Further discussion of results by significant line item follows.

Oil and natural gas revenues increased $27.9 million, or approximately 36.2%, during the year ended December 31, 2018 compared to the same period of 2017. Based on the average realized oil prices in the table below, a substantial portion of the increase in revenue is related to realized oil prices, which are due to increases in the Dated Brent market price.

The revenue changes between the years ended December 31, 2018 and 2017 identified as related to changes in price or volume are shown in the table below:

(in thousands)		
Price	$	25,578
Volume		999
Other		1,341
	$	27,918

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

	Year Ended December 31,	
	2018	2017
Gabon net oil production (MBbls)	1,369	1,518
International net oil sales (MBbls)	1,442	1,423
Average realized oil price ($/Bbl)	$ 70.32	$ 52.58
Average Dated Brent spot* ($/Bbl)	71.34	54.10

*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 in each quarter from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given quarter. We made fifteen liftings for the year ended December 31, 2018 and twelve liftings for the year ended December 31, 2017. Volumes in 2017 were adversely impacted because the last lifting of 2017 was not completed until January 1, 2018. Net revenues of $6.5 million associated with these net volumes were reported as revenue in 2018. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 34,811 and 122,076 barrels at December 31, 2018 and 2017, respectively.

Production expenses were substantially unchanged increasing $0.7 million, or approximately 1.8%, in the year ended December 31, 2018 compared to the same period of 2017 workover costs increased $0.7 million and we saw increases in fuel and personnel costs. These increases were offset by lower FPSO charter fees and customs costs.

Depreciation, depletion and amortization decreased $0.9 million, or approximately 13.3%, in the year ended December 31, 2018 compared to the same period of 2017 due to the favorable impact of depleting our costs over a higher reserve base as a result of improvements in estimated reserves identified at December 31, 2018.

Gain on revision of asset retirement obligations for the year ended December 31, 2018 resulted from the downward revisions of $6.5 million to the liability for asset retirement obligations which exceeded the net book value of the related assets by $3.3 million. See Note 11 to the Financial Statements for further discussion.

General and administrative expenses increased $1.0 million, or approximately 9.8% in the year ended December 31, 2018 compared to the same period of 2017. Stock-based compensation expense increased by $1.3 million during the year ended December 31, 2018 as compared to comparable 2017 period. This increase was primarily related to fair value adjustments associated with stock appreciation rights. Other increases in personnel costs were offset by lower professional services and other taxes in 2018 compared to the 2017 period.

Bad debt expense and other decreased for the year ended December 31, 2018 compared to the same period of 2017 primarily as a result of bad debt recovery related to VAT as a result of payments received during the period.

Interest expense, net for the year ended December 31, 2017 relates to our Amended Term Loan Agreement with the IFC as discussed in Note 13 to the consolidated financial statements and to interest on taxes other than income taxes. On May 22, 2018, we terminated the Amended Term Loan Agreement by prepaying the outstanding principle and accrued interest. The year ended December 31, 2018 includes interest expense related to the IFC loan prior to the May 2018 prepayment offset by interest income on the investment of excess cash.

Other, net for the year ended December 31, 2018 consists primarily of $4.3 million in gains on derivative instruments (see Note 10 to the Financial Statements) and other income offset by foreign currency losses. In 2017 Other, net consists primarily of $2.6 million related to the reversal of accruals for liabilities we are no longer obligated to pay as well as $0.5 million in foreign currency gains offset by $1.0 million losses on derivative instruments.

Income tax expense (benefit) for the year ended December 31, 2018includes a $56.9 million deferred tax benefit primarily related to the recognition of deferred tax assets and the reversal of valuation allowances on deferred tax assets as discussed in Note 8 to the Financial Statements. In addition to the deferred tax benefit, we had a current tax provision of $13.7 million during the year ended December 31, 2018. As a result of the 2017 tax legislation enacted in the U.S., we expect to realize the benefit from our AMT credit carryforwards. The valuation allowance recorded related to AMT credits in previous periods was reversed in 2017 with the exception for a reserve for the possible sequestration of the credits. The $1.3 million reversal was recorded as a deferred income tax benefit during the fourth quarter of 2017. In addition to the deferred tax benefit, we had a current tax provision of $11.6 million during the year ended December 31, 2017. The current tax provision in both periods is primarily attributable to our operations in Gabon and is higher in 2018 than income tax for the comparable 2017 period as a result of higher revenues.

Loss from discontinued operations for the years ended December 31, 2018 and 2017 are attributable to our Angola segment as discussed further in Note 4 to the Financial Statements. The losses from discontinued operations for the 2018 and 2017 are related to ongoing administrative costs.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

We reported net income for the year ended December 31, 2017 of $9.7 million, compared to a net loss of $26.6 million for the same period of 2016. These amounts of income (loss) were inclusive of our loss from discontinued operations for the year ended December 31, 2017 of $0.6 million, and loss from discontinued operations for the year ended December 31, 2016 of $8.3 million. Further discussion of results by significant line item follows.

Oil and natural gas revenues increased $17.2 million, or approximately 28.8%, during the year ended December 31, 2017 compared to the same period of 2016. A substantial portion of the increase in revenue is related to higher realized oil prices as well as higher revenue attributable to the Sojitz acquisition. This was offset in part by an overall decrease in sales volumes. Volumes in 2017 were adversely impacted because the last lifting in 2017 was not completed until January 1, 2018. Net revenues of $6.5 million associated with net volumes delivered to the buyer on January 1, 2018 of 95,525 barrels are reported as revenue in 2018.

The revenue changes between the years ended December 31, 2017 and 2016 identified as related to changes in price or volume are shown in the table below:

(in thousands)		
Price	$	17,716
Volume		(2,850)
Other		2,375
	$	17,241

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

	Year Ended December 31,			
		2017		2016
Gabon net oil production (MBbls)		1,518		1,515
International net oil sales (MBbls)		1,423		1,485
U.S. net oil sales (MBbls)		—		3
Net oil sales (MBbls)		1,423		1,488
Net natural gas sales (MMcf)		—		124
Net oil equivalents (MBOE)		1,423		1,509
Average realized oil price ($/Bbl)	$	52.58	$	40.13
Average realized natural gas price ($/Mcf)		—		1.95
Weighted average realized price ($/BOE)		52.58		39.62
Average Dated Brent spot* ($/Bbl)		54.10		43.67

*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 in each quarter from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given quarter. We made twelve liftings for the years ended December 31, 2017 and 2016. However, volumes for the last lifting in 2017 were low as they exclude the volumes lifted on January 1, 2018 when the lifting operation was completed. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 122,076 and 46,700 barrels at December 31, 2017 and 2016, respectively.

Production expenses increased $2.1 million, or approximately 5.6%, in the year ended December 31, 2017 compared to the same period of 2016, primarily as a result of our increased ownership in the Etame Marin block of Gabon after the November 2016 Sojitz acquisition, costs related to the planned maintenance turnaround, asset integrity work performed during the planned turnaround, costs associated with certain regulatory requirements in Gabon, custom fees and FPSO cost escalation.

Depreciation, depletion and amortization decreased $0.5 million, or approximately 6.8%, in the year ended December 31, 2017 compared to the same period of 2016 due to the favorable impact of depleting our costs over a higher reserve base as a result of improvements in estimated reserves identified at December 31, 2016 and at December 31, 2017 as well as lower lifting volumes.

General and administrative expenses increased $0.8 million, or approximately 8.5% in the year ended December 31, 2017 compared to the same period of 2016. The increase was primarily related to higher legal fees and accounting and auditing costs offset by lower personnel costs. Personnel costs were lower in 2017 as a result of lower wages and employee benefits offset by higher stock-based compensation as 2016 included the benefit related to employee forfeitures.

Bad debt expense and other for the years ended December 31, 2017 and 2016 related to Value Added Tax ("VAT") which the government of Gabon is required to reimburse but has not yet paid.

Other operating expenses for the year ended December 31, 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilization and release of the contracted drilling rig. 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. In January 2017, we resolved the Gabon payroll tax obligation.

General and administrative related to shareholder matters for the year ended December 31, 2016 reflects offsetting insurance proceeds related to costs incurred on shareholder litigation that was settled in 2016.

Other, net for the year ended December 31, 2017 consists primarily of $2.6 million related to the reversal of accruals for liabilities we are no longer obligated to pay as well as $0.5 million in foreign currency gains. These gains were offset by $1.0 million of losses on derivative instruments (see Note 10 to the Financial Statements). In 2016, Other, net included $1.7 million in derivative instrument losses. Foreign currency losses were minimal in 2016.

Interest expense for the years ended December 31, 2017 and 2016 relates to borrowings under our Amended Term Loan Agreement as discussed in Note 13 to the Financial Statements.

Income tax expense increased $1.1 million in the year ended December 31, 2017 compared to the same period of 2016. Income tax expense in both periods is primarily attributable to our operations in Gabon and is higher in 2017 than income tax for the comparable 2016 period primarily as a result of higher revenues. In addition, income tax expense was offset by a $1.3 million benefit from the reversal of valuation allowances on deferred tax assets attributable to Alternative Minimum Tax ("AMT") credit carryforwards in the U.S. as a result of expected refunds of these credits under the tax legislation enacted in December 2017.

Loss from discontinued operations for the year ended December 31, 2017 is attributable to our Angola segment as discussed further in Note 4 to the Financial Statements. The loss from discontinued operations for the 2017 period is related to ongoing administrative costs. For the year ended December 31, 2016 we reported loss from discontinued operations primarily as a result of $3.1 million of income tax on financial gains and $15.0 million accrual for the potential payment of drilling obligations offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the 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 2 to the Financial Statements for our accounting policy elections.

Income Taxes

Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination and evaluation of our annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which we operate and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or our level of operations or profitability in each jurisdiction would impact our tax liability in any given year. We also operate in foreign jurisdictions where the tax laws relating to the oil and natural gas industry are open to interpretation which could potentially result in tax authorities asserting additional tax liabilities. While our income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized, and when it is estimated to be more-likely-than-not that all or some portion of specific deferred tax assets, such as net operating loss carry forwards or foreign tax credit carryovers, will not be realized, a valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered are earnings generated in previous periods, forecasted earnings and the expiration period of carryovers. As of December 31, 2018, the Company had deferred tax assets of $131.0 million primarily attributable to Gabon and U.S. federal taxes related to basis differences in fixed assets, foreign tax credit carryforwards, and net operating loss carryforwards as well as foreign net operating losses for foreign jurisdictions for which a valuation allowance of $90.9 million had been recorded.

In certain jurisdictions, we may deem the likelihood of realizing deferred tax assets as remote where we expect that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. For such jurisdictions, we have not recognized deferred tax assets. Should our expectations change regarding the expected future tax consequences, we may be required to record additional deferred taxes that could have a material effect on our consolidated financial position and results of operations. As of December 31, 2018, we had not recognized deferred tax assets related to our Mutamba branch in Gabon and our United Kingdom subsidiary.

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.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

We review our oil and natural gas producing properties for impairmenton 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 Etame Marin and Equatorial Guinea.

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 asset 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 3 to the Financial Statements.

Ite m 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Foreign Exchange Rate 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 are denominated in the local currency (the Central African CFA Franc, or XAF), and our VAT receivable as well as certain liabilities in Gabon are also denominated in XAF. 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 in response to international political conditions, general economic conditions and other factors beyond our control. As of December 31, 2018, we had net monetary assets of $1.4 million (XAF 784.5 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $0.1 million reduction in the value of these net assets. For 2018, we had expenditures of approximately $11.7 million denominated in XAF.

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 may continue. Sustained low oil and natural gas prices or a resumption of the 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. If oil sales were to remain constant at the most recent annual sales volumes of 1,442 MBbls, a $5 per Bbl decrease in oil price would be expected to cause a $7.2 million decrease per year in revenues and operating income (loss) and a $6.1 million decrease per year in net income (loss).

During the year ended December 31, 2018, we had oil swaps outstanding and during the years ended December 31, 2017 and 2016, we had oil puts outstanding. These instruments were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes. See "*Commodity Price Hedging*" above.

It em 8. Consolidated 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*".

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

None.

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 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, one material weakness was identified in our internal control over financial reporting. As a result of the material weakness, 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, 2018. Notwithstanding the identified material weakness, 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 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 our 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.

At December 31, 2018, management determined that the effectiveness and timeliness of the performance of the control related to the review and analysis of the impact on income taxes of significant, unusual and infrequent transactions was not operating effectively.

Based on our evaluation of the material weakness 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, 2018 as a result of the material weakness.

BDO USA, LLP, our independent registered public accounting firm, has issued their report on our internal control over financial reporting as of December 31, 2018, which is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Except for the change in internal control related to the material weakness identified above, there have been no changes in our internal control over financial reporting during the three months ended December 31, 2018 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 WEAKNESS

In response to the identified material weakness at December 31, 2018, our management, with oversight from our Audit Committee, is taking action to remediate the material weakness described above by hiring an additional permanent employee with tax expertise as well as expertise in accounting for income taxes.

Management is committed to improving our internal control processes and believes that the additional resources described above should assist in remediating 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 weakness or modification to the remediation procedures described above may be necessary. We expect to complete the required remedial actions during 2019. While senior management and our Audit Committee are closely monitoring the implementation of the remediation plan, we cannot provide any assurance that the 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 weakness that exists at December 31, 2018 will continue to exist.

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting

We have audited VAALCO Energy, Inc. and subsidiaries' (the "Company's") internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2018 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) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 8, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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 Annual 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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. 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 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. A material weakness regarding management's failure to design and maintain controls over certain aspects of the accounting for income taxes has been identified and described in management's assessment. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2018 consolidated financial statements, and this report does not affect our report dated March 8, 2019 on those consolidated financial statements.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/BDO USA, LLP

Houston, Texas
March 8, 2019

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 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, 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 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, 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 proxy statement for our 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, and which is incorporated herein by reference. Please see "*Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases 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 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, 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 2019 annual meeting, which will be filed with the SEC within 120 days of December 31, 2018, 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	Restated 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, dated September 26, 2015 (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).
10.1	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.1 to the Company’s Annual Report on Form 10-K filed on March 7, 2018, and incorporated 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	Addendum No. 5 to Exploration and Production Sharing Contract, dated April 25, 2016, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.6 to the Company’s Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.7	Addendum No. 6 to Exploration and Production Sharing Contract, dated September 17, 2018, between the Republic of Gabon, VAALCO Gabon S.A., Addax Petroleum Oil & Gas Gabon, Sasol Gabon S.A. and Petroenergy Resources Corporation (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q filed on November 7, 2018, and incorporated herein by reference).
10.8	Deed of Novation of Trustee and Paying Agent Agreement, dated June 22, 2017, between VAALCO Gabon (Etame), Inc., VAALCO Gabon S.A. and The Bank of New York Mellon, London Branch as the Trustee and Paying Agent and the Account Bank (filed as Exhibit 10.7 to the Company’s Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.9	Production Sharing Agreement, dated November 1, 2006, between Sociedade Nacional de Combustíveis de Angola - Empresa Pública (Sonangol, E.P.), VAALCO Angola (Kwanza), Inc., Sonangol Pesquisa e Produção, SA and InterOil Exploration & Production ASA (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).
10.10*	VAALCO Energy, Inc. 2012 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K/A filed on May 30, 2012, and incorporated herein by reference).
10.11*	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).
10.12*	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).

10.13*	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).
10.14*	Form of 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).
10.15*	Amended and Restated Executive Employment Agreement between VAALCO Energy, Inc. and Cary Bounds, effective as of December 29, 2016 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 3, 2017, and incorporated herein by reference).
10.16*	Amended and Restated Executive Employment Agreement between VAALCO Energy, Inc. and Philip F. Patman, Jr., effective as of April 17, 2017 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 18, 2017, and incorporated herein by reference).
10.17	Settlement Agreement, dated as of December 22, 2015, among VAALCO Energy, Inc., Group 42, Inc. 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 (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).
10.18	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).
10.19*	VAALCO Energy, Inc. 2016 Stock Appreciation 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).
10.20*	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 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

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, 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 8, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 8th day of March 2019, 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/ PHILIP F. PATMAN, JR. Philip F. Patman, Jr.	Chief Financial Officer (Principal Financial Officer)
By:	/s/ ELIZABETH D. PROCHNOW Elizabeth D. Prochnow	Chief Accounting Officer (Principal Accounting Officer)
By:	/s/ ANDREW L. FAWTHROP Andrew L. Fawthrop	Chairman of the Board and Director
By:	/s/ A. JOHN KNAPP, JR. A. John Knapp, Jr.	Director
By:	/s/ STEVEN J. PULLY Steven J. Pully	Director

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for each of the three years ended in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, 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 8, 2019 expressed an adverse opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, TX

March 8, 2019

VA ALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 33,360**	$ 19,669
Restricted cash	**804**	842
Receivables:		
Trade	**11,907**	3,556
Accounts with joint venture owners, net of allowance of $0.5 million for both years presented	**949**	3,395
Other	**1,398**	100
Crude oil inventory	**785**	3,263
Prepayments and other	**6,301**	2,791
Current assets - discontinued operations	**3,290**	2,836
Total current assets	**58,794**	36,452
Oil and natural gas properties and equipment - successful efforts method:		
Wells, platforms and other production facilities	**409,487**	389,935
Work-in-progress	**519**	—
Undeveloped acreage	**23,771**	10,000
Equipment and other	**9,552**	9,432
	443,329	409,367
Accumulated depreciation, depletion, amortization and impairment	**(390,605)**	(386,146)
Net oil and natural gas properties, equipment and other	**52,724**	23,221
Other noncurrent assets:		
Restricted cash	**920**	967
Value added tax and other receivables, net of allowance of $2.0 million and $6.5 million, respectively	**2,226**	6,925
Deferred tax assets	**40,077**	1,260
Abandonment funding	**11,571**	10,808
Total assets	**$ 166,312**	$ 79,633
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 8,083**	$ 11,584
Accounts with joint venture owners	**304**	—
Accrued liabilities and other	**14,138**	12,991
Foreign taxes payable	**3,274**	—
Current portion of long term debt	—	6,666
Current liabilities - discontinued operations	**15,245**	15,347
Total current liabilities	**41,044**	46,588
Asset retirement obligations	**14,816**	20,163
Other long term liabilities	**625**	284
Long term debt, excluding current portion, net	—	2,309
Total liabilities	**56,485**	69,344
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, none issued, 500,000 shares authorized, $25 par value	—	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 67,167,994 and 66,443,971 shares issued, 59,595,742 and 58,862,876 shares outstanding, respectively	**6,717**	6,644
Additional paid-in capital	**72,358**	71,251
Less treasury stock, 7,572,251 and 7,581,095 shares, respectively, at cost	**(37,827)**	(37,953)
Retained earnings (deficit)	**68,579**	(29,653)
Total shareholders' equity	**109,827**	10,289
Total liabilities and shareholders' equity	**$ 166,312**	$ 79,633

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, 2018	2017	2016
Revenues:			
Oil and natural gas sales	**$ 104,943**	$ 77,025	$ 59,784
Operating costs and expenses:			
Production expense	**40,415**	39,697	37,586
Exploration expense	**14**	7	5
Depreciation, depletion and amortization	**5,596**	6,457	6,926
Gain on revision of asset retirement obligations	**(3,325)**	—	—
General and administrative expense	**11,398**	10,377	9,561
Impairment of proved properties	—	—	88
Other operating expense	—	—	8,853
General and administrative related to shareholder matters	—	—	(332)
Bad debt (recovery) expense and other	**(77)**	452	1,222
Total operating costs and expenses	**54,021**	56,990	63,909
Other operating income (expense), net	**365**	(84)	(266)
Operating income (loss)	**51,287**	19,951	(4,391)
Other income (expense):			
Interest expense, net	**(145)**	(1,414)	(2,613)
Other, net	**4,332**	2,113	(2,015)
Total other income (expense)	**4,187**	699	(4,628)
Income (loss) from continuing operations before income taxes	**55,474**	20,650	(9,019)
Income tax expense (benefit)	**(43,254)**	10,378	9,248
Income (loss) from continuing operations	**98,728**	10,272	(18,267)
Loss from discontinued operations	**(496)**	(621)	(8,283)
Net income (loss)	**$ 98,232**	$ 9,651	$ (26,550)
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.65**	$ 0.17	$ (0.31)
Loss from discontinued operations	**(0.01)**	(0.01)	(0.14)
Net income (loss) per share	**$ 1.64**	$ 0.16	$ (0.45)
Basic weighted average shares outstanding	**59,248**	58,717	58,384
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.63**	$ 0.17	$ (0.31)
Loss from discontinued operations	**(0.01)**	(0.01)	(0.14)
Net income (loss) per share	**$ 1.62**	$ 0.16	$ (0.45)
Diluted weighted average shares outstanding	**59,997**	58,720	58,384

See notes to consolidated financial statements

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

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance at January 1, 2016	65,621	(7,514)	$ 6,562	$ 70,150	$ (37,882)	$ (12,754)	$ 26,076
Shares issued - stock-based compensation	489	—	49	(49)	—	—	—
Stock-based compensation expense	—	—	—	167	—	—	167
Treasury stock acquired	—	(41)	—	—	(51)	—	(51)
Net loss	—	—	—	—	—	(26,550)	(26,550)
Balance at December 31, 2016	66,110	(7,555)	6,611	70,268	(37,933)	(39,304)	(358)
Shares issued - stock-based compensation	334	—	33	6	—	—	39
Stock-based compensation expense	—	—	—	977	—	—	977
Treasury stock acquired	—	(26)	—	—	(20)	—	(20)
Net income	—	—	—	—	—	9,651	9,651
Balance at December 31, 2017	66,444	(7,581)	6,644	71,251	(37,953)	(29,653)	10,289
Shares issued - stock-based compensation	**724**	**35**	**73**	**287**	**177**	—	**537**
Stock-based compensation expense	—	—	—	**820**	—	—	**820**
Treasury stock acquired	—	**(26)**	—	—	**(51)**	—	**(51)**
Net income	—	—	—	—	—	**98,232**	**98,232**
Balance at December 31, 2018	**67,168**	**(7,572)**	**$ 6,717**	**$ 72,358**	**$ (37,827)**	**$ 68,579**	**$ 109,827**

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2018	**2017**	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ 98,232**	$ 9,651	$ (26,550)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Loss from discontinued operations	**496**	621	8,283
Depreciation, depletion and amortization	**5,596**	6,457	6,926
Gain on revision of asset retirement obligations	**(3,325)**	—	—
Other amortization	**417**	369	1,424
Deferred taxes	**(56,907)**	(1,260)	—
Unrealized foreign exchange (gain) loss	**834**	(576)	(32)
Stock-based compensation	**2,306**	1,098	192
Commodity derivatives (gain) loss	**(3,520)**	1,032	1,711
Cash settlements (paid)/received on matured derivative contracts, net	**(744)**	195	—
Bad debt (recovery) expense	**(77)**	452	1,222
Other operating (income) loss, net	**(570)**	84	266
Operational expenses associated with equipment and other	**1,604**	1,189	—
Impairment of proved properties	**—**	—	88
Change in operating assets and liabilities:			
Trade receivables	**(8,351)**	3,195	(1,050)
Accounts with joint venture owners	**2,747**	(108)	16,284
Other receivables	**(1,330)**	(43)	(18)
Crude oil inventory	**2,478**	(2,350)	(192)
Prepayments and other	**420**	1,646	517
Value added tax and other receivables	**(777)**	(3,025)	(1,937)
Accounts payable	**(3,409)**	(7,297)	(15,459)
Foreign taxes payable	**2,751**	—	—
Accrued liabilities and other	**(643)**	2,050	(4,586)
Other long-term assets	**—**	—	546
Net cash provided by (used in) continuing operating activities	**38,228**	**13,380**	**(12,365)**
Net cash provided by (used in) discontinued operating activities	**(1,052)**	(4,423)	12,286
Net cash provided by (used in) operating activities	**37,176**	8,957	(79)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions	—	64	(5,692)
Property and equipment expenditures	**(14,127)**	(1,813)	(8,705)
Proceeds from the sale of oil and gas properties	—	250	830
Premiums paid for put options	**—**	—	(2,939)
Net cash used in continuing investing activities	**(14,127)**	(1,499)	(16,506)
Net cash used in discontinued investing activities	**—**	**—**	**—**
Net cash used in investing activities	**(14,127)**	(1,499)	(16,506)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**544**	39	—
Treasury shares	**(58)**	(20)	(51)
Debt issuance costs	—	—	(93)
Debt repayment	**(9,166)**	(10,001)	—
Borrowings	**—**	4,167	—
Net cash used in continuing financing activities	**(8,680)**	(5,815)	(144)
Net cash used in discontinued financing activities	**—**	**—**	**—**
Net cash used in financing activities	**(8,680)**	(5,815)	(144)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**14,369**	1,643	(16,729)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF YEAR	**32,286**	30,643	47,372
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF YEAR	**$ 46,655**	$ 32,286	$ 30,643

See notes to consolidated financial statements.

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Supplemental disclosure of cash flow information:			
Interest paid	**$ 257**	$ 997	$ 1,326
Income taxes paid in cash	**$ 2,720**	$ 15,153	$ 9,210
Income taxes paid in-kind with oil	**$ 9,385**	$ —	$ —
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at year end	**$ 2,138**	$ 455	$ 2,282
Oil and natural gas property additions paid with non-cash assets	**$ 4,197**	$ —	$ —
Gross-up of oil and natural gas properties by establishment of deferred tax liability	**$ 18,613**	$ —	$ —
Asset retirement obligations	**$ (6,527)**	$ 600	$ 1,543
Restricted stock vestings issued out of treasury	**$ (177)**	$ —	$ —

See notes to consolidated financial statements.

1. ORGANIZATION

VAALCO Energy, Inc. (together with its consolidated subsidiaries “we”, “us”, “our”, “VAALCO” or the “Company”) is a Houston, Texas-based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 4 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. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation – The accompanying consolidated financial statements (“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 basisAll intercompany transactions within the consolidated group have been eliminated in consolidation.

Correction of error – Deferred tax liability related to oil and gas properties – Subsequent to the issuance of our condensed consolidated financial statements for the three months ended September 30, 2018, we identified an error related to a gross up in oil and natural gas properties for the establishment of a deferred tax liability of $18.6 million as a result of differences between the book basis attributable to leasehold costs incurred in connection with the extension of the Etame Marin block production sharing contract with Gabon entered into on September 25, 2018 and the tax basis in these costs. To correct this error, we recorded an adjustment as of September 30, 2018 which resulted in an increase in capitalized oil and gas property costs of $18.6 million and a decrease in net deferred tax assets of $18.6 million. This correction only impacted long-term assets and had no impact on total assets or working capital in our consolidated balance sheet. This correction also had no impact on the unaudited condensed consolidated statements of operations or cash flows for the periods ended September 30, 2018. See Note 16 for the restated condensed consolidated balance sheet.

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentation related to the adoption of Accounting Standards Update (“ASU”) No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (“ASU 2016-18”) These reclassifications did not affect our consolidated financial results. See Note 3 – New Accounting Standards for further information associated with ASU 2016-18.

Use of estimates – The preparation of the Financial Statements in conformity with generally accepted accounting principles in the United States (“U.S.”) (“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 Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Our 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 to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures. Due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

Cash and cash equivalents – Cash and cash equivalents 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, 2018 and 2017 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2018 and 2017 include a charter payment escrow for the floating, production, storage and offloading vessel (“FPSO”) offshore Gabon as discussed in Note 12. We invest restricted and excess cash in readily redeemable money market funds.

We are required under the Exploration and Production Sharing Contract entitled “Etame Marin No. G4-160,” dated as of July 7, 1995, as amended, (the “Etame PSC”) for the Etame Marin block in Gabon 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. The current abandonment study was completed in November 2018. This cash funding is reflected under “Other noncurrent assets” as “Abandonment funding” on our consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments. See Note 12 for further discussion.

On February 28, 2019, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account advised that the bank regulator required transfer of the funds to the Central Bank for "CEMAC" (the Central African Economic and Monetary Community), of which Gabon is one of the six member states, for conversion to local currency with a credit back to the Gabonese branch in local currency. Amendment 5 to the PSC provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Contractor shall no longer be held liable for the obligation to remediate the sites.

Accounts with joint owners – Accounts with joint owners represent the excess of charges billed over cash calls paid by the joint owners for exploration, development and production expenditures made by us as an 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 item of the consolidated statements of operations. The majority of our accounts receivable balances are with our joint venture owners, 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. Portions of our costs in Gabon (including our VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). As of December 31, 2018, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately XAF 6.9 billion (XAF 2.3 billion, net to VAALCO). The VAT receivable balance was reduced by XAF14.1 billion (XAF 4.7 billion, net to VAALCO or $4.2 million) associated with a signing bonus as part of the Sixth Amendment to the Etame PSC executed on September 17, 2018 ("PSC Extension"). As of December 31, 2018, the exchange rate was XAF 573.0 = $1.00.

In 2018, 2017 and 2016, we recorded recoveries (allowances) of $0.1 million, $ (0.4) million and $ (0.7) million, respectively, related to VAT which the government of Gabon has not reimbursed. The receivable amount, net of allowances, is reported as a non-current asset in the "Value added tax and other receivables" line item in the consolidated balance sheets. Because both the VAT receivable and the related allowance are denominated in XAF, the exchange rate revaluation of these balances into U.S. dollars at the end of each reporting period also has an impact on profit/loss. Such foreign currency gains/(losses) are reported separately in the "Other, net" line item of the consolidated statements of operations.

The following table provides an analysis of the change in the allowance:

	Year Ended December 31, 2018	2017	2016
		(in thousands)	
Allowance for bad debt			
Balance at beginning of year	$ **(7,033)**	$ (5,211)	$ (4,221)
Bad debt recovery (charge)	**77**	(452)	(1,222)
Reclassification to leasehold costs related to signing bonus	**4,197**	—	—
Reclassification related to Sojitz acquisition	—	(694)	—
Foreign currency gain (loss)	**224**	(676)	232
Balance at end of period	$ **(2,535)**	$ (7,033)	$ (5,211)

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 included in the "Prepayments and other" line item of the consolidated balance sheet, are primarily used for production related activities. These assets are valued at the lower of cost, determined by the weighted-average method, or market.

Oil and natural gas properties, equipment and other – We use the successful efforts method of accounting for oil and natural gas producing activities. Our 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.

Capitalization – 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. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

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 (other than equipment inventory) 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.

Impairment – We review our oil and natural gas producing properties for impairmenton 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. Capitalized equipment inventory is reviewed regularly for obsolescence. We identified equipment inventory in Gabon that required an adjustment of$0.4 million to the “Other operating income (expense), net” line item of the consolidated statement of operations for the year ended December 31, 2018. We identified equipment inventory in Gabon that we do not expect to use and charged $(0.3) million to the “Other operating income (expense), net” line item of the consolidated statement of operations in each of the years ended December 31, 2017 and 2016, respectively. 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 the Etame Marin block and in Equatorial Guinea.

Capitalized interest – Interest costs and commitment fees from external borrowings are capitalized on 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. 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.

We capitalized no interest costs during the years ended December31, 2018, 2017 and 2016.

Lease commitments – We are lessees of office buildings, warehouse and storage facilities, equipment and corporate housing under leasing agreements that expire at various times. All leases are characterized as operating leases and are expensed either as production expenses or general and administrative expenses. See Note 12 for further discussion.

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 11 for disclosures regarding our asset retirement obligations. Where there is a downward revision to the ARO that exceeds the net book value of the related asset, the corresponding adjustment is limited to the amount of the net book value of the asset and the remaining amount is recognized as a gain. During the year ended December 31, 2018, we recorded a downward revision of $6.5 million to the

ARO liability as a result of a change in the expected timing of the abandonment costs when the period of exploitation under the Etame PSC was extended to at least September 16, 2028 as discussed further in Note 9.

Revenue recognition– Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements. There is a single performance obligation (delivering oil to the delivery point, i.e. the connection to the customer's crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. In addition to revenues from customer contracts, the Company has other revenues related to contractual provisions under the Etame Marin block PSC. The Etame PSC is not a customer contract. The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of "Profit Oil" determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. For both royalties and Profit Oil, the Etame PSC provides that the government of Gabon may settle these obligations in-kind, i.e. taking crude oil barrels, rather than with cash payments.

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 for the 2016 grants. 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. We utilize the Black-Scholes option pricing model to measure the fair value of the 2017 and 2018 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.

When awards are forfeited before they vest, previously recognized expense related to such forfeitures is reversed in the period in which the forfeiture occurs.

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 item "Other income (expense)—Other, net," we recognized losses on foreign currency transactions of $0.1 million and $30 thousand in 2018 and 2016, respectively, while we recognized gains on foreign currency transactions of $0.5 million in 2017.

Income taxes – Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination and evaluation of our annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which we operate and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or our level of operations or profitability in each jurisdiction would impact our tax liability in any given year. We also operate in foreign jurisdictions where the tax laws relating to the oil and natural gas industry are open to interpretation which could potentially result in tax authorities asserting additional tax liabilities. While our income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized, and when it is estimated to be more-likely-than-not that all or some portion of specific deferred tax assets, such as net operating loss carry forwards or foreign tax credit carryovers, will not be realized, a valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered are earnings generated in previous periods, forecasted earnings and the expiration period of carryovers. As of December 31, 2018, the Company had deferred tax assets of $131.0 million primarily attributable to U.S. federal taxes related to basis differences in fixed assets, foreign tax credit carryforwards, and net operating loss carryforwards as well as foreign net operating losses for foreign jurisdictions for which a valuation allowance of $90.9 million had been recorded. During the year ended December 31, 2018, management determined that it was more-likely-than-not that a portion of the deferred tax assets related to basis differences in fixed assets and net operating loss carryforwards would be realized, and therefore $16.5 million of the valuation allowance recorded in prior periods was reversed.

In certain jurisdictions, we may deem the likelihood of realizing deferred tax assets as remote where we expect that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. For such jurisdictions, we have not recognized deferred tax assets. Should our expectations change regarding the expected future tax consequences, we may be required to record additional deferred taxes that could have a material effect on our consolidated financial position and results of operations. As of December 31, 2017, we had not recognized deferred tax assets related to our Cost Account in the Gabon jurisdiction. As discussed in Note 8 to the Financial Statements, as a result of the benefits under the PSC Extension which was granted in September 2018, we determined that it was now more-likely-than-not we would recover our Cost Account, and therefore we recorded a deferred tax asset of $57.6 million primarily related to the excess of the Cost Account over the book basis of the Etame Marin block assets.

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.

All of our oil put contracts, which provided for settlement based upon reported the Brent price, had expired as of December 31, 2017. Our derivative instruments at December 31, 2018, consisted of oil swaps, which require us to pay a counterparty when the price of oil exceeds $74.00 per barrel, and where the price of oil falls below $74.00, we receive a payment from the counterparty.

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 in the “Other, net” line item located within the “Other income (expense)” section of the consolidated statements of operations. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the “Commodity derivatives (gain) loss” and “Cash settlements (paid)/received on matured derivative contracts, net” lines items located as adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities on the statements of consolidated cash flows. We paid net cash settlements of $0.7 million during the year ended December 31, 2018 related to matured derivative contracts. We received cash settlements of $0.2 million during the year ended December 31, 2017 related to matured derivative contracts.

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 liabilities, accounts payable, liabilities for stock appreciation rights (“SARs”) and guarantee. 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. The derivative asset commodity swaps referenced below are reported on the consolidated balance sheet on line item “Prepayments and other.” SARs liabilities are measure and reported at fair value using level 2 inputs each period with changes in fair value recognized in net income. The current portion of the SARs liabilities is reported on the consolidated balance sheet on line item “Accrued liabilities and other” while the long-term portion is located on the line item “Other long term liabilities”. 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.

	As of December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Recurring				
Assets				
Derivative asset commodity swaps	$ —	$ 3,520	$ —	$ 3,520
	$ —	$ 3,520	$ —	$ 3,520
Liabilities				
SARs liability	$ —	$ 1,632	$ —	$ 1,632
	$ —	$ 1,632	$ —	$ 1,632

	As of December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Recurring				
Liabilities				
SARs liability	$ —	$ 146	$ —	$ 146
	$ —	$ 146	$ —	$ 146

General and administrative related to shareholder matters – Amounts related to shareholder matters for the year ended December 31, 2016 relatesto 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.

Other, net – “Other, net” in non-operating income and expenses includes gains and losses from derivatives and foreign currency transactions as discussed above. In addition, “Other, net” for the year ended December 31, 2017 includes $2.6 million related to the reversal of accruals for liabilities we are no longer obligated to pay.

3. NEW ACCOUNTING STANDARDS

Not Yet Adopted

In August 2018, the Financial Accounting Standards Board (“FASB”) issued ASU 2018-15, Intangibles - Goodwill and Other - Internal-Use Software (Topic 350): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract, which requires a customer in a cloud computing arrangement that is a service contract to follow the internal-use software guidance in Accounting Standards Codification (“ASC”) 350, Intangibles - Goodwill and Other, in making the determination as to which implementation costs are to be capitalized as assets and which costs are to be expensed as incurred. The new standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted, and an entity can elect to apply the new guidance on a prospective or retrospective basis. The Company is currently evaluating the impact of adopting this guidance.

In August 2018, the FASB issued ASU 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement (“ASU 2018-13”). This ASU modifies the disclosure requirements for fair value measurements. ASU 2018-13 removes the requirement to disclose (1) the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, (2) the policy for timing of transfers between levels, and (3) the valuation processes for Level 3 fair value measurements. ASU 2018-13 requires disclosure of changes in unrealized gains and losses for the period included in other comprehensive income (loss) for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. For all entities, ASU 2018-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. We are currently evaluating the effect that this guidance will have on our consolidated financial statements and disclosures.

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 joint venture owners 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 15, 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 (“ASU 2016-02”), which amends the accounting standards for leases. This accounting standard was further clarified by ASU 2018-10,Codification Improvements to Topic 842 and ASU 2018-11, Leases:

Targeted Improvements, both of which were issued in July 2018 together ("Topic 842"). Topic 842 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. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. In transition, lessees and lessors may use either a prospective approach in which they recognize and measure leases at the date of adoption and recognize a cumulative effect adjustment to the opening balance of retained earnings or they may use a modified retrospective approach in which leases are recognized and measured at the beginning of the earliest period presented. We intend to use the prospective approach when we adopt the new standard effective January 1, 2019. Leases with terms greater than 12 months, which are currently treated as operating leases, will be capitalized. The adoption of this standard will result in the recording of a right of use asset related to certain of our operating leases with a corresponding lease liability. This will result in a significant increase in total assets and liabilities and a decrease in working capital. In connection with our implementation plan, we have reviewed our lease contracts and are evaluating other contracts to identify embedded leases to determine the appropriate accounting treatment. The most significant lease we currently have is related to the FPSO as further discussed in Note 12, and we are finalizing the evaluation of that lease Lease payments reflected in the table in Note 12 represent the minimum amounts due. The new leasing standard requires capitalization based on the expected term of this lease which may or may not extend beyond the minimum period. While we may exercise our right to terminate the contract as early as September 2020, the minimum lease period, the FPSO charter ends in September 2022.

Adopted

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"). Beginning January 1, 2018, we adopted ASU No. 2014-09, and the related additional guidance provided under ASU No. 2016-10, 2016-11 and 2016-12 (together with ASU 2014-09, "Revenue Recognition ASU"). This new standard replaced most existing revenue recognition guidance in U.S. GAAP. The core principle of the Revenue Recognition ASU 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. We adopted the Revenue Recognition ASU via the modified retrospective transition method, taking advantage of the allowed practical expedient that states we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. This standard applies to revenues from contracts with customers. In addition, we recognize other items from carried interest recoupment and royalties paid which are reported in revenues but are not considered to be revenues from contracts with customers. For revenues from contracts with customers, adoption of this standard did not result in a change in the timing or amount of revenue recognized, and therefore the adoption of this standard did not have a material impact on our financial position, results of operations, debt covenants or business practices. The adoption did result in expanded disclosures related to the nature of our sales contracts and other matters related to revenues and the accounting for revenues, which are reflected in Note 7. In addition, we implemented new internal controls and procedures associated with revenue recognition and disclosures related to revenues.

In November 2016, the FASB issued ASU No. 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. We adopted ASU 2016-18 beginning January 1, 2018 with retroactive application to prior periods. Due to the nature of this accounting standards update, this had an impact on items reported in our consolidated statements of cash flows and related disclosures, but no impact on our financial position and results of operations.

The following tables provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets to the amounts shown in the consolidated statements of cash flows:

	December 31,	
	2018	2017
	(in thousands)	
Cash and cash equivalents	**$ 33,360**	$ 19,669
Restricted cash - current	**804**	842
Restricted cash - non-current	**920**	967
Abandonment funding	**11,571**	10,808
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	**$ 46,655**	$ **32,286**

In May 2017, the FASB issued ASU No. 2017-09, Compensation – Stock Compensation (Topic 718): Scope of Modification Accounting ("ASU 2017-09") to clarify when to account for a change to the terms or conditions of a share-based payment award as a modification. Under ASU 2017-09, modification accounting is required only if the fair value, the vesting conditions, or the classification of the award (as equity or liability) changes as a result of the change in terms or conditions. The amendments in ASU 2017-09 are effective for all entities for interim and annual reporting periods beginning after December 15, 2017. The amendments in this update are to be applied prospectively to an award modified on or after the adoption date. The adoption of ASU 2017-09 has not had a material impact on our financial position, results of operations, cash flows and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business ("ASU 2017-01"). The purpose of the amendment is to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the amendments in ASU 2017-01 are effective for interim and annual reporting periods beginning after December 15, 2017. The amendments in this update are to be applied prospectively to acquisitions and disposals completed on or after the effective date, with no disclosures required at transition. The adoption of ASU 2017-01 has not had a material impact on our financial position, results of operations, cash flows and related disclosures

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. The adoption of ASU 2016-15 has not had a material impact on our financial position, results of operations, cash flows and related disclosures.

4. 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 had an effective date of August 1, 2016 and was funded with cash on hand.

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.

Sale of Certain U.S. Properties

In December 2016, we completed the sale of our interests in two wells in the Hefley field in North Texas for $0.8 million resulting in a minimal lossIn April 2017, we completed the sale of our interests in the East Poplar Dome field in Montana for $0.3 million, resulting in a gain of approximately$0.3 million reported on the line "Other operating income (expense), net" in our results of operations for the year ended December 31, 2017.

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). Our working interest is 40%, and we carry Sonangol P&P for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to the decision to withdraw from Angola, we have taken actions to close our office in Angola and reduce 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 assets and liabilities as of December 31, 2018 and 2017 and its results of operations for the years ended December 31, 2018, 2017 and 2016.

Summarized Results of Discontinued Operations

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Operating costs and expenses:			
Exploration expense	**$ —**	$ —	$ 15,137
Depreciation, depletion and amortization	**—**	—	9
General and administrative expense	**467**	615	1,269
Bad debt recovery and other	**—**	—	(7,629)
Total operating costs, expenses and (recovery)	**467**	615	8,786
Other operating loss, net	**—**	—	(172)
Operating loss	**(467)**	(615)	(8,958)
Other income (expense):			
Interest income	**—**	—	3,201
Other, net	**(29)**	(3)	552
Total other income (expense)	**(29)**	(3)	3,753
Loss from discontinued operations before income taxes	**(496)**	(618)	(5,205)
Income tax expense	**—**	3	3,078
Loss from discontinued operations	**$ (496)**	$ (621)	$ (8,283)

Assets and Liabilities Attributable to Discontinued Operations

	As of December 31,	
	2018	**2017**
	(in thousands)	
ASSETS		
Accounts with joint venture owners	**$ 3,290**	$ 2,836
Total current assets	**3,290**	2,836
Total assets	**$ 3,290**	$ 2,836
LIABILITIES		
Current liabilities:		
Accounts payable	**$ 73**	$ 158
Accrued liabilities and other	**15,172**	15,189
Total current liabilities	**15,245**	15,347
Total liabilities	**$ 15,245**	$ 15,347

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases identified in the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2018 and 2017, respectively, which represents what we believe to be the maximum potential amount attributable to VAALCO Angola's interest under the PSA.

Other Matters – Joint Owner Receivable

The government-assigned working interest joint owner 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 joint venture owner 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 joint venture owner 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 item in our summarized results of discontinued operations. Default interest of $3.2 million is shown in the "Interest income" line item in our summarized results of discontinued operations.

5. SEGMENT INFORMATION

Our operations are based in Gabon and Equatorial Guinea. Each of our two 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, 2018, 2017 and 2016 and long-lived assets and segment assets at December 31, 2018 and 2017 are as follows:

	Year Ended December 31, 2018			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	$ 104,938	$ —	$ 5	$ 104,943
Depreciation, depletion and amortization	5,176	—	420	5,596
Bad debt expense and other	(77)	—	—	(77)
Operating income (loss)	61,930	(470)	(10,173)	51,287
Other, net	92	(4)	4,244	4,332
Interest expense, net	(396)	—	251	(145)
Income tax benefit	(26,670)	—	(16,584)	(43,254)
Additions to oil and natural gas properties and equipment - accrual	38,430	187	17	38,634

	Year Ended December 31, 2017			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	$ 76,978	$ —	$ 47	$ 77,025
Depreciation, depletion and amortization	6,196	—	261	6,457
Bad debt expense and other	452	—	—	452
Operating income (loss)	28,488	(122)	(8,415)	19,951
Other, net	3,142	15	(1,044)	2,113
Interest expense, net	(1,414)	—	—	(1,414)
Income tax expense (benefit)	11,638	—	(1,260)	10,378
Additions to oil and natural gas properties and equipment - accrual	1,576	—	126	1,702

	Year Ended December 31, 2016			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	$ 59,460	$ —	$ 324	$ 59,784
Depreciation, depletion and amortization	6,531	—	395	6,926
Impairment of proved properties	—	—	88	88
Bad debt expense and other	1,222	—	—	1,222
Operating income (loss)	3,901	(384)	(7,908)	(4,391)
Other, net	(22)	(8)	(1,985)	(2,015)
Interest expense, net	(2,614)	—	1	(2,613)
Income tax expense	9,248	—	—	9,248
Additions to oil and natural gas properties and equipment - accrual	(4,242)	—	181	(4,061)

(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Long-lived assets from continuing operations:				
As of December 31, 2018	$ 42,195	$ 10,187	$ 342	$ 52,724
As of December 31, 2017	12,638	10,000	583	23,221

(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Total assets from continuing operations:				
As of December 31, 2018	$ 103,401	$ 10,320	$ 49,301	$ 163,022
As of December 31, 2017	63,121	10,095	3,581	76,797

Information about our most significant customers

For the years ended December 31, 2018, 2017 and 2016, 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 purchaser was Glencore Energy UK Ltd. ("Glencore") for these periods and through January 2019. Sales of oil to Glencore were approximately 100% of revenues sold to customers for 2018, 2017 and 2016. We have signed a new contract with Mercuria Energy Trading SA which covers sales from February 2019 through January 2020.

6. EARNINGS PER SHARE

Basic earnings per share ("EPS") 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 of reported net income (loss) to net income (loss) used in calculating EPS as well as a reconciliation from basic to diluted shares follows:

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Net income (loss) - (numerator):			
Income (loss) from continuing operations	**$ 98,728**	$ 10,272	$ (18,267)
(Income) from continuing operations attributable to unvested shares	**(1,231)**	(62)	—
Numerator for basic	**97,497**	10,210	(18,267)
(Income) loss from continuing operations attributable to unvested shares	—	—	—
Numerator for dilutive	**$ 97,497**	$ 10,210	$ (18,267)
Loss from discontinued operations	**$ (496)**	$ (621)	$ (8,283)
Loss from discontinued operations attributable to unvested shares	**6**	4	—
Numerator for basic	**(490)**	(617)	(8,283)
Loss from discontinued operations attributable to unvested shares	—	—	—
Numerator for dilutive	**$ (490)**	$ (617)	$ (8,283)
Net income (loss)	**$ 98,232**	$ 9,651	$ (26,550)
Income attributable to unvested shares	**(1,225)**	(58)	—
Numerator for basic	**97,007**	9,593	(26,550)
Net (income) loss attributable to unvested shares	—	—	—
Numerator for dilutive	**$ 97,007**	$ 9,593	$ (26,550)
Weighted average shares (denominator):			
Basic weighted average shares outstanding	**59,248**	58,717	58,384
Effect of dilutive securities	**749**	3	—
Diluted weighted average shares outstanding	**59,997**	58,720	58,384
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**1,316**	2,823	4,363

7. REVENUE

Substantially all of our revenues are attributable to our Gabon operations. Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements ("COSPAs"). The COSPAs have been and will be renewed or replaced from time to time either with the current buyer or another buyer. Since August 2015, a COSPA has been in place with the same customer, initially for a one-year period, with amendments that extended the period through January 31, 2018. On February 1, 2018, a new COSPA was entered into with this same customer, which terminated January 31, 2019. A new COSPA with a different customer has been executed for the period from February 2019 through January 2020.

COSPAs with customers are renegotiated near the end of the contract term and may be entered into with a different customer or the same customer going forward. Except for internal costs (which are expensed as incurred), there are no upfront costs associated with obtaining a new COSPA.

Customer sales generally occur on a monthly basis when the customer's tanker arrives at the FPSO and the crude oil is delivered to the tanker through a connection. There is a single performance obligation (delivering oil to the delivery point, i.e. the connection to the customer's crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. This is referred to as a "lifting". Liftings can take one to two days to complete. The intervals between liftings are generally

30 days; however, changes in the timing of liftings will impact the number of liftings which occur during the period. Therefore, the performance obligation attributable to volumes to be sold in future liftings are wholly unsatisfied, and there is no transaction price allocated to remaining performance obligations. We have utilized the practical expedient in ASC Topic 606-10-50-14(a) which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Previously, we followed the sales method of accounting to account for crude oil production imbalances. In conjunction with our adoption of ASC Topic 606 on January 1, 2018, we will continue to account for production imbalances as a reduction in reserves. 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.

For each lifting completed under a COSPA, payment is made by the customer in U.S. Dollars by electronic transferthirty days after the date of the bill of lading. For each lifting of oil, the price is determined based on a formula using published Dated Brent prices as well as market differentials plus a fixed contract differential.

Generally, no significant judgments or estimates are required as of a given filing date with regard to applicable price or volumes sold because all of the parameters are known with certainty related to liftings that occurred in the recently completed calendar quarter. As such, we deem this situation to be characterized as a fixed price situation.

In addition to revenues from customer contracts, the Company has other revenues related to contractual provisions under the Etame Marin block PSC. The Etame PSC is not a customer contract, and therefore the associated revenues are not within the scope of ASC 606. The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of "Profit Oil" determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. For both royalties and Profit Oil, the Etame PSC provides that the government of Gabon may settle these obligations in-kind, i.e. taking crude oil barrels, rather than with cash payments.

To date, the government of Gabon has not elected to take its royalties in-kind, and this obligation is settled through a monthly cash payment. Payments for royalties are reflected as a reduction in revenues from customers. Should the government elect to take the production attributable to its royalty in-kind, we would no longer have sales to customers associated with production assigned to royalties.

With respect to the government's share of Profit Oil, the Etame PSC provides that corporate income tax is satisfied through the payment of Profit Oil. In the consolidated statements of operations, the government's share of revenues from Profit Oil is reported in revenues with a corresponding amount reflected in the current provision for income tax expense. Prior to February 1, 2018, the government did not take any of its share of Profit Oil in-kind. These revenues have been included in revenues to customers as the Company entered into the contract with the customer to sell the crude oil and was subject to the performance obligations associated with the contract. For the in-kind sales by the government beginning February 1, 2018, these sales are not considered revenues under a customer contract as the Company is not a party to the contracts with the buyers of this crude oil. However, consistent with the reporting of Profit Oil in prior periods, the amount associated with the Profit Oil under the terms of the Etame PSC is reflected as revenue with an offsetting amount reported in current income tax expense. Payments of the income tax expense will be reported in the period in which the government takes its Profit Oil in-kind, i.e. the period in which it lifts the crude oil. The in-kind payment related to the September lifting was $9.4 million. As of December 31, 2018, the foreign taxes payable attributable to this obligation is $3.3 million.

Certain amounts associated with the carried interest in the Etame Marin block discussed above are reported as revenues. In this carried interest arrangement, the carrying parties, which include the Company and other working interest owners, are obligated to fund all of the working interest costs which would otherwise be the obligation of the carried party. The carrying parties recoup these funds from the carried interest party's revenues.

The following table presents revenues from contracts with customers as well as revenues associated with the obligations under the Etame PSC:

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Revenue from customer contracts:			
Sales under the COSPA	**$ 104,891**	$ 74,693	$ 59,475
Gabonese government share of Profit Oil	**2,193**	11,638	9,248
U.S. oil and natural gas revenue	**5**	47	324
Other items reported in revenue not associated with customer contracts:			
Gabonese government share of Profit Oil taken in-kind	**9,385**	—	—
Carried interest recoupment	**3,545**	2,205	—
Royalties	**(15,076)**	(11,558)	(9,263)
Total revenue, net	**$ 104,943**	$ 77,025	$ 59,784

8. INCOME TAXES

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

On December 22, 2017, the U. S. government enacted the Tax Cuts and Jobs Act, commonly referred to as the Tax Reform Act. The Tax Reform Act includes significant changes to the U.S. income tax system including but not limited to: a federal corporate rate reduction from 35% to 21%; limitations on the deductibility of interest expense and executive compensation; repeal of the Alternative Minimum Tax ("AMT"); full expensing provisions related to business assets; creation of new minimum taxes such as the base erosion anti-abuse tax ("BEAT") and Global Intangible Low Taxed Income ("GILTI") tax; and the transition of U.S. international taxation from a worldwide tax system to a modified territorial tax system, which will result in a one time U.S. tax liability on those earnings which have not previously been repatriated to the U.S. (the "Transition Tax"). The impacts of this legislation are outlined below:

- Beginning January 1, 2018, the U.S. corporate income tax rate is21%. The Company recognized the impacts of this rate change on its deferred tax assets and liabilities in the period enacted, i.e. during the year ended December 31, 2017. As the Company has a full valuation allowance on its net deferred tax asset as of December 31, 2017, the deferred tax recognized due to the change in rate was offset with a change in the valuation allowance. Therefore, there was no overall impact to the Financial Statements in 2017 due to this change in rate.

- The Tax Reform Act also repealed the corporate AMT for tax years beginning on or after January 1, 2018 and provided for existing alternative minimum tax credit carryovers to be refunded beginning in 2018. The Company has approximately $1.4 million in refundable credits, and it expects that a substantial portion will be refunded between 2018 and 2021. As such, most of the valuation allowance in place at the end of 2017 related to these credits was released in 2017 and a deferred tax asset of $1.3 million was reflected as of December 31, 2017 related to the expected benefit in future years.

- The Transition Tax on unrepatriated foreign earnings is a tax on previously untaxed accumulated and current earnings and profits ("E&P") of the Company's foreign subsidiaries. To determine the amount of the Transition Tax, the Company must determine, among other factors, the amount of post-1986 E&P of its foreign subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. Based on the Company's reasonable estimate of the Transition Tax, there is no provisional Transition Tax expense.

- The Tax Reform Act created a new requirement that GILTI income earned by foreign subsidiaries must be included currently in the gross income of the U.S. shareholder. The Company did not have any amounts related to potential GILTI tax.

Other provisions in the legislation, such as interest deductibility and changes to executive compensation plans have not had a material implications to the Company's Financial Statements.

Additionally, the Tax Reform Act may further limit the Company's ability to utilize foreign tax credits in the future. The Tax Reform Act introduces a new credit limitation basket for foreign branch income. Income from foreign branches is now allocated to this specific tax credit limitation basket which cannot offset income in other baskets of foreign income. Under the Tax Reform Act, foreign taxes imposed on the foreign branch profits will not offset U.S. non-branch related foreign source income. Additional analysis will be needed under proposed IRS regulations to determine how this will impact the Company and any future utilization of foreign tax credit carryforwards.

Income taxes attributable to continuing operations for the years ended December 31, 2018, 2017, and 2016 are attributable to foreign taxes payable in Gabon as well as income taxes in the U.S. The Company has not recorded any measurement period adjustments under ASU 2018-05 during the year ended December 31, 2018.

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

	Year Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
U.S. Federal:			
Current	**$ (674)**	$ —	$ —
Deferred	**(15,910)**	(1,260)	—
Foreign:			
Current	**14,327**	11,638	9,248
Deferred	**(40,997)**	—	—
Total	**$ (43,254)**	$ 10,378	$ 9,248

As of December 31, 2017, the Company had deferred tax assets of $154.5 million primarily attributable to U.S. federal taxes related to basis differences in fixed assets, foreign tax credit carryforwards, and net operating loss carryforwards as well as foreign net operating losses for foreign jurisdictions. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. As of December 31, 2017, the Company was in a cumulative three year pre-tax loss position for both the U.S. and Gabon jurisdictions. As of December 31, 2017, we did not anticipate utilization of the foreign tax credits prior to expiration nor did we expect to generate sufficient taxable income to utilize other deferred tax assets. On the basis of this evaluation, valuation allowances of $153.2 million were recorded as of December 31, 2017. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

Taxes paid in Gabon with respect to earnings from the Etame Marin block are determined under the provisions of the Etame PSC. In accordance with the Etame PSC, the Consortium maintains a "Cost Account" which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. For each calendar year, the Consortium is entitled to receive a percentage of the production ("Cost Recovery Percentage") remaining after deducting royalties so long as there are amounts remaining in the Cost Account. Prior to the PSC Extension, the Cost Recovery Percentage was 70%. As a result of the PSC Extension, the Cost Recovery Percentage has been increased to80% for the period from September 17, 2018 through September 16, 2028. See Note 9 for further discussion of the PSC Extension. After September 16, 2028, the Cost Recovery Percentage returns to 70%. The difference between revenues, net of royalties, and the costs recovered for the period is "Profit Oil." 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%. The percentage of Profit Oil paid to the government as tax is a function of production rates. When the Cost Account is less than the entitled recovery percentage (either 70% or 80%, depending on the period), Profit Oil as a percentage of revenues increases and Gabon taxes paid increase as a percentage of revenues. At December 31, 2017, there was $97.6 million remaining in the portion of the Cost Account associated with our interest.

Prior to the PSC Extension, the Cost Recovery Percentage was 70%, and the exploitation periods ended beginning in June 2021. Future proved reserves did not extend beyond 2021. Opportunities for increasing reserves by drilling wells were limited, and while oil prices had improved since 2016, they were not at the levels needed to recover VAALCO's Cost Account. As a result of these factors, the ability to recognize the benefit from the potential deferred tax asset related to the difference between VAALCO's Cost Account and the book basis of the Etame Marin block assets was deemed to be remote, and the deferred tax asset was not recognized. As a result of the PSC Extension in September 2018, the Cost Recovery Percentage increased to 80% and the exploitation periods were extended to at least September 16, 2028, and if the two five-year option periods are elected the period would extend to September 16, 2038. In addition to the benefits under the PSC Extension, we expect higher future oil prices based on current Brent futures strip pricing over the next few years, and we expect future production from the planned drilling of two to three wells in 2019. Given these factors, we determined that the potential for a recovery of our Cost Account was no longer remote, and therefore we recorded a deferred tax asset of $57.6 million. The PSC extension payment was not recoverable for Gabon tax purposes, which resulted in the recording of a deferred tax liability of $18.6 million with an offsetting gross-up to oil and natural gas properties. Additionally, a reduction of $16.1 million was recorded in relation to current year activity and other changes resulting in an ending Gabon net deferred tax asset of $22.9 million.

We also evaluated the amount of the valuation allowance needed on deferred tax assets recognized related to U.S. federal income taxes. In making this evaluation, we considered the impact on future taxable income of increased earnings as a result of the PSC Extension, increases in oil prices during the year, including current oil prices as well as Brent futures strip pricing over the next few years and the future production from the planned drilling of two to three wells in 2019. We also considered the pattern of earnings over the past three years. On the basis of these factors, we determined that it is more likely than not that we will realize a portion of the benefit from the deferred tax assets related to the fixed asset basis differences as well as the net operating losses. Accordingly, we reversed $16.5 million of the valuation allowance based on estimated future earnings. The total change in the valuation allowance related to U.S. net deferred tax assets was a decrease of $37.8 million. As a result of the above mentioned Gabon deferred tax asset, we recorded the corresponding deferred tax liability of $8.6 million attributable to the U.S. federal income tax impact. The deferred tax asset was further reduced by $8.9 million for current year activity and $4.3 million for expiring foreign tax credits. The items above along with other items of $0.1 million resulted in a net deferred tax asset for U.S. federal income tax purposes of $17.2 million.

The primary differences between the financial statement and tax bases of assets and liabilities resulted in deferred tax assets associated with continuing operations at December 31, 2018 and 2017 are as follows:

	As of December 31,	
(in thousands)	**2018**	**2017**
Deferred tax assets:		
Basis difference in fixed assets	**$ 38,479**	$ 46,929
Foreign tax credit carryforward	**43,760**	48,071
Alternative minimum tax credit carryover	**674**	1,349
U.S. federal net operating losses	**20,616**	22,490
Foreign net operating losses	**19,989**	26,371
Asset retirement obligations	**3,111**	4,234
Basis difference in accrued liabilities	**3,816**	3,716
Basis difference in receivables	**387**	1,331
Other	**180**	(26)
Total deferred tax assets	**131,012**	154,465
Valuation allowance	**(90,935)**	(153,205)
Net deferred tax assets	**$ 40,077**	$ 1,260

Foreign tax credits will expire between the years 2019 and 2025. Foreign tax credits of $4.3 million expired during the year. 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. We plan to liquidate the United Kingdom subsidiary and the Gabon branch which carries the NOL's, and therefore the realization of deferred tax assets for these entities is remote. Accordingly, the related deferred tax assets of $8.7 million and $15.9 million, respectively, were written off during the year with a corresponding offset to the valuation allowance. All of the Company's U.S. federal NOLs were incurred prior to 2018 and will expire between 2035 and 2037. U.S. federal NOLs incurred after 2017 do not expire. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. 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 and have recorded a full valuation allowance on these deferred tax assets.

As a result of the 2017 tax legislation enacted in the U.S., we expect to realize the benefit from our AMT credit carryforwards. The valuation allowance recorded related to AMT credits in previous periods was reversed in 2017 with the exception for a reserve for the possible sequestration of the credits. The $1.3 million reversal was recorded as a deferred income tax benefit during the fourth quarter of 2017. As a result of further guidance by the Internal Revenue Service, the $0.1 million reserve for possible sequestration of the credits was reversed in 2018.

On the basis of the evaluations discussed above, valuation allowances of$90.9 million, $153.2 million and $211.8 million have been recorded as of December 31, 2018, 2017 and 2016, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

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 31,2018 and 2017. The Company's policy is to include interest and penalties 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)	2018	2017	2016
U.S.	$ (5,672)	$ (9,453)	$ (9,893)
Foreign	61,146	30,103	874
	$ 55,474	$ 20,650	$ (9,019)

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

	Year Ended December 31,		
(in thousands)	2018	2017	2016
Tax provision computed at U.S. statutory rate	$ 11,650	$ 7,228	$ (3,156)
Foreign taxes not offset in U.S. by foreign tax credits	24,840	6,775	6,319
Impact of Tax Reform Act	—	52,449	—
Recognition of foreign deferred tax assets, net of U.S. impact	(45,751)	—	—
Unrealizable foreign deferred tax assets	24,176		
Effect of change in foreign statutory rates	—	—	2,394
Permanent differences	(104)	309	4,505
Foreign tax credit expirations	4,311	2,394	—
Increase/(decrease) in valuation allowance	(62,270)	(58,777)	(802)
Other	(106)	—	(12)
Total income tax expense (benefit)	$ (43,254)	$ 10,378	$ 9,248

For the years ended December 31, 2018, 2017 and 2016, 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
U.S.	2009-2018
Gabon	2014-2018

9. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Extension of Term of Etame Marin Block PSC

On September 25, 2018, VAALCO together with the other joint owners in the Etame Marin block (the "Consortium") received an implementing Presidential Decree from the government of Gabon authorizing the PSC Extension. Our subsidiary, VAALCO Gabon S.A., has a 33.575% participating interest (working interest including the working interest attributable to the carried interest owner) in the Etame Marin block.

The PSC Extension extends the term for each of the three exploitation areas in the Etame Marin block for a period often years with effect from September 17, 2018, the effective date of the PSC Extension. Prior to the PSC Extension, the exploitation periods for the three exploitation areas in the Etame Marin block would expire beginning in June 2021. The PSC Extension also grants the Consortium the right for two additional extension periods of five years each. The PSC Extension further allows the Consortium to explore the potential for resources within the area of each Exclusive Exploitation Authorization as defined in the PSC Extension.

In consideration for the PSC Extension, the Consortium agreed to a signing bonus of$65.0 million ($21.8 million, net to VAALCO) payable to the government of Gabon (the "signing bonus"). The Consortium paid $35.0 million ($11.8 million, net to VAALCO) in cash on September 26, 2018 and paid $25.0 million ($8.4 million, net to VAALCO) through an agreed upon reduction of the VAT receivable owed by the government of Gabon to the Consortium as of the effective date. An additional $5.0 million ($1.7 million, net to VAALCO) is to be paid in cash by the Consortium following the end of the drilling activities described below. We have accrued our $1.7 million share of this remaining payment as of September 30, 2018. The amount paid through a reduction in VAT has been recorded at $4.2 million which represents the book value of the receivable, net of the valuation allowance as of the effective date. In addition, we recorded an increase of $18.6 million resulting from the deferred tax impact for the difference between book basis and tax basis. A corresponding $18.6 million deferred tax liability was recorded which reduced our net deferred tax assets. We have allocated our share of the signing bonus between proved and unproved leasehold costs using the acreage attributable to the previous exploitation areas and the additional acreage in the expanded exploitation areas resulting in $22.5 million being attributed to proved leasehold costs and $13.7 million attributed to unproved leasehold costs.

Under the PSC Extension, by September 16, 2020, the Consortium is required to drill two wells and two appraisal well bores. We estimate the cost of these wells will be approximately $61.2 million ($20.5 million, net to VAALCO). If the wells are not drilled, then the Consortium must pay the difference between the amounts spent on any wells that were drilled and the estimated costs of the wells as set forth in the Work Program and Budget as approved by the government of Gabon. The Consortium is planning to drill these wells in the second half of 2019. The Consortium is also required to complete two technical studies by September 16, 2020 at an estimated cost of $1.3 million gross ($0.4 million, net to VAALCO).

Prior to the PSC Extension, the Consortium was entitled to take up to 70% of production remaining after the 13% royalty ("Cost Recovery Percentage") to recover its costs so long as there are amounts remaining in the Cost Account. Under the PSC Extension, the Cost Recovery Percentage is increased to 80% for the ten-year period from September 17, 2018 through September 16, 2028. After September 16, 2028, the Cost Recovery Percentage returns to 70%.

Prior to the PSC Extension, the PSC provided for the government of Gabon to take a 7.5% gross working interest carried by the Consortium. The government of Gabon transferred this interest to a third party. Pursuant to the PSC Extension, the government of Gabon will acquire from the Consortium an additional 2.5% gross working interest carried by the Consortium effective June 20, 2026. VAALCO's share of this interest to be transferred to the government of Gabon is 0.8%.

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 the year ended December 31, 2018, oil and natural gas property costs increased significantly as a result of amounts recorded in connection with the PSC Extension and yearend oil prices decreased over the prior year; however, reserves increased significantly over the prior year. We evaluated these and other factors and determined that no impairment was required for any of the Etame fields.

There was no triggering event in the year ended December 31, 2017 that would cause us to believe the value of oil and natural gas producing properties should be impaired.

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 where reserves were impacted by temporary shut-ins on certain wells in the field. We evaluated the undiscounted future net cash flows for the Avouma field and determined that they were in excess of the field's carrying value at December 31, 2016. As a result, no impairment was required for the Avouma field, or any of our other fields in Gabon, for 2016.

Undeveloped Leasehold Costs

We have a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that we acquired in 2012 for which we have $10.0 million capitalized in undeveloped acreage. For a number of years, the Block P interest was in suspension; however, in September 2018, the Ministry of Mines and Hydrocarbons ("EG MMH") lifted the suspension. We are awaiting the EG MMH to approve our appointment as technical operator for Block P. Compania Nacional de Petroleos de Guinea Equatorial ("GEPetrol") will act as the administrative operator. Under the terms of lifting of the suspension, a new joint owner is expected to assume GEPetrol's working interest obligations and be presented to the EG MMH by March 28, 2019. Once the joint owner is approved, we are required to drill one exploration well within one year. While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, we would lose our interest in the license, and the associated capitalized unproved leasehold costs of $10.0 million as of December 31, 2018 would become impaired. 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.

As a result of the PSC Extension, the exploitation area was expanded to include previously undeveloped acreage. We allocated $6.7 million of our share of the signing bonus and $7.1 million of the $18.6 million resulting from the deferred tax impact for the difference between book basis and tax basis to unproved leasehold costs using the acreage attributable to the previous exploitation areas and the additional acreage in the expanded exploitation areas. Exploitation of this additional area is permitted throughout the term of the Etame PSC.

Capitalized Equipment Inventory

Certain capitalized equipment inventory related to the Etame Marin block was increased in value by$0.4 million due to adjustments in obsolescence of some items.

10. DERIVATIVES AND FAIR VALUE

We use derivative financial instruments to achieve a more predictable cash flow from oil production by reducing our exposure to price fluctuations. See Note 2 for further information.

***Commodity swaps* -** In June 2018, we entered into commodity swaps at a Dated Brent weighted average of $74.00 per barrel for the period from and including June 2018 through June 2019 for a quantity of approximately 400,000 barrels. If a liability position exceeds $10.0 million, we would be required to provide a bank letter of credit or deposit cash into an escrow account for the amount by which the liability exceeds $10.0 million. These swaps settle on a monthly basis. At December 31, 2018, our unexpired commodity swaps were for an underlying quantity of 172,000 barrels and had a fair value asset position of $3.5 million reflected in "Prepayments and other" line of our consolidated balance sheet.

Put options - During 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. At December 31, 2017, our crude oil put contracts expired.

While these commodity swaps and 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. We do not enter into derivative instruments for speculative or trading proposes.

The crude oil swaps and 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 swap and put contracts 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:

		Year Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2018**	**2017**	**2016**
			(in thousands)	
Crude oil swaps	Other, net	$ 4,264	$ —	$ —
Crude oil puts	Other, net	—	(1,032)	(1,711)

11. ASSET RETIREMENT OBLIGATIONS

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

(in thousands)	**2018**	**2017**	**2016**
Balance at January 1	**$ 20,163**	$ 18,612	$ 16,166
Accretion	**1,180**	951	903
Acquisitions and dispositions	**—**	(103)	1,544
Revisions	**(6,527)**	703	(1)
Balance at December 31	**$ 14,816**	$ 20,163	$ 18,612

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 2018, we recorded a downward revision of $6.5 million to the ARO liability as a result of a change in the expected timing of the abandonment costs when the period of exploitation under the Etame PSC was extended to at least September 16, 2028 as discussed further in Note 9. The most recently completed abandonment study was in November 2018. As discussed further in Note 2, on February 28, 2019,the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account advised that the bank regulator required transfer of the funds to the Central Bank for CEMAC for conversion to local currency with a credit back to the Gabonese branch in local currency.

12. COMMITMENTS AND CONTINGENCIES

FPSO charter

In connection with the charter of the FPSO (the "FPSO charter"), we, as operator of the Etame Marin block, guaranteed all of the lease payments under the FPSO charter through its contract term, which expires in September 2022. At our election, the FPSO charter may be terminated as early as September 2020. We obtained guarantees from each of our joint owners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.3 million and $0.5 million as of December 31, 2018 and 2017, respectively, representing the guarantee's estimated fair value. The guarantee of the offshore Gabon FPSO lease has $53.9 million in remaining gross minimum obligations as of December 31, 2018.

Estimated future minimum obligations through the end of the FPSO charter which reflects the right of early termination are as follows:

(in thousands)	Full Charter Payment	VAALCO, Net
Year		
2019	$ 31,294	$ 9,718
2020	22,634	7,029
2021	—	—
2022	—	—
2023	—	—
Total	$ 53,928	$ 16,747

The FPSO 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 $10.8 million, $12.8 million and $11.2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Other lease obligations

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

(in thousands)	Gross Obligation	VAALCO, Net
Year		
2019	$ 1,110	$ 627
2020	693	450
2021	—	—
2022	—	—
2023	—	—
Total	$ 1,803	$ 1,077

We incurred rent expense of $1.3 million, $2.4 million and $4.5 million under operating leases for the years ended December 31, 2018, 2017 and 2016

Drilling and other commitments

In connection with the PSC Extension, the Etame Marin block joint owners are required to drill two wells and two appraisal well bores by September 16, 2020. The estimated cost for these wells is approximately $61.2 million ($20.5 million, net to VAALCO). In addition to the drilling commitment, the Etame Marin block joint owners are required to pay $5.0 million ($1.7 million, net to VAALCO) in cash to the government of Gabon following the end of the drilling activities for the two wells. As the payment is not contingent on the success of these wells and at least $5.0 million would be paid if no wells are drilled, we have accrued a liability for our net $1.7 million share as of December 31, 2018. The joint owners are also obligated to perform two technical studies estimated to cost $1.3 million ($0.4 million, net to VAALCO). The costs related to these studies will be recognized in future periods when the studies are performed.

Rig commitment

In 2014, we entered into a long-term contract 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 development wells and workovers of existing wells in the Etame Marin block. We released the drilling rig in February 2016, prior to the original July 2016 contract termination date, and in June 2016, we reached an agreement with the drilling contractor for us to pay $5.1 million, net to VAALCO's interest for unused rig days under the contract. The expense related to the termination was reported in the "Other operating expense" line item in our consolidated statement of operations for 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 2018, we paid $1.1 million for our share of the 2017 obligation. In 2017, we paid $1.2 million for our share of the 2016 obligation. In 2016, we paid $1.7 million for our share of the 2015 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, 2018, for our share of the 2018 obligation was $1.2 million. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.3 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, 2018, for our share of the 2018 obligation was $1.9 million. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.4 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

Abandonment funding

Under the terms of the Etame PSC, we have a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. As a result of the PSC Extension, annual funding payments are spread over the periods from 2018 through 2028. The amounts paid will be reimbursed through the Cost Account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.8 million ($19.2 million, net to VAALCO) on an undiscounted basis. Through December 31, 2018, $37.4 million ($11.6 million, net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of 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.

Regulatory and Joint Interest 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 the "Accrued liabilities and other" line item of 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 in 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. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are working with the currently appointed representatives to resolve the audit findings. 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.

In 2017, the government of Gabon conducted a tax audit of our Gabon subsidiary covering the years 2013 through 2016, and in December 2017, we received a report on their findings. We have evaluated the results of this audit, and have made an accrual of $0.5 million, net to VAALCO, for the estimated additional taxes along with penalties in the "Accrued liabilities and other" line item of our consolidated balance sheet.

At December 31, 2018, we had accrued $1.3 million, net to VAALCO, in the "Accrued liabilities and other" line item of our consolidated balance sheet for potential fees which may result from a customs audit. This matter was fully resolved in January 2019 for $1.3 million, net to VAALCO.

Employment agreements

Our Chief Executive Officer and Chief Financial Officer have employment agreements which provide for payments of annual salary, incentive compensation and certain other benefits if their employment is terminated without cause.

13. DEBT

On May 22, 2018, we terminated an amended term loan agreement we had with the International Finance Corporation (the "IFC") (the "Amended Term Loan Agreement") by prepaying the outstanding principal and accrued interest. We did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

We entered into the Amended Term Loan Agreement on June 29, 2016 through the execution of a Supplemental Agreement with the IFC which, among other things, amended and restated our existing loan agreement to convert the $20.0 million revolving portion of the credit facility, to a term loan with $15.0 million outstanding at that date. The Amended Term Loan Agreement was secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A., and was guaranteed by VAALCO as the parent company. The Amended Term Loan Agreement provided for quarterly principal and interest payments on the amounts outstanding, with interest accruing at a rate of LIBOR plus 5.75%.

The Amended Term Loan Agreement also provided for an additional $5.0 million, which could be requested in a single draw, subject to the IFC's approval, through March 15, 2017. On March 14, 2017, we borrowed $4.2 million under this provision of the Amended Term Loan Agreement. The additional borrowings were to be repaid in five quarterly principal installments commencing June 30, 2017, together with interest which will accrue at LIBOR plus 5.75%.

Interest

Until June 29, 2016, under the terms of the original loan agreement with the IFC, we paid commitment fees on the undrawn portion of the total commitment. Commitment fees had been 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 Amended Term Loan Agreement with the IFC in June 2016, beginning on June 29, 2016, and continuing through March 14, 2017, commitment fees were equal to 2.3% of the undrawn term loan amount of $5.0 million. There are no further commitment fees owing after March 14, 2017.

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

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Interest expense related to debt, including commitment fees	**$ (257)**	$ (997)	$ (1,353)
Deferred finance cost amortization	**(191)**	(369)	(319)
Deferred finance cost write-off due to loan modification	**—**	—	(869)
Interest income	**270**	7	3
Other interest expense not related to debt	**33**	(55)	(75)
Interest expense, net	**$ (145)**	$ (1,414)	$ (2,613)
Average effective interest rate, excluding commitment fees	**7.09%**	6.72%	5.52%

14. SHAREHOLDERS' EQUITY

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, 2018 or 2017.

Treasury stock – In the years ended December 31, 2018, 2017 and 2016, we withheld 26,421, 26,000 and 40,926 shares, respectively, in connection with cashless stock option exercises and restricted stock vestings to satisfy tax withholding obligations related to stock option exercises. In the year ended December 31, 2018, restricted stock vestings of 35,265 shares were issued from treasury.

15. 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, 2018, 1,112,527 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, 2018, 2017 and 2016, non-cash compensation expense was $2.3 million, $1.1 million and $0.2 million, respectively, related to the issuance of stock options, restricted stock and SARs. Because we do not pay significant U.S. 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 $0.5 million and $39 thousand in cash proceeds received from the exercise of stock options in 2018 and 2017, respectively. For 2016, there were no cash proceeds received from the exercise of stock options. During 2018, options for 494,941 shares were granted to employees; these options vest over a three-year period, vesting in three equal parts on the first, second and third anniversaries after the date of grant and have an exercise price of $0.86 per share. Options for 175,644 shares also were granted in 2018 to our non-employee directors, which were fully vested upon their grant and have an exercise price of $1.60 per share.

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 2018, 2017 and 2016, 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.

	Year Ended December 31,		
	2018	2017	2016
Weighted average exercise price - ($/share)	$ 1.05	$ 0.99	$ 1.14
Expected life in years	3.5	3.2	3.0
Average expected volatility	71 %	73 %	71 %
Risk-free interest rate	2.51 %	1.51 %	1.1 %
Weighted average grant date fair value - ($/share)	$ 0.68	$ 0.49	$ 0.49

Stock option activity for the year ended December 31, 2018 is provided below:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2018	2,597	$ 1.77		
Granted	671	1.05		
Exercised	(528)	1.02		
Forfeited/expired	(139)	5.60		
Outstanding at December 31, 2018	2,601	1.54	2.26	$ 989
Exercisable at December 31, 2018	1,649	1.90	2.69	$ 499

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. The intrinsic value of stock options exercised in 2018 and 2017 was $0.6 million and $0.0 million, respectively. There were no exercises of stock options in 2016.

On February 28, 2019, the Company granted stock options for 622,140 shares to employees with an exercise price of $2.33 per share.

As of December 31, 2018, unrecognized compensation cost related to outstanding stock options was $0.2 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 following 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 2018.

	Restricted Stock	Weighted Average Grant Price
	(in thousands)	
Non-vested shares outstanding at January 1, 2018	340	$ 1.10
Awards granted	398	1.00
Awards vested	(231)	1.34
Awards forfeited	—	—
Non-vested shares outstanding at December 31, 2018	507	0.91

The total vest-date fair value of restricted stock awards which vested during 2018, 2017 and 2016 was $0.4 million, $0.3 million and $0.6 million, respectively. The weighted average grant date fair value per share of restricted stock awards was $1.71, $0.98 and $1.11 for the years ended December 31, 2018, 2017 and 2016, respectively.

On February 28, 2019, the Company issued 174,464 shares of service based restricted stock to employees with a grant date fair value of $2.33 per share. The vesting of these shares is dependent upon the employee's continued service with the Company. The shares will vest in three equal parts over three years.

As of December 31, 2018, unrecognized compensation cost related to restricted stock totaled $0.2 million and is expected to be recognized over a weighted average period of 1.2 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 2016 vest over a three-year period with a life of 5 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. On February 28, 2018, 2,373,411 SARs were granted which vest over a three-year period with a life of 5 years and have a $0.86 SAR price per share specified in a SAR award on the date of grant. On February 28, 2019 951,699 SARs were granted which vest over a three-year period with a life of 5 years and have a $2.33 SAR price per share specified in a SAR award on the date of grant.

For the year ended December 31, 2017, 1,049,528 SARs were granted, all having an exercise price of $1.20 per share. One-third of the SARs are to vest on or after the first anniversary of the grant date at such time when the market price per share of our common stock exceeds $1.30; one-third of the SARs are to vest on or after the second anniversary of the grant date at such time when the share price exceeds $1.50; and one-third of the SARs are to vest on or after the third anniversary of the grant date at such time when the share price exceeds $1.75. SARs granted in 2017 vest over a three year period with a life of 5 years.

Total compensation expense related to our SARs awards during the year ended December 31, 2018 was $1.6 million.

SAR activity for the year ended December 31, 2018 is provided below:

	Number of Shares Underlying SARs	Weighted Average Exercise Price Per Share	Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2018	1,076	$ 1.17		
Granted	2,373	0.86		
Exercised	(47)	1.20		
Forfeited/expired	(33)	0.86		
Outstanding at December 31, 2018	3,369	0.95	3.93	$ 1,896
Exercisable at December 31, 2018	371	1.15	2.99	$ 167

Other benefit plans

We sponsor a 401(k) plan, with a company match feature, for our employees. Costs incurred in the years ended December 31, 2018, 2017 and 2016 for the Company's matching contribution and for administering the plan were approximately $0.3 million, $0.2 million and $0.3 million, respectively.

16. SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Our unaudited quarterly results for years ended December 31, 2018 and 2017 were prepared in accordance with GAAP, 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)			
2018:				
Total revenues	$ 27,645	$ 24,426	$ 25,266	$ 27,606
Total operating costs and expenses	14,631	19,017	7,940	12,433
Operating income	13,038	5,723	17,320	15,206
Income from continuing operations	8,711	887	78,626	10,504
Loss from discontinued operations	(52)	(343)	(21)	(80)
Net income	8,659	544	78,605	10,424
Basic net income per share	$ 0.15	$ 0.02	$ 1.31	$ 0.17
Diluted net income per share	$ 0.15	$ 0.02	$ 1.28	$ 0.17
Basic income from continuing operations per share	$ 0.15	$ 0.02	$ 1.31	$ 0.17

Diluted income from continuing operations per share	$	0.15	$	0.02	$	1.28	$	0.17

As discussed further in Note 8, deferred income tax expense (benefit) for the three months ended September 30 and December 31, 2018 included $(66.6) million and $9.0 million, respectively, related to the recognition of deferred tax assets as well as adjustments to valuation allowances.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	(in thousands of dollars except per share information)							
2017:								
Total revenues	$	21,266	$	20,425	$	18,178	$	17,156
Total operating costs and expenses		13,055		15,068		14,454		14,413
Operating income		8,148		5,587		3,721		2,495
Income (loss) from continuing operations		4,435		2,451		(148)		3,534
Loss from discontinued operations		(176)		(168)		(174)		(103)
Net income (loss)		4,259		2,283		(322)		3,431
Basic net income (loss) per share	$	0.07	$	0.04	$	0.00	$	0.06
Diluted net income (loss) per share	$	0.07	$	0.04	$	0.00	$	0.06
Basic income (loss) from continuing operations per share	$	0.07	$	0.04	$	0.00	$	0.06
Diluted income (loss) from continuing operations per share	$	0.07	$	0.04	$	0.00	$	0.06

As discussed in Note 2, subsequent to the issuance of our condensed consolidated financial statements for the three months ended September 30, 2018, we identified an error related to a gross up in oil and natural gas properties for the establishment of a deferred tax liability of $18.6 million as a result of differences between the book basis attributable to leasehold costs incurred in connection with the extension of the Etame Marin block production sharing contract with Gabon entered into on September 25, 2018 and the tax basis in these costs. The condensed consolidated balance sheet below reflects the impact of this error as of September 30, 2018.

	As of September 30, 2018		
	As Previously Reported	Adjustments	As Restated
ASSETS			
Current assets:			
Cash and cash equivalents	$ 33,715	$ —	$ 33,715
Restricted cash	1,025	—	1,025
Receivables:			
Trade	—	—	—
Accounts with joint venture owners, net of allowance of $0.5 million	931	—	931
Other	408	—	408
Crude oil inventory	2,232	—	2,232
Prepayments and other	3,058	—	3,058
Current assets - discontinued operations	3,222	—	3,222
Total current assets	44,591	—	44,591
Oil and natural gas properties, at cost - successful efforts method:			
Proved properties	398,072	11,539	409,611
Unproved properties	16,698	7,073	23,771
Equipment and other	8,821	—	8,821
	423,591	18,612	442,203
Accumulated depreciation, depletion, amortization and impairment	(388,660)	—	(388,660)
Net oil and natural gas properties, equipment and other	34,931	18,612	53,543
Other noncurrent assets:			
Restricted cash	918	—	918
Value added tax and other receivables, net of allowance of $2.1 million	2,306	—	2,306
Deferred tax assets	68,807	(18,612)	50,195
Abandonment funding	10,808	—	10,808
Total assets	$ 162,361	$ —	$ 162,361
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 7,219	$ —	$ 7,219
Accounts with joint venture owners	5,496	—	5,496
Accrued liabilities and other	17,662	—	17,662
Foreign taxes payable	1,775	—	1,775
Current portion of long term debt	—	—	—
Current liabilities - discontinued operations	15,191	—	15,191
Total current liabilities	47,343	—	47,343
Asset retirement obligations	14,459	—	14,459
Other long-term liabilities	1,264	—	1,264
Long term debt, excluding current portion, net	—	—	—
Total liabilities	63,066	—	63,066
Commitments and contingencies			
Shareholders' equity:			
Preferred stock, none issued, 500,000 shares authorized, $25 par value	—	—	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 67,092,825 shares issued and 59,538,878 shares outstanding	6,709	—	6,709
Additional paid-in capital	72,229	—	72,229
Less treasury stock, 7,553,947 shares at cost	(37,798)	—	(37,798)
Retained earnings	58,155	—	58,155
Total shareholders' equity	99,295	—	99,295
Total liabilities and shareholders' equity	$ 162,361	$ —	$ 162,361

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 U.S. (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,		
	2018	**2017**	**2016**
Costs incurred during the year:		*(in thousands)*	
International:			
Exploration costs - capitalized	**$ —**	$ —	$ —
Exploration costs - expensed	**14**	7	5
Acquisition of properties	**36,239**	—	5,754
Development costs	**—**	—	—
Total	**$ 36,253**	$ 7	$ 5,759

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,	
	2018	**2017**
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 30,059**	$ 15,668
Properties being amortized [(1)]	**409,487**	389,935
Total capitalized costs	**$ 439,546**	$ 405,603
Less accumulated depletion, amortization and impairment	**(387,868)**	(384,014)
Net capitalized costs	**$ 51,678**	$ 21,589

(1) Includes $7.8 million and $11.0 million asset retirement cost in 2018 and 2017, respectively . During the year ended December 31, 2018, we recorded a downward revision of $6.5 million to the ARO liability as a result of a change in the expected timing of the abandonment costs when the period of exploitation under the Etame PSC was extended to at least September 16, 2028 as discussed further in Note 9.

Results of Operations for Oil and Natural Gas Producing Activities

	International			U.S.		
	Year Ended December 31,			Year Ended December 31,		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
			(in thousands)			
Crude oil and natural gas sales	**$ 104,938**	$ 76,978	$ 59,460	**$ 5**	$ 47	$ 324
Production costs and other expense [(1)]	**(37,865)**	(41,558)	(38,160)	**(13)**	(26)	(166)
Depreciation, depletion, amortization	**(5,176)**	(6,196)	(6,531)	**(162)**	(1)	(151)
Exploration expenses	**(14)**	(7)	(5)	**—**	—	—
Impairment of proved properties	**—**	—	—	**—**	—	(88)
Other operating expense	**—**	—	(8,853)	**—**	—	—
Bad debt recovery (expense)	**77**	(452)	(1,222)	**—**	—	—
Income tax benefit (expense)	**(37,591)**	(11,638)	(9,248)	**36**	1,260	—
Results from oil and natural gas producing activities	**$ 24,369**	$ 17,127	$ (4,559)	**$ (134)**	$ 1,280	$ (81)

(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 Policies and Estimates – Successful Efforts Method of Accounting for Oil and Natural Gas Activities."* For a discussion of our reserve estimation process, including internal controls, see "*Item 1. Business – Reserve Information*."

Proved reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2016	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	—
Production	(1,518)	—
Revisions of previous estimates	1,925	—
Balance at December 31, 2017	3,049	—
Production	(1,369)	—
Additions associated with PSC Extension	2,235	—
Revisions of previous estimates	1,455	—
Balance at December 31, 2018	5,370	—

Proved developed reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2016	2,855	1,053
Balance at December 31, 2016	2,642	—
Balance at December 31, 2017	3,049	—
Balance at December 31, 2018	3,388	—

Our proved developed reserves are located offshore Gabon. In 2018, we replaced 270% of production by adding a total of 3.7 MMBbls of proved reserves including 2.2 MMBbls of proved reserves additions as a result of extending the Etame PSC in Gabon. We also added 1.1 MMBbls of proved reserves as a result of improved reservoir performance and another 0.4 MMBbls of proved reserves as a result of higher oil pricing. The upward revision of the previous estimates in 2017 was primarily a result of improved well performance and to a lesser degree the higher average crude oil prices. Reserves in 2018 also increased as a result of the PSC Extension. 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 MBbls) 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 MBbls).

We maintain a policy of not booking proved reserves on discoveries until such time as a development plan has been prepared for the discovery indicating that the development well will be drilled within five years from the date of its initial booking. Additionally, the development plan is required to have the approval of our joint owners 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 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. However, all future costs related to future property abandonment when the wells become uneconomic to produce are included in future development costs for purposes of calculating the standardized measure of discounted net cash flows. There were no discounted future net cash flows attributable to U.S. properties as of December 31, 2018, 2017 and 2016.

(In thousands)	International		
	2018	2017	2016
Future cash inflows	$ **387,415**	$ 165,341	$ 106,583
Future production costs	**(228,999)**	(108,387)	(71,260)
Future development costs [1]	**(27,151)**	(8,803)	(10,887)
Future income tax expense	**(38,512)**	(24,798)	(16,346)
Future net cash flows	**92,753**	23,353	8,090
Discount to present value at 10% annual rate	**(12,697)**	(863)	1,351
Standardized measure of discounted future net cash flows	$ **80,056**	$ 22,490	$ 9,441

[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).

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:

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Balance at beginning of period	$ **22,490**	$ 9,441	$ 27,141
Sales of oil and natural gas, net of production costs	**(71,962)**	(37,328)	(22,198)
Net changes in prices and production costs	**55,468**	35,257	(25,958)
Revisions of previous quantity estimates	**33,344**	18,743	19,558
Purchases	**43,236**	—	3,400
Divestitures of reserves	**—**	—	(835)
Changes in estimated future development costs	**1,075**	(692)	—
Development costs incurred during the period	**763**	2,298	—
Accretion of discount	**4,530**	2,482	4,657
Net change of income taxes	**(8,889)**	(7,432)	4,052
Change in production rates (timing) and other	**1**	(279)	(376)
Balance at end of period	$ **80,056**	$ 22,490	$ 9,441

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 2018, the average of such prices reflected a 32% increase during the year and were $70.83 per Bbl for crude oil from Gabon when compared to the average of such prices for 2017 of $53.49 per Bbl for crude oil from Gabon.

Under the Etame 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 Etame PSC was awarded by a decree from . Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the Etame 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 February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for Profit Oil (see discussion in Note 7 above).

The Consortium maintains a Cost Account, which entitles it to receive a portion of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). Prior to the PSC Extension, the Consortium was entitled to a 70% Cost Recovery Percentage. Under the PSC Extension, the Cost Recovery Percentage is increased to 80% for the ten-year period from September 17, 2018 through September 16, 2028. After September 16, 2028, the Cost Recovery Percentage returns to 70%. At December 31, 2018, there was $65.5 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.

The Etame PSC allows for exploitation period through the carve-out of development areas which include all producing fields in the Etame Marin block as well as additional undeveloped areas where reserves may exist. The PSC Extension extends the term for each of the three exploitation areas in the Etame Marin block for a period of ten years with effect from September 17, 2018, the effective date of the PSC Extension. Prior to the PSC Extension, the exploitation periods for the three exploitation areas in the Etame Marin block would expire beginning in June 2021. The PSC Extension also grants the Consortium the right for two additional extension periods of five years each. This compares to the economic end date of reserves under the current reserve report prepared by our independent reserve engineering firm of Netherland, Sewell & Associates, Inc.

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, 2018, we have no proved reserves related to Block P in Equatorial Guinea.

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 S8 (Nos. 333-218824, 333-197180 and 333-183515) of VAALCO Energy, Inc. of our reports dated March 8, 2019, relating to the consolidated financial statements and financial statement schedule and the effectiveness of VAALCO Energy Inc.'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, 2018.

/s/ BDO USA, LLP

Houston, Texas
March 8, 2019

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

Exhibit 23.2

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, 2018. 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, 2018, 2017, and 2016 and to the inclusion of our report dated February 1, 2019, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2018. We further consent to the incorporation by reference thereof into VAALCO Energy, Inc.'s Registration Statements on Forms S-8 (Nos. 333-218824, 333-197180, and 333-183515).

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Houston, Texas
March 8, 2019

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 8, 2019

/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, Philip F. Patman, Jr., 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 8, 2019

/s/ Philip F. Patman, Jr.
Philip F. Patman, Jr.
Chief 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, 2018, 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 8, 2019

/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, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Philip F. Patman, Jr., Chief Financial 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 8, 2019

/s/ Philip F. Patman, Jr.
Philip F. Patman, Jr., Chief Financial Officer

February 1, 2019

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 reserves and future revenue, as of December 31, 2018, to the VAALCO Gabon S.A. (VAALCO) interest in certain oil properties located in the Etame Marin Permit, 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. 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 United States 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 gross (100 percent) oil reserves and the net oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2018, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net[(1)]	Total	Present Worth at 10%
Proved Developed Producing	10,364.9	2,800.5	52,507.1	49,860.4
Proved Developed Non-Producing	2,174.4	587.5	11,812.4	9,342.0
Proved Undeveloped	7,336.3	1,982.2	28,433.8	20,854.1
Total Proved	19,875.6	5,370.3	92,753.3	80,056.5

Totals may not add because of rounding.

(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 ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Etame Marin Permit. Included are determinations of cost oil incorporating the unrecovered cost pool 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 Gabonese income taxes, referred to herein 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 Gabonese government. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, operating expenses, and production taxes and credits for VAALCO's share of state reimbursement but before consideration of any United States 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 Brent spot price for each month in the period January through December 2018. The average price of $71.54 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $70.83 per barrel of oil is held constant throughout the lives of the properties.

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 include the cost of workovers and recurring electrical submersible pump replacements. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and internal planning budgets. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. 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, 2028. 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. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

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 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

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

Date Signed: February 1, 2019

Date Signed: February 1, 2019

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 210.410(a). Also included is supplemental information from (1) the 2018 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 2018 Petroleum Resources Management System:

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

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. 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.