VAALCO ENERGY INC /DE/
Form 10-K
March 07, 2018

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, 2017

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or 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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 2017 was approximately $54.2 million based on a closing price of $0.94 on June 30, 2017.

As of February 28, 2018, there were outstanding 58,862,876 shares of common stock, $0.10 par value per share, of the registrant.

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

VAALCO ENERGY, INC.

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Glossary 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.
- Mcf — One thousand cubic feet of natural gas.
- MMbtu — One million British thermal units, a measure commonly used for natural gas pricing.
- MMcf — One million cubic feet of natural gas.
- MMBbl — One million Bbls.

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

- Carried interest — Working interest owners (defined below) whose share of costs are paid by the non-carried working interest owners and whose share of revenues are paid to non-carried working interest owners until such owners costs have been repaid.
- Consortium –A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under a Production Sharing Contract with the Republic of Gabon.
- PSC — A production sharing contract; Etame PSC is the Etame Production Sharing Contract, as amended, and as it may be further amended, that we have entered into with the Republic of Gabon, related to the Etame Marin block located offshore Gabon.
- FPSO — A floating, production, storage and offloading vessel.
- Participating interest — Working interest (as defined below) attributable to 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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

- Proved oil and natural gas reserves — Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible (from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

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

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

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

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

- Reserves — Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.
- Undeveloped oil and natural gas reserves — Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

- Unproved properties — Properties with no proved reserves.

Terms used to assign a present value to reserves

- Standardized measure — 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 report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, (the "Exchange Act") which are intended to be covered by the safe harbors created by those laws. We have based these forward-looking statements on our current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of our operations. All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements 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", "wi "should," "may," "likely," "plan," "probably" or similar expressions, we are making forward-looking statements. Many risks a 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;
- 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;
- future capital requirements and our ability to attract capital;
- our ability to replace our loan facility under our agreement with the International Finance Corporation ("IFC credit facility"), as amended ("Amended Term Loan Agreement") with another credit facility to help fund our future capital requirements;
- 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 extend the license period for the Etame block offshore Gabon;

- our ability to meet the financial covenants of our Amended Term Loan Agreement;
- 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;

- 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;
- our ability to meet the continued listing standards of the New York Stock Exchange ("NYSE"), or to cure any deficiency in meeting the listing standards;
- the timing and effectiveness of our remediating the significant deficiencies and material weaknesses in our internal control over financial reporting;
- 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;
- our ability to pay the expenditures required in order to develop certain of our properties offshore Equatorial Guinea;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- 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 venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit; and
- actions of operators of our oil and natural gas properties.

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

Our forward-looking statements speak only as of the date made, and 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 are expressly qualified in their entirety by this "Special Note Regarding Forward-Looking Statements," which constitute cautionary statements.

PART I

Item 1. Business

BACKGROUND

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

We are 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 our Etame Production Sharing Contract (“Etame PSC”) related to the Etame Marin block located offshore the Republic of Gabon (“Gabon”) in West Africa. We also currently own interests in an undeveloped block offshore Equatorial Guinea, West Africa. As discussed further in Note 5 to the audited consolidated financial statements included in Part III, Item 8 – “Consolidated Financial Statements and Supplementary Data”(“Financial Statements”), we have discontinued operations associated with our activities in Angola, West Africa.

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

STRATEGY

Our strategy is to utilize our technical expertise and operational infrastructure, with a focus on extending our existing license in Gabon, further developing our Gabon resources and expanding into new development opportunities in West Africa. 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. Beginning in the third quarter of 2014, the global prices for oil and natural gas began a dramatic decline, which continued through 2015 and into 2016. During this period, we scaled back our global operations, divested non-core assets, amended our credit agreement and focused on reducing costs and maximizing our cash flows. Crude prices improved during 2017 from $55 per Bbl at the end of 2016 to $67 per Bbl at the end of 2017. We have conducted no drilling activities in 2016 and 2017, but we may drill two or three development wells in 2018, subject to partner and governmental approval.

At December 31, 2017, we had estimated net proved developed reserves of 3.0 million barrels of oil equivalent. For 2017, our reserves replacement amount was equal to 127% of our 2017 Gabon production, as reflected in the reserve report issued by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. (NSAI"). We added 1.3 MMBOE of reserves through reservoir performance additions and 0.6 MMBOE 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 $40.35 for the 2016 year-end report to $53.49 for the 2017 year-end report.

Assuming oil and natural gas prices continue at current levels (and holding other variables constant), we believe that through March 31, 2019 we will be able generate cash flows sufficient to cover our operating expenses. However, an unfavorable resolution of our current obligations or a return to the levels of depressed oil and natural gas prices seen in the first quarter of 2016 would have a material adverse effect on our liquidity, financial condition and results of operations. To fund any potential growth opportunities going forward, we are considering multiple alternatives, including, but not limited to, additional debt or equity financing through traditional sources or strategic partnerships (see "— Strategic Alternatives and Operating Strategies" below). There can be no guarantee of future capital acquisition or fundraising success. We currently have no availability for additional borrowings under our Amended Term Loan Agreement. Our current cash position and our ability to access additional capital may limit our available opportunities.

We believe that improved crude oil prices as well as increases in our reserves have favorable implications for our company's cash flows, potential access to capital, liquidity and financial condition and we may incur capital expenditures in 2018 for development, which may require additional capital.

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

Our strategic growth alternatives are as follows:

- Identify viable acquisition targets and/or merger opportunities;
- Consider joint ventures that allow us to leverage our operating capabilities and proven West Africa experience;
- Exit non-core exploration assets to focus on development opportunities; and

- Obtain external funding necessary for growth opportunities and maintaining our liquidity.

Our operating strategies for 2018 are financially driven and are as follows:

- Maximize our cash flow;
- Manage our capital expenditures and improve our financial flexibility:
- Identify new sources of liquidity to strengthen our balance sheet and fund new opportunities, including development drilling;
- Subject to government and partner approvals, undertake the next Etame Marin block drilling program in 2018;
- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in prices;
- Continue our focus on operating safely and complying with internationally accepted environmental operating standards;
- Optimize production through careful management of wells and infrastructure, including minimizing downtime;
- Further reduce field-level costs;
- Minimize administrative costs; and
- Opportunistically hedge against exposures to changes in oil prices.

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

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

· Our operational capacity to take on new development projects;
· Our familiarity with local practices and infrastructure; and
· Our market intelligence to provide early insight into available opportunities.

SEGMENT AND GEOGRAPHIC INFORMATION

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

Gabon Segment

Offshore – Etame Marin Block

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

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

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

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

Southeast Etame. We drilled one well in the Southeast Etame field in 2015, and this well is continuing to produce. The Southeast Etame field is included in the exploitation area for the Etame field which has a term of 20 years through June 2021.

North Tchibala field. We drilled two wells in the North Tchibala field in 2015. These wells targeted the Dentale formation, and are producing currently. The North Tchibala field is included in the exploitation area for the Avouma/South Tchibala field. This exploitation area expires in March 2025.

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 drilling the first well of a multi-well drilling campaign in 2014. As a result of this campaign, in 2015, two new development wells were drilled in the Etame field and brought on production, and three new development wells were drilled and brought on production in the Southeast Etame field and the North Tchibala field. The first well drilled was not placed on production due to high levels of hydrogen sulfide (“H_2S”) present in fluids produced from the well. See “— Hydrogen Sulfide Impact” below.

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

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

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 5 of the Financial Statements for further discussion.

In July 2017, the ESP in the South Tchibala 2-H well failed, resulting in the well being temporarily shut-in.

In October 2017, we began workover operations on the South Tchibala 1-HB well. These operations were successfully completed in November 2017, and the well was returned to production. However, this well experienced an ESP failure in late December, and it remains temporarily shut-in. We began workover operations on the South Tchibala 2-H well in November 2017. These operations were successfully completed in November 2017, and the well was returned to production. In November 2017, the Avouma 2-H well experienced ESP failures, and the well remains temporarily shut-in. We are working with the manufacturer and other technical consultants to investigate the root causes of the ESP failures. Excluding the Avouma platform wells, the wells on the other three platforms with ESPs have operated without incident for up to four years.

During July 2017, production was temporarily shut-in for periodic maintenance, and as a result, production volumes were lower in the three months ended September 30, 2017 and our production expense increased as a result of the maintenance-related costs.

Our current net production is averaging approximately 3,500 barrels of oil equivalent per day (BOEPD), down from a 4,160 barrels of oil equivalent per day (BOEPD) average for fiscal 2017 as a result of natural decline and temporarily shutting in the Avouma 2-H well.

For 2017, our total proved reserves replacement was 127% of our 2017 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 include nine 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 ten producing wells and two wells shut in at Avouma due to ESP failures. 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, 2017, 2016 and 2015, aggregate production from the block was approximately 5.6 MMBbls (1.5 MMBbls net to us), 6.2 MMBbls (1.5 MMBbls net to us) and 6.8 MMBbls (1.7 MMBbls net to us), respectively. Our net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13%.

Hydrogen Sulfide Impact

Four of our wells are currently shut-in for safety and marketability reasons because of high levels of H_2S. 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. These identified processing facilities are not economic at current forecasted oil prices. As of December 31, 2017, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2017, we had no undeveloped leasehold costs related to the Etame Marin block. The sixth extension period of the exploration acreage on the Etame Marin block expired at the end of July 2014, with the Consortium having fully met all of the obligations under its terms.

Abandonment Costs

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

We are required under the Etame PSC to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was completed in January 2016 resulting in estimated gross abandonment costs of approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $2.3 million in 2018, and $4.9 million over the years from 2019 to 2021, net of estimated interest income. 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, 2017 and 2016 were $20.2 million and $18.6 million, respectively, which are included in the total “Asset retirement obligation” line item on our consolidated balance sheets as of December 31, 2017 and 2016. 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, 2017 and 2016.

Onshore – Mutamba Iroru Block

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

Equatorial Guinea Segment

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

United States Segment

In 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 during the year ended December 31, 2017. In December 2016, we completed the sale of our interests in two producing wells in the Hefley field (Granite Wash formation) in North Texas for $0.8 million, resulting in an immaterial loss. Our remaining interests in the U.S. are inconsequential.

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

In November 2016, OPEC reached a decision to reduce its level of production effective January 1, 2017. Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. In November 2017, OPEC reached a decision to extend the period of the reduced production levels through December 2018. As a result of natural production declines, production in 2017 was not impacted by this agreement, and for 2018 we do not expect our production or drilling plans will be impacted by the agreement.

DRILLING ACTIVITY

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

	International						
	Gross				Net		
	2017	2016	2015		2017	2016	2015
Exploratory wells							
Productive	—	—	—		—	—	—
Dry	—	—	1.0	(1)	—	—	0.5
In progress	—	—	—		—	—	—
Development wells	—	—	—		—	—	—
Productive	—	—	6.0	(2)	—	—	1.8
Dry	—	—	—		—	—	—

In progress	—	—	—	—	—	—
Total wells	—	—	7.0	—	—	2.3

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

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

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the PSC and the total number of productive oil and natural gas wells as of December 31, 2017:

	International			
Acreage in thousands	Gross		Net	
Developed acreage	28.7		8.9	
Undeveloped acreage	327.0		128.0	(1)
Productive natural gas wells	—		—	
Productive oil wells	12.0	(2)	3.7	

(1)

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

(2) Includes two Avouma wells temporarily shut-in pending workovers. 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

Net Proved Reserves

In accordance with the current guidelines of the SEC, estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2017, the average of such price used for our reserve estimates was $53.49 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2016 of $40.35 per Bbl.

Reserves are reported by geographic area. International consists solely of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa. We have no proved reserves related to our other international ventures and as a result of the sale of the Hefley wells in December 2016, we have no proved reserves in the United States. There have been no estimates of total proved net oil or 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. Natural gas volumes include natural gas liquid (“NGL”) barrels which were converted to Mmcf using the relative prices of the products. The table below sets forth our estimated net proved reserve quantities for the years ended December 31, 2017, 2016, and 2015 as prepared by NSAI, independent petroleum engineers.

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	As of December 31,			
	2017		2016	2015
	(in thousands)			
Crude oil				
Proved developed reserves (MBbls)				
International	3,049		2,642	2,840
United States	—		—	15
Total proved developed reserves (MBbls)	3,049		2,642	2,855
Proved undeveloped reserves (MBbls)				
International	—	—	—	—
United States	—		—	—
Total proved undeveloped reserves (MBbls)	—		—	—
Total proved reserves (MBbls)				
International	3,049		2,642	2,840
United States	—		—	15
Total proved reserves (MBbls)	3,049		2,642	2,855
Natural gas				
Proved developed reserves (MMcf)				
International	—	—	—	—
United States	—		—	1,053
Total proved developed reserves (MMcf)	—		—	1,053
Total proved reserves (MMcf)				
International	—	—	—	—
United States	—		—	1,053
Total proved reserves (MMcf)	—		—	1,053
Total proved reserves (MBOE)	3,049		2,642	3,031
Standardized measure of discounted future net cash flows	$ 22,490		$ 9,441	$ 27,141

Changes in Proved Reserves

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

	Proved Reserves		
	Crude Oil (MBbls) (in thousands)	Natural Gas (MMCF)	Oil Equivalent (MBOE)
Balance at January 1, 2015	8,260	1,406	8,494
Production	(1,659)	(181)	(1,688)
Revisions of previous estimates	(3,746)	(172)	(3,775)
Balance at December 31, 2015	2,855	1,053	3,031
Production	(1,518)	(124)	