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, 2019

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	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.10	EGY	New York Stock Exchange
Common Stock, par value $0.10	EGY	London 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 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 28, 2019, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $97.2 million based on a closing price of $1.67 on June 28, 2019.

As of March 3, 2020, there were outstanding 57,978,990 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.

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Glossary of Terms

Terms used to describe quantities of crude 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.
- *BOPD* — One barrel of crude oil per day.
- *MBbl* — One thousand Bbls.
- *MBOPD* — One thousand barrels of crude oil per day.
- *MMBbl* — One million Bbls.

Terms used to describe legal ownership of crude 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 is 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 the Etame PSC.
- *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 crude oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of crude oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the crude 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 crude 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 crude 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 crude 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 crude 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 crude oil and natural gas reserves* — Developed crude 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 crude oil and natural gas reserves* — Proved crude oil and natural gas reserves are those quantities of crude 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 crude 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 crude oil (HKO) elevation and the potential exists for an associated natural gas cap, proved crude 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 that 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 crude 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 crude oil and natural gas or related substances to market, and all permits and financing required to implement the project.

- *Proved undeveloped crude oil and natural gas reserves* — Proved undeveloped crude 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* — Crude oil and natural gas companies use seismic data as their principal source of information to locate crude 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 that digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- *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 crude 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," and "probably" or 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 crude oil and natural gas prices;
- the discovery, acquisition, development and replacement of crude 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 or obtain debt financing arrangements;
- our ability to pay the expenditures required in order to develop certain of our properties;
- operating hazards inherent in the exploration for and production of crude oil and natural gas;
- difficulties encountered during the exploration for and production of crude oil and natural gas;
- the impact of competition;
- our ability to identify and complete complementary opportunistic acquisitions;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- weather conditions;
- the uncertainty of estimates of crude 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 crude oil to commercial markets;
- timing and amount of future production of crude oil and natural gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- 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 crude 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 that 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 the statements are 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.

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.

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 crude oil production and the costs to find and produce such crude oil. Prior to 2019, we 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. 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 September 2019, VAALCO commenced its 2019/2020 drilling campaign. During the remainder of 2019, the Company drilled one development well and one appraisal wellbore and during the first quarter of 2020, we drilled the remaining development well and appraisal wellbore required under the PSC Extension. In addition, we commenced drilling a third development well, which is expected to be completed in late March of 2020. We are now focused on maximizing value, growing reserves and increasing production and will continue our efforts to repeat similar drilling campaigns in the future. We are also pursuing accretive growth opportunities, including potential acquisitions, 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. We completed a dual listing of our common stock on the London Stock Exchange on September 26, 2019, which we believe will provide us access to additional sources of capital to help fund our growth objectives.

In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. VAALCO intends to manage both operating expenses as well as capital expenditure levels in view of the existing and expected pricing environment. In addition, the Company continues to evaluate all uses of cash and whether to pursue growth opportunities in light of ongoing economic conditions. In addition, we will evaluate whether to pursue growth opportunities in light of ongoing economic conditions.

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 crude oil prices;
- Manage capital expenditures related to Etame 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;
- Maximize our cash flow and income generation;
- Continue planning for additional development in Etame as well as future activity in Equatorial Guinea;
- Preserve a strong balance sheet by maintaining conservative leverage ratios and exhibiting financial discipline;
- Opportunistically hedge against exposures to changes in crude 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 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 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 has seven producing wells; the Avouma/South Tchibala field, which has three producing wells; the Ebouri field, which has one producing well; the Southeast Etame field, which has one producing well and the North Tchibala field, which has one producing well.

Development. As previously announced, we commenced our 2019/2020 drilling campaign in September 2019. In order to execute our drilling campaign, we contracted the Vantage Drilling International Topaz jackup drilling rig, and in September 2019, we spud the Etame 9P appraisal wellbore at the Etame field offshore Gabon. In October 2019, the Etame 9P, targeting the subcropping Dentale reservoir, was successfully drilled to a total depth of 10,260 feet and encountered both Gamba and Dentale crude oil sands. We did not encounter hydrogen sulfide ("H_2S") in either the Gamba or Dentale reservoirs, which could impact the safety and marketability of production from those wells. In December 2019, VAALCO reached total depth of approximately 8,900 feet in drilling the Etame 9H development well and completed approximately 1,000 feet of the horizontal section within the Gamba reservoir as planned. The horizontal section of the Etame 9H development well is at the top of the Gamba structure where the high-quality reservoir is approximately 45 feet thick. After installing production equipment, the Etame 9H development well was brought online at an initial rate of 5,500 BOPD gross, (1,500 BOPD net to VAALCO), with no H_2S.

Shortly after completion of the Etame 9H development well, the Company began drilling the Etame 11H horizontal development well from the Etame platform, targeting the same Gamba reservoir at a different location in the Etame field. The Company reached a total measured depth of approximately 9,022 feet in the Etame 11H development well and completed approximately 860 feet of horizontal section within the Gamba reservoir. Similar to Etame 9H well, the initial development well in the 2019/2020 program, the horizontal section of the Etame 11H well is at the top of the Gamba structure but at a different location. After installing production equipment, the Etame 11H well was brought online at an initial flow rate of approximately 5,200 BOPD gross, (1,400 BOPD net to VAALCO), in early January 2020 with no H_2S.

We drilled the SE Etame 4P appraisal wellbore to evaluate a Gamba step out area in Southeast Etame field during the first quarter of 2020. With the drilling of the SE Etame 4P appraisal wellbore, VAALCO has satisfied the drilling commitment as part of the PSC Extension that VAALCO signed in late 2018. The SE Etame 4P appraisal wellbore indicated the presence of approximately 1.0 to 2.0 MMBbls of hydrocarbons in the Gamba reservoir, and the Company began drilling a third development well, the SE Etame 4H as part of the ongoing 2019/2020 drilling campaign. This development well is expected to come online in late March of 2020.

Production. Production operations in the Etame Marin block include ten platform wells, plus three subsea wells across all fields tied back by pipelines to deliver crude oil and associated natural gas through a riser system to allow for delivery, processing, storage and ultimately offloading the crude oil from a leased FPSO vessel anchored to the seabed on the block. Production from seven of our wells is aided by an electric submersible pump ("ESP"). We have thirteen producing wells; however, one is temporarily shut-in pending workovers. 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, 2019, 2018 and 2017, aggregate production from the block was approximately 4.7 MMBbls (1.3 MMBbls net to us), 5.1 MMBbls (1.4 MMBbls net to us) and 5.6 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%. Periodically, we perform workovers on our wells to maintain or restore production. For further discussion on workovers see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Current Developments*."

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. H_2S was not encountered in any of the wells or appraisal wellbores drilled in the 2019/2020 drilling campaign. 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. We have determined that these identified processing facilities are not economically attractive at current crude oil prices. As of December 31, 2019, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2019, we had $13.8 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 Etame 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 most recent abandonment study was completed in November 2018 and resulted in estimated gross abandonment costs of approximately $61.8 million ($19.2 million, net to VAALCO) on an undiscounted basis. Through December 31, 2019, $36.7 million ($11.4 million, net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $1.5 million in 2020 and $0.8 million for 2021 through 2028. Amounts paid are reimbursable through a "Cost Account" under the Etame PSC, which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. These amounts are non-refundable. Our estimated liabilities for the abandonment of these Gabon offshore facilities as of December 31, 2019 and 2018 were $15.8 million and $14.8 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2019 and 2018. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Crude oil and natural gas properties and equipment – successful efforts method" in the line item "Wells, platforms and other production facilities" on our consolidated balance sheets as of December 31, 2019 and 2018.

Equatorial Guinea Segment

VAALCO has a 31% working interest in an undeveloped portion of a block offshore Equatorial Guinea acquired in 2012 (the "Block P interest"). The Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH") approved our appointment as operator for Block P on November 12, 2019 and we are currently waiting on a production sharing contract amendment to begin activities in Block

P. VAALCO is in commercial discussions with Levene HydroCarbon Limited ("Levene") where Levene would potentially cover all or substantially all of VAALCO's cost to drill an exploratory well and purchase a portion of VAALCO's working interest in Block P in an exchange for VAALCO serving as a non-owner operator, under a service agreement with Levene, on Blocks 3, 4 and 19 in Equatorial Guinea. Levene and VAALCO have executed a non-binding Memorandum of Understanding regarding the commercial discussions however, neither have executed any binding agreements and there can be no certainty a transaction will be completed. Further, approval of the assignment by the Equatorial Guinea Ministry of Mines and Hydrocarbons must be obtained prior to any transaction being completed. As of December 31, 2019, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. VAALCO and its current and potential future 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. The 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. As of 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. Near the end of 2019, OPEC had an agreement in place to reduce production by a total of 1.2 MBOPD until March 2020; however, we have not been advised whether this will require us to reduce production for 2020. We do not expect our production will be impacted by the agreement because of natural declines in production and capacity limitations. Nevertheless, there can be no assurance that this agreement or future agreements would not result in limitations on our production.

DRILLING ACTIVITY

We had no drilling activity during the period from January 1, 2016 through December 31, 2018. As discussed above, we commenced the 2019/2020 drilling campaign in September 2019. The following table sets forth the total number of exploratory and development wells drilled in 2019, 2018, 2017 on a gross and net basis:

	International					
	Gross			Net		
	2019	2018	2017	2019	2018	2017
Exploratory wells						
Productive	**1**	—	—	**0.3**	—	—
Dry	**—**	—	—	**—**	—	—
In progress	**—**	—	—	**—**	—	—
Development wells	**—**	—	—	**—**	—	—
Productive	**1**	—	—	**0.3**	—	—
Dry	**—**	—	—	**—**	—	—
In progress	**1**	—	—	**0.3**	—	—
Total wells	**3**	—	—	**0.9**	—	—

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the Etame PSC and the total number of productive crude oil and natural gas wells as of December 31, 2019:

	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 crude oil wells	11.0 (2)	3.4	

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

(2) Excludes two wells (Etame 10H and Ebouri 2H), which were temporarily shut-in pending workovers and excludes the Etame 8H, the Etame 5H 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 SEC guidelines, estimates of future net cash flow from our properties and the present value thereof are made using the average of the first-day-of-the-month price for each of the twelve 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 2019, the average of such price used for our reserve estimates was $63.60 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2018 of $70.83 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 crude oil or natural gas reserves filed with or included in reports to any U.S. 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, 2019, 2018 and 2017 as prepared by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI").

	As of December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Crude oil			
Proved developed reserves (MBbls)	**4,966**	3,388	3,049
Proved undeveloped reserves (MBbls)	— —	1,982 —	—
Total proved reserves (MBbls)	**4,966**	5,370	3,049

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)**
	(in thousands)
Balance at January 1, 2017	2,642
Production	(1,518)
Revisions of previous estimates	1,925
Balance at December 31, 2017	3,049
Production	(1,369)
Extensions and discoveries	2,235
Revisions of previous estimates	1,455
Balance at December 31, 2018	5,370
Production	**(1,269)**
Revisions of previous estimates	**865**
Balance at December 31, 2019	**4,966**

	As of December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Standardized measure of discounted future net cash flows	$ **70,431**	$ 80,057	$ 22,490

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 the Etame 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 were primarily related to the Etame 9H and the South Tchibala 3H wells. At December 31, 2019, the reserves associated with the Etame 9H were reclassified from proved undeveloped reserves to proved developed producing reserves. The reserves associated with the South Tchibala 3H well were removed from proved undeveloped volumes because VAALCO and the Etame joint owners decided to remove the well from the 2019 development schedule and instead drill the Etame 11H. Drilling and completing the Etame 11H well resulted in reserve additions classified as proved developed nonproducing reserves at year end 2019.

At December 31, 2019, we had estimated net proved reserves of 5.0 MMBbls. For 2019, our proved reserve additions of 0.9 MMBbl were equal to 68% of our 2019 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 offset by downward revisions of proved reserves as a result of lower average crude oil prices of 0.2 MMBbls. The decrease in the average of the first-day-of-the-month prices for each of the twelve months of the year adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was from $70.83 for the 2018 year-end report to $63.60 for the 2019 year-end report.

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 crude 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.

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 crude 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 crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude 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 crude 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, 2019, we had no PUDs because future development wells have not been approved by joint venture owners. At December 31, 2018, we had PUDs associated with two wells, one that, as such time, the Consortium had planned to drill in 2019. For the first of these two wells, we completed drilling during the last half of 2019 and the second well was completed during first quarter 2020. As a result of crude oil prices in 2017, our PUDs were uneconomic to develop at prices calculated in accordance with SEC guidelines. Accordingly, we had no PUDs recorded at December 31, 2017.

Controls over Reserve Estimates

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our crude 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 30 years of experience in the crude 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 Master's degree in petroleum engineering and Texas Professional Engineering (PE) certification, 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 crude 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 2019, 2018 and 2017 operations are shown in the tables below. All volumes are for crude oil produced from the Etame Marin block.

	Year Ended December 31,		
	2019	2018	2017
Net crude oil sales (MBbl)	**1,251**	1,442	1,423
Average crude oil sales price ($/Bbl)	$ **65.20**	$ 70.32	$ 52.58
Average production expense ($/Bbl)	$ **30.13**	$ 28.03	$ 27.90

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 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. In 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. 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 either the SEC's website 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, 2019, 2018 and 2017, 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 crude oil to Glencore were approximately 100% of revenues sold to customers for 2018. Our contract with Mercuria Energy Trading SA covers crude oil sales from February 2019 through January 2020. The Company signed a new contract with ExxonMobil Corporation ("Exxon") that covers sales from February 2020 through January 2021 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

The terms of the Etame PSC include 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.

EMPLOYEES

As of December 31, 2019, we had 111 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 crude oil and natural gas industry is highly competitive. Competition is particularly intense from other independent operators and from major crude oil and natural gas companies with respect to acquisitions and development of desirable crude 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 crude 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 crude oil and natural gas companies in addition to numerous independent crude oil companies, individual proprietors, investors and others. We also compete against companies developing alternatives to petroleum-based products, including those that are developing renewable fuels. 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 crude 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, crude oil and natural gas production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on crude 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 crude 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 crude oil and natural gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the crude 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.

2014 Hydrocarbons Law - Up until 2014, the fiscal and regulatory framework governing the exploration and production of hydrocarbons in Gabon was notably unregulated. Successive model contracts issued by the State of Gabon acted as guidelines; all fiscal aspects of each contract were negotiable between the State of Gabon and exploratory parties, including work commitments and exploration costs for each PSC.

In September 2014, Law No. 11/2014, of 28 August 2014, came into force in Gabon ("2014 Hydrocarbons Law"). The 2014 Hydrocarbons Law was not exhaustive; it sought to provide a framework of governing principles and rules, applicable to both the exploratory and extracting industry of hydrocarbons, as well as the downstream sector, to be complemented by implementing regulations.

Under the Gabonese Civil Code ("Civil Code"), laws will not have retroactive effects unless they expressly or tacitly provide otherwise. The Civil Code further provides that former laws continue to govern the effects of existing contracts, save in case of express or tacit derogation by the legislator and that, in any event, the application of a new law to existing contracts cannot modify the effects already produced by existing contracts under a former law, except via express derogation by the legislator.

The 2014 Hydrocarbons Law explicitly provided that establishment conventions, petroleum contracts, petroleum titles, mining concessions and exploitation permits concluded or granted by the State of Gabon prior to the date of its publication remained in force until their expiration date.

However, the 2014 Hydrocarbons Law further provided that unless such arrangements became consistent with the requirements of the 2014 Hydrocarbons Law, establishment conventions, mining concessions and exploitation permits in effect could not be extended or renewed. Furthermore, the 2014 Hydrocarbons Law prohibited establishment conventions and mining concessions, and provided that the exploitation of new discoveries in areas covered by existing conventions and concessions would be required to be made in accordance with the 2014 Hydrocarbons Law.

2019 Hydrocarbons Law - The 2014 Hydrocarbons Law was repealed in its entirety by Law No. 002/2019, of 16 July 2019, published on 22 July 2019 ("2019 Hydrocarbons Law"). As with the 2014 Hydrocarbons Law, the 2019 Hydrocarbons Law contains provisions applicable to both the upstream and downstream segments. However, despite the publication of the 2019 Hydrocarbons Law, there are various issues and matters yet to be fully enacted by implementing regulations.

Under the transitory provision contained in the 2019 Hydrocarbons Law, existing PSCs and other petroleum contracts, permits and authorizations remain in full force and effect until their expiration.

However, any renewal or extension of those instruments are subject to the provisions of the 2019 Hydrocarbons Law, and its implementing regulations.

The 2019 Hydrocarbons Law also provides for obligations for immediate application, irrespective of the date of signature of existing PSCs or petroleum contracts and/or granting of petroleum permits and authorizations. These include (i) the requirement for foreign producers and explorers applying for an exclusive development and production authorization to conduct their operations in Gabon through a company incorporated in Gabon rather than through branches of entities incorporated in other jurisdictions; and (ii) the obligation for all companies undertaking hydrocarbon activities to domicile their site rehabilitation funds with the Bank of Central African States, which is the Central African Economic and Monetary Community ("CEMAC") or a Gabonese bank or financial institution subject to the Central Africa Banking Commission, which supervises banks and financial institutions licensed to operate in CEMAC countries, within one year after the entry into force of the 2019 Hydrocarbons Law.

PSCs entered into between independent contractors and the State of Gabon since the implementation of the 2019 Hydrocarbons Law must include a clause providing that participation by the State of Gabon cannot exceed a 10 percent participating interest in the operations, to be carried by the contractor.

The 2019 Hydrocarbons Law also entitles the Gabon Oil Company to acquire a maximum 15 percent stake at market value in all PSCs as of the date of signature.

In addition, the 2019 Hydrocarbons Law provides that the State of Gabon may acquire an equity stake of up to 10 percent, at market value, in an operator applying for or already holding an exclusive development and production authorization.

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 Equatorial Guinea property and part of the public domain. The monetization of such hydrocarbons is to be pursued exclusively by Equatorial Guinea under its constitution, which reserves the exploitation of mineral and hydrocarbons resources exclusively to Equatorial Guinea and the public sector. However, the constitution also provides that Equatorial Guinea 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 crude 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 Equatorial Guinea. PSCs are subject to ratification by the President of the Republic of Equatorial Guinea 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 Equatorial Guinea.

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 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 grants the ministry responsible for petroleum operations ("Ministry") significantly broad regulatory, inspective and auditing powers concerning the performance of petroleum operations. These include the powers to negotiate, sign, amend and perform all contracts entered into between the State of Equatorial Guinea and independent contractors, as well as the right to access all data and information required for the control of contractors and their activities, including free access to the locations and facilities where petroleum operations are conducted.

In addition, the Ministry can also order (i) the suspension of petroleum operations; (ii) the evacuation of persons from locations; (iii) the suspension of the use of any machine or equipment; and/or (iv) any other action it deems necessary or appropriate when the Ministry determines that a given petroleum operation may cause injury to or death of persons, damage properties, or harm the environment, or whenever the national interest so requires.

Until June 2016, the Ministry responsible for petroleum operations was the Ministry of Mines, Industry and Energy, whose organization and authority was granted under Decree No. 170/2005, of 15 August 2005.

In June 2016, the President of Equatorial Guinea appointed the EG MMH and the Minister of Industry and Energy, effectively splitting the Ministry of Mines, Industry and Energy into two Ministries. However, no legislation on the organization and authority of each Ministry has been enacted, and, in effect, the EG MMH has been exercising the powers contained within the Hydrocarbons Law to the Ministry responsible for petroleum operations.

All contracts signed with the State of Equatorial Guinea for the exploration and production of hydrocarbons have taken the form of PSCs. A model PSC, approved along with the Hydrocarbons Law, must be used as the basis for any negotiation between independent contractors and the State of Equatorial Guinea. Over time, however, revised copies of the model PSC, reflecting changes made during negotiations of certain PSCs, have been used for the negotiation of subsequent PSCs.

The Hydrocarbons Law and Petroleum Regulations provide the Ministry responsible for petroleum operations with the power to award contracts for the exploration and production of hydrocarbons, and decide whether the award is made by means of competitive international public tender or direct negotiation. These contracts, however, which are to be negotiated by the Ministry, shall only become effective after they have been ratified by the President of Equatorial Guinea and on the date of delivery to the contractor of a written notice of the President's ratification. In practice, however, this notification to operators has been provided by the Ministry.

GEPetrol, established in 2001, is the national oil company of Equatorial Guinea and Sociedad Nacional de Gas de Guinea Equatorial ("Sonagas"), established in 2005, is the national gas company of Equatorial Guinea.

The Hydrocarbons Law provides that these national companies are exclusively owned by the State of Equatorial Guinea, and must be supervised by the Ministry responsible for petroleum operations.

Under the applicable laws, the State of Equatorial Guinea may elect to have, either directly or through a national company, a minimum interest of 20 percent in a PSC, although, to the Company's knowledge, Sonagas does not hold any participating interest in a PSC in effect in Equatorial Guinea.

The State of Equatorial Guinea's interest (through GEPetrol or otherwise) may be, and typically is, carried. No costs are paid by the State of Equatorial Guinea or GEPetrol with respect to a carried interest. The Hydrocarbons Law provides that the State of Equatorial Guinea (through GEPetrol or otherwise) will only be required to contribute to any cost for petroleum operations that it has a carried interest in from the period where it notifies the contractor that it no longer wants its interest carried. In effect, however, the carry normally ends with the approval of the development and production of the asset subject to the PSC.

The terms and effects of the carry of an interest of the State of Equatorial Guinea (through GEPetrol or otherwise) are not clearly established in the Hydrocarbons Law or the Petroleum Regulations; the contractor that carries the State of Equatorial Guinea's interest is given the right to a percentage of the cost recovery oil pertaining to that interest, as agreed in each PSC.

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 crude 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 crude 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. However, the extent that 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 crude 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.

Item 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 that we consider immaterial based on information currently available to us may also materially adversely affect us.

Risks Related to Our Business

Crude 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, crude oil and natural gas reserves value and future rate of growth are substantially dependent upon prevailing prices for crude oil and natural gas. Our ability to enter into debt financing arrangements and to obtain additional capital on reasonable terms is also substantially dependent on crude oil and natural gas prices. Historically, world-wide crude oil and natural gas prices and markets have been volatile and may continue to be volatile in the future. 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. During 2019, the spot price per Bbl of Brent crude oil ranged from a high of $75 to a low of $53. The average price at which we sold our crude oil in 2019 was $65.20 per Bbl as compared to $70.32 per Bbl in 2018 and $52.58 per Bbl in 2017. In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. VAALCO intends to manage both operating expenses as well as capital expenditure levels in view of the existing and expected pricing environment. In addition, the Company continues to evaluate all uses of cash and whether to pursue growth opportunities in light of ongoing economic conditions.

Because the crude oil price we are required to use by the SEC to estimate our future net cash flows is the average of the first day of the month 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 crude oil and natural gas prices increase.

Prices for crude oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude 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 crude oil and natural gas, actions by OPEC member countries and other state-controlled oil companies to agree upon and maintain crude oil price and production controls, the level of consumer demand that is impacted by economic growth rates, weather conditions, domestic and foreign governmental regulations and taxes, the price and availability of alternative fuels, technological advances affecting energy consumption, the health of international economic and credit markets, changes in the level of demand resulting from global or national health epidemics and concerns, such as the recent coronavirus 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 crude oil and natural gas production. Moreover, our commodity price hedging arrangements may not fully mitigate the effects volatility in crude oil and natural gas prices and may also curtail benefits from future increases in commodity prices.

In the event of depressed crude oil and natural gas prices, there is the risk that, among other things:

- our revenues, cash flows and profitability may decline substantially, which could also indirectly impact expected production by reducing the amount of funds available to engage in exploration, drilling and production;
- third parties' confidence in our commercial or financial ability to explore and produce crude oil and natural gas could erode, which could impact our ability to execute on our business strategy;
- it may become more difficult to retain, attract or replace key employees; and
- our suppliers, hedge counterparties, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events may have a material adverse effect on our business, results of operations and financial condition.

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

At December 31, 2019, we had no PUDS. As discussed above in "Item 1. Business — *Segment and Geographic Information — Gabon Segment*", we commenced our 2019/2020 drilling program during September 2019.

Our future success depends upon our ability to find, develop or acquire additional crude oil and natural gas reserves that are economically recoverable. In general, production from crude 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 crude 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 crude 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. Additionally, seismic and other technology does not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or economically producible. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including declines in crude oil or natural gas prices and/or prolonged periods of historically low crude oil and natural gas prices, 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. If we are unable to increase our proved quantities, there will likely be a material impact on our cash flows, business and operations.

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 13 producing wells; however, one is currently temporarily shut-in pending workovers. Production from these fields constituted 100% of our total production for the year ended December 31, 2019. In addition, at December 31, 2019, 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. 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 crude 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. In particular, offshore drilling and development operations require highly capital-intensive techniques.

Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including 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. If we are unable to continue drilling operations and we do not replace the reserves we produce or acquire additional reserves, our reserves revenues and cash flow will decrease over time, which could have a material effect on our ability to continue as a going concern.

Our business requires significant capital expenditures, and we may not be able to obtain needed capital or financing to fund our exploration and development activities or potential acquisitions on satisfactory terms or at all.

Our exploration and development activities as well as our active pursuit of complementary opportunistic acquisitions are capital intensive. To replace and grow our reserves, we must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude 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, the EG MMH approved our appointment as technical operator on November 12, 2019. Since we have been 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 crude oil prices, thereby adversely affecting their ability to make timely payment of cash calls.

If low crude oil and natural gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to enter into debt financing arrangements, 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 or to acquire additional reserves.

We do not currently have any commitments for future external funding for capital expenditures or acquisitions beyond cash generated from operating activities. 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 and fund acquisitions. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing stockholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities or our ability to make future acquisitions. 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 or prevent us from consummating acquisitions of additional reserves. Such a curtailment in operations or activities could lead to a decline in our estimated net proved reserves, and would likely materially adversely affect our business, financial condition and results of operations.

If crude oil and natural gas prices decline materially, we may be required to take write-downs in the value of our crude 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 average price received for crude oil and natural gas based on closing prices of the average of the first day of the month price over the twelve-month period prior to the end of the reporting period. During 2019, 2018 and 2017, 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. In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. If at March 31, 2020 prices remain at this level or decline further, we may be required to take write-downs in the value of our crude oil and natural gas properties.

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 crude 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 for 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 crude 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.

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, CEMAC 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 crude 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 the assessments related to this audit will have significant, if any, negative impact on our reported earnings or cash flows, we can make no assurances that this will be the case. In addition, if a dispute arises with our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign crude oil ministries and national oil companies, to the jurisdiction of the U.S.

As part of securing the first of two five-year extensions to the Etame PSC, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. On March 5, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account transferred the funds to the CEMAC, of which Gabon is one of the six member states. The U.S. dollars were converted to local currency with a credit back to the Gabonese branch. The Etame PSC provides these payments must be denominated in U.S. dollars and the CEMAC regulations provide for establishment of a U.S. dollar account with the Central Bank. Although we have requested establishment of such account, the Central Bank has not complied with our requests. As a result, we were not able to make the annual abandonment funding payment in 2019. Pursuant to Amendment No. 5 to the Etame PSC, in the event that the Gabonese bank fails for any reason to reimburse all of the principal and interest due, we shall no longer be held liable for the resulting shortfall in funding the obligation to remediate the sites. For additional information, see "–Our results of operations, financial conditions and cash flows could be adversely affected by changes in currency exchange rates and regulations."

Private ownership of crude oil and natural gas reserves under crude 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.

For instance, the terms of the Etame PSC include provisions for, among other things, payments to the government of Gabon for a 13% royalty interest based on crude oil production at published prices and payments for a shared portion of "profit oil", based on daily production rates, which such "profit oil" can be taken in-kind through taking crude oil barrels rather than making cash payments.

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.

Acquisitions and divestitures of properties and businesses may subject us to additional risks and uncertainties, including that acquired assets may not produce as projected, may subject us to additional liabilities and may not be successfully integrated with our business. In addition, any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sales or divestments.

One of our growth strategies is to capitalize on opportunistic acquisitions of crude oil and natural gas reserves and/or the companies that own them and other strategic transactions that fit within our overall business strategy. Any future acquisition will require an assessment of recoverable reserves, title, future crude oil and natural gas prices, operating costs, potential environmental hazards, potential tax and employer liabilities, regulatory requirements 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 crude 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 (including potential regulatory actions) that we are not indemnified for or that our indemnity, insurance or other protection is inadequate to protect against potential losses;
- an increase in our costs or a decrease in our revenues associated with any claims or disputes with governments or other interest owners;
- an incurrence of non-cash charges in connection with an acquisition and the potential future impairment of goodwill or intangible assets acquired in an acquisition;
- the risk that crude 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 during the acquisition and throughout the integration process;
- losses of key employees at the acquired businesses;
- difficulties in operating a significantly larger combined organization and adding operations;
- delays in achieving the expected synergies from acquisitions;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- challenges in coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations 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 addition, acquisitions of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger.

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. In addition, we may be required to recognize losses in accordance with exit or disposal activities.

We may experience a financial loss if our significant customer fails to pay us for our crude oil or natural gas or reduces the volume of crude oil and natural gas that they purchase from us.

Our ability to collect payments from the sale of crude oil and natural gas to our customer depends on the payment ability of our customer base, which includes several significant customers. If our significant customer fails to pay us for any reason or letters of credit are insufficient or unavailable to mitigate the risk of nonpayment from our significant customer, we could experience a material loss. In addition, if our significant customer ceases to purchase our crude oil or natural gas or reduce the volume of the crude oil or natural gas that they purchase from us, the loss or reduction could have a detrimental effect on our production volumes and may cause a temporary interruption in sales of, or a lower price for, our crude oil and natural gas.

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.

We monitor the economic and political environments of the countries that 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;
- the incurrence of significant costs for security personnel and systems;
- 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;
- the imposition of U.S. government or international sanctions that limit our ability to conduct our business;
- 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 flows. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks. If any violent action causes us to become involved in a dispute, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States or international arbitration, which could adversely affect the outcome of such dispute.

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

As a crude 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, and 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 crude oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- 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;
- 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;
- a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues; and
- business interruptions, including use of social engineering schemes and/or ransomware, could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

To protect against such attempts of unauthorized access or attack, we have implemented multiple layers of cybersecurity protections, infrastructure protection technologies, disaster recovery plans and employee training. While we have invested significant amounts in the protection of our technology systems and maintain what we believe are adequate security controls over sensitive data, there can be no guarantee such plans, to the extent they are in place, will be effective.

Any cyber incident 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 crude 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 crude 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 crude 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 crude 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 crude oil and natural gas prices; contract for drilling equipment; and secure trained personnel. Our competitors may also use superior technology that we may be unable to afford or that would require costly investment by us in order to compete.

Competition due to advances in renewable fuels may lessen the demand for our products and negatively impact our profitability.

Alternatives to petroleum-based products and production methods are continually under development. For example, a number of automotive, industrial and power generation manufacturers are developing alternative clean power systems using fuel cells or clean-burning gaseous fuels that may address increasing worldwide energy costs, the long-term availability of petroleum reserves and environmental concerns, which if successful could lower the demand for crude oil and natural gas. If these non-petroleum based products and crude oil alternatives continue to expand and gain broad acceptance such that the overall demand for crude oil and natural gas is decreased, it could have an adverse effect on our operations and the value of our assets.

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

The crude 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 crude 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.

The physical and regulatory impact of climate change could disrupt our business and cause us to incur significant costs in preparing for or responding to their 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.

In addition, we expect continued and increasing regulatory attention to climate change issues and emissions of greenhouse gases, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of crude oil and natural gas combustion). For example, in April 2016, 195 nations, including Gabon, Equatorial Guinea and the U.S., signed and officially entered into an international climate change accord (the “Paris Agreement”). The Paris Agreement calls for signatory countries to set their own greenhouse gas emissions targets, make these emissions targets more stringent over time and be transparent about the greenhouse gas emissions reporting and the measures each country will use to achieve its greenhouse gas targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is effectively a successor agreement to the Kyoto Protocol treaty, an international treaty aimed at reducing emissions of greenhouse gases, to which various countries and regions are parties. It cannot be determined at this time what effect the Paris Agreement, and any related greenhouse gas emissions targets, regulations or other requirements, will have on our business, results of operations and financial condition. It also cannot be determined what impact the U.S.'s withdrawal from the Paris Agreement will have on international climate change regulation. This regulatory uncertainty, however, could result in a disruption to our business or operations.

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 crude oil and natural gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, crude 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 that we are not fully insured against 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 that these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of crude 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, 2019, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable crude 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 crude 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 crude 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 the first day of the month prices received for crude oil and natural gas for the preceding twelve months. Future reductions in prices, below the average calculated for 2019, 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 crude oil and natural gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of crude 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 crude 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 U.S. at favorable tax rates.

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 flows. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our results of operation, 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 that 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, crude 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 crude 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 that 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 Marin block 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 VAALCO) 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.

Our operations may be adversely affected by political, social and economic instability of the region in which we operate.

We operate in countries that have experienced political, social and economic instability or are in close proximity to areas where such events have and continue to occur. In Gabon, allegations of voting irregularities were reported after the most recent presidential elections in August 2016. The contested re-election of Ali Bongo triggered protests and violence between supporters of the opposition candidate, Jean Ping, who declared himself the victor, and government security forces. This public unrest included arson of the Lower House of Parliament, damage of private property and damage to the headquarters of the opposition party. On January 7, 2019, a group of five Gabonese soldiers briefly took control of the Gabon Television headquarters. Government security forces regained control of the broadcasting headquarters the same day and the state's operations returned to normal the next day. Mr. Bongo suffered a stroke during an official visit to Saudi Arabia in October 2018 after which he has spent extensive periods recuperating outside of Gabon. Mr. Bongo has since returned to Gabon to fulfill his role as president.

Since 2017, Gabonese employee unions in the judicial administration, tax administration and other financial institutions have declared a succession of strikes. These strikes have caused various administrative delays.

In Equatorial Guinea, Teodoro Obiang Nguema Mbasogo has been President since 1979. There have been several attempted coups in recent history, notably in 2002, 2004 and 2009, when the Presidential Palace allegedly came under attack. In January 2018, the authorities claimed to have thwarted an attempted coup the previous month.

Since 2006, the President of Equatorial Guinea has changed Government appointments every two or three years. In May 2018, the Supreme Court upheld a ban on the country's main opposition party, the CI Party, which was accused of involvement in acts of violence ahead of elections held in November 2017.

While we monitor the economic and political environments of the countries in which we operate, 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.

We operate in countries and regions that are subject to legal and regulatory risk.

Investment in companies with assets in developing countries is generally only suitable for sophisticated investors who fully appreciate the significance of the risks involved in, and are familiar with, investing in developing countries. Investors should also note that developing countries could be subject to rapid change and that the information set out in this document may become outdated relatively quickly. Moreover, financial turmoil in developing countries tends to adversely affect prices in equity markets of other developing countries as investors move their money to more stable, developed markets.

Our operations in Etame, Block P and any future opportunistic acquisitions of oil and natural gas reserves may require protracted negotiations with host governments, local governments and communities, local competent authorities, national oil companies and third parties and may be subject to economic, social and political considerations outside of our control, such as the risks of expropriation, nationalization, renegotiation, forced interruption, suspension of operations, curtailment of sales, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation or enforcement of laws, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls and foreign governmental regulations that favor or require the awarding of contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction.

While the laws of each of Gabon and Equatorial Guinea respectively recognize private and public property and the right to own property is protected by law, the laws of each country reserve, at the respective government's discretion, the right to expropriate property and terminate contracts (including the Etame PSC and the Block P PSC) for reasons of public interest, subject to reasonable compensation, determinable by the respective government in its discretion.

The respective applicable laws governing the exploration and production of hydrocarbons in Gabon and Equatorial Guinea (Law No. 002/2019 in Gabon and Law No. 8/2006 9 in Equatorial Guinea) each provide the respective government officials with significantly broad regulatory, inspective and auditing powers with respect to the performance of petroleum operations, which include the powers to negotiate, sign, amend and perform all contracts entered into between the respective governments and independent contractors. The executive branches of each respective government also retain significant discretionary powers, giving considerable control over the executive, judiciary and legislative branches of each government, and the ability to adopt measures with a direct impact on private investments and projects, including the right to appoint ministers responsible for petroleum operations. Further, in Equatorial Guinea, any new PSC or equivalent agreement for the exploration and exploitation of hydrocarbons is subject to presidential ratification before it can become effective.

Any of the factors detailed above or similar factors could have a material adverse effect on our business, results of operations or financial condition. If disputes arise in connection with our operations in Gabon, Equatorial Guinea or any future jurisdiction in which we operate, we may be subject to the exclusive jurisdiction of foreign courts or foreign arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign ministries and national companies, to the legal jurisdiction of the United States.

While we are not aware of any activities that would lead to the seizure of any assets, we cannot guarantee that there will not be regulations imposed on any individual or company that is related to our operations or our activities in the relevant region. Such measures, which would be beyond our control, could have a material adverse effect on our business, reputation, results of operations, financial condition and the price of our common stock.

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 was expected to assume GEPetrol's working interest obligations and was expected to be presented to the EG MMH by March 28, 2019. The EG MMH approved our appointment as operator for Block P on November 12, 2019, and we are currently waiting on a production sharing contract amendment to begin activities in Block P. If the joint owners of Block P fail to meet the commitments under the production sharing contract amendment, VAALCO's capitalized costs associated with Block P interest would be 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.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments; or
- the counter-party to the derivative instrument defaults on its contract obligations.

In addition, certain types of derivative arrangements may limit the benefit we could receive from increases in the prices for crude oil and natural gas and may expose us to cash margin requirements.

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. Disruptions in the market could also occur that lead to sudden changes in the liquidity of the counterparties to our hedge transactions that limit their ability to perform under their hedging contracts with us. 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.

In the past, our management has concluded that certain control deficiencies either individually or in the aggregate constituted a material weakness in our internal control over financial reporting. While the material weakness has been remediated and our management has concluded that our internal control over financial reporting was effective as of December 31, 2019, our management does not expect that our internal controls and disclosure controls will prevent or detect all possible errors or all instances of 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 mistakes. Further, controls can be circumvented by the individual acts of some persons or by two or more persons acting in collusion. 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 any control system designed under a cost-effective approach, 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, President 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 crude oil and natural gas from proved properties and maximizing production from crude 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.

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

Opposition toward crude oil and natural gas drilling and development activity has been growing globally. Companies in the crude oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Future activist efforts could result in the following:

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

Activism worldwide may increase if the current administration in the U.S. is perceived to be following, or actually follows, through on certain proposed initiatives to promote increased fossil fuel exploration and production in the U.S. Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly.

Our common stock currently trades on the NYSE and the LSE, but an active trading market for our common stock may not be sustained. The market price of our common stock could fluctuate significantly as a result of:

- dilutive issuances of our common stock;
- announcements relating to our business or the business of our competitors;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- actual or anticipated quarterly variations in our operating results;
- conditions generally affecting the crude oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets in general can experience considerable price and volume fluctuations. Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the common stock may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. Also, certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in our common stock by those institutions, which could adversely affect the trading price of our common stock. There is no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, our operations could be adversely impacted, and the trading price of the common stock may be adversely affected.

Substantial future sales of common stock, or the perception that such sales might occur, or additional offerings of common stock could depress the market price of our common stock.

We cannot predict what effect, if any, future sales of common stock, or the availability of common stock for future sale, or the offer of additional common stock in the future, will have on the market price of common stock. Sales or an additional offering of substantial numbers of common stock in the public market, or the perception or any announcement that such sales or an additional offering could occur, could adversely affect the market price of common stock and may make it more difficult for shareholders to sell their common stock at a time and price which they deem appropriate and could also impede our ability to raise capital through the issuance of equity securities.

We do not currently intend to pay dividends on the common stock and our ability to pay dividends in the future may be limited; consequently, the only opportunity for investors to achieve a return on their investment is if the price of the common stock appreciates.

We have never declared or paid dividends on our common stock. We intend to retain future earnings, if any, to support the development of the business, and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, would be at the discretion of the board of directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. Consequently, investors must rely on sale of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

We may not continue to repurchase shares under our stock repurchase plan and our repurchases may not materially enhance the long-term value of our business or stock.

On June 20, 2019, we announced that our board of directors authorized a stock repurchase plan pursuant to which we may repurchase up to $10.0 million of our common stock. Pursuant to the plan, share repurchases may be made through a variety of methods, including open market purchases, privately negotiated transactions, block purchases and other methods. The timing and number of shares repurchased will depend on a variety of factors, including price, general business and market conditions, our capital allocation policy and alternative investment opportunities. Our repurchase program does not obligate us to repurchase any specific number of shares and may be suspended or discontinued at any time. Any repurchases of our stock pursuant to the stock repurchase plan may materially reduce the amount of cash we have available and may not materially enhance the long-term value of our business or our stock.

Dual-listing on the NYSE and the LSE may lead to an inefficient market in the common stock.

Dual-listing of our common stock will result in differences in liquidity, settlement and clearing systems, trading currencies, prices and transaction costs between the exchanges where the common stock will be quoted. These and other factors may hinder the transferability of the common stock between the two exchanges.

The common stock is quoted on the NYSE and on the LSE. Consequently, the trading in and liquidity of the common stock is split between these two exchanges. The price of the common stock may fluctuate and may at any time be different on the NYSE and the LSE. Investors could seek to sell or buy common stock to take advantage of any price differences between the two markets through a practice referred to as arbitrage. Any arbitrage activity could create unexpected volatility in both common stock prices on either exchange and in the volumes of common stock available for trading on either market. This could adversely affect the trading of the common stock on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the common stock on these exchanges. In addition, holders of common stock in either jurisdiction will not be immediately able to transfer such shares for trading on the other market without effecting necessary procedures with our transfer agents/registrars. This could result in time delays and additional cost for shareholders.

The common stock is quoted and traded in USD on the NYSE. The common stock is quoted and traded in GBX on the LSE. The market price of the common stock on those exchanges may also differ due to exchange rate fluctuations.

Our certificate of incorporation and bylaws do not contain any rights of preemption in favor of existing shareholders, which means that shareholders may be diluted if additional common stock is issued.

Our shareholders do not have preemptive rights and we, without shareholder consent, may issue additional common stock, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, working capital, capital expenditures, investments, acquisitions and repayment or refinancing of borrowings. We actively seek to expand our business through complementary or strategic acquisitions and may issue additional common stock in connection with those acquisitions. We also issue common stock to our executive officers, employees and independent directors as part of their compensation. This may have the effect of diluting the interests of existing shareholders. Additionally, to the extent that preemptive rights are granted, shareholders in certain jurisdictions may experience difficulties or may be unable to exercise their preemptive rights.

Any issuance of preferred shares will rank in priority to the common stock.

While VAALCO does not currently have any Preferred Shares outstanding, under the Certificate of Incorporation, VAALCO is authorized to issue up to 500,000 Preferred Shares. Any issuance of Preferred Shares would rank in priority to the Common Shares with respect to payment of dividends, liquidation, and other matters.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Item 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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

GENERAL

Our common stock is traded on the New York Stock Exchange and London Stock Exchange under the symbol EGY.

As of February 28, 2020, based upon information received from our transfer agent and brokers and nominees, there were approximately 42 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

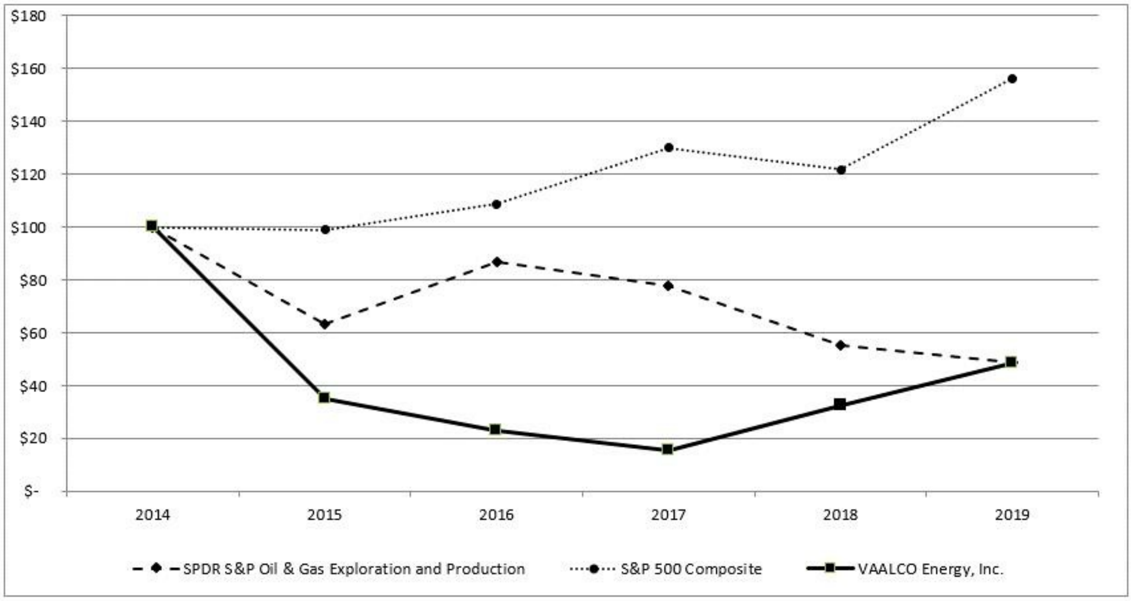
We have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future.

Securities Authorized for Issuance under Equity Compensation Plans

See *Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* for discussion of shares of common stock that may be issued under our compensation plans.

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, 2014 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.



	2014	2015	2016	2017	2018	2019
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 63	$ 87	$ 78	$ 55	$ 49
S&P 500 Composite	$ 100	$ 99	$ 109	$ 130	$ 122	$ 156
VAALCO Energy, Inc.	$ 100	$ 35	$ 23	$ 15	$ 32	$ 49

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

On June 20, 2019, our Board of Directors authorized and approved a share repurchase program for up to $10.0 million of the currently outstanding shares of our common stock over a period of 12 months. Under the stock repurchase program, we may repurchase shares through open market purchases, privately-negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the Exchange Act.

The following table represents details of the various repurchases during the three months ended December 31, 2019:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program
October 1, 2019 - October 31, 2019	205,564	$ 2.01	205,564	$ 7,264,153
November 1, 2019 - November 30, 2019	352,532 *	1.95	349,259	6,581,781
December 1, 2019 - December 31, 2019	205,291 *	1.87	181,000	6,254,218
	763,387	1.95	735,823	

** Includes shares to satisfy tax withholding obligations related to restricted stock vesting. See Note 16 to the Financial Statements for further discussion.*

Item 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, 2019, 2018, 2017, 2016 and 2015 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,				
	2019	**2018**	**2017**	**2016**	**2015**
(In thousands, except per share amounts)					
Total revenues	$ 84,521	$ 104,943	$ 77,025	$ 59,784 [1]	$ 80,445 [1]
Income (loss) from continuing operations	(2,848) [2]	98,728 [2]	10,272	(18,267) [2]	(120,554) [2]
Basic income (loss) from continuing operations per share	(0.05)	1.65	0.17	(0.31)	(2.07)
Diluted income (loss) from continuing operations per share	(0.05)	1.63	0.17	(0.31)	(2.07)
Net property, plant and equipment	68,258	52,724	23,221	28,019	33,357
Total assets	211,537 [3]	166,312 [3]	79,633	81,032	123,958
Total long-term liabilities	38,067 [4]	15,441	22,756	25,836	31,166

(1) The decrease in total revenues is tied to the decrease in crude 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) The loss from continuing operations in 2019 was primarily impacted by a $3.1 million charge to increase the valuation allowances on U.S. deferred tax assets due to a decrease in future estimated taxable earnings primarily as a result of lower crude oil prices. 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 crude oil and natural gas prices. Losses from continuing operations in 2015 were primarily impacted by decreased revenues and crude oil and natural gas property impairments.

(3) Total assets increased substantially in 2018 due to the recognition of certain deferred tax benefits. Total assets increased in 2019 with the adoption of the new accounting standard for leases. See Note 13 of the Financial Statements for further discussion.

(4) Total long-term liabilities increased in 2019 with the adoption of the new accounting standard for leases. See Note 13 of the Financial Statements for further discussion.

Item 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 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. For discussion related to changes in financial condition and results of operations for 2018 as compared with 2017, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2018 Form 10-K, which was filed with the SEC on March 8, 2019. 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 also have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. For further discussion of our two operating segments see *Item 1. Business – Segment and Geographical Information – "Gabon Segment" and "Equatorial Guinea Segment".* 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 crude oil production and the costs to find and produce such crude oil. Crude 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. In September 2019, we commenced the drilling of the 2019/2020 drilling program.

CURRENT DEVELOPMENTS

During the year ended December 31, 2019, ICE Dated Brent crude oil prices have fluctuated between $53 and $75 per Bbl. During the year ended December 31, 2018, ICE Dated Brent crude oil prices fluctuated between $51 and $86 per Bbl. In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. VAALCO intends to manage both operating expenses as well as capital expenditure levels in view of the existing and expected pricing environment. In addition, the Company continues to evaluate all uses of cash and whether to pursue growth opportunities in light of ongoing economic conditions. If at March 31, 2020 prices remain at this level or decline further, we may be required to take write-downs in the value of our crude oil and natural gas properties.

In the third quarter of 2019, the Company and the Etame joint venture owners executed definitive agreements to resolve past audit findings for the periods from 2007 through 2016, which requires VAALCO to make $4.4 million in payments to the other joint venture owners. In October 2019, the Company paid $1.1 million of the $4.4 million. The remaining amount due was paid in February 2020.

As previously announced, we commenced our 2019/2020 drilling campaign in September 2019. In order to execute our drilling campaign, we contracted the Vantage Drilling International Topaz jackup drilling rig. We drilled one appraisal wellbore and one development well during the second half of 2019 and drilled the second appraisal wellbore and development well during the first quarter of 2020. For further discussion see *Item 1. – Business – Gabon Segment*.

In the first quarter of 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. For further discussion see "*Discontinued Operations-Angola"* below.

On September 26, 2019, VAALCO began trading its common shares on the London Stock Exchange's Main Market under the ticker EGY.

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 carried 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 Financial Statements for all periods presented. See Note 4 to the Financial Statements. In the first quarter of 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. Pursuant to the settlement agreement, the Company agreed to pay $4.5 million to Angola National Agency of Petroleum, Gas, and Biofuels, as National Concessionaire, and to eliminate the $3.3 million receivable from Sonangol P&P. The receivable was related to joint interest billings and was reflected as current assets from discontinued operations at year-end 2018. As a result, the Company adjusted a previously accrued liability and recognized a net of tax non-cash benefit from discontinued operations of $5.7 million in the first quarter of 2019. In July 2019, subsequent to the publication of an executive decree from the Ministry of Mineral Resources and Petroleum, the Company paid the $4.5 million due under the settlement agreement

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2019 and 2018 are as follows:

	Years Ended December 31,		Increase (Decrease) in
	2019	2018	2019 over 2018
	(in thousands)		
Net cash provided by operating activities before change in operating assets and liabilities	**$ 24,213**	$ 45,086	$ (20,873)
Net change in operating assets and liabilities	**6,945**	(6,858)	13,803
Net cash provided by continuing operating activities	**31,158**	38,228	(7,070)
Net cash used in discontinued operating activities	**(4,686)**	(1,052)	(3,634)
Net cash provided by operating activities	**26,472**	37,176	(10,704)
Net cash used in continuing investing activities	**(10,348)**	(14,127)	3,779
Net cash used in investing activities	**(10,348)**	(14,127)	3,779
Net cash used in continuing financing activities	**(3,655)**	(8,680)	5,025
Net cash used in financing activities	**(3,655)**	(8,680)	5,025
Net change in cash, cash equivalents and restricted cash	**$ 12,469**	$ 14,369	$ (1,900)

The decrease in net cash provided by our operating activities for the year ended December 31, 2019 compared to the same period of 2018 includes a $20.9 million decrease in cash generated by continuing operations before change in operating assets and liabilities, which was mainly due to lower revenue as referenced below in Results of Operations. This was partially offset by net cash provided by our operating activities from changes in operating assets and liabilities of $13.8 million. The increase in cash resulting from the net change in operating assets and liabilities of $6.9 million for the year ended December 31, 2019 reflects increases of $1.0 million in "Prepayments and other" as well as increases of $6.0 million in accounts payable, $4.2 million in "Accrued liabilities and other" and a $2.4 million increase in "Foreign taxes payable" offset by increases in $4.3 million in trade and other receivables.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. No drilling activities were conducted during 2018 as we were looking to secure the PSC Extension. For 2019, the $10.3 million in cash basis expenditures consisted of $8.0 million related to the 2019/2020 drilling program and $2.3 million paid for equipment and enhancements. 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. See "—*Capital Expenditures*" below for further discussion. There were no other significant investing activities in 2019 and 2018.

Net cash used in financing activities during the year ended December 31, 2019 included $3.9 million for treasury stock purchases primarily made under the Company's stock repurchase plan. 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.

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 wellbores by September 16, 2020. In February 2020, these commitments were fully met as a result of drilling the Etame 9P and SE Etame 4P appraisal wellbores in 2019 and 2020, respectively, as well as the completion of the Etame 9H and Etame 11H development wells in 2019 and 2020, respectively. The estimated cost of the two wells and two appraisal wellbores is approximately $56.4 million ($18.9 million, net to VAALCO). The joint venture owners and the government of Gabon have approved the drilling of the third development well, the SE Etame 4H with an estimated cost of $26.5 million ($8.9 million, net to VAALCO). No further drilling is planned for 2020; however, we may expend funds related to the next drilling campaign, which will begin in 2021. We expect any capital expenditures made during 2020 will be funded by cash on hand and cash flow from operations. We intend to manage capital expenditures levels in view of the existing and expected pricing environment.

During 2019, we had accrual basis capital expenditures attributable to continuing operations of $22.2 million compared to $38.6 million and $1.7 million accrual basis capital expenditures in 2018 and 2017, 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 2019 were attributable to expenditures related to the 2019/2020 drilling program, equipment and enhancements. Capital expenditures in 2018 were attributable to the PSC Extension signing bonus, equipment and enhancements.

Contractual Obligations

The table below provides aggregated information on our net share of cash obligations and commitments at December 31, 2019:

	Note Reference [1]	2020	2021	2022	2023	2024	Thereafter	Total
					(in thousands)			
Operating leases [2]	Note 13	13,655	13,310	9,130	—	—	—	36,095
Purchase obligations [3]	Note 13	7,322	7,113	5,263	—	—	—	19,698
Drilling and other commitments [4]	Note 12	6,677	—	—	—	—	—	6,677
Abandonment funding [5]	Note 12	1,526	763	763	763	763	3,054	7,632
Total cash obligations		$ 29,180	$ 21,186	$ 15,156	$ 763	$ 763	$ 3,054	$ 70,102

(1) References are to the notes to Financial Statements accompanying *Item 15. Exhibits and Financial Statement Schedules.*

(2) Associated with operating leases accounted for under ASC 842 as discussed in Note 13 to the Financial Statements.

(3) Associated with the non-lease components not accounted for under ASC 842 as discussed in Note 13 to the Financial Statements.

(4) Associated with the execution of the PSC Extension and settlement of the JV audit settlement as discussed in Note 12 to the Financial Statements.

(5) 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, 2019, $36.7 million ($11.4 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 $4.9 million ($1.5 million, net to VAALCO) and paid in December 2020; 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 wellbores by September 16, 2020. This commitment was fully met in February 2020. 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, 2019, and payment was made in February 2020. See "*Item 1. Business – Segment and Geographic Information – Gabon Segment*" from above for further discussion.

The EG MMH approved our appointment as operator for Block P on November 12, 2019, and the Company is currently waiting on a production sharing contract amendment to begin activities in Block P. VAALCO intends to seek a joint venture owner on a promoted basis that will cover all or substantially all of the cost to drill an exploratory well. If joint owners fail to meet the commitments under the production sharing contract amendment, the capitalized costs associated with the Block P interest would be impaired. See "*Item 1. Business – Segment and Geographic Information – Equatorial Guinea Segment*" from above for further discussion.

During the year ended December 31, 2019, we entered into contracts for a drilling rig and helicopter. There were no other material changes in our contractual obligations during the year ended December 31, 2019.

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. See Note 12 to the Financial Statements for further discussion.

Commodity Price Hedging

The price we receive for our crude oil significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Crude 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 crude oil prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a portion of our anticipated crude 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 crude 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 the consolidated statement of operations. 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 had commodity swap contracts for approximately 172,000 barrels of crude oil. On May 6, 2019, the Company entered into commodity swaps at a Dated Brent weighted average of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. As of December 31, 2019, we had remaining swaps for approximately 275,000 barrels and the estimated mark-to-market value of our open commodity price swaps was an asset of $0.6 million, which is recorded on the "Prepayments and other" line item on our consolidated balance sheet.

Capital Resources

Historically, our primary sources of liquidity were cash on hand, cash flows from operations and borrowings under our prior debt facility. During the year ended 2019, our primary sources of liquidity were cash on hand and cash flows from operations, and our primary uses of cash in 2019 have been to fund capital expenditures to development activities in the Etame Marin block. As we pursue opportunistic acquisitions, we continually monitor the availability of capital resources, including equity and debt financings that could be utilized to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves, production and balancing the long-term development of our assets with a focus on generating attractive corporate-level returns will be highly dependent on the capital resources available to us.

Cash on Hand

At December 31, 2019, we had unrestricted cash of $45.9 million. We invest cash not required for immediate operational and capital expenditure needs in short-term money market instruments primarily with financial institutions where we determine our credit exposure is negligible. As operator of the Etame Marin block 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.

We currently sell our crude oil production from Gabon under a term contract that began in February 2020 and ends in January 2021. Pricing under this contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Liquidity

In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. VAALCO intends to manage both operating expenses as well as capital expenditure levels in view of the existing and expected pricing environment. In addition, the Company continues to evaluate all uses of cash and whether to pursue growth opportunities in light of ongoing economic conditions. Despite the lower Brent crude oil prices, based on current expectations, we believe we have sufficient liquidity through our existing cash balances and cash flow from operations to execute the remaining commitments under the 2019/2020 drilling program and support our other cash requirements through March 2021. We intend to manage both operating expenses as well as capital expenditure levels in view of the existing and expected pricing environment. In addition, we will evaluate whether to pursue growth opportunities in light of ongoing economic conditions.

If we require additional capital funding for capital expenditures, acquisitions or other reasons, we may seek such capital through borrowings under new credit facilities, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. Our future cash flows as well as our ability to borrow funds and to obtain additional capital on attractive terms are substantially dependent on crude oil prices. Further, the availability of capital resources to us on attractive terms may be limited due to the geographic location of our primary producing assets. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our planned drilling program. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

At December 31, 2019, we had 5.0 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 crude oil and natural gas reserves that are economically recoverable.

OFF BALANCE SHEET ARRANGEMENTS

None.

RESULTS OF OPERATIONS

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Net income for the year ended December 31, 2019 decreased $95.6 million, or approximately 97.4% to $2.6 million, compared to a net income of $98.2 million for the same period of 2018. The decrease in net income was mainly due to incurring tax expense of $23.9 million during 2019 while receiving a large tax benefit of $43.3 million in 2018. The tax benefit received in 2018 was due to the signing of the PSC extension. Also contributing to the decrease in net income were lower revenues as a result of receiving lower oil prices and having lower sales volumes, increased operating costs and lower gains on derivative instruments. Net income for the year ended December 31, 2019 includes income from discontinued operations of $5.4 million. Net income for the year ended December 31, 2018 is inclusive of a loss from discontinued operations for the year ended December 31, 2018 of $0.5 million as well as a $56.9 million deferred tax benefit related to the recognition of deferred tax assets and the reversal of valuation allowance on deferred tax assets. Substantially all of our operations are attributable to our Gabon segment. Further discussion of results by significant line item follows.

	Year ended December 31, 2019	Year ended December 31, 2018	Increase/(Decrease)
	(in thousands except per bbl information)		
Net crude oil sales volume (MBbls)	**1,251**	1,442	(191)
Average crude oil sales price (per Bbl)	**$ 65.20**	$ 70.32	$ (5.12)
Net crude oil revenue	**$ 84,521**	**$** 104,943	$ (20,422)
Operating costs and expenses:			
Production expense	**37,689**	40,415	(2,726)
Exploration expense	**—**	14	(14)
Depreciation, depletion and amortization	**7,083**	5,596	1,487
Gain on revision of asset retirement obligations	**(379)**	(3,325)	2,946
General and administrative expense	**14,855**	11,398	3,457
Bad debt (recovery) expense	**(341)**	(77)	(264)
Total operating costs and expenses	**58,907**	54,021	4,886
Other operating income (expense), net	**(4,421)**	365	(4,786)
Operating income	**$ 21,193**	$ 51,287	$ (30,094)

Crude oil revenues decreased $20.4 million, or approximately 19.5%, during the year ended December 31, 2019 compared to the same period of 2018. The decrease in revenue is attributable to lower sales volumes as described below and to a lesser extent lower prices.

The revenue changes between the years ended December 31, 2019 and 2018 identified as related to changes in price or volume are shown in the table below:

(in thousands)	
Price	$ (6,402)
Volume	(13,431)
Other	(589)
	$ (20,422)

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

	Years Ended December 31, 2019	Years Ended December 31, 2018
Gabon net crude oil production (MBbls)	1,269	1,369
Gabon net crude oil sales (MBbls)	1,251	1,442
Average realized crude oil price ($/Bbl)	$ 65.20	$ 70.32
Average Dated Brent spot price* ($/Bbl)	64.28	71.34

*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 year from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given year. We made fifteen liftings for both years ended December 31, 2019 and 2018. Production volumes for the year ended December 31, 2019 were lower than the comparable 2018 period in part due to the planned annual full-field shut down in August that took nine days to complete, the loss of production from three wells for several months during the year (i.e., the Etame 4H, N. Tchibala 2H and the Etame 10H) and natural decline. Sales volumes were lower between the periods in part because sales volumes for the year ended December 31, 2018 included 95,525 net barrels associated with the last lifting in 2017 that was not completed until January 1, 2018 and production volumes were higher in 2018 than 2019. Net revenues of $6.5 million associated with the net volumes for the last lifting in 2017 were reported as revenue in 2018. Our share of crude oil inventory aboard the FPSO, excluding royalty barrels, was approximately 38,476 and 34,811 barrels at December 31, 2019 and 2018, respectively.

Production expenses decreased $2.7 million, or approximately 6.7%, due to lower workover and personnel-related costs offset by higher transportation, customs and other costs in the year ended December 31, 2019 compared to the same period of 2018.

Depreciation, depletion and amortization increased $1.5 million, or approximately 26.6%, in the year ended December 31, 2019 compared to the same period of 2018 due to higher depletable costs associated with the PSC Extension and drilling costs associated with the Etame 9P and Etame 9H wells.

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 $3.5 million, or approximately 30.3% in the year ended December 31, 2019 compared to the same period of 2018. The increase in expense was in part related to a $1.0 million increase in stock appreciation rights ("SARs") expense. SARs liability awards are fair valued. The primary driver to changes in the fair value of these awards is changes in the Company's stock price. See Note 17 to Financial Statements for further discussion. Other expense categories that increased during the year ended December 31, 2019 compared to the same period in 2018 were accounting and audit fees, legal and other professional services costs, which increased as a result of our listing on the London Stock Exchange in September 2019.

Bad debt (recovery) expense and other reflected higher bad debt recoveries for the year ended December 31, 2019 compared to the same period of 2018.

Other operating income (expense), net for the year ended December 31, 2019 is related to a $4.4 million agreement to resolve a legacy issue related to findings from Etame joint ventures owners' audits for the periods from 2007 through 2016. During the year ended December 31, 2018, we recorded a reduction in inventory obsolescence.

Interest income (expense), net for the year ended December 31, 2019 relates to interest income on cash balances whereas the December 31, 2018 period includes interest expense related to our former term loan with the IFC as discussed in Note 15 to the Financial Statements and to interest on taxes other than income taxes.

Derivative instruments gain (loss), net for the year ended December 31, 2019 is attributable to our commodity swaps as discussed in Note 10 to the Financial Statements and the $0.4 million loss is a result of an increase in the price of Dated Brent crude oil during the year ended December 31, 2019 as compared to a decrease in the price of Dated Brent crude oil that resulted in a $4.3 million gain during the comparable prior year.

Other, net for the year ended December 31, 2019 and 2018 consists primarily of foreign currency gains (losses) as discussed in Note 1 of the Financial Statements.

Income tax expense for the year ended December 31, 2019 was $23.9 million. This is comprised of $14.5 million of deferred tax expense and a current tax provision of $9.4 million. The deferred income tax expense for the year ended December 31, 2019 included a $3.1 million charge to increase the valuation allowances on U.S. deferred tax assets due to a decrease in future estimated taxable earnings primarily as a result of lower crude oil prices. The income tax benefit for the year ended December 31, 2018 includes a $56.9 million deferred tax benefit related to the recognition of deferred tax assets and the reversal of valuation allowances on deferred tax assets. In addition to the deferred tax benefit, we had a current tax provision of $13.7 million during the year ended December 31, 2018. The current tax provision in both periods is primarily attributable to our operations in Gabon and is lower in 2019 than income tax for the comparable 2018 period as a result of lower revenues. See Note 8 to the Financial Statements for further discussion.

Income (loss) from discontinued operations, net of tax for the years ended December 31, 2019 and 2018 are attributable to our Angola segment as discussed further in Note 4 to the Financial Statements. The gain from discontinued operations for the year ended December 31, 2019 is primarily related to recording a $5.7 million after tax gain on the finalized Angola settlement. The loss from discontinued operations for the year ended December 31, 2018 was related to Angola administration costs.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the Financial Statements in accordance with 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 crude 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, 2019, the Company had deferred tax assets of $108.8 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 $84.6 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.

Oil and Gas Accounting Reserves Determination

The successful efforts method of accounting depends on the estimated reserves we believe are recoverable from our crude oil and natural gas reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable crude oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future crude oil and natural gas quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially going forward as additional data from development activities and production performance becomes available and as economic conditions impacting crude oil and natural gas prices and costs change.

Management is responsible for estimating the quantities of proved crude oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the U.S. as prescribed by the Society of Petroleum Engineers. Reserve estimates are independently evaluated at least annually by our independent qualified reserves engineers, NSAI.

Our senior executives and reserve engineers oversee the review of our crude oil and natural gas reserves and related disclosures by our appointed independent reserve engineers. The senior executives meet with the reserve engineers periodically to review the reserves process and results, and to confirm that the independent reserve engineers have had access to sufficient information, including the nature and satisfactory resolution of any material differences of opinion between us and the independent reserve engineers.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves;
- calculating our unit-of-production depletion rates. Proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense; and
- assessing, when necessary, our crude oil and natural gas assets for impairment using undiscounted future cash flows based on management's estimates. If impairment is indicated, discounted values will be used to determine the fair value of the assets. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

See *Item 15. Exhibits and Financial Statement Schedules – Supplemental Information on Crude Oil and Natural Gas Producing Activities (unaudited)*

Successful Efforts Method of Accounting for Crude Oil and Natural Gas Activities

We use the successful efforts method to account for our crude 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 the crude 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 a crude 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. Our assessment involves a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to estimate undiscounted future net cash flows related to proved reserves. Such assumptions include commodity prices, capital spending, production and abandonment costs and reservoir data. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs to estimate the undiscounted future net cash flows. The undiscounted estimated future net cash flows used in the 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.

In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. If at March 31, 2020 prices remain at this level or decline further, we may be required to take write-downs in the value of our crude oil and natural gas properties.

Impairment of Unproved Property

We evaluate our undeveloped crude 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 crude oil and natural gas leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist mainly of acquisition costs related to undeveloped acreage in the Etame Marin block in Gabon and to Block P in Equatorial Guinea.

Future Dismantlement, Restoration, and Abandonment Costs

We have significant obligations to remove tangible equipment and restore land and seabed at the end of crude 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 crude 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 an asset retirement obligation ("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 crude 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 crude 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 crude oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. See Note 2 and Note 11 for disclosures regarding the asset retirement obligations.

Derivative instruments and hedging activities

The Company uses derivative financial instruments to achieve a more predictable cash flow from crude oil sales by reducing the exposure to price fluctuations.

The Company's derivative instruments at December 31, 2019, consisted of crude oil swaps for approximately 275,000 barrels, which require the Company to pay a counterparty when the price of crude oil exceeds $66.70 per barrel, and where the price of crude oil falls below $66.70, the Company received a payment from the counterparty. See Note 10 for further discussion.

The Company records balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. The significant inputs used to estimate fair value are crude oil prices, volatility, discount rate and the contract terms of the derivative instruments. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the "Derivative instruments gain (loss), 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 "Derivative instruments gain (loss), net" and "Cash settlements 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.

NEW ACCOUNTING STANDARDS

See Note 3 to the Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in 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 crude 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, 2019, we had net monetary assets of $2.2 million (XAF 1,306.0 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $0.2 million reduction in the value of these net assets. For 2019, we had expenditures of approximately $10.7 million denominated in XAF.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our crude oil and natural gas production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for crude oil and natural gas have been volatile and unpredictable in recent years, and this volatility may continue. Sustained low crude oil and natural gas prices or a resumption of the decreases in crude 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 crude oil sales were to remain constant at the most recent annual sales volumes of 1,251 MBbls, a $5 per

Bbl decrease in crude oil price would be expected to cause a $6.3 million decrease per year in revenues and operating income (loss) and a $3.1 million decrease per year in net income (loss).

During the years ended December 31, 2019 and 2018, we had crude oil swaps outstanding and during the year ended December 31, 2017, we had crude 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.

Item 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*".

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

None.

Item 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. Based on this evaluation, our principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2019.

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").

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

Based on the evaluation, our management concluded that the Company's internal control over financial reporting was effective as of December 31, 2019.

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.

BDO USA, LLP, our independent registered public accounting firm, has issued their report on our internal control over financial reporting as of December 31, 2019, which is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REMEDIATION OF MATERIAL WEAKNESSES

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2018, our management concluded that there was a material weakness in our internal control over financial reporting related to a gross up in crude 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.

In response to the identified material weakness at December 31, 2018, our management, with oversight from our Audit Committee, made the following changes in its financial reporting processes in 2019:

- Management hired an experienced International Tax Manager who has experience in taxes in the jurisdictions where we operate.
- The International Tax Manager, along with the CFO and CAO, has been integrated in the review process of all significant and unusual transactions identified by us.
- More frequent and improved timely communications between management, its external tax advisors and its external auditors regarding significant and unusual transactions and evaluating their financial impact, including significant and unusual tax matters, whenever they arise.
- More frequent meetings during our financial statement close and reporting processes to ensure requests are being properly addressed and information is being properly disseminated.
- As part of the communications improvements, having follow-up meetings to determine if any changes in facts or circumstances or other factors that formed part of an earlier decision warrant revisiting or revising earlier decisions.

After completing our testing of the design and operational effectiveness of these controls, our management concluded that we remediated the previously identified material weaknesses as of December 31, 2019.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Except for the change in internal control related to the remediation of the material weakness identified above, there have been no changes in our internal control over financial reporting during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

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 its subsidiaries' (the "Company's") internal control over financial reporting as of December 31, 2019, 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019 based on the COSO criteria.

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, 2019 and 2018, 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, 2019, and the related notes and our report dated March 9, 2020 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.

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 9, 2020

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 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, and that is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, and that is incorporated herein by reference.

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

Except as set forth below, information required by this item will be included in the proxy statement for our 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, and that is incorporated herein by reference.

The following table provides information as of December 31, 2019 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 16 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	2,833,500	$ 1.54	68,241
Total	2,833,500	$ 1.54	68,241

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

Information required by this item will be included in the proxy statement for our 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, and that 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 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, and that 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).
4.1(a)	Description of securities
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*	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).
10.10*	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).

10.11*	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).
10.12*	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).
10.13*	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).
10.14	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).
10.15	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).
10.16*	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).
10.17*	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).
10.18*	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 8, 2019, 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)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH(a)	Inline XBRL Taxonomy Schema Document.
101.CAL(a)	Inline XBRL Calculation Linkbase Document.
101.DEF(a)	Inline XBRL Definition Linkbase Document.
101.LAB(a)	Inline XBRL Label Linkbase Document.
101.PRE(a)	Inline XBRL Presentation Linkbase Document.
104(a)	Cover Page Interactive Data File (formatted as Inline XBRL and Contained in Exhibit 101)

(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 9, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 9th day of March 2020, 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/ WILLIAM R. THOMAS William R. Thomas	President and Director
By:	/s/ ELIZABETH D. PROCHNOW Elizabeth D. Prochnow	Chief Financial Officer (Principal Financial Officer)
By:	/s/ JASON DOORNIK Jason Doornik	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 its subsidiaries (the “Company”) as of December 31, 2019 and 2018, 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, 2019, 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 its subsidiaries as of December 31, 2019 and 2018, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 9, 2020 expressed an unqualified opinion thereon.

Change in Accounting Principle

As discussed in Notes 3 and 13 to the consolidated financial statements, on January 1, 2019, the Company adopted Accounting Standards Codification Topic 842 – *Leases*, using the effective date method.

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 9, 2020

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(in thousands, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 45,917**	$ 33,360
Restricted cash	**911**	804
Receivables:		
Trade	**14,335**	11,907
Accounts with joint venture owners, net of allowance of $0.5 million for both years	**2,714**	949
Other	**1,517**	1,398
Crude oil inventory	**1,072**	785
Prepayments and other	**3,292**	6,301
Current assets - discontinued operations	**—**	3,290
Total current assets	**69,758**	58,794
Crude oil and natural gas properties and equipment - successful efforts method:		
Wells, platforms and other production facilities	**422,651**	409,487
Work-in-progress	**7,378**	519
Undeveloped acreage	**23,771**	23,771
Equipment and other	**11,157**	9,552
	464,957	443,329
Accumulated depreciation, depletion, amortization and impairment	**(396,699)**	(390,605)
Net crude oil and natural gas properties, equipment and other	**68,258**	52,724
Other noncurrent assets:		
Restricted cash	**925**	920
Value added tax and other receivables, net of allowance of $1.0 million and $2.0 million, respectively	**3,683**	2,226
Right of use operating lease assets	**33,383**	—
Deferred tax assets	**24,159**	40,077
Abandonment funding	**11,371**	11,571
Total assets	**$ 211,537**	$ 166,312
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 15,897**	$ 8,083
Accounts with joint venture owners	**—**	304
Accrued liabilities and other	**29,773**	14,138
Operating lease liabilities - current portion	**11,990**	—
Foreign taxes payable	**5,740**	3,274
Current liabilities - discontinued operations	**350**	15,245
Total current liabilities	**63,750**	41,044
Asset retirement obligations	**15,844**	14,816
Operating lease liabilities - net of current portion	**21,371**	—
Other long term liabilities	**852**	625
Total liabilities	**101,817**	56,485
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	**—**	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 67,673,787 and 67,167,994 shares issued, 58,024,571 and 59,595,742 shares outstanding, respectively	**6,767**	6,717
Additional paid-in capital	**73,549**	72,358
Less treasury stock, 9,649,216 and 7,572,251 shares, respectively, at cost	**(41,429)**	(37,827)
Retained earnings	**70,833**	68,579
Total shareholders' equity	**109,720**	109,827
Total liabilities and shareholders' equity	**$ 211,537**	$ 166,312

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in thousands, except per share amounts)		
Revenues:			
Crude oil and natural gas sales	**$ 84,521**	$ 104,943	$ 77,025
Operating costs and expenses:			
Production expense	**37,689**	40,415	39,697
Exploration expense	**—**	14	7
Depreciation, depletion and amortization	**7,083**	5,596	6,457
Gain on revision of asset retirement obligations	**(379)**	(3,325)	—
General and administrative expense	**14,855**	11,398	10,377
Bad debt (recovery) expense and other	**(341)**	(77)	452
Total operating costs and expenses	**58,907**	54,021	56,990
Other operating income (expense), net	**(4,421)**	365	(84)
Operating income	**21,193**	51,287	19,951
Other income (expense):			
Derivative instruments gain (loss), net	**(446)**	4,264	(1,032)
Interest income (expense), net	**733**	(145)	(1,414)
Other, net	**(438)**	68	3,145
Total other income (expense), net	**(151)**	4,187	699
Income from continuing operations before income taxes	**21,042**	55,474	20,650
Income tax expense (benefit)	**23,890**	(43,254)	10,378
Income (loss) from continuing operations	**(2,848)**	98,728	10,272
Income (loss) from discontinued operations, net of tax	**5,411**	(496)	(621)
Net income	**$ 2,563**	$ 98,232	$ 9,651
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ (0.05)**	$ 1.65	$ 0.17
Income (loss) from discontinued operations, net of tax	**0.09**	(0.01)	(0.01)
Net income per share	**$ 0.04**	$ 1.64	$ 0.16
Basic weighted average shares outstanding	**59,143**	59,248	58,717
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ (0.05)**	$ 1.63	$ 0.17
Income (loss) from discontinued operations, net of tax	**0.09**	(0.01)	(0.01)
Net income per share	**$ 0.04**	$ 1.62	$ 0.16
Diluted weighted average shares outstanding	**59,143**	59,997	58,720

See notes to consolidated financial statements

VAALCO ENERGY, INC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (DEFICIT)

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
				(in thousands)			
Balance at January 1, 2017	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
Shares issued - stock-based compensation	**506**	**(10)**	**50**	**206**	—	—	**256**
Stock-based compensation expense	—	—	—	**985**	—	—	**985**
Treasury stock acquired	—	**(2,067)**	—	—	**(3,602)**	**(309)**	**(3,911)**
Net income	—	—	—	—	—	**2,563**	**2,563**
Balance at December 31, 2019	**67,674**	**(9,649)**	**$ 6,767**	**$ 73,549**	**$ (41,429)**	**$ 70,833**	**$ 109,720**

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 2,563**	$ 98,232	$ 9,651
Adjustments to reconcile net income to net cash provided by operating activities:			
(Income) loss from discontinued operations	**(5,411)**	496	621
Depreciation, depletion and amortization	**7,083**	5,596	6,457
Gain on revision of asset retirement obligations	**(379)**	(3,325)	—
Other amortization	**241**	417	369
Deferred taxes	**14,480**	(56,907)	(1,260)
Unrealized foreign exchange (gain) loss	**(50)**	834	(576)
Stock-based compensation	**3,506**	2,388	1,098
Cash settlements paid on exercised stock appreciation rights	**(491)**	(82)	—
Derivatives instruments (gain) loss	**446**	(4,264)	1,032
Cash settlements received on matured derivative contracts, net	**2,439**	744	195
Bad debt (recovery) expense	**(341)**	(77)	452
Other operating (income) loss, net	**58**	(570)	84
Operational expenses associated with equipment and other	**69**	1,604	1,189
Change in operating assets and liabilities:			
Trade receivables	**(2,428)**	(8,351)	3,195
Accounts with joint venture owners	**(2,075)**	2,747	(108)
Other receivables	**(94)**	(1,330)	(43)
Crude oil inventory	**(287)**	2,478	(2,350)
Prepayments and other	**(1,014)**	1,164	1,646
Value added tax and other receivables	**275**	(777)	(3,025)
Accounts payable	**6,011**	(3,409)	(7,297)
Foreign taxes payable	**2,396**	2,751	—
Accrued liabilities and other	**4,161**	(2,131)	2,050
Net cash provided by continuing operating activities	**31,158**	38,228	13,380
Net cash used in discontinued operating activities	**(4,686)**	(1,052)	(4,423)
Net cash provided by operating activities	**26,472**	37,176	8,957
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions	—	—	64
Proceeds from the sale of crude oil and natural gas properties	—	—	250
Property and equipment expenditures	**(10,348)**	(14,127)	(1,813)
Net cash used in continuing investing activities	**(10,348)**	(14,127)	(1,499)
Net cash used in discontinued investing activities	**—**	**—**	**—**
Net cash used in investing activities	**(10,348)**	(14,127)	(1,499)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**256**	544	39
Treasury shares	**(3,911)**	(58)	(20)
Borrowings	**—**	—	4,167
Debt repayment	**—**	(9,166)	(10,001)
Net cash used in continuing financing activities	**(3,655)**	(8,680)	(5,815)
Net cash used in discontinued financing activities	**—**	**—**	**—**
Net cash used in financing activities	**(3,655)**	(8,680)	(5,815)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**12,469**	14,369	1,643
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF YEAR	**46,655**	32,286	30,643
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF YEAR	**$ 59,124**	$ 46,655	$ 32,286

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Supplemental disclosure of cash flow information:			
Interest paid in cash	$ —	$ 257	$ 997
Income taxes (received) paid in cash	$ **(674)**	$ 2,720	$ 15,153
Income taxes paid in-kind with crude oil	$ **7,268**	$ 9,385	$ —
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at end of period	$ **13,646**	$ 2,138	$ 455
Crude oil and natural gas property additions paid with non-cash assets	$ —	$ 4,197	$ —
Gross-up of crude oil and natural gas properties by establishment of deferred tax liability	$ —	$ 18,613	$ —
Recognition of right-of-use operating lease assets	$ **44,681**	$ —	$ —
Recognition of right-of-use operating lease liabilities	$ **44,656**	$ —	$ —
Asset retirement obligations	$ **595**	$ (6,527)	$ 600
Restricted stock issued out of treasury	$ **309**	$ 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, the Company has production operations and conducts exploration activities in Gabon, West Africa. The Company has opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 4 below, VAALCO has discontinued operations associated with activities in Angola, West Africa.

The Company's consolidated subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., 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 basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentation related to the presentation of stock based compensation and derivatives on the Company's consolidated statements of cash flows. These reclassifications had no material impact on the Company's financial position or results of operations.

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. The Financial Statements include amounts that are based on management's best estimates and judgments. Actual results could differ from those estimates.

Estimates of crude 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, 2019 and 2018 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2019 and 2018 include a charter payment escrow for the floating, production, storage and offloading vessel ("FPSO") offshore Gabon as discussed in Note 12. The Company invests restricted and excess cash in readily redeemable money market funds. The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets to the amounts shown in the consolidated statement of cash flows.

	December 31,	
	2019	**2018**
	(in thousands)	
Cash and cash equivalents	**$ 45,917**	$ 33,360
Restricted cash - current	**911**	804
Restricted cash - non-current	**925**	920
Abandonment funding	**11,371**	11,571
Total cash, cash equivalents and restricted cash	**$ 59,124**	$ 46,655

The Company conducts regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on the consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments. See Note 11 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 African Economic and Monetary Community ("CEMAC") 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. The Etame PSC provides these payments must be denominated in U.S. dollars and the CEMAC regulations provide for establishment of a U.S. dollar account with the Central Bank. Although we have requested establishment of such account, the Central Bank has not complied with our requests. As a result, we were not able to make the annual abandonment funding payment in 2019. Amendment No. 5 to the Etame PSC also 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 the Company as an operator.

Bad debts – Quarterly, the Company evaluates its accounts receivable balances to confirm collectability. When collectability is in doubt, the Company records 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 the accounts receivable balances are with the Company's joint venture owners, purchasers of the 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 to the Company. Portions of the costs in Gabon (including the VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). As of December 31, 2019, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately XAF 5.4 billion (XAF 1.8 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, 2019, the exchange rate was XAF 585.7 = $1.00.

In 2019, 2018 and 2017, the Company recorded recoveries (allowances) of $0.3 million, $0.1 million and $(0.4) 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:

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Allowance for bad debt			
Balance at beginning of year	$ **(2,535)**	$ (7,033)	$ (5,211)
Bad debt recovery (charge)	**341**	77	(452)
Reclassification to leasehold costs related to signing bonus	—	4,197	—
Reclassification of Sojitz acquisition	—	—	(694)
Adjustment associated with settlement of customs audit	**623**	—	—
Foreign currency gain	**63**	224	(676)
Balance at end of period	$ **(1,508)**	$ (2,535)	$ (7,033)

Crude oil inventory – Crude oil inventories are carried at the lower of cost or market and represent the 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.

Crude Oil and natural gas properties, equipment and other – The Company uses the successful efforts method of accounting for crude oil and natural gas producing activities. Management believes that this method is preferable, as the Company has focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results.

Capitalizatio**n** – 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-by-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-by-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 crude oil and natural gas producing activities, as well as property, plant and equipment unrelated to crude 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 – The Company reviews the crude oil and natural gas producing properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. This may occur if a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. The fair value measurement used in the impairment test is generally calculated with a discounted cash flow model using several Level 3 inputs that 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 the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of crude 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 crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Capitalized equipment inventory is reviewed regularly for obsolescence. The Company recorded no material adjustments for inventory obsolescence for the years 2019 or 2017. The Company 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. When undeveloped crude 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 in Gabon and in Block P 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.

The Company capitalized no interest costs during the years ended December 31, 2019, 2018 and 2017.

Lease commitments – The Company 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 13 for further discussion.

Asset retirement obligations ("ARO") – The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of crude oil and natural gas production operations. The removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore crude 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 crude oil and natural gas properties. The Company uses 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 crude 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 crude 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 the 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, the Company 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. In the second half of 2019, the Company recorded $0.6 million in additions associated with the spudding of the Etame 9H and Etame 11H development wells at the Etame field in conjunction with commencement of its 2019/2020 drilling campaign and $0.4 million downward revision associated with the Mutamba Iroru block onshore Gabon.

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 crude 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. See Note 7 for further discussion.

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 labor costs.

Stock-based compensation – The Company measured 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 the 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 the SARs uses the following inputs: (i) the quoted market price of the Company's common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term that is based on the contractual term, (iv) the expected volatility that is based on the historical volatility of the Company's stock for the length of time corresponding to the expected term of the SARs, (v) the expected dividend yield is based on the anticipated dividend payments, (vi) the risk-free interest rate that 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. The Company utilizes the Black-Scholes option pricing model to measure the fair value of the 2019, 2018 and 2017 SARs.

The 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. See Note 17 for further discussion.

Foreign currency transactions – The U.S. dollar is the functional currency of the Company's 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," the Company recognized losses on foreign currency transactions of $0.2 million and $0.1 million in 2019 and 2018, respectively, while the Company recognized gains on foreign currency transactions of $0.5 million 2017.

Income taxes – The annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to the Company in the various jurisdictions in which the Company operates. The determination and evaluation of the annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which the Company operates 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 the level of operations or profitability in each jurisdiction would impact the tax liability in any given year. The Company also operates in foreign jurisdictions where the tax laws relating to the crude oil and natural gas industry are open to interpretation, which could potentially result in tax authorities asserting additional tax liabilities. While the 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. We also record as income tax expense the increase or decrease in the value of the government's allocation of Profit Oil which results due to change in value from the time the allocation is originally produced to the time the allocation is actually lifted.

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.

In certain jurisdictions, the Company may deem the likelihood of realizing deferred tax assets as remote where the Company expects 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, the Company has not recognized deferred tax assets. Should the expectations change regarding the expected future tax consequences, the Company may be required to record additional deferred taxes that could have a material effect on the consolidated financial position and results of operations. See Note 8 for further discussion.

Derivative instruments and hedging activities – The Company uses derivative financial instruments to achieve a more predictable cash flow from crude oil production by reducing the exposure to price fluctuations.

All of the crude oil put contracts, which provided for settlement based upon reported the Brent price, had expired as of December 31, 2017. The Company's derivative instruments at December 31, 2018, consisted of crude oil swaps, which require the Company to pay a counterparty when the price of crude oil exceeds $74.00 per barrel, and where the price of crude oil falls below $74.00, the Company received a payment from the counterparty. On May 6, 2019, the Company entered into commodity swaps at a Dated Brent weighted average of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. See Note 10 for further discussion.

The Company records 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 "Derivative instruments gain (loss), 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 "Derivative instruments (gain) loss, net" and "Cash settlements 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. The Company received net cash settlements of $2.4 million, $0.7 million and $0.2 million during the years ended December 31, 2019, 2018 and 2017, respectively, 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 the internally developed present value of future cash flows model that underlies the fair-value measurement).

Fair value of financial instruments – The Company's 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 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 measured 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 the 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.

	Balance Sheet Line	As of December 31, 2019 Level 1	Level 2	Level 3	Total
		(in thousands)			
Assets					
Derivative asset commodity swaps	Prepayments and other	$ —	$ 636	$ —	$ 636
		$ —	$ 636	$ —	$ 636
Liabilities					
SARs liability	Accrued liabilities	$ —	$ 2,638	$ —	$ 2,638
SARs liability	Other long-term liabilities	—	852	—	852
		$ —	$ 3,490	$ —	$ 3,490

	Balance Sheet Line	As of December 31, 2018 Level 1	Level 2	Level 3	Total
		(in thousands)			
Assets					
Derivative asset commodity swaps	Prepayments and other	$ —	$ 3,520	$ —	$ 3,520
		$ —	$ 3,520	$ —	$ 3,520
Liabilities					
SARs liability	Accrued liabilities	$ —	$ 1,007	$ —	$ 1,007
SARs liability	Other long-term liabilities	—	625	—	625
		$ —	$ 1,632	$ —	$ 1,632

Other, net – "Other, net" in non-operating income and expenses includes gains and losses from 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 the Company was no longer obligated to pay.

3. NEW ACCOUNTING STANDARDS

Not Yet Adopted

In December 2019, the Financial Accounting Standards Board ("FASB") issued ASU No. 2019-12, *Income Taxes (Topic 740: Simplifying the Accounting for Income Taxes* ("ASU 2019-12"), which removes certain exceptions to the general principles in Topic 740. ASU 2019-12 is effective for the fiscal years beginning after December 15, 2020, with early adoption permitted. The Company is currently evaluating this guidance to determine the impact it may have on its consolidated financial statements.

In August 2018, the 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 does not expect a material impact of adopting this guidance on the Company's financial position, results of operations, cash flows and related disclosures upon adoption on January 1, 2020.

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. ASU 2018-13 applies to all entities and is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. The Company does not expect a material impact of adopting this guidance on the Company's financial position, results of operations and cash flows; however, the Company does expect an expansion to its current disclosures upon adoption on January 1, 2020.

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 the Company's trade and joint venture owners' receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date that is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model that increases the allowance when losses are probable. Initially, ASU 2016-13 was 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. The FASB subsequently issued ASU No. 2019-04 ("ASU 2019-04"): Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives, and Topic 825, Financial Instruments and ASU No. 2019-05 ("ASU 2019-05"): Financial Instruments-Credit Losses (Topic 326) - Targeted Transition Relief. ASU 2019-04 and ASU 2019-05 provide certain codification improvements related to implementation of ASU 2016-13 and targeted transition relief consisting of an option to irrevocably elect the fair value option for eligible instruments. In November 2019, the FASB issued ASU No. 2019-10, Financial Instruments—Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates. This amendment deferred the effective date of ASU No. 2016-13 from January 1, 2020 to January 1, 2023 for calendar year end smaller reporting companies, which includes the Company. The Company plans to defer the implementation of ASU 2016-13, and related updates, until January 2023.

Adopted

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 previously classified as operating leases on the balance sheet under ASC 840 - Leases. 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 under ASC 840 - Leases. 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. The Company used the prospective approach with adoption of the new standard effective January 1, 2019. Leases with terms greater than 12 months, which were previously treated as operating leases, have been capitalized. The adoption of this standard resulted in the recording of a right of use ("ROU") asset related to certain of the Company's operating leases with a corresponding lease liability. This resulted in a significant increase in total assets and liabilities and a decrease in working capital. In connection with the Company's implementation plan, the Company reviewed its lease contracts and evaluated other contracts to identify embedded leases to determine the appropriate accounting treatment. The new leasing standard requires capitalization based on the expected term of the lease that may or may not extend beyond the minimum period. The most significant lease the Company currently has is related to the FPSO. As of January 1, 2019, for operating leases under which the Company is the lessee, the Company recorded a non-cash adjustment of $38.9 million in "Right of use operating lease assets" to recognize an aggregate ROU asset, and the Company recorded a corresponding $10.2 million and $28.7 million in "Operating lease liabilities" and "Long-term operating lease liabilities," respectively, for the aggregate operating lease liability. The Company has accounted for lease and non-lease components of its operating leases separately. The Company has not recognized ROU assets or lease liabilities for its short-term leases. The Company's adoption did not have and is not expected in the future to have a material effect on the Company's consolidated statements of operations or cash flows. See Note 13 for further discussion.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"). Beginning January 1, 2018, the Company 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. The Company adopted the Revenue Recognition ASU via the modified retrospective transition method, taking advantage of the allowed practical expedient that states 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. This standard applies to revenues from contracts with customers. In addition, the Company recognizes other items from carried interest recoupment and royalties paid that 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 the financial position, results of operations, debt covenants or business practices. The adoption did result in expanded disclosures related to the nature of the sales contracts and other matters related to revenues and the accounting for revenues, which are reflected in Note 7.

4. DISPOSITIONS

Sale of Certain U.S. Properties

In April 2017, the Company completed the sale of the Company's 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 the results of operations for the year ended December 31, 2017.

Discontinued Operations - Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola ("PSA"). The working interest is 40%, and the Company carries Sonangol P&P for 10% of the work program. On September 30, 2016, the Company notified Sonangol P&P that the Company was withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, the Company notified the national concessionaire, Sonangol E.P., that the Company was withdrawing from the PSA. Further to the decision to withdraw from Angola, the Company has taken actions to close the office in Angola and reduce future activities in Angola. As a result of this strategic shift, the Company 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 the consolidated statements of operations. The Company segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in the consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment assets and liabilities as of December 31, 2019 and 2018 and its results of operations for the years ended December 31, 2019, 2018 and 2017.

Summarized Results of Discontinued Operations

	Years Ended December 31, 2019	2018	2017
		(in thousands)	
Operating costs and expenses:			
Gain on settlement of drilling obligation	**$ (7,193)**	$ —	$ —
General and administrative expense	**344**	467	615
Total operating costs, expenses and (recovery)	**(6,849)**	467	615
Operating income (loss)	**6,849**	(467)	(615)
Other income (expense):			
Other, net	**—**	(29)	**(3)**
Total other income (expense)	**—**	(29)	**(3)**
Income (loss) from discontinued operations before income taxes	**6,849**	(496)	(618)
Income tax expense	**1,438**	—	3
Income (loss) from discontinued operations	**$ 5,411**	$ (496)	$ (621)

Assets and Liabilities Attributable to Discontinued Operations

	December 31, 2019	2018
	(in thousands)	
ASSETS		
Accounts with joint venture owners	$ —	$ 3,290
Total current assets	—	3,290
Total assets	$ —	$ 3,290
LIABILITIES		
Current liabilities:		
Accounts payable	**$ 8**	$ 73
Accrued liabilities and other	**342**	15,172
Total current liabilities	**350**	15,245
Total liabilities	$ **350**	$ 15,245

Drilling Obligation

Under the Block 5 PSA, the Company 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 Block 5 PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The Block 5 PSA provided for a stipulated payment of $10.0 million for each of the three exploration wells that a drilling obligation remained under the terms of the Block 5 PSA, of which the Company's participating interest share would be $5.0 million per well. The Company reflected an accrual of $15.0 million for a potential payment as of December 31, 2018. In the first quarter of 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. Pursuant to the settlement agreement, the Company agreed to pay $4.5 million to Angola National Agency of Petroleum, Gas, and Biofuels, as National Concessionaire, and to eliminate the $3.3 million receivable from Sonangol P&P. The receivable was related to joint interest billings and was reflected as a current asset from discontinued operations at year-end 2018. As a result, the Company adjusted a previously accrued liability and recognized a net of tax non-cash benefit from discontinued operations of $5.7 million in the first quarter of 2019. In July 2019, subsequent to the publication of an executive decree from the Ministry of Mineral Resources and Petroleum, the Company paid the $4.5 million due under the settlement agreement.

5. SEGMENT INFORMATION

The Company's operations are based in Gabon and Equatorial Guinea. Each of the two reportable operating segments is organized and managed based upon geographic location. The Company's 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 that are not allocated to the reportable operating segments.

Segment activity of continuing operations for the years ended December 31, 2019, 2018 and 2017 and long-lived assets and segment assets at December 31, 2019 and 2018 are as follows:

	Years Ended December 31, 2019			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	**$ 84,521**	**$ —**	**$ —**	**$ 84,521**
Depreciation, depletion and amortization	**6,825**	**—**	**258**	**7,083**
Gain on revision of asset retirement obligations	**(379)**	—	—	**(379)**
Bad debt recovery and other	**(341)**	**—**	**—**	**(341)**
Other operating income (expense), net	**(4,456)**	**—**	**35**	**(4,421)**
Operating income (loss)	**35,049**	**(438)**	**(13,418)**	**21,193**
Derivatives instruments loss, net	**—**	**—**	**(446)**	**(446)**
Interest income	**5**	**—**	**728**	**733**
Other, net	**(230)**	**(3)**	**(205)**	**(438)**
Income tax expense	**20,311**	**12**	**3,567**	**23,890**
Additions to crude oil and natural gas properties and equipment – accrual	**22,116**	**—**	**57**	**22,173**

	Years Ended December 31, 2018			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	$ 104,938	$ —	$ 5	$ 104,943
Depreciation, depletion and amortization	5,176	—	420	5,596
Gain on revision of asset retirement obligations	(3,325)	—	—	(3,325)
Bad debt recovery and other	(77)	—	—	(77)
Other operating income, net	365	—	—	365
Operating income (loss)	61,930	(470)	(10,173)	51,287
Derivatives instruments gain, net	—	—	4,264	4,264
Interest income (expense), net	(396)	—	251	(145)
Other, net	92	(4)	(20)	68
Income tax benefit	(26,670)	—	(16,584)	(43,254)
Additions to crude oil and natural gas properties and equipment – accrual	38,430	187	17	38,634

(in thousands)	Years Ended December 31, 2017 Gabon	Equatorial Guinea	Corporate and Other	Total
Revenues-crude 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
Other operating expense, net	(84)	—	—	(84)
Operating income (loss)	28,488	(122)	(8,415)	19,951
Derivatives instruments loss, net	—	—	(1,032)	(1,032)
Interest expense, net	(1,414)	—	—	(1,414)
Other, net	3,142	15	(12)	3,145
Income tax expense	11,638	—	(1,260)	10,378
Additions to crude oil and natural gas properties and equipment – accrual	1,576	—	126	1,702

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Long-lived assets from continuing operations:				
As of December 31, 2019	**$ 57,930**	**$ 10,000**	**$ 328**	**$ 68,258**
As of December 31, 2018	$ 42,195	$ 10,187	$ 342	52,724

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Total assets from continuing operations:				
As of December 31, 2019	**$ 151,686**	**$ 10,087**	**$ 49,764**	**$ 211,537**
As of December 31, 2018	$ 103,401	$ 10,320	$ 49,301	163,022

Information about the Company's most significant customers

The Company sells crude oil production from Gabon under term contracts with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. From August 2015 through January 2019, the Company sold its crude oil to Glencore Energy UK Ltd. ("Glencore"). The Company signed a new contract with Mercuria Energy Trading SA ("Mercuria") that covers sales from February 2019 through January 2020 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The Company signed a new contract with ExxonMobil Corporation ("Exxon") that covers sales from February 2020 through January 2021 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Sales of crude oil to Glencore and Mercuria were approximately 6% and 94%, respectively, of total revenues for the period during the terms of their contracts.

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, the Company assumes that restricted stock is outstanding on the date of vesting, and the Company assumes 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:

	Years Ended December 31, 2019	2018	2017
		(in thousands)	
Net income (loss) (numerator):			
Income (loss) from continuing operations	**$ (2,848)**	$ 98,728	$ 10,272
(Income) loss from continuing operations attributable to unvested shares	**21**	(1,231)	(62)
Numerator for basic	**(2,827)**	97,497	10,210
Loss from continuing operations attributable to unvested shares	**(21)**	—	—
Numerator for dilutive	**$ (2,848)**	$ 97,497	$ 10,210
Income (loss) from discontinued operations, net of tax	**$ 5,411**	$ (496)	$ (621)
(Income) loss from discontinued operations attributable to unvested shares	**(39)**	6	4
Numerator for basic	**5,372**	(490)	(617)
Income from discontinued operations attributable to unvested shares	**39**	—	—
Numerator for dilutive	**$ 5,411**	$ (490)	$ (617)
Net income	**$ 2,563**	$ 98,232	$ 9,651
Net income attributable to unvested shares	**(18)**	(1,225)	(58)
Numerator for basic	**2,545**	97,007	9,593
Net income attributable to unvested shares	**18**	—	—
Numerator for dilutive	**$ 2,563**	$ 97,007	$ 9,593
Weighted average shares (denominator):			
Basic weighted average shares outstanding	**59,143**	59,248	58,717
Effect of dilutive securities	**—**	749	3
Diluted weighted average shares outstanding	**59,143**	59,997	58,720
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**603**	1,316	2,823

7. REVENUE

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 COSPA with a different customer was executed for the period from February 2019 through January 2020. A new COSPA with a different customer has been executed for the period from February 2020 through January 2021.

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 crude 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 that 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. The Company has 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, the Company followed the sales method of accounting to account for crude oil production imbalances. In conjunction with the adoption of ASC Topic 606 on January 1, 2018, the Company will continue to account for production imbalances as a reduction in reserves. The volumes sold may be more or less than the volumes that the Company is entitled based on the ownership interest in the property, and the Company would recognize a liability if the 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 transfer thirty days after the date of the bill of lading. For each lifting of crude 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, the Company deemed 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, the Company 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 that 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 2018 lifting was $9.4 million. The in-kind payment related to the April 2019 lifting was $7.3 million. As of December 31, 2019, the foreign taxes payable attributable to this obligation is $5.7 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 that 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:

	Years Ended December 31,		
	2019	2018	2017
Revenue from customer contracts:		*(in thousands)*	
Sales under the COSPA	**$ 86,554**	$ 104,891	$ 74,693
Gabonese government share of Profit Oil	**—**	2,193	11,638
U.S. crude oil and natural gas revenue	**—**	5	47
Other items reported in revenue not associated with customer contracts:			
Gabonese government share of Profit Oil taken in-kind	**7,268**	9,385	—
Carried interest recoupment	**2,950**	3,545	2,205
Royalties	**(12,251)**	(15,076)	(11,558)
Total revenue, net	**$ 84,521**	$ 104,943	$ 77,025

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 included 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 resulted in a one time U.S. tax liability on those earnings that had not previously been repatriated to the U.S. (the "Transition Tax"). The Company has appropriately accounted for the Tax Reform Act provisions in its financial statements. However, the Company continues to monitor new regulations and legislation that has resulted due to the Tax Reform Act and will further analyze the implications as they arise.

Income taxes attributable to continuing operations for the years ended December 31, 2019, 2018, and 2017 are attributable to foreign taxes payable in Gabon as well as income taxes in the U.S.

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

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
U.S. Federal:			
Current	**$ (337)**	$ (674)	$ —
Deferred	**3,916**	(15,910)	(1,260)
Foreign:			
Current	**9,747**	14,327	11,638
Deferred	**10,564**	(40,997)	—
Total	**$ 23,890**	$ (43,254)	$ 10,378

As of December 31, 2019 and 2018, the Company had deferred tax assets of $108.8 million and $131.0 million, respectively 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. In assessing the realizability of the deferred tax assets, the Company considers all available positive and negative evidence, and the Company makes a determination whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. Numerous judgments and assumptions are inherent in this assessment including the determination of future taxable income, which is affected by a number of factors, including future operating conditions (particularly as related to prevailing crude oil prices) and changing tax laws.

As of December 31, 2019 and 2018, the Company anticipated it will only be able to partially utilize its deferred tax assets. On the basis of this evaluation, a valuation allowance of $84.6 million and $90.9 million were recorded as of December 31, 2019 and 2018, respectively. 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 to 80% 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. We also record as income tax expense the increase or decrease in the value of the government's allocation of Profit Oil which results due to change in value from the time the allocation is originally produced to the time the allocation is actually lifted.

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, the Company expected higher future crude oil prices based on current Brent futures strip pricing over the next few years, and the Company expects future production from the drilling of two wells in 2019. Expectations related to future crude oil prices, drilling activities and other factors are evaluated quarterly in order to estimate the future taxable income which is considered in the evidence used to determine the realizability of deferred tax assets.

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, 2019 and 2018 are as follows:

	As of December 31,	
(in thousands)	**2019**	**2018**
Deferred tax assets:		
Basis difference in fixed assets	**$ 26,590**	$ 38,479
Foreign tax credit carryforward	**34,144**	43,760
Alternative minimum tax credit carryover	**337**	674
U.S. federal net operating losses	**30,572**	20,616
Foreign net operating losses	**11,770**	19,989
Asset retirement obligations	**3,407**	3,111
Basis difference in accrued liabilities	**676**	3,816
Basis difference in receivables	**171**	387
Other	**1,120**	180
Total deferred tax assets	**108,787**	131,012
Valuation allowance	**(84,628)**	(90,935)
Net deferred tax assets	**$ 24,159**	$ 40,077

Foreign tax credits will expire between the years 2020 and 2025. Foreign tax credits of $9.6 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 NOLs for the Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues. The Company liquidated the United Kingdom subsidiary and plans to liquidate the Gabon branch associated with its Mutamba operations, both of which carried NOLs. Accordingly, the related deferred tax assets of $8.7 million and $15.9 million, respectively, were written off in 2018 with a corresponding offset to the valuation allowance. All of the Company's U.S. federal NOLs that were incurred prior to 2018 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. In assessing the realizability of the deferred tax assets, we consider all available positive and negative evidence in determining whether it is more likely than not that some or all of the deferred tax assets will not be realized. Numerous judgments and assumptions are inherent in this assessment including the determination of future taxable income, which is affected by a number of factors including future operating conditions (particularly as related to prevailing crude oil prices) and changing tax laws. The Company does 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., the Company expects to realize the benefit from the AMT credit carryforwards.

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, 2019 and 2018. 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)	**2019**	**2018**	**2017**
U.S.	**$ (13,330)**	$ (5,672)	$ (9,453)
Foreign	**34,372**	61,146	30,103
	$ 21,042	$ 55,474	$ 20,650

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)	**2019**	**2018**	**2017**
Tax provision computed at U.S. statutory rate	**$ 4,386**	$ 11,650	$ 7,228
Foreign taxes not offset in U.S. by foreign tax credits	**16,015**	24,840	6,775
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	**—**	—	—
Permanent differences	**180**	(104)	309
Foreign tax credit expirations	**9,616**	4,311	2,394
Increase/(decrease) in valuation allowance	**(6,307)**	(62,270)	(58,777)
Other	**—**	(106)	—
Total income tax expense (benefit)	**$ 23,890**	$ (43,254)	$ 10,378

For the years ended December 31, 2019, 2018 and 2017, the Company is 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.	2009-2019
Gabon	2015-2019

9. CRUDE 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. The Company's 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 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. 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. The Company has accrued the $1.7 million share of this remaining payment as of December 31, 2019. This payment was made in February 2020. 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, the Company 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 the net deferred tax assets. The Company has allocated the 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 wellbores. 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 completed drilling one development well and one appraisal wellbore during the second half of 2019 and completed the remaining development well and appraisal wellbore during the first quarter 2020. 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). These studies are currently being performed.

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

The Company reviews the crude 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 a crude 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 the 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.

There was no triggering event in the year ended December 31, 2019 that would cause the Company to believe the value of crude oil and natural gas producing properties should be impaired. During the year ended December 31, 2018, crude oil and natural gas property costs increased significantly as a result of amounts recorded in connection with the PSC Extension and year-end crude oil prices decreased over the prior year; however, reserves increased significantly over the prior year. The Company 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 the Company to believe the value of crude oil and natural gas producing properties should be impaired.

Undeveloped Leasehold Costs

The Company has a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that the Company acquired in 2012 for which the Company has $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. The EG MMH approved our appointment as operator for Block P on November 12, 2019 and the Company is currently waiting on a production sharing contract amendment to begin activities in Block P. VAALCO intends to seek a joint venture owner on a promoted basis that will cover all or substantially all of the cost to drill an exploratory well. If VAALCO fails to meet the defined commitments when the new PSC amendment terms are agreed, the capitalized costs associated with Block P would be impaired. As of December 31, 2019, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. The 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. The Company allocated $6.7 million of the 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

Capitalized equipment inventory is reviewed regularly for obsolescence. Adjustments for inventory obsolescence are recorded on "Other operating loss, net" line item of the consolidated statement of operations, but were not material for the years ended December 31, 2019, 2018 and 2017.

10. DERIVATIVES AND FAIR VALUE

The Company uses derivative financial instruments to achieve a more predictable cash flow from crude oil production by reducing the exposure to price fluctuations. See Note 2 for further information.

***Commodity swaps* -** In June 2018, the Company 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. On May 6, 2019, the Company entered into commodity swaps at a Dated Brent weighted average of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. If a liability position exceeds $10.0 million, the Company 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, 2019, the unexpired commodity swaps were for an underlying quantity of 274,870 barrels and had a fair value asset position of $0.6 million reflected in “Prepayments and other” line of the consolidated balance sheet.

				Swaps
Settlement Period	**Type of Contract**	**Index**	**Barrels**	**Weighted Average Fixed Price**
January 2020 to June 2020	Swaps	Dated Brent	274,870	66.70
			274,870	

Put options - During 2016, the Company 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, the 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 crude oil prices, the Company has not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. The Company does not enter into derivative instruments for speculative or trading proposes.

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

To mitigate counterparty risk, the Company enters 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 the consolidated statements of operations:

		Years Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2019**	**2018**	**2017**
			(in thousands)	
Crude oil swaps and put options	Realized gain - contract settlements	**$ 2,439**	$ 744	$ 195
	Unrealized gain (loss)	**(2,885)**	3,520	(1,227)
	Derivative instruments gain (loss), net	**$ (446)**	$ 4,264	$ (1,032)

11. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company’s asset retirement obligations:

	Year Ended December 31,		
(in thousands)	**2019**	**2018**	**2017**
Beginning balance	**$ 14,816**	$ 20,163	$ 18,612
Accretion	**812**	1,180	951
Additions	**595**	—	—
Acquisitions and dispositions	—	—	(103)
Revisions	**(379)**	(6,527)	703
Ending balance	**$ 15,844**	$ 14,816	$ 20,163

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

The Company is required under 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. In 2018, the Company 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. In 2019, the Company recorded $0.6 million in additions associated with the Etame 9H and Etame 11H development wells. In December 2019, the Company recorded $0.4 million downward revision associated with the Mutamba Iroru block onshore Gabon. 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"), the Company, 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 the Company's election, the FPSO charter may be terminated as early as September 2020. The Company obtained guarantees from each of the joint owners for their respective shares of the payments. Although the Company believes the need for performance under the charter guarantee is remote, the Company recorded a liability of $0.4 million and $0.3 million as of December 31, 2019 and 2018, respectively, representing the guarantee's estimated fair value.

Estimated future minimum obligations through the end of the FPSO charter, which reflects the right of early termination in September 2021 are as follows:

	Balance at December 31, 2019	
(in thousands)	**Full Charter Payment**	**VAALCO, Net**
Year		
2020	$ 32,233	10,010
2021	24,042	7,467
2022	—	—
2023	—	—
2024	—	—
Total	$ 56,275	$ 17,477

The FPSO charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of crude oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of crude oil per day. VAALCO's net share of payments was $12.1 million, $10.8 million and $12.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

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 wellbores by September 16, 2020. As a result of drilling the Etame 9P appraisal wellbore in 2019 and the South East Etame 4P appraisal wellbore in 2020 and drilling the Etame 9H and the Etame 11H development wells in 2019, this drilling commitment has been fulfilled. 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, the Company has accrued a liability for the net $1.7 million share as of December 31, 2019, which was paid in February 2020. The joint owners are also obligated to perform two technical studies by September 16, 2020 estimated to cost $1.3 million ($0.4 million, net to VAALCO). These studies are currently being performed. The costs related to these studies will be recognized in future periods when the studies are performed. See Note 13 for discussion related to equipment lease commitments.

Drilling Rig

In 2019, the Company contracted a drilling rig to be used to drill two wells, including two appraisal wellbores, for the Etame Marin joint operations. The agreement includes options to drill four additional wells at the Etame Marin block, and it elected to exercise these options to drill a third development well and perform three workovers. The drilling rig contract stipulates a day rate of approximately $75,000. The Company expects the term associated with the drilling rig commitment to be less than one year. As of March 9, 2020, the only remaining commitment under the contract was related to two workovers which the Company expects will be completed in the second quarter of 2020.

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC the Consortium is required to provide to the local government refinery a volume of crude oil at a 15% discount to market price (the "Gabon DMO"). The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of crude oil refined by the refinery per year. In 2019, the Company paid $1.2 million for the share of the 2018 obligation. In 2018, the Company paid $1.1 million for the share of the 2017 obligation. In 2017, the Company paid $1.2 million for the share of the 2016 obligation. The Company accrues an amount for the Gabon DMO based on management's best estimate of the volume of crude oil required because the refinery does not publish throughput figures. The amount accrued at December 31, 2019, for the share of the 2019 obligation was $1.1 million. The amount accrued at December 31, 2018, for the share of the 2018 obligation was $1.2 million. These costs are cost recoverable under the terms of the Etame PSC. Also, 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, 2019, for the share of the 2019 obligation was $2.2

million. The amount accrued at December 31, 2018, for the share of the 2018 obligation was $1.9 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, the Company has 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, 2019, $36.7 million ($11.4 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 the consolidated balance sheet. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments.

Regulatory and Joint Interest Audits

The Company is subject to periodic routine audits by various government agencies in Gabon, including audits of the petroleum Cost Account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under the joint operating agreements.

In 2016, the government of Gabon conducted an audit of the operations in Gabon, covering the years 2013 through 2014. The Company received the findings from this audit and responded to the audit findings in January 2017. Since providing the response, there have been changes in the Gabonese officials responsible for the audit. The Company is working with the currently appointed representatives to resolve the audit findings. The Company does not anticipate that the ultimate outcome of this audit will have a material effect on the financial condition, results of operations or liquidity.

In 2017, the government of Gabon conducted a tax audit of the Gabon subsidiary covering the years 2013 through 2016, and in December 2017, the Company received a report on their findings. In April 2018, the Company reached a final settlement of the audit resulting in a payment for taxes of $0.2 million and penalties of $0.2 million, net to VAALCO.

At December 31, 2018, the Company had accrued $1.3 million, net to VAALCO, in the "Accrued liabilities and other" line item of the 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.

In July 2019, the Company reached an agreement in principle to resolve a legacy issue related to findings from Etame joint venture owners' audits for the periods from 2007 through 2016 for $4.4 million net to VAALCO. The agreement in principle also provides for procedures to minimize the chances of future audit claims. Accordingly, the Company recorded an expense in the consolidated statements of operations in the line item "Other operating income (expense), net". The final settlement agreements were executed by all the joint venture owners effective September 9, 2019. In October 2019, the Company paid $1.1 million of the $4.4 million. The balance of the amount due was paid in February 2020.

Employment agreements

The Company's Chief Executive Officer has an employment agreement, which provides for payments of annual salary, incentive compensation and certain other benefits if their employment is terminated without cause.

13. LEASES

Under the new leasing standard that became effective January 1, 2019, there are two types of leases: finance and operating. Regardless of the type of lease, the initial measurement of the lease results in recording a ROU asset and a lease liability at the present value of the future lease payments.

Practical Expedients – The new standard provides a package of three practical expedients to simplify adoption. At the transition date, the entity may elect not to reassess: (1) whether any expired or existing contracts as of the adoption date are or contain leases under the new definition of a lease, (2) lease classification for expired or existing leases as of the adoption date and (3) initial direct costs for any existing leases as of the adoption date. These three expedients must be elected or not elected as a package. An entity that elects to apply all three of the practical expedients will, in effect, continue to classify leases that commence before the adoption date in accordance with current GAAP, unless the lease classification is reassessed after the adoption date. A lessee that elects to apply all of the practical expedients beginning on the adoption date will follow subsequent measurement guidance in ASC 842. The Company has elected to use these practical expedients, effectively carrying over its previous identification and classification of leases that existed as of January 1, 2019. Additionally, a lessee may elect not to recognize ROU assets and liabilities arising from short-term leases provided there is no purchase option the entity is likely to exercise. The Company has elected this short-term lease exemption. The adoption of ASC 842 resulted in a material increase in the Company's total assets and liabilities on the Company's consolidated balance sheet as certain of its operating leases are significant. In addition, adoption resulted in a decrease in working capital as the ROU asset is noncurrent but the lease liability has both long-term and short-term portions. There was no material overall impact on results of operations or cash flows. In the statement of cash flows, operating leases remain an operating activity.

The Company has entered into several agreements for the lease of office, warehouse and storage yard space, the FPSO, a hydraulic workover rig (“HWU”), and a helicopter. The duration for these agreements range from 21 to 45 months. The FPSO, HWU, helicopter, and office space contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset related to the lease component are included in the calculation of ROU assets and lease liabilities. Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities. For leases on ROU assets used in joint operations, generally the operator reflects the full amount of the lease component, including the amount that will be funded by the non-operators. As operator for the Etame Marin block, the ROU asset recorded for the FPSO, HWU, helicopter, and warehouse and storage yard space used in the joint operations includes the gross amount of the lease components. The ROU asset and lease liability for the HWU was removed from the Company’s consolidated balance sheet when the contract for the HWU was cancelled in December 2019.

The FPSO lease includes an option to extend the term through September 2022. The Company considered this option reasonably certain of exercise and has included it in the calculation of ROU assets and lease liabilities. For all other leases that contain an option to extend, the Company has concluded that it is not reasonably certain it will exercise the renewal option and the renewal periods have been excluded in the calculation for the ROU assets and liabilities. During third quarter of 2019, the Company notified the lessor of the FPSO of its intent to extend the lease term by the first option that extends the FPSO lease to September 2021.

The FPSO agreement also contains options to purchase the assets during or at the end of the lease term. The Company does not consider these options reasonably certain of exercise and has excluded the purchase price from the calculation of ROU assets and lease liabilities.

The FPSO and helicopter leases include provisions for variable lease payments, under which the Company is required to make additional payments based on the level of production or the number of days or hours the asset is deployed. Because the Company does not know the extent that the Company will be required to make such payments, they are excluded from the calculation of ROU assets and lease liabilities.

The discount rate used to calculate ROU assets and lease liabilities represents the Company’s incremental borrowing rate. The Company determined this by considering the term and economic environment of each lease, and estimating the resulting interest rate the Company would incur to borrow the lease payments.

For the year ended December 31, 2019, the components of the lease costs and the supplemental information were as follows:

		Years Ended December 31, 2019
Lease cost:		*(in thousands)*
Operating lease cost	$	16,428
Short-term lease cost		3,470
Variable lease cost		5,819
Total lease expense		25,717
Lease costs capitalized		3,653
Total lease costs	$	29,370
Other information:		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows to operating leases	$	19,229
Weighted-average remaining lease term		2.7 years
Weighted-average discount rate		6.18%

The table below describes the presentation of the total lease cost on the Company's consolidated statement of operations. As discussed above, the Company's joint venture owners are required to reimburse the Company for their share of certain expenses, including certain lease costs.

	Years Ended December 31, 2019
	(in thousands)
Production expense	$ 7,859
General and administrative expense	196
Lease costs billed to the joint venture owners	20,181
Total lease expense	28,236
Lease costs capitalized	1,134
Total lease costs	$ 29,370

The following table describes the future maturities of the Company's operating lease liabilities at December 31, 2019:

Year	Lease Obligation
	(in thousands)
2020	$ 13,655
2021	13,310
2022	9,130
2023	—
2024	—
	36,095
Less: imputed interest	2,734
Total lease liabilities	$ 33,361

Under the joint operating agreements, other joint owners are obligated to fund $24.9 million of the $36.1 million in future lease liabilities.

With respect to the periods prior to adoption of the new leasing standard, the Company incurred rent expense of $17.0 million and $19.1 million, respectively, associated with the FPSO and other leased equipment for the years ended December 31, 2018 and 2017.

14. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

	December 31, 2019	December 31, 2018
	(in thousands)	
Accrued accounts payable invoices	$ **4,650**	$ 4,669
Joint venture audit settlement	**3,322**	—
Gabon DMO, PID and PIH obligations	**3,314**	3,145
Capital expenditures	**11,792**	2,038
Stock appreciation rights	**2,638**	1,007
Accrued wages and other compensation	**1,731**	1,802
Other	**2,326**	1,477
Total accrued liabilities and other	$ **29,773**	$ 14,138

15. DEBT

On May 22, 2018, the Company terminated an amended term loan agreement the Company had with the International Finance Corporation (the "IFC") (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.

The Company 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 the 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 the 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, the Company 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

Under the terms of the Amended Term Loan Agreement with the IFC, from 2016, through March 14, 2017, commitment fees were equal to 2.3% of the undrawn term loan amount of $5.0 million. There were no further commitment fees owing after March 14, 2017.

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

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Interest expense related to debt, including commitment fees	**$ —**	$ (257)	$ (997)
Deferred finance cost amortization	**—**	(191)	(369)
Interest income	**733**	270	7
Other interest expense not related to debt	**—**	33	(55)
Interest income (expense), net	**$ 733**	$ (145)	$ (1,414)
Average effective interest rate, excluding commitment fees	**N/A**	7.09%	6.72%

16. 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, 2019 or 2018.

Treasury stock – On June 20, 2019, the Board of Directors authorized and approved a share repurchase program for up to $10.0 million of the currently outstanding shares of the Company's common stock over a period of 12 months. Under the stock repurchase program, the Company intends to repurchase shares through open market purchases, privately-negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the "Exchange Act".

The Board of Directors also authorized the Company to enter into written trading plans under Rule 10b5-1 of the Exchange Act. Adopting a trading plan that satisfies the conditions of Rule 10b5-1 allows a company to repurchase its shares at times when it might otherwise be prevented from doing so due to self-imposed trading blackout periods or pursuant to insider trading laws. Under any Rule 10b5-1 trading plan, the Company's third-party broker, subject to Securities and Exchange Commission regulations regarding certain price, market, volume and timing constraints, would have authority to purchase the Company's common stock in accordance with the terms of the plan. The Company may from time to time enter into Rule 10b5-1 trading plans to facilitate the repurchase of its common stock pursuant to its share repurchase program.

From commencement of the plan in June 2019 through December 31, 2019, the Company purchased 2,067,188 shares of common stock at an average price of $1.81 per share for an aggregate purchase price of $3.7 million under the plan. From January 1, 2020 through the settlement date of March 5, 2020, the Company has purchased 44,368 shares of its common stock at an average price of $1.99 per share for an aggregate purchase price of $0.1 million.

For the majority of restricted stock awards granted by the Company, the number of shares issued on the date the restricted stock awards vest is net of shares withheld to meet applicable tax withholding requirements. Although these withheld shares are not issued or considered common stock repurchases under the Company's stock repurchase program, they are treated as common stock repurchases in the Financial Statements as they reduce the number of shares that would have been issued upon vesting. See Note 17 for further discussion.

17. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

The stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of the Board of Directors to issue various types of incentive compensation. Currently, the Company has issued stock options, restricted shares and SARs from the 2014 Long-Term Incentive Plan ("2014 Plan"). At December 31, 2019, 68,241 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. The Company has no set policy for sourcing shares for option grants. Historically the shares issued under option grants have been new shares.

The Company records non-cash compensation expense related to stock-based compensation as general and administrative expense. For the years ended December 31, 2019, 2018 and 2017, non-cash compensation expense was $3.5 million, $2.4 million and $1.1 million, respectively, related to the issuance of stock options, restricted stock and SARs. The Company computes a deferred tax benefit for restricted shares, SARs and stock options expected to generate future tax deductions by applying the federal statutory tax rate. For restricted shares, the Company's actual tax deduction is based on the value of the shares at the time of vesting. The Company receives a tax deduction for certain stock option exercises during the period the stock option awards are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards.

	Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Stock-based compensation - equity awards	**$ 985**	$ 820	$ 977
Stock-based compensation - liability awards	**2,521**	1,568	121
Total stock-based compensation	**$ 3,506**	$ 2,388	$ 1,098

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 the 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 $0.3 million, $0.5 million and $39 thousand in cash proceeds received from the exercise of stock options in 2019, 2018 and 2017, respectively.

On February 28, 2019, the Company granted stock options for 622,140 shares 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 with an exercise price of $2.33 per share. On April 1, 2019, the Company granted stock options for 44,163 shares to an employee with an exercise price of $2.29 per share. On June 6, 2019, the Company granted stock options for 257,228 shares to directors with an exercise price of $1.43 per share; these options vested immediately.

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 the non-employee directors, which were fully vested upon their grant and have an exercise price of $1.60 per share. During 2017, options for 1,162,930 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. Options for 465,950 shares also were granted in 2017 to the non-employee directors, which were fully vested upon their grant.

The Company uses 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 2019, 2018 and 2017, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because the Company has 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.

	Years Ended December 31,		
	2019	2018	2017
Weighted average exercise price - ($/share)	**$ 2.08**	$ 1.05	$ 0.99
Expected life in years	**3.2**	3.5	3.2
Average expected volatility	**73 %**	71 %	73 %
Risk-free interest rate	**2.33 %**	2.51 %	1.51 %
Weighted average grant date fair value - ($/share)	**$ 1.06**	$ 0.68	$ 0.49

Stock option activity for the year ended December 31, 2019 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, 2019	2,601	$ 1.54		
Granted	923	2.08		
Exercised	(260)	0.99		
Unvested shares forfeited	(306)	1.50		
Vested shares expired	(124)	6.70		
Outstanding at December 31, 2019	2,834	1.55	2.77	$ 2,301
Exercisable at December 31, 2019	1,858	1.46	2.34	$ 1,736

The intrinsic value of a stock option is the amount that the current market value of the underlying stock exceeds the exercise price of the option. The intrinsic value of stock options exercised in 2019, 2018 and 2017 was $0.3 million, $0.6 million and $0.0 million, respectively.

As of December 31, 2019, unrecognized compensation cost related to outstanding stock options was $0.3 million, which is expected to be recognized over a weighted average period of 1.5 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 2019.

	Restricted Stock	Weighted Average Grant Price
	(in thousands)	
Non-vested shares outstanding at January 1, 2019	507	$ 0.91
Awards granted	309	2.00
Awards vested	(307)	1.12
Awards forfeited	(166)	1.29
Non-vested shares outstanding at December 31, 2019	343	1.52

The total vest-date fair value of restricted stock awards, which vested during 2019, 2018 and 2017 was $0.6 million, $0.4 million and $0.3 million, respectively. The weighted average grant date fair value per share of restricted stock awards was $2.00, $1.71 and $0.98 for the years ended December 31, 2019, 2018 and 2017, 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. On April 1, 2019, the Company issued 22,926 shares of service based restricted stock to employees with a grant date fair value of $2.29 per share. On June 6, 2019, the Company issued 111,888 shares of service based restricted stock to directors with a grant date fair value of $1.43 per share, which vested immediately. On February 28, 2018, the Company issued 323,474 shares of service based restricted stock with a grant date fair value of $0.86 per share. The vesting of the shares granted to employees 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, 2019, unrecognized compensation cost related to restricted stock totaled $0.2 million and is expected to be recognized over a weighted average period of 1.5 years.

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 the 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 the Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of the Board of Directors.

On February 28, 2019, 951,699 SARs were granted that 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. On May 10, 2019, 196,892 SARs were granted which vest over a three-year period with a life of 5 years and have a $1.72 SAR price per share specified in a SAR award on the date of grant.

During 2018, 2,373,411 SARs were granted that 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. During 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 the Company's 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 the SARs awards during the year ended December 31, 2019 was $2.5 million.

SAR activity for the year ended December 31, 2019 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, 2019	3,369	$ 0.96		
Granted	1,148	2.23		
Exercised	(558)	1.04		
Unvested shares forfeited	(541)	1.41		
Vested shares expired	—	—		
Outstanding at December 31, 2019	3,418	1.30	3.21	$ 3,240
Exercisable at December 31, 2019	952	0.99	2.56	$ 1,173

Other benefit plans

The Company sponsors a 401(k) plan, with a company match feature, for the employees. Costs incurred in the years ended December 31, 2019, 2018 and 2017 for the Company's matching contribution and for administering the plan were approximately $0.4 million, $0.3 million and $0.2 million, respectively.

SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The unaudited quarterly results for years ended December 31, 2019 and 2018 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)			
2019:				
Total revenues	$ 19,765	$ 25,230	$ 17,603	$ 21,923
Total operating costs and expenses	14,182	14,461	16,137	14,127
Operating income	5,546	6,370	1,501	7,776
Income (loss) from continuing operations	830	(871)	(3,858)	1,051
Income (loss) from discontinued operations	5,671	(162)	(61)	(37)
Net income (loss)	6,501	(1,033)	(3,919)	1,014
Basic net income (loss) per share	$ 0.10	$ (0.01)	$ (0.07)	$ 0.02
Diluted net income (loss) per share	$ 0.10	$ (0.01)	$ (0.07)	$ 0.02
Basic income (loss) from continuing operations per share	$ 0.01	$ (0.01)	$ (0.07)	$ 0.02
Diluted income (loss) from continuing operations per share	$ 0.01	$ (0.01)	$ (0.07)	$ 0.02

Deferred income tax expense (benefit) for the three months ended September 30, 2019 included a $4.8 million charge to increase the valuation allowances on US deferred tax assets and for the three months ended December 31, 2019 included $1.7 million benefit as a result of a decrease in valuation allowances on deferred tax assets.

	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.

SUPPLEMENTAL INFORMATION ON CRUDE 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 the producing properties in the state of Texas, and International, which includes the producing properties offshore Gabon (Africa).

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
	2019	2018	2017
Costs incurred during the year:	(in thousands)		
International:			
Exploration costs - capitalized	**$ 2,952**	$ —	$ —
Exploration costs - expensed	**—**	14	7
Acquisition of properties	**—**	36,239	—
Development costs	**15,654**	—	—
Total	**$ 18,606**	$ 36,253	$ 7

Capitalized Costs Relating to Crude Oil and Natural Gas Producing Activities

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

	December 31,	
	2019	2018
Capitalized costs:	(in thousands)	
Properties not being amortized	**$ 38,818**	$ 30,059
Properties being amortized (1)	**422,651**	409,487
Total capitalized costs	**$ 461,469**	$ 439,546
Less accumulated depletion, amortization and impairment	**(393,800)**	(387,868)
Net capitalized costs	**$ 67,669**	$ 51,678

(1) Includes $8.1 million and $7.8 million of asset retirement costs in 2019 and 2018, respectively. During 2019, the Company recorded $0.6 million in additions associated with the Etame 9H and Etame 11H development wells at the Etame Marin field. During 2018, the Company 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 Crude Oil and Natural Gas Producing Activities

	International			U.S.		
	Year Ended December 31,			Year Ended December 31,		
	2019	2018	2017	2019	2018	2017
	(in thousands)					
Crude oil and natural gas sales	**$ 84,521**	$ 104,938	$ 76,978	**$ —**	$ 5	$ 47
Production costs and other expense [1]	**(38,461)**	(37,865)	(41,558)	**(6)**	(13)	(26)
Depreciation, depletion, amortization	**(6,825)**	(5,176)	(6,196)	**—**	(162)	(1)
Exploration expenses	**—**	(14)	(7)	**—**	—	—
Other operating expense	**(4,457)**	—	—	**—**	—	—
Bad debt recovery (expense)	**341**	77	(452)	**—**	—	—
Income tax benefit (expense)	**(21,702)**	(37,591)	(11,638)	**—**	36	1,260
Results from crude oil and natural gas producing activities	**$ 13,417**	$ 24,369	$ 17,127	**$ (6)**	$ (134)	$ 1,280

[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 that 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 Crude Oil and Natural Gas Activities.*" For a discussion of the reserve estimation process, including internal controls, see "*Item 1. Business – Reserve Information*."

Proved reserves:	Proved Developed (MBbls)	Proved Undeveloped (MBbls)	Total Proved (MBbls)
Balance at January 1, 2017	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 the PSC Extension	253	1,982	2,235
Revisions of previous estimates	1,455	—	1,455
Balance at December 31, 2018	3,388	1,982	5,370
Production	**(1,269)**	**—**	**(1,269)**
Revisions of previous estimates	**2,847**	**(1,982)**	**865**
Balance at December 31, 2019	**4,966**	**—**	**4,966**

Total proved reserves:	Proved Developed (MBbls)	Proved Undeveloped (MBbls)	Total Proved (MBbls)
Balance at January 1, 2017	2,642	—	2,642
Balance at December 31, 2017	3,049	—	3,049
Balance at December 31, 2018	3,388	1,982	5,370
Balance at December 31, 2019	**4,966**	**—**	**4,966**

The proved developed reserves are located offshore Gabon. In 2019, the Company replaced 68% of production by adding 1.1 MMBbls of reserves through reservoir performance additions offset by downward revisions for lower average crude oil prices of 0.2 MMBbls.

In 2018, the Company 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. The Company 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 crude 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.

The Company maintains 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 the 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 Crude 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 its or the Company's performance.

In accordance with the guidelines of the SEC, the estimates of future net cash flow from the properties and the present value thereof are made using crude 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, 2019, 2018 and 2017.

	International		
(In thousands)	**2019**	**2018**	**2017**
Future cash inflows	$ **319,693**	$ 387,415	$ 165,341
Future production costs	**(193,626)**	(228,999)	(108,387)
Future development costs [1]	**(12,758)**	(27,151)	(8,803)
Future income tax expense	**(36,058)**	(38,512)	(24,798)
Future net cash flows	**77,251**	92,753	23,353
Discount to present value at 10% annual rate	**(6,820)**	(12,697)	(863)
Standardized measure of discounted future net cash flows	$ **70,431**	$ 80,056	$ 22,490

(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,		
	2019	**2018**	**2017**
		(in thousands)	
Balance at beginning of period	$ **80,056**	$ 22,490	$ 9,441
Sales of crude oil and natural gas, net of production costs	**(46,873)**	(71,962)	(37,328)
Net changes in prices and production costs	**(5,118)**	55,468	35,257
Revisions of previous quantity estimates	**28,921**	33,344	18,743
Purchases	**—**	43,236	—
Changes in estimated future development costs	**(4,033)**	1,075	(692)
Development costs incurred during the period	**7,185**	763	2,298
Accretion of discount	**11,175**	4,530	2,482
Net change of income taxes	**1,270**	(8,889)	(7,432)
Change in production rates (timing) and other	**(2,152)**	1	(279)
Balance at end of period	$ **70,431**	$ 80,056	$ 22,490

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 the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of crude 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 crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude 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 crude oil and natural gas reserves attributable to the 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 the 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 2019, the average of such prices reflected an 11% decrease during the year and were $63.60 per Bbl for crude oil from Gabon when compared to the average of such prices for 2018 of $70.83 per Bbl for crude oil from Gabon.

Under the Etame PSC in Gabon, the Gabonese government is the owner of all crude oil and natural gas mineral rights. The right to produce the crude oil and natural gas is stewarded by the Directorate Generale de Hydrocarbures and the Etame PSC was awarded by a decree. 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, the Company was 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, 2019, there was $47.9 million in the Cost Account, net to the Company's 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 crude 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, the Company only recovers 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 crude 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 the independent reserve engineering firm of Netherland, Sewell & Associates, Inc.

The PSC for Block P in Equatorial Guinea entitles the Company 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 crude 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, 2019, the Company has no proved reserves related to Block P in Equatorial Guinea.

Exhibit 4.1

DESCRIPTION OF SECURITIES

The following description sets forth certain material terms and provisions of our securities that are registered under Section 12 of the Securities Exchange Act of 1934, as amended. This description also summarizes relevant provisions of Delaware law. The following summary does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the applicable provisions of Delaware law and our certificate of incorporation and our bylaws, copies of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.1 is a part. In addition, you should be aware that the summary below does not give full effect to the terms of the provisions of statutory or common law, and we encourage you to read our certificate of incorporation, our bylaws and the applicable provisions of Delaware law for additional information.

Description of Capital Stock

Common Stock

We are currently authorized to issue up to 100,000,000 shares of common stock, par value $0.10 per share. As of March 3, 2020, there were 57,978,990 shares of common stock outstanding. Holders of our common stock are entitled to cast one vote for each share held of record on each matter submitted to a vote of stockholders. There is no cumulative voting for election of directors. Subject to the prior rights of any series of preferred stock which may from time to time be outstanding, if any, holders of our common stock are entitled to receive ratably dividends when, as and if declared by the board of directors out of funds legally available for such purpose and, upon the liquidation, dissolution or winding up of the company, are entitled to share ratably in all assets remaining after payment of liabilities and payment of accrued dividends and liquidation preferences on the preferred stock, if any. There are no redemption or sinking fund provisions that are applicable to our common stock. Subject only to the requirements of the Delaware General Corporation Law, or DGCL, the board of directors may issue shares of our common stock without stockholder approval, at any time and from time to time, to such persons and for such consideration as the board of directors deems appropriate. Holders of our common stock have no preemptive rights and have no rights to convert their common stock into any other securities. The outstanding common stock is validly authorized and issued, fully paid and nonassessable.

Preferred Stock

We are authorized to issue up to 500,000 shares of preferred stock, par value $25.00 per share. As of March 3, 2020, there were no shares of preferred stock outstanding. Shares of preferred stock may be issued from time to time in one or more series as the board of directors may from time to time determine, each of said series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions thereof, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the DGCL, the board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series of preferred stock.

The authority of the board of directors with respect to each series shall include, but not be limited to, determination of the following:

- the number of shares constituting that series and the distinctive designation of that series;
- the dividend rate on the shares of that series, whether dividends shall be cumulative, and if so, from which date or dates, and the relative rights of priority, if any, of payment of dividends on shares of that series;
- whether that series shall have voting rights, in addition to the voting rights provided by law, and, if so, the terms of such voting rights;

- whether that series shall have conversion privileges, and, if so, the terms and conditions of such conversion, including provision for adjustment of the conversion rate in such events as the board of directors shall determine;

- whether or not the shares of that series shall be redeemable, and, if so, the terms and conditions of such redemption, including the date or date upon or after which they shall be redeemable, and the amount per share payable in case of redemption, which amount may vary under different conditions and at different redemption dates;

- whether that series shall have a sinking fund for the redemption or purchase of shares of that series, and, if so, the terms and amount of such sinking fund;

- the rights of the shares of that series in the event of voluntary or involuntary liquidation, dissolution or winding up of the corporation, and the relative rights of priority, if any, of payment of shares of that series;and

- any other relative rights, preferences and limitations of that series.

The issuance of any such preferred stock by our board of directors could adversely affect the rights of the holders of our common stock and therefore, reduce the value of the common stock. The ability of the board of directors to issue preferred stock could discourage, delay, or prevent a takeover of us.

Anti-Takeover Effects of Provisions of Our Certificate of Incorporation and Our Bylaws

Our Restated Certificate of Incorporation, Bylaws and Delaware law contain several provisions that may make the acquisition of control of us by means of a tender offer, open market purchases, a proxy fight, or otherwise more difficult.

Delaware Law

Section 203 of the Delaware General Corporation Law restricts certain transactions between a corporation organized under Delaware law or its majority-owned subsidiaries and any person, referred to as an interested stockholder, holding 15% or more of the corporation's outstanding voting stock, together with the affiliates or associates of such person. Section 203 prevents, for a period of three years following the date that a person becomes an interested stockholder, the following types of transactions between the corporation and the interested stockholder, unless certain conditions, described below, are met:

- mergers or consolidations;

- sales, leases, exchanges or other transfers of 10% or more of the aggregate assets of the corporation;

- issuances or transfers by the corporation of any stock of the corporation which would have the effect of increasing the interested stockholder's proportionate share of the stock of any class or series of the corporation;

- any other transaction which has the effect of increasing the proportionate share of the stock of any class or series of the corporation which is owned by the interested stockholder; and

- receipt by the interested stockholder of the benefit, except proportionately as a stockholder, of loans, advances, guarantees, pledges or other financial benefits provided by the corporation.

The three-year ban does not apply if either the proposed transaction or the transaction by which the interested stockholder became an interested stockholder is approved by the board of directors of the corporation prior to the date such stockholder becomes an interested stockholder. Additionally, an interested stockholder may avoid the statutory restriction if, upon the consummation of the transaction whereby such stockholder becomes an interested stockholder, the stockholder owns at least 85% of the outstanding voting stock of the corporation without regard to those shares owned by the corporation's officers and directors or certain employee stock plans. Business combinations are also permitted within the three-year period if approved by the board of directors and authorized at an annual or special meeting of stockholders by the holders of at least 66^{2}/3% of the outstanding voting stock not owned by the interested stockholder. In addition, any transaction is exempt from the statutory ban if it is proposed at a time when the corporation has proposed, and a majority of certain continuing directors of the corporation have approved, a transaction with a party who is not an interested stockholder of the corporation, or who becomes such with board approval, if the proposed transaction involves:

- certain mergers or consolidations involving the corporation;
- a sale or other transfer of over 50% of the aggregate assets of the corporation; or
- a tender or exchange offer for 50% of more of the outstanding voting stock of the corporation.

A corporation may, at its option, exclude itself from the coverage of Section 203 by amending its certificate of incorporation or bylaws by action of its stockholders to exempt itself from coverage, provided that such bylaw or charter amendment shall not become effective until 12 months after the date it is adopted. We have not adopted such a charter or bylaw amendment.

Board of Directors

Number of Directors. Our Bylaws provide that the number of directors shall be not less than three nor more than 15, the exact number to be fixed from time to time by our board of directors. Vacancies in the board of directors or newly created directorships resulting from an increase in the number of directors may be filled by a majority of the remaining directors. Accordingly, our board of directors could prevent any stockholder from obtaining majority representation on our board of directors by enlarging the size of the board of directors and filling the new directorships with the board of directors' own nominees.

Removal of Directors. Our Restated Certificate of Incorporation and Bylaws provide that a director may be removed only for cause. "Cause" is defined to exist only if the director has been (1) convicted of a felony, adjudicated to be liable for gross negligence, recklessness or misconduct in the performance of his or her duty to us in a manner of substantial importance to us, or adjudicated to be mentally incompetent, which mental incompetency directly affects his or her ability as one of our directors; and (2) such conviction or adjudication was made by a court of competent jurisdiction and is no longer subject to appeal.

Certain Voting Requirements in Our Restated Certificate and Bylaws

Amendment of Restated Certificate of Incorporation. The affirmative vote of the holders of at least 66/3% of the voting power of all our outstanding voting shares is required to alter, amend, adopt any provision inconsistent with, or repeal the provisions of our Restated Certificate of Incorporation relating to the election, removal and classification of directors and amendment of our Bylaws.

Amendments to Bylaws. Our Restated Certificate of Incorporation and Bylaws further provide that the board of directors has the power to make, alter, amend and repeal our Bylaws, except so far as bylaws adopted by our stockholders otherwise provide. Notwithstanding the foregoing, our Bylaws may not be altered, amended or repealed, and no provision inconsistent therewith may be adopted, by action of the stockholders without the affirmative vote of at least 66^{2}/3% of the voting power of all our outstanding shares.

Supermajority Vote for Certain Transactions. Under Delaware law, and subject to certain exceptions, unless a greater vote is required in the corporation's certificate of incorporation, a merger, consolidation or dissolution of a corporation may be approved by a majority vote of the outstanding stock of the corporation entitled to vote thereon. Our Restated Certificate of Incorporation contains provisions that require the approval of holders of at least 80% of the voting power of the then outstanding shares of our capital stock entitled to vote as a condition for any of the following actions:

- a merger or consolidation;
- a share exchange;
- the adoption of any plan or proposal for liquidation, dissolution or reorganization; and
- a sale, lease or other disposition of all or substantially all of our assets on a consolidated basis.

The 80% voting requirement is not applicable if such action is approved by a majority of our "continuing directors" prior to the transaction. The term "continuing director" is defined to mean:

- any member of our board of directors as of December 31, 1992;
- any new director who is proposed to be a director of ours by a majority of the continuing directors then on the board of directors; and
- any successor of a continuing director who is recommended to succeed a continuing director by a majority of the continuing directors then on the board of directors.

The affirmative vote of the holders of at least 80% of the voting power of all our outstanding voting shares is required to amend, repeal, or adopt any provisions inconsistent with, the provisions of our Restated Certificate of Incorporation described in this paragraph.

Advance Notice Procedure for Stockholder Proposals. Our Bylaws establish an advance notice procedure for the nomination of candidates for election as directors, as well as for stockholder proposals considered at annual meetings of stockholders. These procedures may operate to limit the ability of stockholders to bring business before a stockholders' meeting, including with respect to the nomination of directors or considering any transaction that could result in a change in control.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

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 Energy (EG), Inc.	Energy	100 %	7/3/12	Delaware
VAALCO Energy Mauritius (EG), Limited	Energy	100 %	11/23/12*	Mauritius
VAALCO Gabon S.A.	Energy	100 %	6/4/14	Gabon

* Date of Certificate of Incorporation on Change of Name

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

VAALCO Energy, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-218824, 333-197180 and 333-183515) of VAALCO Energy, Inc. of our reports dated March 9, 2020, relating to the consolidated financial statements and the effectiveness of VAALCO Energy Inc.'s internal control over financial reporting, which appear in this Form 10-K.

/s/ BDO USA, LLP

Houston, Texas
March 9, 2020

[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, 2019. 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, 2019, 2018, and 2017 and to the inclusion of our report dated February 6, 2020, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2019. 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 2, 2020

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 9, 2020

/s/ Cary Bounds
Cary Bounds
Chief Executive Officer

Exhibit 31.2

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

I, Elizabeth D. Prochnow, certify that:

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

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date March 9, 2020

/s/ Elizabeth D. Prochnow
Elizabeth D. Prochnow
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, 2019, 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 9, 2020

/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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Elizabeth D. Prochnow, 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 9, 2020

/s/ Elizabeth D. Prochnow
Elizabeth D. Prochnow, Chief Financial Officer

February 6, 2020

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, 2019, 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, 2019, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net(1)	Total	Present Worth at 10%
Proved Developed Producing	12,483.4	3,372.9	52,357.9	49,161.0
Proved Developed Non-Producing	5,895.9	1,593.0	24,893.6	21,270.4
Total Proved Developed	18,379.3	4,966.0	77,251.5	70,431.5

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. Our study indicates that as of December 31, 2019, there are no proved undeveloped reserves for these properties. 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.

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 2019. The average price of $63.15 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $63.60 per barrel 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 permit-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 minor facilities projects and a portion of the cost of a 3-D seismic acquisition. 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. Capital costs and 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 permit-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

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

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

Date Signed: February 6, 2020

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

Date Signed: February 6, 2020

JRC:WKE

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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.