UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-32167

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

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

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

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

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

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

Securities registered under Section 12(g) of the Exchange Act: None

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

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

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

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

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

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

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

Emerging growth company ☐

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

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

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

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

VAALCO ENERGY, INC.

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Gl ossary of Terms

Terms used to describe quantities of oil and natural gas

- *Bbl* — One stock tank barrel, or 42 United States ("U.S.") gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *BOE* — One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of natural gas to oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids.
- *BOPD* — One barrel of oil per day.
- *MBbl* — One thousand Bbls.
- *MBOE*— One thousand barrels of oil equivalent.
- *Mcf* — One thousand cubic feet of natural gas.
- *MMbtu* — One million British thermal units, a measure commonly used for natural gas pricing.
- *MMcf* — One million cubic feet of natural gas.
- *MMBbl* — One million Bbls.

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

- *Carried interest* — Working interest owners (defined below) whose share of costs are paid by the non-carried working interest owners and whose share of revenues are paid to non-carried working interest owners until such owners costs have been repaid.
- *Consortium* –A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under a Production Sharing Contract with the Republic of Gabon.
- *PSC* — A production sharing contract; Etame PSC is the Etame Production Sharing Contract, as amended, and as it may be further amended, that we have entered into with the Republic of Gabon, related to the Etame Marin block located offshore Gabon.
- *FPSO* — A floating, production, storage and offloading vessel.
- *Participating interest* — Working interest (as defined below) attributable toa non-carried interest owner adjusted to include its relative share of the benefits and obligations attributable to carried working interest owners.
- *Royalty interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas.
- *Working interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe interests in wells and acreage

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

Terms used to classify reserve quantities

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Terms used to assign a present value to reserves

- *Standardized measure* — The standardized measure of discounted future net cash flows ("standardized measure") is the present value, discounted at an annual rate of 10%, of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission

("SEC"), using the 12-month unweighted average of first-day-of-the-month Brent prices adjusted for historical marketing differentials, (the "12-month average"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service, derivatives or to depreciation, depletion and amortization.

Terms used to describe seismic operations

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

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

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

- volatility of, and declines and weaknesses in oil and natural gas prices;
- the discovery, acquisition, development and replacement of oil and natural gas reserves;
- our ability to maintain sufficient liquidity in order to fully implement our business plan;
- our ability to generate cash flows that, along with our cash on hand, will be sufficient to support our operations and cash requirements;
- future capital requirements and our ability to attract capital;
- our ability to replace our loan facility under our agreement with the International Finance Corporation ("IFC credit facility"), as amended ("Amended Term Loan Agreement") with another credit facility to help fund our future capital requirements;
- our ability to resolve satisfactorily matters related to our exit from Angola, including our obligations to pay the amount, as it is ultimately determined, of our liabilities to Sonangol E.P. with respect to our production sharing contract;
- our ability to extend the license period for the Etame block offshore Gabon;
- our ability to meet the financial covenants of our Amended Term Loan Agreement;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the impact of competition;
- weather conditions;
- the uncertainty of estimates of oil and natural gas reserves;
- currency exchange rates;

- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- our ability to meet the continued listing standards of the New York Stock Exchange ("NYSE"), or to cure any deficiency in meeting the listing standards;
- the timing and effectiveness of our remediating the significant deficiencies and material weaknesses in our internal control over financial reporting;
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- timing and amount of future production of oil and natural gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- our ability to pay the expenditures required in order to develop certain of our properties offshore Equatorial Guinea;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- changes in customer demand and producers' supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit; and
- actions of operators of our oil and natural gas properties.

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

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

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Ite m 1. Business

BACKGROUND

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

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

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

STRATEGY

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

At December 31, 2017, we had estimated net proved developed reserves of 3.0 million barrels of oil equivalent. For 2017, our reserves replacement amount was equal to 127% of our 2017 Gabon production, as reflected in the reserve report issued by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. (NSAI"). We added 1.3 MMBOE of reserves through reservoir performance additions and 0.6 MMBOE through positive pricing revisions. The increase in the average of the first-day-of-the-month prices adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was from $40.35 for the 2016 year-end report to $53.49 for the 2017 year-end report.

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

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

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

Our strategic growth alternatives are as follows:

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

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

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

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

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

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

SEGMENT AND GEOGRAPHIC INFORMATION

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

Gabon Segment

Offshore – Etame Marin Block

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

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

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

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

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

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

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

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

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

On November 22, 2016, we closed on the purchase of an additional 2.98% working interest (3.23% participating interest) in the Etame Marin block from Sojitz Etame Limited ("Sojitz"), which had an effective date of August 1, 2016. See Note 5 of the Financial Statements for further discussion.

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

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

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

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

For 2017, our total proved reserves replacement was 127% of our 2017 total net production in Gabon. See "*—Reserve Information*" below. These results occurred primarily due to (i) better-than-forecasted results for production and (ii) increased crude oil prices.

Production. Production operations in the Etame Marin block include nine platform wells, plus three subsea wells across all fields tied back by pipelines to deliver oil and associated natural gas through a riser system to allow for delivery, processing, storage and ultimately offloading the oil from a leased FPSO vessel anchored to the seabed on the block. Production from seven of our wells is aided by ESPs. We currently have ten producing wells and two wells shut in at Avouma due to ESP failures. The FPSO has production limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day. For the years ended December 31, 2017, 2016 and 2015, aggregate production from the block was approximately 5.6 MMBbls (1.5 MMBbls net to us), 6.2 MMBbls (1.5 MMBbls net to us) and 6.8 MMBbls (1.7 MMBbls net to us), respectively. Our net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13%.

Hydrogen Sulfide Impact

Four of our wells are currently shut-in for safety and marketability reasons because of high levels of H_2S. These wells have been excluded from the above-referenced well count. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including the construction of one or more processing facilities capable of removing H_2S, the recompletion of the temporarily abandoned wells and the potential drilling of additional wells. These identified processing facilities are not economic at current forecasted oil prices. As of December 31, 2017, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

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

Abandonment Costs

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

We are required under the Etame PSC to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was completed in January 2016 resulting in estimated gross abandonment costs of approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $2.3 million in 2018, and $4.9 million over the years from 2019 to 2021, net of estimated interest income. Amounts paid are reimbursable through the cost account and are non-refundable. Our estimated liabilities for the abandonment of these Gabon offshore facilities as of December 31, 2017 and 2016 were $20.2 million and $18.6 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2017 and 2016. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Property and equipment – successful efforts method" in the line item "Wells, platforms and other production facilities" on our consolidated balance sheets as of December 31, 2017 and 2016.

Onshore – Mutamba Iroru Block

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

Equatorial Guinea Segment

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

United States Segment

In April 2017, we completed the sale of our interests in the East Poplar Dome field in Montana for $0.3 million, resulting in a gain of approximately $0.3 million during the year ended December 31, 2017. In December 2016, we completed the sale of our interests in two producing wells in the Hefley field (Granite Wash formation) in North Texas for $0.8 million, resulting in an immaterial loss. Our remaining interests in the U.S. are inconsequential.

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

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

DRILLING ACTIVITY

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

	International					
	Gross			Net		
	2017	2016	2015	2017	2016	2015
Exploratory wells						
Productive	—	—	—	—	—	—
Dry	—	—	1.0 [1]	—	—	0.5
In progress	—	—	—	—	—	—
Development wells	—	—	—	—	—	—
Productive	—	—	6.0 [2]	—	—	1.8
Dry	—	—	—	—	—	—
In progress	—	—	—	—	—	—
Total wells	—	—	7.0	—	—	2.3

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

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

ACREAGE AND PRODUCTIVE WELLS

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

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

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

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

RESERVE INFORMATION

Net Proved Reserves

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

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

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

Changes in Proved Reserves

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

	Proved Reserves		
	Crude Oil (MBbls)	Natural Gas (MMCF)	Oil Equivalent (MBOE)
		(in thousands)	
Balance at January 1, 2015	8,260	1,406	8,494
Production	(1,659)	(181)	(1,688)
Revisions of previous estimates	(3,746)	(172)	(3,775)
Balance at December 31, 2015	2,855	1,053	3,031
Production	(1,518)	(124)	(1,539)
Purchases of minerals in place	308	—	308
Sales of minerals in place	(12)	(929)	(167)
Revisions of previous estimates	1,009	—	1,009
Balance at December 31, 2016	2,642	—	2,642
Production	(1,518)	—	(1,518)
Revisions of previous estimates	1,925	—	1,925
Balance at December 31, 2017	3,049	—	3,049

The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in preceding years' estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of an increase or decrease in the projected economic life of such properties resulting from changes in product prices. Crude oil amounts shown for Gabon are recoverable under a PSC, and the reserves in place at the end of the contract remain the property of the Gabon government. The reserves at the end of the contract are not included in the table above.

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

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.

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

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

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

Proved Undeveloped Reserves

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. As a result of the current crude oil prices in 2017, our PUDs are uneconomic to develop at prices calculated in accordance with SEC guidelines. Accordingly, we had no PUDs recorded at December 31, 2017, 2016 and 2015.

Controls over Reserve Estimates

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

Our controls over reserve estimation include retaining NSAI as our independent petroleum and geological firm for all years presented. We provide information to NSAI about our oil and natural gas properties which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. NSAI prepares its own estimates of the reserves attributable to our properties. The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. He graduated from Rice University in 2004 with a Bachelor of Science Degree in Chemical Engineering and from 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 2017, 2016, and 2015 operations are shown in the tables below.

	Year Ended December 31,								
	2017			2016			2015		
	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)
Net production sold									
International	1,423	1,423	—	1,485	1,485	—	1,679	1,679	—
United States	—	—	—	24	3	124	33	3	181
Total production sold	1,423	1,423	—	1,509	1,488	124	1,712	1,682	181

	Year Ended December 31,								
	2017			2016			2015		
	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)
Average sales price									
International	$ 52.58	$ 52.58	$ —	$ 40.17	$ 40.17	$ —	$ 47.87	$ 47.87	$ —
United States	—	—	—	13.50	23.54	1.95	15.09	32.67	2.21
Overall average sales price	52.58	52.58	—	39.62	40.13	1.95	47.24	47.85	2.21

	Year Ended December 31,		
	2017	2016	2015
Average production expense per MBOE			
International	$ 27.90	$ 25.22	$ 23.79
United States	—	5.58	4.67
Overall average production expense	27.90	24.91	23.42

DISCONTINUED OPERATIONS-ANGOLA

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

AVAILABLE INFORMATION

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

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

CUSTOMERS

For the period from the second quarter of 2014 and through April 2015, our crude oil from Gabon was sold under a contract with The Vitol Group at the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA ("Total") for May through July of 2015 and Glencore Energy UK Ltd. ("Glencore") beginning in August of 2015. The contract with Glencore expires in January of 2019. Sales of oil to Glencore were approximately 100% of total revenues for 2017.

EMPLOYEES

As of December 31, 2017, we had 102 full-time employees, 75 of whom were located in Gabon. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. We believe relations with our employees are satisfactory.

COMPETITION

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

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

INSURANCE

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

REGULATORY

General

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

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

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

Gabon

Our exploration and production activities offshore Gabon are subject to Gabonese regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in Gabon.

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

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

Furthermore, under Article 260 of the 2014 Hydrocarbons Law, all oil and gas companies, even those carrying out operations under the previous legal framework, must make payment of two financial contributions set forth in the new Hydrocarbons Law, namely the Investment Diversification Fund (payment of 1% of the Contractor’s turnover during the production phase), and the Hydrocarbons Investment Fund (payment of 2% of the Contractor’s turnover during the production phase), within two years of the entry into force thereof. Under Article 260, oil and gas companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities at the Banque des Etats de l’Afrique Centrale or at a Gabonese banking or financial institution.

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

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—Société Nationale des Hydrocarbures du Gabon—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to Article 4 of the Hydrocarbons Law, the State may acquire an equity stake of up to 20%, at market value, within any companies applying for or already holding an exclusive production authorization. The contractor must carry the State in its 20% participating interest in the hydrocarbons agreements during the exploration phase. The parties are free to agree on a higher stake at market value. Further, under Article 86 of the Hydrocarbons Law, the national oil company may also acquire participating interests of up to 15%, at market value.

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

Under the 2014 Hydrocarbons Law, assignment of interests in production sharing contracts is subject to the Ministry of Hydrocarbons’ consent and tothe State’s preemption rights. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within two years of the entry into force of the Hydrocarbons Law under its Article 254.

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

Hydrocarbons agreements entered into prior to the Hydrocarbon Law’s publication remain in force until their expiration and should continue to be governed by their own provisions. Our understanding is that the Hydrocarbons Law applies to any issues not expressly dealt with in these contracts’ provisions.

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

As discussed in “— Segment and Geographic Information—Gabon Segment—Offshore – Etame Marin Block—Production,” production from the Etame block is stored in an FPSO which we lease from a third party. Over the past 15 years, this vessel was imported under a temporary import license issued to us. Customs officials have advised us that the temporary import license cannot be renewed and that the owner of the FPSO, Tinworth Pte. Limited, an affiliate of BW Offshore Limited, needs to obtain a permanent import license in order to continue operating in Gabon. We are working to find other forms of relief. Should these other efforts fail and the vessel owner does not obtain the permanent import license, this could result in customs fines and penalties being owed by the vessel owner. We are also working with the owner to ensure that they meet the requirements to obtain the permanent import license. In connection with this regulatory matter, the Gabon government could take actions which would impede the operations of the FPSO if this is not resolved. This matter could have an adverse impact on our financial position, results of operations or cash flows.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection or pollution control subject to the laws and regulations of Equatorial Guinea if exploration drilling occurs in that country. The cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, our business and financial results could be adversely affected. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

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

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

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

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

Environmental Regulations in the United States

Currently, we conduct no operations in the U.S. and have only inconsequentialinterests in two U.S. properties. However, our prior operations in the U.S., and any future operations we may conduct in the U.S., may subject us to certain liabilities under U.S. federal, state and local environmental regulations. In the U.S., environmental laws and regulations are administered by the U.S. Environmental Protection Agency ("EPA") and counterpart state agencies in the various states where operations are conducted.

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

Some of our prior operations on U.S. onshore properties involved hydraulic fracturing activities associated with drilling in shale formations. Hydraulic fracturing has been increasingly the subject of significant focus among many non-governmental organizations and regulators. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of both water supply sources and disposal methods.

Superfund

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

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

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

The Oil Pollution Act of 1990

The Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the Clean Water Act ("CWA") imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening U.S. waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages. The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill.

Other Environmental Regulation in the U.S.

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

The CWA and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes as well as fill materials, into state waters and waters of the U.S., a term broadly defined but which remains subject to litigation and rulemaking over the scope of related waters.

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

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. A critical habitat or suitable habitat designation by the U.S. Fish and Wildlife Service could also result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development.

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

It em 1A. Risk Factors

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

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

Our revenues, cash flow, profitability, oil and natural gas reserves value and future rate of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on reasonable terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and decreased further in 2015 and early 2016. During 2015, based on New York Mercantile Exchange ("NYMEX") pricing, the spot price per Bbl of Brent crude oil ranged from a high of $66 to a low of $35. During 2016, the spot price per Bbl of Brent crude oil ranged from a high of $55 to a low of $26. During 2017, the spot price per Bbl of Brent crude oil ranged from a high of $67 to a low of $44.

As a result of the low oil and natural gas prices since 2014, our revenues, operating income, cash flows and borrowing capacity have been materially and adversely affected and have required reductions in the carrying value of our oil and natural gas properties and our planned level of capital expenditures. The average price at which we sold our crude oil in 2017 was $52.58 per Bbl compared to $40.13 per Bbl in 2016 and $47.85 per Bbl in 2015. Because the oil price we are required to use by the SEC to estimate our future net cash flows is the average price over the 12 months prior to the date of determination of future net cash flows, the full effect of increasing or falling prices may not be reflected in our estimated net cash flows for several quarters. We review the carrying value of our properties on a quarterly basis and once incurred, a write-down in the carrying value of our properties is not reversible at a later date, even if oil and natural gas prices increase.

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

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

At December 31, 2017 and 2016, we had no proved undeveloped reserves. We may have higher capital expenditures for our development activities during 2018 should we undertake the drilling of two or three development wells in Gabon. Drilling activities would be subject to partner and government approval.

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

There can be no assurance that our development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including declines in oil or natural gas prices, title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, prolonged periods of historically low oil and natural gas prices, failure of wells drilled in similar formations, equipment failures (such as our experience with our electronic submersible pumps in 2016 and 2017 – see Item 1.

“Business – Segment and Geographic Information – Gabon Segment – Development”), delays in the delivery of equipment and availability of drilling rigs. Our Equatorial Guinea property is operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

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

The Etame Marin block consists of five fields with 12 producing wells, including two wells which are temporarily shut-in pending workover operations Production from these fields constituted approximately 99% of our total production for the year ended December 31, 2017. In addition, at December 31, 2017, 100% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations, financial condition, and cash flows could be materially adversely affected.

Because our properties are concentrated in the same geographic area, many of our rights under the 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. In addition, there is no guarantee that we will be able to extend the life of the PSC beyond its current expiration dates, the first of which is in 2021.

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

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

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

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

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

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

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

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

If low oil and natural gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may be unable to obtain or expend the capital necessary to undertake or complete future drilling programs. Our ability to secure additional or replacement financing is currently limited. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet our capital requirements. In addition, we currently have no availability for additional borrowings under our Amended Term Loan Agreement, and we may be unable to replace our Amended Term Loan Agreement with a new source of capital. The outstanding indebtedness under our term loan with the IFC matures in June 2019. Interest is due quarterly, and we began repaying the principal amounts of this outstanding indebtedness in March 2017. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under any financing sources is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our properties. Such a curtailment in operations could lead to a possible expiration of our PSCs and a decline in our estimated net proved reserves, and would likely adversely affect our business, financial condition and results of operations.

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

The $9.2 million principal outstanding at December 31, 2017 under our Amended Term Loan Agreement matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding through its maturity on June 30, 2019.

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

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

In addition, the Amended Term Loan Agreement includes certain financial ratios, including;

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

As of December 31, 2017, we were in compliance with all of our financial covenants under our Amended Term Loan Agreement. However, we can make no assurance that we will be able to continue to comply with these financial covenants in the future. Failure to maintain these covenants or otherwise negotiate amendments to the Amended Term Loan Agreement could require us to immediately pay down any outstanding amounts.

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

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

If oil and natural gas prices decline materially, we may be required to take write-downs in the value of our oil and natural gas properties.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using the un-weighted average price received for oil and natural gas based on closing prices on the first day of each month during the twelve-month period prior to the end of the reporting period As a result of declines in prices and increased development well costs, during 2015, we recorded impairments totaling $81.3 million related to the Etame Marin block and to various fields in the U.S. During 2016 and 2017, no impairments were necessary related to the Etame Marin block. The sale of our interests in two wells in North Texas caused us to perform an impairment test, resulting in a $0.1 million impairment charge taken during the third quarter of

2016. Material declines in crude oil prices will cause the estimated quantities and present values of our reserves to be reduced, which may necessitate further write-downs.

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

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

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

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

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

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

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

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

As discussed in Item 1. "Business – Regulatory – Gabon," customs officials have advised us that the temporary import license cannot be renewed and that the owner of the FPSO needs to obtain a permanent import license in order to continue operating in Gabon. We are working to find other forms of relief. We are also working with the owner to ensure that they meet the requirements to obtain the permanent import license; however, the Gabon government could take actions which would impede the operations of the FPSO if this is not resolved. This matter could have an adverse impact on our financial position, results of operations or cash flows.

Private ownership of oil and natural gas reserves under oil and natural gas leases in the U.S. differs distinctly from our rights in foreign reserves where the state generally retains ownership of the minerals, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the U.S. may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Beginning in February 2018, Gabon will take the portion of their oil attributable to profit oil in kind rather than our continuing to market their share of production on their behalf. We anticipate that this will cause fluctuations in the timing of and realized prices for oil sales.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities because of climate-related damages to our facilities and our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

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

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

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

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and natural gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including non-escalated prices and costs and capital expenditures subsequent to December 31, 2017, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and natural gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

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

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and natural gas for the preceding twelve months. Future reductions in prices below the average calculated for 2017 would result in the estimated quantities and present values of our reserves being reduced.

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

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

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

Fluctuations in currency exchange rates may negatively impact our earnings, which are subject to financial covenants under our Amended Term Loan Agreement. Failure to maintain these covenants could preclude us from borrowing under our Amended Term Loan Agreement and require us to immediately pay down any outstanding amounts under the agreement, which could affect cash flows or restrict business. As of December 31, 2017, we were in compliance with all financial covenants under our Amended Term Loan Agreement.

Acquisitions and divestitures of properties and businesses subject our company to additional risks and uncertainties. We may be unable to integrate successfully the operations of any acquisitions with our operations, and we may not realize all the anticipated benefits of any future acquisitions. Any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sale or divestment.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. Under a production sharing agreement ("PSA"), we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We are currently engaged in discussions with newly appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be substantially less than the accrued amount.

Due to the uncertainties as to the ultimate outcome, we have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. However, an unfavorable result on the resolution of the ultimate amount of the penalty could have a material adverse effect on our financial position, results of operations, or cash flows.

During 2016 and 2017, we were not in compliance with the New York Stock Exchange's average minimum market capitalization and minimum share price requirements, and have been at risk of the NYSE delisting our common stock, which could materially impair the liquidity and value of our common stock.

Our common stock is currently listed on the NYSE.On April 6 and June 28, 2017, we received notices from the NYSE that we were not in compliance with a provision of the NYSE's continued listing standards that require the average closing price of our common stock to be at least $1.00 per share over a consecutive 30-trading-day period. The 30 trading-day average closing price of the Company's common stock for these notices had been $0.99 per share. In addition, we received a notification from the NYSE on November 30, 2016 that our market capitalization had fallen below the NYSE's continued listing standard because our average market capitalization had fallen below $50 million over a trailing 30 trading-day period and our last reported stockholders' equity was less than $50 million. This notice from the NYSE does not affect our business operations or trigger any default or other violation of our debt or other material obligations.

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

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

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

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.

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

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

We are highly dependent upon the efforts of our senior management and other key employees. The loss of the services of our chief executive officer and chief financial officer, as well as any loss of the services of one or more other members of our senior management, could delay or prevent the achievement of our objectives. We do not maintain any "key-man" insurance policies on any of our senior management, and do not intend to obtain such insurance. In addition, due to the specialized nature of our business, we are highly dependent upon our ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas from proved properties and maximizing production from oil and natural gas properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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.

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 under the symbol EGY. The following table sets forth the range of high and low sales prices of the common stock for the periods indicated.

Period	High	Low
2017		
First Quarter	$ 1.30	$ 0.81
Second Quarter	1.14	0.85
Third Quarter	0.94	0.68
Fourth Quarter	0.94	0.70
2016		
First Quarter	$ 1.69	$ 0.87
Second Quarter	1.26	0.76
Third Quarter	1.10	0.79
Fourth Quarter	1.26	0.71

On February 28, 2018, the last reported sale price of the common stock on the New York Stock Exchange was $0.86 per share.

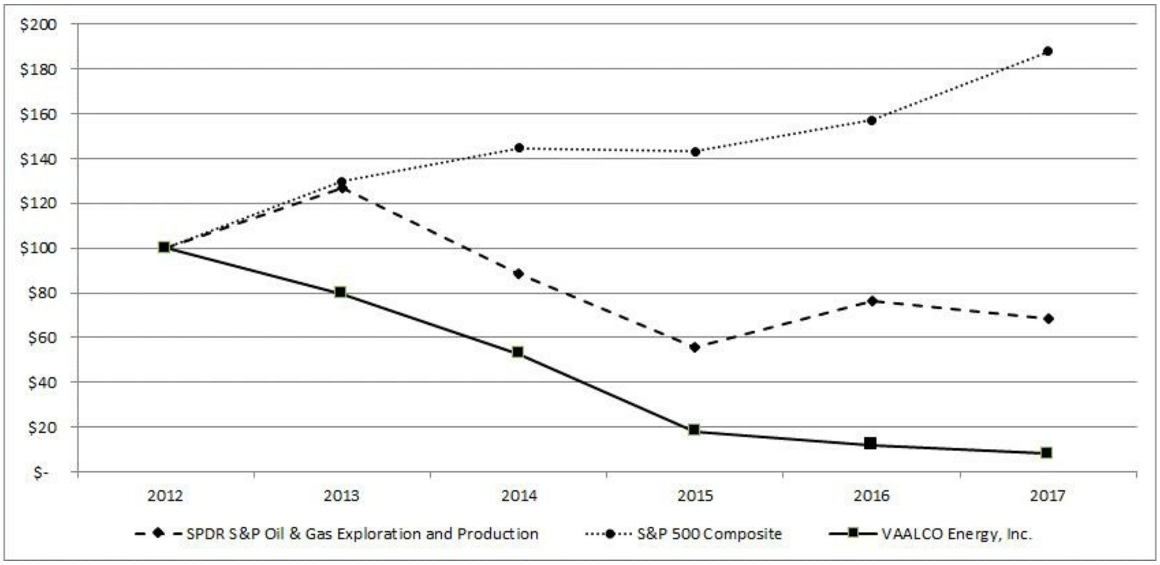
As of February 28, 2018, based upon information received from our transfer agent and brokers and nominees, there were approximately 44 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in "street" names.

Dividends

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

Performance Graph

The following graph compares the annual percentage change in our cumulative total stockholder return on common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. The graph assumes $100 was invested on December 31, 2012 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.



	2012	2013	2014	2015	2016	2017
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 127	$ 88	$ 56	$ 77	$ 69
S&P 500 Composite	$ 100	$ 130	$ 145	$ 143	$ 157	$ 188
VAALCO Energy, Inc.	$ 100	$ 80	$ 53	$ 18	$ 12	$ 8

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2017 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 12 to the Financial Statements for additional information on stock-based compensation.

Plan Category	**Number of 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	2,365,175	$ 1.73	2,404,442
Equity compensation plans not approved by security holders	231,706	2.28	—
Total	2,596,881	$ 1.77	2,404,442

Issuer Purchases of Equity Securities for Year Ended December 31, 2017

During 2017, we acquired 26,000 shares to satisfy tax withholding obligations related to stock option exercises.

It em 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information. The financial information for each of the five years ended December 31, 2017, 2016, 2015, 2014 and 2013 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 Notes thereto. The following information is not necessarily indicative of future results.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
(In thousands, except per share amounts)					
Total revenues	$ 77,025	$ 59,784 [1]	$ 80,445 [1]	$ 127,691 [1]	$ 169,277
Income (loss) from continuing operations	10,272	(18,267) [2]	(120,554) [2]	(73,753) [2]	46,094
Basic income (loss) from continuing operation per share attributable to common shareholders	0.17	(0.31)	(2.07)	(1.29)	0.80
Diluted income (loss) from continuing operations per share attributable to common shareholders	0.17	(0.31)	(2.07)	(1.29)	0.79
Net property, plant and equipment	23,221	28,019	33,357 [3]	93,479 [3]	126,984
Total assets	79,633	81,032	123,958 [3]	248,849 [3]	308,167
Total long-term liabilities	22,756	25,836	31,166	29,846	11,464

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

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

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

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

INTRODUCTION

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We have opportunities to participate in development and exploration activities as a non-operator in Equatorial Guinea, West Africa. As discussed further in Note 5 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa, and in April 2017 we completed the sale of our interests in Montana.

A significant component of our results of operations is dependent upon the difference between prices received for our offshore Gabon oil production and the costs to find and produce such oil. Oil and natural gas prices have been volatile and subject to fluctuations based on a number of factors beyond our control. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through 2015 and into 2016. During this period, we scaled back our global operations, divested non-core assets, amended our credit agreement and focused on reducing costs and maximizing our cash flows. Current prices, while higher than those in early 2016, are significantly less than they were in the several years prior to mid-2014. A decline in oil and natural gas prices and a sustained period of oil and natural gas prices at depressed levels could have a material adverse effect on our financial condition.

CURRENT DEVELOPMENTS

During 2016, the global oil supply continued to outpace demand, having a dampening effect on the recovery of realized crude oil prices. While global oil supply and demand were closer to being balanced during 2017, no assurances can be made that this trend will continue. Prices for crude oil improved during the second half of 2016 (ICE Dated Brent crude oil prices increased from approximately $36 per Bbl in early January 2016 to approximately $55 per Bbl at the end of 2016, and fluctuated between $44 and $67 per Bbl from January 2017 through December 2017).

On June 29, 2016, we executed the Amended Term Loan Agreement with the IFC to convert $20.0 million of the revolving portion of the credit facility into a term loan with $15.0 million outstanding at that date. The Amended Term Loan Agreement also provided us with an option to borrow an additional $5.0 million in a single draw, subject to IFC approval, through March 15, 2017. On March 14, 2017, we borrowed $4.2 million under the provisions of the Amended Term Loan Agreement. Currently under the Amended Term Loan Agreement, we have $9.0 million in total debt, net of deferred financing costs, outstanding. See Note 8 to the Financial Statements and "Capital Resources and Liquidity—Liquidity—Credit Facility" below for additional details about the Amended Term Loan Agreement. There is no further ability to borrow additional sums under the Amended Term Loan Agreement.

Our common stock is currently listed on the NYSE. On April 6 and June 28, 2017, we received notices from the NYSE that we were not in compliance with a provision of the NYSE's continued listing standards that require the average closing price of our common stock to be at least $1.00 per share over a consecutive 30-trading-day period. The 30 trading-day average closing price of the Company's common stock for these notices had been $0.99 per share. In addition, we received a notification from the NYSE on November 30, 2016 that our market capitalization had fallen below the NYSE's continued listing standard because our average market capitalization had fallen below $50 million over a trailing 30 trading-day period and our last reported stockholders' equity was less than $50 million. This notice from the NYSE does not affect our business operations or trigger any default or other violation of our debt or other material obligations. We have until May 30, 2018 to regain compliance with the minimum market capitalization rule. We are evaluating options to either regain compliance with these rules or list on a different exchange.

DISCONTINUED OPERATIONS-ANGOLA

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). The four year primary term, referred to as the Initial Exploration Phase ("IEP"), with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. The IEP was extended on two occasions to run until December 1, 2014. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and the co-participating interest owner, the Angolan national oil company, Sonangol P&P, to drill two additional exploration wells. Our working interest is 40%, and it carries Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to our decision to withdraw from Angola, we have closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented.

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, which represents what we believe to be the maximum potential amount attributable toour interest under the PSA. However, we are currently engaged in discussions with newly appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be substantially less than the accrued amount.

Other Matters – Partner Receivable

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

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

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2017, 2016 and 2015 are as follows:

	Year Ended December 31,			Increase (Decrease) in the Year	
	2017	2016	2015	2017 Over (Under) 2016	2016 Over (Under) 2015
			(in thousands)		
Net cash provided by (used in) operating activities before change in operating assets and liabilities	**$ 19,312**	$ (6,470)	$ 8,021	$ 25,782	$ (14,491)
Net change in operating assets and liabilities	**(8,230)**	(9,268)	33,513	1,038	(42,781)
Net cash provided by (used in) continuing operating activities	**11,082**	(15,738)	41,534	26,820	(57,272)
Net cash provided by (used in) discontinued operating activities	**(4,423)**	12,286	(2,659)	(16,709)	14,945
Net cash provided by (used in) operating activities	**6,659**	(3,452)	38,875	10,111	(42,327)
Net cash used in continuing investing activities	**(1,649)**	(1,287)	(62,133)	(362)	60,846
Net cash used in discontinued investing activities	**—**	—	(20,877)	—	20,877
Net cash used in investing activities	**(1,649)**	(1,287)	(83,010)	(362)	81,723
Net cash provided by (used in) financing activities	**(5,815)**	(144)	441	(5,671)	(585)
Net change in cash and cash equivalents	**$ (805)**	$ (4,883)	$ (43,694)	$ 4,078	$ 38,811

The increase in net cash provided by our operating activities for 2017 compared to 2016 was primarily related to a $25.8 million increase in cash generated by continuing operations before change in operating assets and liabilities which in large part was the result of higher 2017 crude oil prices and lower operating costs and expenses. Net cash provided by our operating assets and liabilities increased by $1.0 million from 2016 to 2017. This overall improvement was offset by a reduction in cash generated by our discontinued operation from 2016 to 2017 of $16.7 million. The decrease in cash generated by discontinued operations was the result of a benefit received in 2016 of $19.0 million from our Angolan joint interest partner in payment of partner receivables. Net cash provided by operations decreased by $42.3 million between 2015 and 2016. Working capital changes contributed to $42.8 million of the decrease in net cash provided by operations between 2015 and 2016.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. These expenditures were significantly lower in 2016 and 2017. No drilling activities were conducted during these two years as we conserved cash during the recent period of low crude oil prices. For 2017, the cash basis expenditures of $1.8 million for property and equipment was primarily related to equipment purchases. During 2016, these expenditures on a cash basis (including expenditures attributable to discontinued operations) were $8.7 million compared to $88.9 million in 2015. These cash property and equipment expenditures are included in capital expenditures. See "—*Capital Expenditures*" below for further discussion.

There were no other significant investing activities in 2017. For 2016, other significant investing activities included $5.7 million for the November 2016 acquisition of Sojitz' interest in the Etame Marin block and $2.9 million to purchase oil puts used to mitigate the potential impact of price declines in 2016 and 2017, as discussed further in Note 10 to the Financial Statements. In addition, restricted cash inflows of $15.2 million in 2016 are primarily a result of us withdrawing from the joint operating agreement for Block 5 offshore Angola. Under the production sharing agreement for Block 5, we and our working interest partner, Sonangol P&P, were obligated to perform exploration activities in Angola. Prior to the September 30, 2016 quarterly reporting period, we classified the $15.0 million commitment for drilling these wells as long term restricted cash on our balance sheet. As a result of our decision to terminate the contract, we are no longer reflecting the $15.0 million as restricted cash. Restricted cash decreased by $5.5 million in 2015 because one commitment well, the Kindele #1, was drilled in Angola.

With respect to cash flows related to financing activities, for 2017, we had cash increases from $4.2 million of borrowings and cash decreases from $10.0 million of debt repayments under the Amended Term Loan Agreement. There were no significant financing activities in 2016. Net cash provided by financing activities included $0.4 million related to stock option exercises in 2015.

Capital Expenditures

At December 31, 2017, we had no material commitments for capital expenditures to be made in future years. However, we may drill two or three development wells in 2018, subject to partner and government approval. We currently have no availability for additional borrowings under our Amended Term Loan Agreement. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances.

During 2017, we had accrual basis capital expenditures attributable to continuing operations of $1.7 million compared to $(4.1) million and $66.4 million accrual basis capital expenditures in 2016 and 2015, 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 2017 and 2016 were mainly for equipment and enhancements. Capital Expenditures in 2015 were primarily associated with the drilling of five development wells offshore Gabon.

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

Contractual Obligations

The table below provides aggregated information on our net share of cash obligations and commitments at December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter	Total
IFC credit facility[(1)]	$ 6,666	$ 2,500	$ —	$ —	$ —	$ —	$ 9,166
Operating leases[(2)]	11,895	10,126	7,369	—	—	—	29,390
Abandonment funding[(3)]	2,298	1,642	1,642	1,641	—	—	7,223
Total cash obligations	$ 20,859	$ 14,268	$ 9,011	$ 1,641	$ —	$ —	$ 45,779

(1) See discussion of the Amended Term Loan Agreement above under "—Credit Facility". Interest estimated to be paid on borrowings under the Amended Term Loan Agreement in each of 2018 through 2019 is $0.4 million and $0.1 million.

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

(3) See *"Abandonment funding"* in Note 9 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 January 2016, the abandonment cost estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. The obligation for abandonment of the Gabon offshore facilities is included in the "Asset retirement obligations" line item on our consolidated balance sheet. Through December 31, 2017, $34.8 million ($10.8 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 $7.4 million ($2.3 million net to VAALCO) and paid in December 2018; however, future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Regulatory and Joint Interest Audits

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

As of December 31, 2017, we had accrued $1.8 million net to VAALCO in "Accrued liabilities and other" on our consolidated balance sheet for these various audits by governmental agencies in Gabon. See Note 9 to the Financial Statements for further discussion.

Capital Resources

Credit Facility

Historically, our primary sources of capital have been cash flows from operating activities, borrowings under the credit facility with the IFC and cash balances on hand. The $9.2 million in principal outstanding under our Amended Term Loan Agreement matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding continuing through June 30, 2019. Interest accrues on the unpaid balance at the per annum rate of LIBOR plus 5.75%. The current portion of the outstanding debt was $6.7 million as of December 31, 2017. Our repayment obligations under the Amended Term Loan Agreement require us to pay installments of principal totaling $6.7 million in 2018 and $2.5 million in 2019. We may make no further borrowings under the terms of the Amended Term Loan Agreement.

The indebtedness under our Amended Term Loan Agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A. and is guaranteed by VAALCO Energy, Inc., as the parent company.

The Amended Term Loan Agreement contains a number of restrictive covenants that impose significant operating and financial restrictions on us. These covenants restrict our ability to engage in certain actions, including potentially limiting our ability to sell assets, make future borrowings or incur other additional indebtedness. Our ability to meet our quarter-end net debt to EBITDAX ratio and our debt service coverage ratio can be affected by events beyond our control, including changes in commodity prices.

Under the Amended Term Loan Agreement, quarter-end net debt to EBITDAX (as defined in the loan agreement) must be no more than 3.0 to 1.0. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at semi-annual review period. Forecasting our compliance with these and other financial covenants in future periods is inherently uncertain. Factors that could impact our quarter-end financial covenants in future periods include future realized prices for sales of oil and natural gas, estimated future production, returns generated by our capital program, and future interest costs, among others. We are in compliance with all financial covenants as of December 31, 2017, and we expect to be in compliance with these covenants through maturity. However, there can be no assurance that we will be able to comply with these financial covenants in future periods. In addition, if we receive any waivers or amendments to our Amended Term Loan Agreement, the lender may impose additional operating and financial restrictions on us.

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

Cash on Hand

At December 31, 2017, we had unrestricted cash of $19.7 million. As operator of the Etame Marin and Mutamba Iroru blocks in Gabon, we enter into project related activities on behalf of our working interest partners. We generally obtain advances from partners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations for the foreseeable future.

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

Liquidity

As discussed above, our revenues, cash flow, profitability, oil and gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices. After a period of low commodity prices, oil and gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. As discussed above, we may drill two or three development wells in 2018. Any drilling program we enter into would require approval of our partners and the government of Gabon. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances. We believe that at current prices, cash generated from continuing operations, together with cash on hand at December 31, 2017, are adequate to support our operations and cash requirements during 2018 and through March 31, 2019.

At December 31, 2017, we had 3.0 MMBOE of proved reserves, all of which are related to the Etame Marin block offshore Gabon. The current term for exploitation of the reserves in the Etame Marin block ends in June 2021, and as discussed in Item 1. "Business – Strategy" above, we are focused on extending the license for the block, and this could favorably improve our long-term liquidity. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. While both short-term and long-term liquidity are impacted by crude oil prices, our long-term liquidity also depends upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable.

OFF BALANCE SHEET ARRANGEMENTS

In connection with the charter of the FPSO (see "*FPSO charter*" in Note 9 to the Financial Statements), we, as operator of the Etame Marin block, guaranteed all of the lease payments under the charter through its contract term, which expires in September 2020. At our election, the charter may be extended for two one-year periods beyond September 2020. We obtained guarantees from each of our partners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.5 million and $0.7 million as of December 31, 2017 and 2016, respectively, representing the guarantee's fair value. The guarantee of the offshore Gabon FPSO lease has $85.2 million in remaining gross minimum obligations for the total amount of charter payments at December 31, 2017. There have been no other material off-balance sheet arrangements entered into since December 31, 2017.

RESULTS OF OPERATIONS

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

We reported net income for the year ended December 31, 2017 of $9.7 million, compared to a net loss of $26.6 million for the same period of 2016. These amounts of income (loss) were inclusive of our loss from discontinued operations for the year ended December

31, 2017 of $0.6 million, and loss from discontinued operations for theyear ended December 31, 2016 of $8.3 million. Further discussion of results by significant line item follows.

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

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

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

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

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

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

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

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

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

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

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

Other operating expenses for the year ended December 31, 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilization and release of the contracted drilling rig. In June 2016, we reached an agreement with the drilling contractor to pay less than our originally estimated maximum day rate, plus demobilization costs, in seven equal monthly installments beginning in July 2016. In January 2017, we resolved the Gabon payroll tax obligation.

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

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

Interest expense for the year ended December 31, 2017 and 2016 relates to borrowings under our Amended Term Loan Agreement as discussed in Note 8 to the Financial Statements.

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

Loss from discontinued operations for the year ended December 31, 2017 is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. The loss from discontinued operations for the 2017 period is related to ongoing administrative costs. For the year ended December 31, 2016 we reported loss from discontinued operations primarily as a result of $3.1 million of income tax on financial gains and $15.0 million accrual for the potential payment of drilling obligations offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other operating loss, net in 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilization and release of the contracted drilling rig.

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

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

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

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

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

Income tax expense decreased $5.3 million in 2016 compared to 2015. Income tax expense in both periods is primarily attributable to our operations in Gabon and is lower in 2016 than income tax for the comparable 2015 period as a result of lower revenues.

Loss from discontinued operations is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. Results for discontinued operations for the year ended December 31, 2016 were primarily as a result of $3.1 million of income tax on financial gains and $15.0 million accrual for the potential payment of drilling obligations offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest. Results for 2015 were primarily attributable to dry hole costs for the Kindele #1 well, higher general and administrative expense and impairments of equipment inventory, offset by higher foreign exchange gains.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

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

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

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

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

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

Impairment of Unproved Property

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

Asset Retirement Obligations ("ARO")

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

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

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

NEW ACCOUNTING STANDARDS

See Note 4 to the Financial Statements.

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

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

Foreign Exchange Risk

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

Interest Rate Risk

The floating rate on borrowings under our Amended Term Loan Agreement exposes us to risks associated with changes in interest rates (LIBOR). At December 31, 2017 and 2016, we had $9.2 million and $15.0 million, respectively, in borrowings outstanding with the IFC. Our deferred financing costs totaled $0.2 million and $0.6 million at December 31, 2017 and 2016, respectively. Fluctuations in floating interest rates will cause our interest costs to fluctuate. During years ended December 31, 2017, 2016 and 2015, the average effective interest rate on our debt, excluding commitment fees, was 6.72%, 5.52% and 4.09%, respectively. If the balance of the debt at December 31, 2017 were to remain constant, a 1% change in market interest rates would impact our cash flow by an estimated $92,000 per year. As future quarterly payments reduce the principal of the term loan, our cash flow becomes less sensitive to fluctuations in interest rate.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our oil and natural gas production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for oil and natural gas have been volatile and unpredictable in recent years, and this volatility may continue. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through the first half of 2016. Current prices remain significantly lower than they were in years prior to 2015. Sustained low oil and natural gas prices or a resumption of the decreases in oil and natural gas prices could have a material adverse effect on our financial condition, the carrying value of our proved reserves, our undeveloped leasehold interests and our ability to borrow funds and to obtain additional capital on attractive terms. If oil sales were to remain constant at the most recent annual sales volumes of 1,423 MBbls, a $5 per Bbl decrease in oil price would be expected to cause a $7.1 million decrease per year in revenues and operating income (loss) and a $6.0 million decrease per year in net income.

During the years ended December 31, 2017 and 2016, we had oil puts outstanding which were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes. These puts had expired as of December 31, 2017, and we had no other commodity price derivatives outstanding during this period. As of and during the year ended December 31, 2015, we had no commodity price derivatives outstanding.

It em 8. Financial Statements and Supplementary Data

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

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

None.

It em 9A. Controls and Procedures

MANAGEMENT’S EVALUATION OF 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, 2017.

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, 2017.

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 the 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, an independent registered public accounting firm, audited the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, as stated in their report 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, 2016, our management concluded that there were material weaknesses in our internal control over financial reporting. In response to the identified material weaknesses at December 31, 2016, our management, with oversight from our Audit Committee, undertook the following remedial actions during 2017:

- Improved the timing of the periodic financial close, reporting process and analysis of results through the use of a detail financial close plan;
- Implemented and redesigned new controls to strengthen the review process of key financial information;
- Expanded the scope of reporting of financial data to management;
- Hired additional permanent employees for key roles in accounting and finance, which had previously been performed by professional consultants;
- Implemented training programs which included cross-training and professional training related to accounting standards and industry practices;
- Developed and implemented formal policies and procedures related to the annual physical observation of equipment inventory; and
- Implemented improved procedures related to equipment inventory record keeping.

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, 2017.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Except for the remediation procedures detailed above for the previously identified material weaknesses, there have been no other changes in our internal control over financial reporting during the three months ended December 31, 2017 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.'s. (the "Company's") internal control over financial reporting as of December 31, 2017, 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, 2017 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 and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the years then ended and the related notes and financial statement schedule and our report dated March 7, 2018 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 7, 2018

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 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

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

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the Company's proxy statement for its 2018 annual meeting, which will be filed with the Commission within 120 days of December31, 2017, and which is incorporated herein by reference. Please see "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities" for information on securities that may be issued under our stock incentive plans.

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

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

VAALCO ENERGY, INC. AND SUBSIDIARIES

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

(a) 3. Exhibits:

3.1	Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on September 28, 2015, and incorporated herein by reference).
3.3	First Amendment to the Second Amended and Restated Bylaws of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
3.4	Certificate of Elimination of Series A Junior Participating Preferred Stock of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.1(a)	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
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(a)	Addendum No. 5 to Exploration and Production Sharing Contract, dated April 25, 2016, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.7(a)	Deed of Novation of Trustee and Paying Agent Agreement, dated June 22, 2017, by and among 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.
10.8	Production Sharing Agreement, dated November 1, 2006, between Sonangol, E.P. and VAALCO Angola (Kwanza), Inc. (filed as Exhibit 10.8 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.9	Supplemental Loan Agreement, dated June 29, 2016, between VAALCO Gabon (Etame), Inc. and International Finance Corporate (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on July 6, 2016, and incorporated herein by reference).
10.10*	VAALCO Energy, Inc. 2001 Stock Incentive Plan (filed as Exhibit 99.1 to the Company’s Registration Statement on Form S-8 filed on August 17, 2001, and incorporated herein by reference).
10.11*	VAALCO Energy, Inc. 2012 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on May 30, 2012, and incorporated herein by reference).
10.12*	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).
10.13*	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).

10.14*	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).
10.15*	Form of Restricted Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan(filed as Exhibit 10.22 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.16*	Employment Agreement between the Company and Cary Bounds (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 29, 2016, and incorporated herein by reference).
10.17*	Employment Agreement between the Company and Philip Patman, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 17, 2017, and incorporated herein by reference).
10.18*	Employment Agreement, effective April 17, 2017, between VAALCO Energy, Inc. and Philip Patman, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 18, 2017, and incorporated herein by reference)
10.19	Settlement Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Group 42, Inc. Mr. Paul A. Bell, Michael Keane, BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff Stockholder Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Kornitzer Capital Management, Inc. and John C. Kornitzer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed onDecember 23, 2015, and incorporated herein by reference).
10.20	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).
10.21*	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).
10.22*	Form of Stock Appreciation Rights Agreement under the VAALCO Energy, Inc. 2016 Stock Appreciate Rights Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company
23.1(a)	Consent of BDO USA, LLP
23.2(a)	Consent of Deloitte & Touche LLP
23.3(a)	Consent of Netherland, Sewell & Associates, Inc. —Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Label Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.

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

Item 16. Form 10-K Summary

None.

SIGNATURES

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

VAALCO ENERGY, INC.
(Registrant)

By /s/ CARY BOUNDS
Cary Bounds

Chief Executive Officer

Dated March 7, 2018

In accordance with the Exchange Act, this report has been signedbelow on the 7th day of March, 2018, by the following persons on behalf of the registrant and in the capacities indicated.

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

Report of Indep endent 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. (the “Company”) and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, shareholders’ equity (deficit), and cash flows for the years then ended, and the related notes and financial statement schedule listed in the accompanying index as of and for the years ended December 31, 2017 and 2016 (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company's internal control over financial reporting as of December 31, 2017, 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 7, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

/s/ BDO USA, LLP

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

Houston, Texas
March 7, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited, before the effects of the retrospective adjustments for the discontinued operations as discussed in Note 5 to the consolidated financial statements, the consolidated statements of operations, shareholders' equity (deficit), and cash flows of VAALCO Energy, Inc. and subsidiaries (the "Company") for the year ended December 31, 2015 (the 2015 consolidated financial statements before the effects of the retrospective adjustments discussed in Note 5 to the consolidated financial statements are not presented herein). Our audit also includes the financial statement schedule listed in the index at item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audit.

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

In our opinion, such 2015 consolidated financial statements, before the effects of the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements, present fairly, in all material respects, the results of operations and cash flows of VAALCO Energy, Inc. and subsidiaries for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic 2015 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

The 2015 consolidated financial statements were prepared assuming that the Company would continue as a going concern. The Company's 2015 recurring losses from operations and insufficient liquidity due to depressed oil and gas prices, raised substantial doubt about its ability to continue as a going concern. The 2015 consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 16, 2016

VA ALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
ASSETS	*(in thousands)*	
Current assets:		
Cash and cash equivalents	**$ 19,669**	$ 20,474
Restricted cash	**842**	741
Receivables:		
Trade	**3,556**	6,751
Accounts with partners, net of allowance of $0.5 million at December 31, 2017 and December 31, 2016	**3,395**	3,297
Other	**100**	120
Crude oil inventory	**3,263**	913
Prepayments and other	**2,791**	4,040
Current assets - discontinued operations	**2,836**	2,139
Total current assets	**36,452**	38,475
Property and equipment - successful efforts method:		
Wells, platforms and other production facilities	**389,935**	389,231
Undeveloped acreage	**10,000**	10,000
Equipment and other	**9,432**	9,779
	409,367	409,010
Accumulated depreciation, depletion, amortization and impairment	**(386,146)**	(380,991)
Net property and equipment	**23,221**	28,019
Other noncurrent assets:		
Restricted cash	**967**	918
Value added tax and other receivables, net of allowance of $6.5 million and $4.7 million at December 31, 2017 and December 31, 2016, respectively	**6,925**	5,110
Deferred tax asset	**1,260**	—
Abandonment funding	**10,808**	8,510
Total assets	**$ 79,633**	$ 81,032
LIABILITIES AND SHAREHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	**$ 11,584**	$ 19,096
Accrued liabilities and other	**12,991**	10,506
Current portion of long term debt	**6,666**	7,500
Current liabilities - discontinued operations	**15,347**	18,452
Total current liabilities	**46,588**	55,554
Asset retirement obligations	**20,163**	18,612
Other long term liabilities	**284**	284
Long term debt, excluding current portion, net	**2,309**	6,940
Total liabilities	**69,344**	81,390
Commitments and contingencies (Note 9)		
Shareholders' equity (deficit):		
Preferred stock, none issued, 500,000 shares authorized, $25 par value	**—**	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 66,443,971 and 66,109,565 shares issued, 58,862,876 and 58,554,470 shares outstanding	**6,644**	6,611
Additional paid-in capital	**71,251**	70,268
Less treasury stock, 7,581,095 and 7,555,095 shares at cost	**(37,953)**	(37,933)
Accumulated deficit	**(29,653)**	(39,304)
Total shareholders' equity (deficit)	**10,289**	(358)
Total liabilities and shareholders' equity (deficit)	**$ 79,633**	$ 81,032

See notes to consolidated financial statements.

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

	Year Ended December 31, 2017	2016	2015
Revenues:			
Oil and natural gas sales	**$ 77,025**	$ 59,784	$ 80,445
Operating costs and expenses:			
Production expense	**39,697**	37,586	40,096
Exploration expense	**7**	5	10,409
Depreciation, depletion and amortization	**6,457**	6,926	32,998
General and administrative expense	**10,377**	9,561	12,294
Impairment of proved properties	**—**	88	81,322
Other operating expense	**—**	8,853	—
General and administrative related to shareholder matters	**—**	(332)	2,372
Bad debt expense and other	**452**	1,222	2,968
Total operating costs and expenses	**56,990**	63,909	182,459
Other operating income (expense), net	**(84)**	(266)	(1,092)
Operating income (loss)	**19,951**	(4,391)	(103,106)
Other income (expense):			
Interest expense, net	**(1,414)**	(2,613)	(1,325)
Other, net	**2,113**	(2,015)	(1,536)
Total other income (expense)	**699**	(4,628)	(2,861)
Income (loss) from continuing operations before income taxes	**20,650**	(9,019)	(105,967)
Income tax expense	**10,378**	9,248	14,587
Income (loss) from continuing operations	**10,272**	(18,267)	(120,554)
Loss from discontinued operations	**(621)**	(8,283)	(38,102)
Net income (loss)	**$ 9,651**	$ (26,550)	$ (158,656)
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ 0.17**	$ (0.31)	$ (2.07)
Loss from discontinued operations	**(0.01)**	(0.14)	(0.65)
Net income (loss) per share	**$ 0.16**	$ (0.45)	$ (2.72)
Basic weighted average shares outstanding	**58,717**	58,384	58,289
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ 0.17**	$ (0.31)	$ (2.07)
Loss from discontinued operations	**(0.01)**	(0.14)	(0.65)
Net income (loss) per share	**$ 0.16**	$ (0.45)	$ (2.72)
Diluted weighted average shares outstanding	**58,720**	58,384	58,289

See notes to consolidated financial statements

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

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance at January 1, 2015	65,195	(7,394)	$ 6,519	$ 64,351	$ (37,299)	$ 146,892	$ 180,463
Shares issued - stock-based compensation	846	—	85	957	—	—	1,042
Stock-based compensation expense	—	—	—	3,810	—	—	3,810
Treasury stock acquired	—	(120)	—	—	(583)	—	(583)
Net loss	—	—	—	—	—	(158,656)	(158,656)
Balance at December 31, 2015	66,041	(7,514)	6,604	69,118	(37,882)	(11,764)	26,076
Cumulative effect adjustment for adoption of ASU 2016-09	(420)	—	(42)	1,032	—	(990)	—
Balance at January 1, 2016 after cumulative effect adjustments	65,621	(7,514)	6,562	70,150	(37,882)	(12,754)	26,076
Shares issued - stock-based compensation	489	—	49	(49)	—	—	—
Stock-based compensation expense	—	—	—	167	—	—	167
Treasury stock acquired	—	(41)	—	—	(51)	—	(51)
Net loss	—	—	—	—	—	(26,550)	(26,550)
Balance at December 31, 2016	66,110	(7,555)	6,611	70,268	(37,933)	(39,304)	(358)
Shares issued - stock-based compensation	334	—	33	6	—	—	39
Stock-based compensation expense	—	—	—	977	—	—	977
Treasury stock acquired	—	(26)	—	—	(20)	—	(20)
Net income	—	—	—	—	—	9,651	9,651
Balance at December 31, 2017	66,444	(7,581)	$ 6,644	$ 71,251	$ (37,953)	$ (29,653)	$ 10,289

See notes to consolidated financial statements

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

	Year Ended December 31,		
	2017	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ 9,651**	$ (26,550)	$ (158,656)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Loss from discontinued operations	**621**	8,283	38,102
Depreciation, depletion and amortization	**6,457**	6,926	32,998
Other amortization	**369**	1,424	304
Deferred taxes	**(1,260)**	—	1,349
Unrealized foreign exchange gain	**(576)**	(32)	(5,243)
Dry hole costs and impairment of unproved leasehold	—	—	10,244
Stock-based compensation	**1,098**	192	3,810
Commodity derivatives loss	**1,032**	1,711	—
Cash settlements received on matured derivative contracts	**195**	—	—
Bad debt provision	**452**	1,222	2,699
Other operating (income) loss, net	**84**	266	1,092
Operational expenses associated with equipment and other	**1,189**	—	—
Impairment of proved properties	—	88	81,322
Change in operating assets and liabilities:			
Trade receivables	**3,195**	(1,050)	14,174
Accounts with partners	**(108)**	16,284	(13,816)
Other receivables	**(43)**	(18)	(609)
Crude oil inventory	**(2,350)**	(192)	1,266
Value added tax and other receivables	**(3,025)**	(1,937)	(2,286)
Other long-term assets	**(2,298)**	(2,827)	(1,566)
Prepayments and other	**1,646**	517	3,129
Accounts payable	**(7,297)**	(15,459)	30,187
Accrued liabilities and other	**2,050**	(4,586)	3,034
Net cash provided by (used in) continuing operating activities	**11,082**	**(15,738)**	**41,534**
Net cash provided by (used in) discontinued operating activities	**(4,423)**	12,286	(2,659)
Net cash provided by (used in) operating activities	**6,659**	(3,452)	38,875
CASH FLOWS FROM INVESTING ACTIVITIES:			
(Increase) decrease in restricted cash	**(150)**	15,219	5,536
Acquisitions	**64**	(5,692)	—
Property and equipment expenditures	**(1,813)**	(8,705)	(68,067)
Proceeds from the sale of oil and gas properties	**250**	830	398
Premiums paid for put options	—	(2,939)	—
Net cash used in continuing investing activities	**(1,649)**	(1,287)	(62,133)
Net cash used in discontinued investing activities	—	—	(20,877)
Net cash used in investing activities	**(1,649)**	(1,287)	(83,010)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**39**	—	441
Treasury shares	**(20)**	(51)	—
Debt issuance costs	—	(93)	—
Debt repayment	**(10,001)**	—	—
Borrowings	**4,167**	—	—
Net cash provided by (used in) continuing financing activities	**(5,815)**	(144)	441
Net cash provided by discontinued financing activities	—	—	—
Net cash provided by (used in) financing activities	**(5,815)**	(144)	441
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(805)**	(4,883)	(43,694)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**20,474**	25,357	69,051
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 19,669**	$ 20,474	$ 25,357

See notes to consolidated financial statements.

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 997	$ 1,326	$ 1,337
Income taxes paid	$ 15,153	$ 9,210	$ 15,163
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at period end	$ 455	$ 2,282	$ 15,132
Asset retirement obligations	$ 600	$ 1,543	$ 542

See notes to consolidated financial statements.

1. ORGANIZATION

VAALCO Energy, Inc. and its consolidated subsidiaries ("VAALCO" or the "Company") is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. As non-operator, we have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 5 below, we have discontinued operations associated with ouractivities in Angola, West Africa.

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

2. LIQUIDITY

Our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and natural gas prices. After a period of low commodity prices, oil and gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. We may drill two or three development wells in 2018. Any drilling program we enter into would require approval of our partners and the government of Gabon. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances. We believe that at current prices, cash generated from continuing operations together with cash on hand at December 31, 2017 are adequate to support our operations and cash requirements during 2018 and through March 31, 2019.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentationrelated to reclassifying material and supplies to prepayments and other. These reclassifications did not affect our consolidated financial results.

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

Estimates of oil and natural gas reserves used to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures. Due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

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

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classifiedas a current or non-current asset based on its designated purpose and time duration. Current amounts in restricted cash at December 31, 2017 and 2016 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long term amounts at December 31, 2017 and 2016 include a charter payment escrow for the floating, production, storage and offloading vessel ("FPSO") offshore Gabon as discussed in Note 9.

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

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

Bad debts – Quarterly, we evaluate our accounts receivable balances to confirm collectability. When collectability is in doubt, we record an allowance against the accounts receivable and a corresponding income charge for bad debts which appears in the "Bad debt expense and other" line item of the consolidated statements of operations. The majority of our accounts receivable balances are with our joint venture partners, purchasers of our production and the government of Gabon for reimbursable Value-Added Tax ("VAT"). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed us. Portions of our costs in Gabon (including our VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). As of December 31, 2017, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately XAF 21.2 billion (XAF 7.1 billion, net to VAALCO). As of December 31, 2017, the exchange rate was XAF 547.5 = $1.00.

In June 2016, we entered into an agreement with the government of Gabon to receive payments related to the outstanding VAT receivable balance of XAF 16.3 billion (XAF 4.9 billion, net to VAALCO), representing the outstanding balance as of December 31, 2015, in thirty-six monthly installments of $0.3 million net to VAALCO. We received one monthly installment payment in July 2016; however, no further payments have been received as of December 31, 2017. We are in discussions with the Gabonese government regarding the timing of the resumption of payments.

In 2017, 2016 and 2015, we recorded allowances of $0.4 million, $0.7 million and $2.7 million, respectively, related to VAT which the government of Gabon has not reimbursed. The receivable amount, net of allowances, is reported as a non-current asset in the "Value added tax and other receivables" line item in the consolidated balance sheets. Because both the VAT receivable and the related allowance are denominated in XAF, the exchange rate revaluation of these balances into U.S. dollars at the end of each reporting period also has an impact on profit/loss. Such foreign currency gains/(losses) are reported separately in the "Other, net" line item of the consolidated statements of operations.

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

	Year Ended December 31,		
	2017	**2016**	**2015**
	(in thousands)		
Allowance for bad debt			
Balance at beginning of year	$ **(5,211)**	$ (4,221)	$ (2,400)
Charge to cost and expenses	**(452)**	(1,222)	(2,699)
Reclassification related to Sojitz acquisition	**(694)**	—	—
Foreign currency gain (loss)	**(676)**	232	878
Balance at end of period	$ **(7,033)**	$ (5,211)	$ (4,221)

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

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

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

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

Impairment – We review our oil and natural gas producing properties for impairment on a field-by-field basis quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. We evaluate our undeveloped oil and natural gas leases for impairment periodically by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts, lease expiration terms and future plans for exploration or development. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Capitalized equipment inventory is reviewed regularly for obsolescence. We identified equipment inventory in Gabon that we do not expect to use and charged $0.3 million, $0.3 million and $1.5 million to the "Other operating loss, net" line item of the consolidated statement of operations in the years ended December 31, 2017, 2016 and 2015, respectively.

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

Capitalized interest – Interest costs and commitment fees from external borrowings are capitalized on exploration and development projects that are not subject to current depletion. Interest and commitment fees are capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

We capitalized no interest costs for the years ended December 31, 2017 or 2016. We capitalized $0.8 million in interest costs during the year ended December 31, 2015.

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

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

Revenue recognition – We recognize oil and natural gas revenues when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances. We recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property, and we would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. As of December 31, 2017 and 2016, we had no recorded oil and natural gas imbalances.

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

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

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

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

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Gains and losses on foreign currency transactions are included in income. Within the consolidated statements of operations line item "Other income (expense)—Other, net," we recognized gains on foreign currency transactions of $0.5 million in 2017, while we recognized losses on foreign currency transactions of $30 thousand and $0.8 million in 2016 and 2015, respectively.

Income taxes – We account for income taxes under an asset and liability approach that recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the Financial Statements and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized. Wereport interest related to income tax liabilitiesin the "Interest expense" line item on the consolidated statements of operations, and we report penalties in the "Other, net" line item on the consolidated statements of operations.

Derivative Instruments and Hedging Activities – We use derivative financial instruments to achieve a more predictable cash flow from oil production by reducing our exposure to price fluctuations. Our derivative instruments at December 31, 2016 consisted of fixed price oil puts, which give us the option to sell a contracted volume of oil at a contracted price on a contracted date in the future.
All of our oil put contracts, which provided for settlement based upon reported the Brent price, had expired as of December 31, 2017.

We record balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the "Other, net" line item located within the "Other income (expense)" section of the consolidated statements of operations. We received cash settlements of $0.2 million during the year ended December 31, 2017 related to matured derivative contracts.

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

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

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

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

Fair value of financial instruments – Our current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets, accounts payable 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. With respect to our other financial instruments included in current assets and liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments. The carrying value of our long-term debt approximates fair value, as the interest rates are adjusted based on market rates currently in effect.

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

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

4. NEW ACCOUNTING STANDARDS

Not Yet Adopted

In May 2017, the Financial Accounting Standards Board ("FASB") issued ASU No. 2017-09, Compensation – Stock Compensation (Topic 718): Scope of Modification Accounting (ASU 2017-09) to clarify when to account for a change to the terms or conditions of a share-based payment award as a modification. Under ASU 2017-09, modification accounting is required only if the fair value, the vesting conditions, or the classification of the award (as equity or liability) changes as a result of the change in terms or conditions. The amendments in ASU 2017-09 are effective for all entities for interim and annual reporting periods beginning after December 15, 2017. The amendments in this update are to be applied prospectively to an award modified on or after the adoption date. It has not been the Company's practice to make modifications to share-based payment awards which would have been impacted by this standard, and while there can be no assurance that this will not occur in future periods, we do not expect adoption of this standard to have a material impact on our financial position, results of operations, cash flows and related disclosures.

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

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash ("ASU 2016-18"), which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted. We do not plan to early adopt this standard. Restricted cash will be included as a component of Cash, cash equivalents and restricted cash on our Consolidated Statement of Cash Flows for all periods presented. Due to the nature of this accounting standards update, this will have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

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

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including our trade and partner receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date which is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model which increases the allowance when losses are probable. This change is effective for all public companies for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years and will be applied with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We are currently evaluating the provisions of ASU 2016-13 and are assessing its potential impact on our financial position, results of operations, cash flows and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which amends the accounting standards for leases. ASU 2016-02 retains a distinction between finance leases and operating leases. The primary change is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Certain aspects of lease accounting have been simplified and additional qualitative and quantitative disclosures are required along with specific quantitative disclosures required by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. We are required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period presented in the financial statements. Assuming adoption January 1, 2019, we expect that leases in effect on January 1, 2017 and leases entered into after such date will be reflected in accordance with the new standard in the audited consolidated financial statements included in our Annual Report on Form 10-K for 2019, including comparative financial statements presented in such report. We are in the early stages of our gap assessment, but we expect that leases with terms greater than 12 months which are currently treated as operating leases will be capitalized. We expect adoption of this standard to result in the recording of a right of use asset related to certain of our operating leases with a corresponding lease liability. This is expected to result in a material increase in total assets and liabilities as certain of our operating leases are significant as disclosed in Note 9. We do not expect there will be a material overall impact on results of operations or cash flows. We have developed an implementation plan related to this new standard. In connection with our implementation plan, we will be reviewing our lease contracts and evaluating other contracts to identify embedded leases and determining the appropriate accounting treatment, and we will be evaluating the impact on processes and procedures as well as the internal controls related to the proper accounting for leases under the new standard.

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

Adopted

In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory (ASU 2015-11) to simplify the measurement of inventory. This simplification applies to all inventory other than that measured using last-in, first out ("LIFO") or the retail inventory method and requires measurement of inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation. This guidance is to be applied prospectively effective for annual periods beginning after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. We adopted ASU 2015-11 in the first quarter of 2017, and the application of this guidance did not have a significant impact on our financial position, results of operations or cash flows.

5. ACQUISITIONS AND DISPOSITIONS

Sojitz Acquisition

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

The following amounts represent the fair value of identifiable assets acquired and liabilities assumed in the Sojitz acquisition.

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

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

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

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

Sale of Certain U.S. Properties

During 2015, we completed the sale of our interests in various wells in Texas and Alabama for $0.4 million resulting in a minimal loss. In December 2016, we completed the sale of our interests in two wells in the Hefley field in North Texas for $0.8 million resulting in a minimal loss. In April 2017, we completed the sale of our interests in the East Poplar Dome field in Montana for $0.3 million, resulting in a gain of approximately $0.3 million reported on the line "Other operating income (expense), net" in our results of operations for the year ended December 31, 2017.

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). The four year primary term, referred to as the Initial Exploration Phase ("IEP"), with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. The IEP was extended on two occasions to run until December 1, 2014. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and the co-participating interest owner, the Angolan national oil company, Sonangol P&P, to drill two additional exploration wells. Our working interest is 40%, and it carries Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to the decision to withdraw from Angola, we have taken actions to close our office in Angola and reduce future activities in Angola. As a result of this strategic shift, we classified all the related assets and liabilities as those of discontinued operations in the condensed consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in our condensed consolidated statements of operations. We segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in our condensed consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment assets and liabilities as of December 31, 2017 and 2016 and its results of operations for the years ended December 31, 2017, 2016 and 2015.

Summarized Results of Discontinued Operations

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Operating costs and expenses:			
Exploration expense	**$ —**	$ 15,137	$ 36,044
Depreciation, depletion and amortization	**—**	9	12
General and administrative expense	**615**	1,269	2,535
Bad debt recovery and other	**—**	(7,629)	—
Total operating costs, expenses and (recovery)	**615**	8,786	38,591
Other operating loss, net	**—**	(172)	(1,856)
Operating loss	**(615)**	(8,958)	(40,447)
Other income (expense):			
Interest income	**—**	3,201	—
Other, net	**(3)**	552	2,345
Total other income (expense)	**(3)**	3,753	2,345
Loss from discontinued operations before income taxes	**(618)**	(5,205)	(38,102)
Income tax expense	**3**	3,078	—
Loss from discontinued operations	**$ (621)**	$ (8,283)	$ (38,102)

Assets and Liabilities Attributable to Discontinued Operations

	December 31, 2017		December 31, 2016	
	(in thousands)			
ASSETS				
Accounts with partners	**$**	**2,836**	$	2,139
Total current assets		**2,836**		2,139
Total assets	**$**	**2,836**	$	2,139
LIABILITIES				
Current liabilities:				
Accounts payable	**$**	**158**	$	77
Foreign taxes payable		—		3,078
Accrued liabilities and other		**15,189**		15,297
Total current liabilities		**15,347**		18,452
Total liabilities	**$**	**15,347**	$	18,452

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases identified in the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, respectively, which represents what we believe to be the maximum potential amount attributable to VAALCO Angola's interest under the PSA.

Other Matters – Partner Receivable

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

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

6. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Proved Properties

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

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

During 2016, our negative price differential to Brent narrowed and we incurred no significant capital spending. We considered these and other factors and determined that there were no events or circumstances triggering an impairment evaluation for most of our fields, with the exception of the Avouma field in the Etame Marine block offshore Gabon. At the Avouma field, the electrical submersible pumps ("ESPs") in the South Tchibala 2-H well and the Avouma 2-H well failed, and these wells were temporarily shut in. After utilizing a hydraulic workover unit to replace the failed ESP systems, the South Tchibala 2-H and the Avouma 2-H wells resumed production in December 2016 and January 2017, respectively. The reserves used in our impairment evaluation of the Avouma field prior to the fourth quarter of 2016 were revised to reflect the impact of this lost production for several months and the impact of the forward price curve. The undiscounted future net cash flows for the Avouma field were in excess of the field's carrying value at December 31, 2016. As a result, no impairment was required for the Avouma field, or any of our other fields in Gabon, for 2016.

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

Undeveloped Leasehold Costs

We have a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that we acquired in 2012 for which we have $10.0 million capitalized in undeveloped acreage. It is currently unlikely that we will be making any near-term expenditures with respect to any development of this property. We and our partners will need to evaluate the timing and budgeting for exploration and development activities under a development and production area in the block, including the approval of a development and production plan to develop the Venus discovery on the block. Our production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

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

Capitalized Exploratory Well Costs

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

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

Capitalized Equipment Inventory

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

7. ASSET RETIREMENT OBLIGATIONS

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

(in thousands)	**2017**	2016	2015
Balance at January 1	**$ 18,612**	$ 16,166	$ 14,846
Accretion	**951**	903	778
Additions	**—**	—	1,085
Acquisitions and dispositions	**(103)**	1,544	—
Revisions	**703**	(1)	(543)
Balance at December 31	**$ 20,163**	$ 18,612	$ 16,166

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

We are required under the Etame PSC to conduct regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. The most recently completed abandonment study was in January 2016. The final results of the abandonment study resulted in an increase in the costs necessary to fund future abandonment obligations.

8. DEBT

In January 2014, we executed a loan agreement with the International Finance Corporation ("IFC credit facility") for a $65.0 million revolving credit facility, which was secured by the assets of our Gabon subsidiary. On June 29, 2016, we executed a supplemental agreement with the IFC which, among other things, amended and restated our existing loan agreement to convert the $20.0 million revolving portion of the credit facility, to a term loan with $15.0 million outstanding ("Amended Term Loan Agreement"). The

Amended Loan Agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A., and is guaranteed by VAALCO as the parent company. The Amended Term Loan Agreement provides for quarterly principal and interest payments on the amounts currently outstanding through June 30, 2019, with interest accruing at a rate of LIBOR plus 5.75%.

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

The estimated fair value of the borrowings under the Amended Term Loan Agreement is $9.2 million when measured using a discounted cash flow model over the life of the current borrowings at forecasted interest rates. The inputs to this model are Level 3 in the fair value hierarchy.

Covenants

Under the Amended Term Loan Agreement, the ratio of quarter-end net debt to EBITDAX (as defined in the Amended Term Loan Agreement) must be no more than 3.0 to 1.0. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at each semi-annual review period. Certain of VAALCO's subsidiaries are contractually prohibited from making payments, loans or transferring assets to VAALCO or other affiliated entities. Specifically, under the Amended Term Loan Agreement, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Amended Term Loan Agreement. We were in compliance with all financial covenants as of December 31, 2017.

Interest

Until June 29, 2016, under the terms of the original IFC credit facility, we paid commitment fees on the undrawn portion of the total commitment. Commitment fees had been equal to 1.5% of the unused balance of the senior tranche of $50.0 million and 2.3% of the unused balance of the subordinated tranche of $15.0 million when a commitment was available for utilization. With the execution of the Amended Term Loan Agreement with the IFC in June 2016, beginning on June 29, 2016, and continuing through March 14, 2017, commitment fees were equal to 2.3% of the undrawn term loan amount of $5.0 million. There are no further commitment fees owing after March 14, 2017.

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

	Year Ended December 31,		
	2017	**2016**	**2015**
		(in thousands)	
Interest incurred, including commitment fees	**$ 997**	$ 1,353	$ 1,496
Deferred finance cost amortization	**369**	319	304
Deferred finance cost write-off due to loan modification	—	869	—
Capitalized interest	—	—	(771)
Other interest not related to debt [(a)]	**48**	72	296
Interest expense, net	**$ 1,414**	$ 2,613	$ 1,325
Average effective interest rate, excluding commitment fees	**6.72%**	5.52%	4.09%

(a) The "Other interest not related to debt" line item i ncludes interest income.

9. COMMITMENTS AND CONTINGENCIES

Litigation

Butcher settlement

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

McDonough litigation

On December 7, 2016, a lawsuit was filed against the Company alleging that a former worker on the Company's oil and gas platforms off the coast of Gabon was terminated because of his age in violation of the Age Discrimination in Employment Act and the Texas Commission on Human Rights Act. The Plaintiff sought damages for lost wages and benefits as well as attorneys' fees. The case was pending in the U.S. District Court for the Southern District of Texas styled as *McDonough v. VAALCO Energy, Inc.*, No. 4:17-cv-

00361. In a February 2017 demand letter, the plaintiff made a demand for $361,000 to settle this claim. On June 22, 2017, the court entered a final order of dismissal, pursuant to the plaintiff's motion for voluntary dismissal, and entered final judgment in favor of the Company. This matter is now resolved, and had no material effect on our financial condition, results of operations or liquidity.

FPSO charter

In connection with the charter of the FPSO, we, as operator of the Etame Marin block, guaranteed all of the lease payments under the charter through its contract term, which expires in September 2020. At our election, the charter may be extended for two one-year periods beyond September 2020. We obtained guarantees from each of our partners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.5 million and $0.7 million as of December 31, 2017 and December 31, 2016, respectively, representing the guarantee's estimated fair value. The guarantee of the offshore Gabon FPSO lease has $85.2 million in remaining gross minimum obligations as of December 31, 2017.

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

(in thousands)	Full Charter Payment	VAALCO Net
Year		
2018	31,294	9,719
2019	31,294	9,719
2020	22,634	7,029
Total	$ 85,222	$ 26,467

The charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of oil per day. VAALCO's net share of payments was $12.8 million, $11.2 million and $10.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Other lease obligations

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

(in thousands)	Gross Obligation	VAALCO Net
Year		
2018	6,101	2,176
2019	407	407
2020	340	340
2021	—	—
2022	—	—
Thereafter	—	—
Total	$ 6,848	$ 2,923

We incurred rent expense of $2.4 million, $4.5 million and $4.3 million under operating leases for the years ended December 31, 2017, 2016 and 2015.

Rig commitment

In 2014, we entered into a long-term contract for the Constellation II drilling rig that was under a long-term contract for the multi-well development drilling campaign offshore Gabon. The campaign included the drilling of development wells and workovers of existing wells in the Etame Marin block. We began demobilization in January 2016 and released the drilling rig in February 2016, prior to the original July 2016 contract termination date, because we no longer intended to drill any wells in 2016 on our Etame Marin block offshore Gabon. In June 2016, we reached an agreement with the drilling contractor for us to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We paid this amount, plus the demobilization charges, in seven equal monthly installments, which began in July 2016 and ended in January 2017. The related expense was reported in the "Other operating expense" line item in our consolidated statement of operations for the year ended December 31, 2016.

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC, effective in April 2016, the consortium is required to provide to the local government refinery a volume of crude at a 15% discount to market price (the "Gabon DMO"). Prior to April 2016, the discount was 25%. The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of oil refined by the refinery per year. In 2017, we paid $1.2 million for our share of the 2016 obligation. In 2016, we paid $1.7 million for our share of the 2015 obligation. In 2015, we paid $2.3 million for our share of the 2014 obligation. We accrue an amount for the Gabon DMO based on management's best estimate of the volume of crude required, because the refinery does not publish throughput figures. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.3 million. The amount accrued at December 31, 2016, for our share of the 2016 obligation was $1.1 million. These costs are cost recoverable under the terms of the

Etame PSC. Also, beginning in April 2016, the consortium is required to pay an additional 1% of revenues for provisions for diversified investments ("PID") and for investments in hydrocarbons ("PIH"). The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.4 million. The amount accrued at December 31, 2016, for our share of the 2016 obligation was $0.4 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

Abandonment funding

As part of securing the first of two five-year extensions to the Etame field production license to which we are entitled from the government of Gabon, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over a period of ten years at 12.14% of the total abandonment estimate for the first seven years, with annual payments for the remaining unfunded estimated costs spread over the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of our consolidated balance sheet. Future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Regulatory and Joint Interest Audits

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

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

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

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

At December 31, 2017, we had accrued $1.3 million net to VAALCO in the "Accrued liabilities and other" line item of our consolidated balance sheet for potential fees which may result from a customs audit.

Employment agreements

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

10. DERIVATIVES AND FAIR VALUE

As of December 31, 2017, we had no derivative instruments outstanding. During the year ended December 31, 2017 and 2016, we had oil puts outstanding for anticipated sales volumes for the period from April 22, 2016 through December 31, 2017. Our put contracts are subject to agreements similar to a master netting agreement under which we have the legal right to offset assets and liabilities. At December 31, 2016, the fair value of all of the put contracts were an asset of $1.2 million.

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

Derivative Item	Balance Sheet Line	Carrying Value	Fair Value Measurements Using Level 1	Fair Value Measurements Using Level 2	Fair Value Measurements Using Level 3
			(in thousands)		
Crude oil puts	Prepayments and other				
Balance at December 31, 2017		$ —	$ —	$ —	$ —
Balance at December 31, 2016		$ 1,227	$ —	$ 1,227	$ —

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

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

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

		Year Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2017**	**2016**	**2015**
			(in thousands)	
Crude oil puts	Other, net	**$ (1,032)**	$ (1,711)	$ —

11. SHAREHOLDERS' EQUITY (DEFICIT)

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2017 or 2016.

Treasury stock – In the years ended December 31, 2017, 2016 and 2015, we withheld 26,000, 40,926 and 120,455 shares, respectively, in connection with cashless stock option exercises and restricted stock vestings to satisfy tax withholding obligations related to stock option exercises.

12. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

Our stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of our Board of Directors to issue various types of incentive compensation. Currently, we have issued stock options, restricted shares and SARs from the 2014 Long-Term Incentive Plan ("2014 Plan"). At December 31, 2017, 2,404,442 shares were authorized for future grants under this plan.

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

We record non-cash compensation expense related to stock-based compensation as general and administrative expense.For the years ended December 31, 2017, 2016 and 2015, non-cash compensation expense was $1.1 million, $0.2 million and $3.8 million, respectively, related to the issuance of stock options and restricted stock. Because we do not pay significant United States federal income taxes, no amounts were recorded for tax benefits.

Stock options

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors, which in the past has been a five year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. There were $39 thousand in cash proceeds received from the exercise of stock options in 2017. For 2016 and 2015 there were no cash proceeds received from the exercise of stock options. 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 our non-employee directors, which were fully vested upon their grant.

We use the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the vesting period of the option. During 2017, 2016 and 2015, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because we have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future, no expected dividend yield was input to the Black-Scholes model.

	Year Ended December 31,		
	2017	2016	2015
Weighted average exercise price - ($/share)	$ 0.99	$ 1.14	$ 4.41
Expected life in years	3.2	3.0	2.5
Average expected volatility	73 %	71 %	61 %
Risk-free interest rate	1.51 %	1.10 %	0.88 %
Weighted average grant date fair value - ($/share)	$ 0.49	$ 0.49	$ 1.65

Stock option activity for the year ended December 31, 2017 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, 2017	2,644	$ 3.92		
Granted	1,629	0.99		
Exercised	(37)	1.04		
Forfeited/expired	(1,639)	4.48		
Outstanding at December 31, 2017	2,597	1.77	3.53	$ —
Exercisable at December 31, 2017	1,506	2.30	3.28	$ —

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.The intrinsic value of stock options exercised in 2017 and 2015 was $0.0 million and $0.3 million, respectively. There were no exercises of stock options in 2016.

On February 28, 2018, the Company granted stock options for 494,941 shares with an exercise price of $0.86 per share.

As of December 31, 2017, 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 2017.

	Restricted Stock	Weighted Average Grant Price
	(in thousands)	
Non-vested shares outstanding at January 1, 2017	252	$ 1.31
Awards granted	426	0.98
Awards vested	(297)	1.12
Awards forfeited	(41)	1.00
Non-vested shares outstanding at December 31, 2017	340	1.10

The total vest-date fair value of restricted stock awards which vested during 2017, 2016 and 2015 was $0.3 million, $0.6 million and $0.7 million, respectively. The weighted average grant date fair value per share of restricted stock awards was $0.98, $1.11 and $3.34 for the years ended December 31, 2017, 2016 and 2015, respectively.

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 these shares is dependent upon the employee's continued service with the Company. The shares will vest in three equal parts over three years.

As of December 31, 2017, unrecognized compensation cost related to restricted stock totaled $0.2 million and is expected to be recognized over a weighted average period of 1.6 years.

Stock appreciation rights ("SARs")

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

The 815,355 SARs granted in the three months ended March 31, 2016 vest over athree-year period with a life of5 years and have a maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant.The compensation expense related to these awards through December 31, 2016 was $25 thousand.

On February 28, 2018, 2,373,411 SARs were granted which vest over a three-year period with a life of 5 years and have a $0.86 SAR price per share specified in a SAR award on the date of grant.

For the year ended December 31, 2017, 1,049,528 SARs were granted, all having an exercise price of$1.20 per share. One-third of the SARs are to vest on or after the first anniversary of the grant date at such time when the market price per share of our common stock exceeds $1.30; one-third of the SARs are to vest on or after the second anniversary of the grant date at such time when the share price exceeds $1.50; and one-third of the SARs are to vest on or after the third anniversary of the grant date at such time when the share price exceeds $1.75. SARs granted in 2017 vest over a three year period with a life of 5 years; these SARs have a maximum spread equal to 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. The compensation expense related to these awards through December 31, 2017 was $0.1 million.

SAR activity for the year ended December 31, 2017 is provided below:

	Number of Shares Underlying SARs	Weighted Average Exercise Price Per Share	Term	Value
	(in thousands)		(in years)	(in thousands)
Outstanding at January 1, 2017	180	$ 1.04		
Granted	1,049	1.20		
Exercised	—	—		
Forfeited/expired	(153)	1.20		
Outstanding at December 31, 2017	1,076	1.17	3.21	$ —
Exercisable at December 31, 2017	60	1.04	3.21	$ —

Other benefit plans

We sponsor a 401(k) plan, with a company match feature, for our employees. Costs incurred in the years ended December 31, 2017, 2016 and 2015 for administering the plan, including the company match feature, were approximately $0.2 million, $0.3 million and $0.4 million, respectively.

13. INCOME TAXES

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

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

- Beginning January 1, 2018, the U.S. corporate income tax rate will be21%. The Company is required to recognize the impacts of this rate change on its deferred tax assets and liabilities in the period enacted. However, as the Company has a full valuation allowance on its net deferred tax asset, any deferred tax recognized due to the change in rate will be offset with a change in the valuation allowance. Therefore, there was no overall impact to the Financial Statements in 2017 due to this change in rate.

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

- The Transition Tax on unrepatriated foreign earnings is a tax on previously untaxed accumulated and current earnings and profits ("E&P") of the Company's foreign subsidiaries. To determine the amount of the Transition Tax, the Company must determine, among other factors, the amount of post-1986 E&P of its foreign subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. Based on the Company's reasonable estimate of the Transition Tax, there is no provisional Transition Tax expense. The Company has not completed our accounting for the income tax effects of the transition tax and is continuing to evaluate this provision of the Tax Act.

- The Tax Reform Act creates a new requirement that GILTI income earned by foreign subsidiaries must be included currently in the gross income of the U.S. shareholder. Due to the complexity of the new GILTI tax rules, the Company is continuing to evaluate this provision of the Tax Act. Under U.S. GAAP, the Company is permitted to make an accounting policy election to either treat taxes due on future inclusions in U.S. taxable income related to GILTI as a current period expense when incurred or to factor such amounts into the Company's measurement of its deferred taxes. The Company has not yet completed its analysis of the GILTI tax rules and is not yet able to reasonably estimate the effect of this provision of the Tax Act or make an accounting policy election for the accounting treatment whether to record deferred taxes attributable to the GILTI tax. The Company has not recorded any amounts related to potential GILTI tax in the Company's Financial Statements.

Other provisions in the legislation, such as interest deductibility and changes to executive compensation plans are not expected to have material implications to the Company's Financial Statements. The income tax effects recorded in the Company's Financial Statements as a result of the Tax Reform Act are provisional in accordance with the Securities and Exchange Commission's Staff Accounting Bulletin number 118 "(SAB 118") as the Company has not yet completed its evaluation of the impact of the new law. SAB 118 allows for a measurement period of up to one year after the enactment date of the Tax Reform Act to finalize the recording of the related tax impacts. The Company does not believe potential adjustments in future periods would materially impact the Company's financial condition or results of operations.

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

In April 2017, the Company was notified by the U.S. Internal Revenue Service ("IRS") that they would be conducting an audit ofts 2014 U.S. federal tax return. The audit was concluded in 2018, and there were no significant findings as a result

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

	Year Ended December 31,		
(in thousands)	2017	2016	2015
U.S. Federal:			
Current	$ —	$ —	$ —
Deferred	(1,260)	—	1,349
Foreign:			
Current	11,638	9,248	13,238
Deferred	—	—	—
Total	$ 10,378	$ 9,248	$ 14,587

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, 2017 and 2016 are as follows:

	As of December 31,	
(in thousands)	2017	2016
Deferred tax assets:		
Basis difference in fixed assets	$ 46,929	$ 89,016
Foreign tax credit carryforward	48,071	50,339
Alternative minimum tax credit carryover	1,349	1,349
U.S. federal net operating losses	22,490	30,230
Foreign net operating losses	26,371	25,543
Asset retirement obligations	4,234	6,514
Basis difference in receivables	1,331	1,824
Other	3,690	6,952
Total deferred tax assets	154,465	211,767
Valuation allowance	(153,205)	(211,767)
Net deferred tax assets	$ 1,260	$ —

Foreign tax credits will expire between the years 2018 and 2024. The alternative minimum tax credits do not expire, and foreign net operating losses ("NOLs") are not subject to expiry dates. The NOL for our United Kingdom subsidiary can be carried forward indefinitely, while the NOLs for our Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues. The U.S federal NOL will expire between 2035 and 2037. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. We do not anticipate utilization of the foreign tax credits prior to expiration nor do we expect to generate sufficient taxable income to utilize other deferred tax assets. On the basis of this evaluation, valuation allowances of $153.2 million, $211.8 million and $210.7 million have been recorded as of December 31, 2017, 2016 and 2015, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

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

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, 2017 and 2016. 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:

(in thousands)	Year Ended December 31, 2017	2016	2015
United States	$ (9,453)	$ (9,893)	$ (15,177)
Foreign	30,103	874	(90,790)
	$ 20,650	$ (9,019)	$ (105,967)

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

(in thousands)	Year Ended December 31, 2017	2016	2015
Tax provision computed at U.S. statutory rate	$ 7,228	$ (3,156)	$ (37,089)
Foreign taxes not offset in U.S. by foreign tax credits	6,775	6,319	(394)
Impact of Tax Reform Act	52,449	—	—
Effect of change in foreign statutory rates	—	2,394	3,014
Permanent differences	309	4,505	1,803
Foreign tax credit adjustments	2,394	—	—
Increase/(decrease) in valuation allowance	(58,777)	(802)	47,253
Other	—	(12)	—
Total income tax expense	$ 10,378	$ 9,248	$ 14,587

At December 31, 2017, 2016 and 2015, we were subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

Jurisdiction	Years
United States	2008-2017
Gabon	2013-2017

14. EARNINGS PER SHARE

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

A reconciliation from basic to diluted shares follows:

	Year Ended December 31, 2017	2016	2015
		(in thousands)	
Basic weighted average shares outstanding	**58,717**	58,384	58,289
Effect of dilutive securities	**3**	—	—
Diluted weighted average shares outstanding	**58,720**	58,384	58,289
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**2,823**	4,363	5,586

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

15. SEGMENT INFORMATION

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

Segment activity of continuing operations for the years ended December 31, 2017, 2016 and 2015 and long-lived assets and segment assets at December 31, 2017 and 2016 are as follows:

	Year Ended December 31, 2017				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 76,978	$ —	$ 47	$ —	$ 77,025
Depreciation, depletion and amortization	6,196	—	1	260	6,457
Bad debt expense and other	452	—	—	—	452
Operating income (loss)	28,488	(122)	352	(8,767)	19,951
Other, net	3,142	15	—	(1,044)	2,113
Interest expense, net	(1,414)	—	—	—	(1,414)
Income tax expense (benefit)	11,638	—	—	(1,260)	10,378
Additions to property and equipment - accrual	1,576	—	—	126	1,702

	Year Ended December 31, 2016				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 59,460	$ —	$ 324	$ —	$ 59,784
Depreciation, depletion and amortization	6,531	—	151	244	6,926
Impairment of proved properties	—	—	88	—	88
Bad debt expense and other	1,222	—	—	—	1,222
Other operating expense	8,853	—	—	—	8,853
Operating income (loss)	3,901	(384)	(72)	(7,836)	(4,391)
Other, net	(22)	(8)	—	(1,985)	(2,015)
Interest expense, net	(2,614)	—	—	1	(2,613)
Income tax expense	9,248	—	—	—	9,248
Additions to property and equipment - accrual	(4,242)	—	—	181	(4,061)

	Year Ended December 31, 2015				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 79,947	$ —	$ 498	$ —	$ 80,445
Depreciation, depletion and amortization	32,125	—	633	240	32,998
Impairment of proved properties	78,080	—	3,242	—	81,322
Bad debt expense and other	2,968	—	—	—	2,968
Operating income (loss)	(87,243)	(1,342)	(4,366)	(10,155)	(103,106)
Other, net	(1,034)	(33)	—	(469)	(1,536)
Interest expense, net	(1,144)	—	—	(181)	(1,325)
Income tax expense	13,238	—	—	1,349	14,587
Additions to property and equipment - accrual	66,269	—	—	150	66,419

(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Long-lived assets from continuing operations:					
As of December 31, 2017	$ 12,638	$ 10,000	$ —	$ 583	$ 23,221
As of December 31, 2016	17,291	10,000	—	728	28,019

Information about our most significant customers

For the period from the second quarter of 2014 and through April 2015, our crude oil from Gabon was sold under a contract with The Vitol Group at the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA ("Total") for May through July of 2015 and Glencore Energy UK Ltd. ("Glencore") for August of 2015 through December of 2017. The contract with Glencore U.K. ends in January 2019. Sales of oil to Glencore were approximately 100% of total revenues for 2017.

16. SUBSEQUENT EVENTS

The last lifting in 2017 was not completed until January 1, 2018 due to unsafe weather conditions. Net revenues of $6.5 million associated with net volumes delivered to the buyer on January 1, 2018 of 95,525 barrels will be reported as revenue in 2018. The 7.1% increase in the January 2018 lifting price over the December 2017 lifting price positively impacted January's revenue by $0.5 million.

17. SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Our unaudited quarterly results for years ended December 31, 2017 and 2016 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)			
2017:				
Total revenues	$ 21,266	$ 20,425	$ 18,178	$ 17,156
Total operating costs and expenses	13,055	15,068	14,454	14,413
Operating income (loss)	8,148	5,587	3,721	2,495
Income (loss) from continuing operations	4,435	2,451	(148)	3,534
Loss from discontinued operations	(176)	(168)	(174)	(103)
Net income (loss)	4,259	2,283	(322)	3,431
Basis net income (loss) per share	$ 0.07	$ 0.04	$ (0.01)	$ 0.06
Diluted net income (loss) per share	$ 0.07	$ 0.04	$ (0.01)	$ 0.06

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands of dollars except per share information)			
2016:				
Total revenues	$ 10,976	$ 18,847	$ 14,635	$ 15,326
Total operating costs and expenses	24,509	14,232	10,919	14,249
Operating income (loss)	(13,515)	4,615	3,690	819
Income (loss) from continuing operations	(15,430)	(498)	1,016	(3,355)
Loss from discontinued operations	7,806	(20)	(15,783)	(286)
Net income (loss)	(7,624)	(518)	(14,767)	(3,641)
Basis net income (loss) per share	$ (0.13)	$ (0.01)	$ (0.25)	$ (0.06)
Diluted net income (loss) per share	$ (0.13)	$ (0.01)	$ (0.25)	$ (0.06)

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

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

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
	2017	2016	2015
Costs incurred during the year:		*(in thousands)*	
International:			
Exploration costs - capitalized	**$ —**	$ —	$ —
Exploration costs - expensed	**7**	5	170
Acquisition of properties	**—**	5,754	—
Development costs	**—**	—	60,397
Total	**$ 7**	$ 5,759	$ 60,567

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

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

	December 31,	
	2017	2016
Capitalized costs:	(in thousands)	
Properties not being amortized	**$ 15,668**	$ 15,980
Properties being amortized [(1)]	**389,935**	389,231
Total capitalized costs	**$ 405,603**	$ 405,211
Less accumulated depletion, amortization and impairment	**(384,014)**	(379,473)
Net capitalized costs	**$ 21,589**	$ 25,738

(1) Includes $11.0 million and $10.3 million asset retirement cost in 2017 and 2016, respectively.

Results of Operations for Oil and Natural Gas Producing Activities

	International			United States		
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
	(in thousands)					
Crude oil and natural gas sales	**$ 76,978**	$ 59,460	$ 79,947	**$ 47**	$ 324	$ 498
Production costs and other expense [(1)]	**(41,558)**	(38,160)	(42,399)	**(26)**	(166)	(171)
Depreciation, depletion, amortization	**(6,196)**	(6,531)	(32,125)	**(1)**	(151)	(633)
Exploration expenses	**(7)**	(5)	(9,159)	—	—	(1,250)
Impairment of proved properties	—	—	(78,080)	—	(88)	(3,242)
Other operating expense	—	(8,853)	—	—	—	—
Bad debt expense	**(452)**	(1,222)	(2,700)	—	—	—
Income tax	**(11,638)**	(9,248)	(13,238)	**1,260**	—	(1,349)
Results from oil and natural gas producing activities	**$ 17,127**	$ (4,559)	$ (97,754)	**$ 1,280**	$ (81)	$ (6,147)

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

Estimated Quantities of Proved Reserves

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

Proved reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2015	8,260	1,406
Production	(1,659)	(181)
Revisions of previous estimates	(3,746)	(172)
Balance at December 31, 2015	2,855	1,053
Production	(1,518)	(124)
Purchases of minerals in place	308	—
Sales of minerals in place	(12)	(929)
Revisions of previous estimates	1,009	—
Balance at December 31, 2016	2,642	—
Production	(1,518)	—
Revisions of previous estimates	1,925	—
Balance at December 31, 2017	3,049	—

Proved developed reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2015	3,224	1,406
Balance at December 31, 2015	2,855	1,053
Balance at December 31, 2016	2,642	—
Balance at December 31, 2017	3,049	—

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

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

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

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

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

	International			United States			Total		
(In thousands)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Future cash inflows	$ **165,341**	$ 106,583	$ 140,190	$ —	$ —	$ 3,086	$ **165,341**	$ 106,583	$ 143,276
Future production costs	**(108,387)**	(71,260)	(81,973)	—	—	(1,644)	**(108,387)**	(71,260)	(83,617)
Future development costs [1]	**(8,803)**	(10,887)	(10,900)	—	—	(259)	**(8,803)**	(10,887)	(11,159)
Future income tax expense	**(24,798)**	(16,346)	(21,598)	—	—	—	**(24,798)**	(16,346)	(21,598)
Future net cash flows	**23,353**	8,090	25,719	—	—	1,183	**23,353**	8,090	26,902
Discount to present value at 10% annual rate	**(863)**	1,351	491	—		(252)	**(863)**	1,351	239
Standardized measure of discounted future net cash flows	$ **22,490**	$ 9,441	$ 26,210	$ —	$ —	$ 931	$ **22,490**	$ 9,441	$ 27,141

(1) Includes costs expected to be incurred to abandon the properties.

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

Changes in Standardized Measure of Discounted Future Net Cash Flows

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

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Balance at beginning of period	$ **9,441**	$ 27,141	$ 149,387
Sales of oil and natural gas, net of production costs	**(37,328)**	(22,198)	(40,349)
Net changes in prices and production costs	**35,257**	(25,958)	(146,536)
Revisions of previous quantity estimates	**18,743**	19,558	(104,158)
Purchases	—	3,400	—
Divestitures of reserves	—	(835)	—
Changes in estimated future development costs	**(692)**	—	(15,604)
Development costs incurred during the period	**2,298**	—	60,004
Accretion of discount	**2,482**	4,657	27,312
Net change of income taxes	**(7,432)**	4,052	104,303
Change in production rates (timing) and other	**(279)**	(376)	(7,218)
Balance at end of period	$ **22,490**	$ 9,441	$ 27,141

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

In accordance with the current guidelines of theU.S. Securities and Exchange Commission ("SEC"), estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of theproperties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2017, the average of such prices reflected a 33% increase during the year and were $53.49 per Bbl for crude oil from Gabon when compared to the average of such prices for 2016 of $40.35 per Bbl for crude oil from Gabon.

Under the PSC in Gabon, the Gabonese government is the owner of all oil and natural gas mineral rights. The right to produce the oil and natural gas is stewarded by the Directorate Generale de Hydrocarbures and the PSC was awarded by a decree from the State. Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, we were authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for "profit oil" (see discussion below).

The consortium maintains a Cost Account, which entitles it to receive 70% of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). At December 31, 2017, there was $97.6 million in the cost account net to our interest. As payment of corporate income taxes, the consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, we only recover ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also because of the nature of the Cost Account, decreases in oil prices result in a higher number of barrels required to recover costs, therefore at higher oil prices, our net reserves after taxes would decrease, but at lower prices our Cost Recovery barrels increase.

The Etame PSC allows for the carve-out of development areas which include all producing fields in the Etame Marin block. The Etame development area has a term of 20 years and will expire in 2021. The Avouma/South Tchibala field development area has a term of 20 years and will expire in 2025. The Ebouri field development area has a term of 20 years and will expire in 2026. The balance of the Etame Marin block comprises the exploration area, which expired in July 2014. This compares to the economic end date of reserves under the current reserve report prepared by our independent reserve engineering firm of November 2020.

The Mutamba Iroru PSC entitles us to receive 70% of any future production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. The Mutamba Iroru PSC provides for all commercial discoveries to be reclassified into a development area with a term of twenty years. At December 31, 2017, we have no proved reserves related to the Mutamba Iroru block.

The PSC for Block P in Equatorial Guinea entitles us to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 10% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2017, we have no proved reserves related to Block P in Equatorial Guinea.

SCH EDULE I — PARENT COMPANY FINANCIAL STATEMENTS

VAALCO ENERGY, INC.

CONDENSED UNCONSOLIDATED BALANCE SHEETS

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

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 576**	$ 1,038
Receivables:		
Other	**101**	21
Prepayments and other	**599**	1,696
Total current assets	**1,276**	2,755
Equipment and other	**1,304**	1,225
	1,304	1,225
Accumulated depreciation, depletion and amortization	**(721)**	(497)
Net property and equipment	**583**	728
Other noncurrent assets:		
Restricted cash	**50**	—
Deferred tax asset	**1,260**	—
Investment in subsidiaries	**8,091**	—
Total assets	**$ 11,260**	$ 3,483
LIABILITIES AND EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	**$ 98**	$ 310
Accrued liabilities and other	**873**	1,024
Total current liabilities	**971**	1,334
Losses in excess of investment in subsidiaries	**—**	2,507
Total liabilities	**971**	3,841
Commitments and contingencies		
VAALCO Energy Inc. shareholders' equity (deficit):		
Common stock, $0.10 par value; 100,000,000 shares authorized, 66,443,971 and 66,109,565 shares issued, 58,862,876 and 58,554,470 shares outstanding	**6,644**	6,611
Additional paid-in capital	**71,251**	70,268
Less treasury stock, 7,581,095 and 7,555,095 shares at cost	**(37,953)**	(37,933)
Accumulated deficit	**(29,653)**	(39,304)
Total equity (deficit)	**10,289**	(358)
Total liabilities and equity (deficit)	**$ 11,260**	$ 3,483

See accompanying notes to the condensed unconsolidated financial statements.

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

	Year Ended December 31,		
	2017	**2016**	**2015**
Operating costs and expenses:			
Depreciation, depletion and amortization	**$ 260**	$ 244	$ 240
General and administrative expense	**8,489**	7,935	7,550
Shareholder matters	**—**	(332)	2,372
Total operating costs and expenses	**8,749**	7,847	10,162
Other operating income (expense), net	**(12)**	16	—
Operating loss	**(8,761)**	**(7,831)**	**(10,162)**
Other income (expense):			
Interest expense, net	**—**	(2)	(181)
Other, net	**(1,044)**	(1,985)	(469)
Equity in subsidiary earnings (losses)	**18,196**	(16,732)	(146,495)
Total other income (expense)	**17,152**	(18,719)	(147,145)
Income before income taxes	**8,391**	(26,550)	(157,307)
Income tax (benefit) expense	**(1,260)**	—	1,349
Net income (loss)	**$ 9,651**	$ (26,550)	$ (158,656)

See accompanying notes to the condensed unconsolidated financial statements.

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

	Year Ended December 31,		
	2017	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	**$ 9,651**	$ (26,550)	$ (158,656)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**260**	244	240
Other operating loss, net	**12**	—	—
Deferred tax asset	**(1,260)**	—	1,349
Stock-based compensation	**1,098**	192	3,810
Equity in (earnings) losses from subsidiaries	**(18,196)**	16,732	146,495
Commodity derivatives net (gain) loss	**1,032**	—	—
Cash settlements received on matured commodity derivative contracts	**195**	—	—
Change in operating assets and liabilities:			
Other receivables	**(80)**	(21)	293
Prepayments and other	**(130)**	(955)	(236)
Accounts payable	**(212)**	(658)	753
Accrued liabilities and other	**(272)**	(1,855)	517
Net cash used in operating activities	**(7,902)**	**(12,871)**	**(5,435)**
CASH FLOWS FROM INVESTING ACTIVITIES			
Investment in subsidiaries	**—**	—	(7,044)
Return of investment in subsidiaries	**7,598**	12,556	—
Decrease in restricted cash	**(50)**	1,582	8,418
Property and equipment expenditures	**(127)**	(178)	(160)
Net cash provided by investing activities	**7,421**	13,960	1,214
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuances of common stock	39	—	441
Treasury shares	**(20)**	(51)	—
Net cash provided by (used in) financing activities	**19**	(51)	441
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(462)**	1,038	(3,780)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**1,038**	—	3,780
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 576**	$ 1,038	$ —

See accompanying notes to the condensed unconsolidated financial statements.

Notes to Condensed Unconsolidated Financial Statements

Note 1- The condensed financial statements of VAALCO Energy, Inc. (the "Parent Company") have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended, because certain of VAALCO's subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our IFC Term Loan, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Term Loan. The restricted net assets associated with each of these entities exceed 25% of the consolidated net assets of VAALCO Energy, Inc. as of December 31, 2017 and 2016.

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

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

Exhibit 10.1

EXPLORATION AND

PRODUCTION SHARING

CONTRACT

BETWEEN THE

REPUBLIC OF GABON

AND

VAALCO GABON (ETAME), INC.

TABLE OF CONTENTS

EXPLORATION AND PRODUCTION

SHARING CONTRACT

BETWEEN

The Republic of Gabon, herein represented by PAUL TOUNGUI, Minister of Mines, Energy and Petroleum, as the party of the first part,

AND

1. Vaalco Gabon (Etame), Inc., a company incorporated under the laws of the State of Delaware, United States of America, with main office in Houston, Texas, United States Of America, at 4600 Post Oak Place, Suite 309, and represented by Charles W. Alcorn duly authorized to this effect;

The company Vaalco Gabon (Etame), Inc. is a subsidiary guaranteed by its parent company Vaalco Energy, Inc., whose net assets were US$ 13,681,000 on December 31, 1994, incorporated under the laws of the State of Delaware, United States of America, with main office in Houston, Texas, United States of America, signatory of the commitment set forth in Article 46 of the Contract and the subject of Attachment 3;

2. Vaalco Energy (Gabon), Inc., a company incorporated under the laws of the State of Delaware, United States of America, with main office in Houston, Texas, United States Of America, at 4600 Post Oak Place, Suite 309, and represented by Charles W. Alcorn duly authorized to this effect;

The company Vaalco Energy (Gabon), Inc. is a subsidiary guaranteed by its parent company Vaalco Energy, Inc., whose net assets were US$ 13,681,000 on December 31, 1994, incorporated under the laws of the State of Delaware, United States of America, with main office in Houston, Texas, United States of America, signatory of the commitment set forth in Article 46 of the Contract and the subject of Attachment 3; as the party of the second part,

The two above mentioned companies constitute the Contractor; The Republic of Gabon and the Contractor being also hereinafter called jointly “the Parties” and individually “the Party”.

Whereas:

the State is the owner of the natural resources from the surface and subsurface of its territory, from offshore areas under its sovereignty or which are part of its economic zone,

· the discovery and production of Hydrocarbon natural resources are an important factor for the implementation of the economic and social development policy of the country and for the advancement of the welfare of its in habitants,

· to this end, exploration and exploitation of the national resources are considered to be of public usefulness,

- pursuant to Law No. 15/62 of June 2, 1962, establishing a Mining Code in the Republic of Gabon and subsequent amendments, to Decree, No. 981/PR of October 16, 1970, establishing .the conditions for application of the Mining Code; and to Law No. 14/82 of January 24, 1983 regulating Hydrocarbons exploration and exploitation activities, the State wishes to undertake the exploration, exploitation, transportation, storage and marketing of Hydrocarbons,

- it is in the State's interest that the above-mentioned operations be carried out in strict compliance with adequate methods and with the speed compatible with the prevailing practices of the Hydrocarbon industry, and so as to achieve the above-mentioned objectives;

- the Contractor possesses the capital, technical and commercial competence, the required personnel and organizational expertise necessary to successfully carry out the operations specified hereunder and wishes to cooperate with the State by helping it to develop. a Hydrocarbons industry thereby promoting economic expansion of the country and the social welfare of its inhabitants;

- and, it being specified that, for the purposes of the interpretation of this Contract, the following definitions are adopted:

- **Calendar Year** signifies a period of twelve consecutive months starting on January first and ending on the following December thirty-first, in accordance with the Gregorian calendar;

- **Contractual Year** signifies a period of twelve consecutive months from the Effective Date or' the anniversary of said Effective Date;

- **Exclusive Exploration Authorization** signifies the administrative instrument whereby the State authorizes Contractor to undertake on an exclusive basis in the Delimited Area all prospection, exploration and research work aimed at the discovery of Hydrocarbons;

- **Exclusive Exploitation Authorization** signifies the administrative instrument whereby the Government authorizes Contractor to undertake on an exclusive basis all the development, exploitation, and production work on the Fields within the Exploitation Area;

- **Barrel** signifies one US Barrel, i.e. 42 US gallons, measured at a temperature of 60°F;

- **Budget** signifies the estimated expenses, broken down by budget item, relative to the Petroleum Operations appearing in the Annual Work Programs;

- **Condensate** signifies Liquid Hydrocarbons obtained through the expansion of Natural Gas;

- **Contract** signifies this document and its Appendices, which are part of the Contract, and any renewal, extension, replacement or amendment to the Contract which may be decided by the Parties;

- **Contractor** signifies the State's contracting Parties, as well as any organizations, establishments, public or private entities, companies to which any interest may be transferred in ¬application of the provisions of Articles 19 or 42;

- **Petroleum Costs** signifies all the expenditures effectively borne and paid by Contractor for the performance of the Petroleum Operations, as determined according to the Accounting Agreement in Attachment 2, for which said Contractor is recognized the right to recovery of their amounts;

- **Effective Dat**e signifies the date on which the Contract goes into effect, such as defined in Article 50 hereinbelow;

- **State** signifies the Republic of Gabon, owner of the natural resources from the surface and subsurface of the national territory, marine areas under its sovereignty or part of .its' economic zone; the State alone owns the mining titles. Depending on the case, it exercises the prerogatives of a Public Authority and has the powers attributed thereto or acts as Contractor-State, within the framework of partnerships or joint ventures with companies or as a shareholder either through Administrations and agents of public services or through companies it controls. The State may be referred to as, "the Ministry in charge of Hydrocarbons", "the Administration" or "The Departments in charge of Hydrocarbons", or, in general, "the Administration";

- **Exploration Well** signifies any well intended to detect a Field or to determine its extension and magnitude;

- **Development Well** signifies Hydrocarbons from the Field; any well intended to produce Hydrocarbons from the Field;

- **C.F.A. Franc** signifies the currency defined in Title 11 of the Monetary Cooperation Convention between the Member Countries of the Bank of the Central African States (B.E.A.C.) and the Republic of France, signed in Brazzaville on November 23, 1972;

- **Natural Gas** signifies methane, ethane, propane, butane and, more generally, all gaseous Hydrocarbons, either dry or wet, whether or not associated with liquid Hydrocarbons;

- **Field** signifies an accumulation of Hydrocarbons in the subsurface;

- **Hydrocarbons** signifies Crude Petroleum, Condensates, and Natural Gas;

- **Operator** signifies the company duly designated by the Contractor to conduct and perform the Petroleum Operations in the name and on behalf of, and under the responsibility of the latter;

- **Petroleum Operations** signifies all Hydrocarbon prospecting, exploration, development, production, transportation and storage operations and, more generally, all other operations directly connected with the above, carried out under this Contract, with the exception of refining and marketing operations;

- **Crude Petroleum** signifies crude mineral oil, condensate, asphalt, ozokerite and any type of Hydrocarbons and bitumen, both solid and liquid, in their natural state or obtained from Natural Gas through condensation or extraction;

- **Total Available Production** signifies the total Hydrocarbon production from the exploitation of all the Fields located within the Delimited Area, computed on said area after degassing, dehydration, stabilization, decantation, desalting and gasoline recovery (for the Natural Gas), at the time when it is sent towards the evacuation lines or, if no pipelines are available, towards storage facilities; the following is deducted from this production:

    - Hydrocarbons re-injected into the Field or used in the Petroleum Operations, under the conditions set forth in Article 26.1,b of the Contract;

    - Hydrocarbons burned or destroyed provided that Contractor has abided by the regulations in force and the guidelines and applicable recommendations of the Administration.

- **Net Production** signifies the Total Available Production of Hydrocarbons less the proportional mining royalty;

- **Remaining Production** signifies the Net Production less the removals of hydrocarbons made by Contractor in connection with the recovery of the Petroleum Costs;

- **Annual Work Program** signifies all the Petroleum Operations that Contractor agrees to perform during a Calendar Year in the Delimited or Exploitation Area, appearing in a document describing on an itemized basis these Petroleum Operations;

- **Affiliated Company** signifies a company or any other business:

    - which controls one or more companies comprising Contractor,

    - or which is controlled by one or more companies forming Contractor,

    - or which is controlled by a company that itself controls the Contractor.

Such control signifies the direct or indirect ownership of more than fifty percent of the stock of the capital of the controlled company and thus entitling the controlling company to the absolute majority of the voting rights;

- **Non-Affiliated Company** or **Third Party** signifies a company or any entity other than the Parties which does not fall under the preceding definition.

- **Underlifting** signifies a situation in which one of the Parties, at a given time and in proportion to its rights, has failed to remove and dispose of the full share of Hydrocarbons to which it is entitled in application of the provisions of the Contract;

- **Overlifting** signifies a situation in which one of the Parties, during a given period, has already removed and disposed of a quantity of Hydrocarbons in excess of that to which it is entitled in application of the provisions of the Contract;

- **Delimited Area** signifies the surface area within the perimeter described in Attachment 1;

- **Exploitation Area** signifies a surface area located within the Delimited Area on which the State grants the Contractor, according to the applicable laws and the Contract, an Exclusive Exploitation Authorization.

The above having been stated, the following is mutually agreed and established:

ARTICLE 1

GENERAL CONDITIONS

1.1. This Contract is a Hydrocarbon exploration and production sharing agreement. Its clauses are governed by the laws and regulations in effect in Gabon.

1.2. It defines the rights and obligations of the Parties, governs their mutual relationship and establishes the rules and terms for exploration, exploitation and production sharing. It applies to the Petroleum Operations that Contractor is to perform on an exclusive basis in the Delimited Area and any Exploitation Area, it being understood that all substances and products other than Hydrocarbons are beyond the Contract's scope of application.

1.3. For all the work required for performance of the Petroleum Operations, Contractor is required to comply with generally accepted Hydrocarbon industry practices.

1.4. Contractor shall supply all the financial and technical means necessary for the proper performance of the Petroleum Operations. Subject to written approval of the Petroleum Operations, the Contractor may use Third Parties or Affiliated Companies Funds for the financing of corresponding investments.

The Contractor shall send to the Hydrocarbon Services a certified copy of the loans agreements and contracts which have been obtained and must be concluded under the condition that the above-mentioned approval has been obtained.

However, interest, agios, financial charges of any nature and currency exchange losses arising from such financing, whatever their source and payment terms, are deductible for the purposes of Article 26.4 or chargeable to Petroleum Costs which give rise to recovery under Articles 24 and 26.10, only in the cases and according to the modalities and restrictions provided in said Articles and in the Accounting Agreement.

1.5. The Contractor shall alone bear the financial risk attached to the performance of the Petroleum Operations, subject to the provisions of Article 19.

1.6. Throughout the term of the Contract, the total production originating from the Petroleum Operations will be shared between the Parties according to the terms defined in Articles 24, 25, and 26.

1.7. The Delimited Area is defined in Attachment 1.

1.8. In the month following the Effective Date, the Contractor shall inform the Administration of the name of the designated Operator who will be responsible for performing the Petroleum Operations.

The Operator, in the name and on behalf of the Contractor, shall communicate to the Administration all reports, information and data mentioned in the Contract as well as any contract or convention binding the companies comprising the Contractor. The Operator will act as the designated representative of all the companies forming the Contractor, for the performance of the Petroleum Operations. The Contractor may at any time designate another Operator, subject to prior approval from the Administration.

1.9. For the practical terms of performance of this Contract, the person responsible for Departments in charge of Hydrocarbons represents the State; he makes all the decisions, grants any necessary or useful authorization for the performance of the Petroleum Operations.

1.10. During the term of the Contract, the State may at any time and particularly at the time of participation pursuant to the provisions of Article 19, delegate the management of its rights and obligations resulting from said participation to a company or organization of its choice.

ARTICLE 2

TECHNICAL CONSULTING COMMITTEE

2.1. Within the month following the Effective Date, a Technical Consulting Committee will be formed. It will be composed of the same number of members representing the State and the Contractor. The representatives of the State will be designated from among the Administration supervisory staff, from the General Hydrocarbon Department and from the land, financial, or customs Administration. The Chairman of the Technical Consulting Committee shall be selected from among the representatives from the General Hydrocarbons Department.

2.2. The Technical Consulting Committee is a body responsible for issuing opinions, suggestions and recommendations on:

- the exploration, development and .production work on discovered Fields, and on the related expenditures;
- the application of the Field conservation rules pronounced by the Administration or, in the absence of such rules, based on commonly accepted Hydrocarbon industry practice;
- anti-pollution measures and safety and health regulations on the work sites;
- the choice between purchasing or renting, by the Contractor, of major equipment and facilities, in application of the provisions of Article 10.2;
- the programs and budgets provided by Articles 5.1 and 20.1, before they are submitted to the Administration for approval;
- the conditions for personnel employment, in accordance with the provisions of Article 38;

the provisions to be taken by Contractor for the training of Gabonese personnel in application of the provisions of Article 39 and the implementation of said provisions;

Within the framework of its powers, the Technical Consulting Committee may assign studies to subcommittees created for that purpose.

2.3. The opinions, suggestions and recommendations of the Technical Consulting Committee will be adopted by majority of votes, each member being entitled to one vote and with the authority to represent only one other member of the Committee.

The Technical Consulting Committee deliberates validly if at least two thirds of its members are present or represented; the presence of the Chairman or of his representative, if the former is unable to attend, is indispensable.

2.4. The Technical Consulting Committee meets at least twice a year in the exploration period and at least four times a year during the development and exploitation period. Meetings are called at the initiative of the Contractor or the Administration and convened by summons from the• Chairman of the Technical Consulting Committee issued at least fifteen days prior to the meeting date. In emergencies, the members meet as quickly as possible or consult by telex.

Contractor may request that the Technical Consulting Committee be convened in an extraordinary meeting in order to submit specific questions to it.

The agenda is prepared by the Party requesting the meeting; the documents necessary for the proper conduct of the meeting are prepared by Contractor or, if applicable, by the Administration. Contractor will hold the office of Secretary of the Technical Consulting Committee.

2.5. The expenses deriving from the activity of the Technical Consulting Committee, as well as those borne by the Administration within this context will be borne by Contractor and considered as Petroleum Costs.

ARTICLE 3

EXPLORATION PERIODS

3.1. On the effective date, the Contractor is granted an Exclusive Exploration Authorization on the Delimited Area for a first period of three years Contractual Years. This period may be extended at Contractor's request, presented at least forty-five days before expiration of this period, by a maximum of three months to permit Contractor to complete any drilling then in progress.

This extension will be granted by decision of the Departments in charge of Hydrocarbons.

Nevertheless, Contractor shall make its best effort to start drilling so that, under normal circumstances, the drilling operations can be completed before the normal expiration of the above-mentioned Period.

3.2. If, during the first extension period granted pursuant to Article 3.1, the Contractor has fulfilled the obligations deriving from this Contract, in particular the work obligations defined in Article 4, the Exclusive Exploration Authorization shall be extended at the request of Contractor for a second period of three Contractual Years.

The second period may also be extended by a maximum of three months for the same reasons and under the same conditions as those stated in Article 3.1.

Contractor must file its renewal application for the second period at least thirty days prior to expiration of the first period. If Contractor has benefited from the extension described in Article 3.1, the above-mentioned thirty-day term is counted from the end of said extension, in order to allow Contractor to examine and evaluate the results from drilling and to determine the desirability of filing a renewal application. Renewal will be granted through edict from the Minister of Hydrocarbons.

3.3. At the end of the first period, in the event that that the Exclusive Exploration Authorization is not renewed, Contractor must surrender all the Delimited Area, with the exception of the Exploitation Areas or surface areas for which it has filed an application for an Exclusive Exploitation Authorization which is being processed.

ARTICLE 4

WORK COMMITMENTS DURING THE EXPLORATION PERIOD

4.1. During the exploration period defined in Article 3.1, Contractor shall perform at least the following work:

- acquire and process 1,500 km of 2-D seismic data and shoot one 3-D seismic survey;
- Re-process and make a reinterpretation of existing, available seismic data;
- Prepare a feasibility study of the development of the Tchibala North South discoveries within the first six months;
- Drill one exploration well.

In order to carry out this work program under the best technical conditions in accordance with generally accepted Hydrocarbon industry practices, Contractor will invest an a mount estimated at US $7,800,000.

Contractor is required to start the geological and geophysical work covered by the above commitments within four months after the Effective Date.

4.2. During the second exploration period defined in Article 3.2, Contractor shall carry out the following minimum work:

- acquire and process 2,000 km of 2-D seismic data and shoot a 3-D seismic survey if the exploration well was a discovery;
- drill two exploration wells.

In order to carry out this work program under the best technical conditions in accordance with generally accepted Hydrocarbon industry practices, Contractor will invest an amount estimated at US $14,500,000.

4.3. The above-specified wells will be drilled to a minimum depth 2,500 (two thousand rive hundred) meters or until the Gamba geological formation is penetrated for at least fifty meters if it extends beyond the contractual depth. If at 2,500 meters, said geological formation has not been encountered, the Parties will meet in order to examine the desirability of continuing the Well in the interest of each.

Drilling will be stopped at a lesser depth than originally estimated if, having drilled the well in accordance with approved practices of the Hydrocarbon industry, the stoppage is justified by one of the following reasons:

- the Gamba formation is encountered at a lesser depth than the contractual depth; in this case, the Parties will meet to examine the desirability of continuing the well in the interest of each;
- basement is encountered at a lesser depth than projected;
- continuation of drilling presents an obvious hazard because of the presence of abnormal formation pressure;
- rock formations are encountered the hardness of which renders it impractical to continue drilling with standard equipment;
- Hydrocarbon-bearing formations are encountered which; before being penetrated, must be protected by setting casing, thus preventing attainment of the contractual depth.

In the event that drilling is stopped for any of the above-listed reasons, the well shall be considered to have been drilled to the contractual depth, provided that the Contractor timely presents its reasons to the Administration and the Administration accepts these reasons as justified.

4.4. The Contractor is required to meet its work commitments for an exploration period even if this entails for the Contractor exceeding the amount estimated for that period.

On the other hand, if Contractor has met the work commitments for an amount less than the amount estimated for that period, it is considered to have met those commitments.

4.5. If the Administration notices that' Contractor has not met its work commitments during an exploration period, it will so advise Contractor in writing. The procedure provided by Article 48.10 is then applicable, as required.

ARTICLE 5

PREPARATION AND APPROVAL OF ANNUAL WORK PROGRAMS AND CORRESPONDING BUDGETS

5.1. Within a maximum of two months after the Effective Date, Contractor shall submit to the Administration for approval an Annual Work Program and the corresponding Budget for the entire Delimited Area, specifying the Petroleum Operations for the period from the Effective Date until the following December 31.

By September 30 of the Calendar Year, Contractor shall submit to the Administration for approval an Annual Work Program and the corresponding Budget for the entire Delimited Area, specifying the Petroleum Operations it intends to perform during the subsequent Calendar Year.

The Annual Work Program and the corresponding Budget mentioned above shall be examined by the Technical Consulting Committee, in accordance with the provisions of Article 2.2 prior to being submitted for Administration approval; the advice, suggestions and recommendations of the Technical Consulting Committee must be attached.

5.2. If the Administration believes that modifications of the Petroleum Operations planned in the Annual Work Program are necessary or useful, it shall notify the Contractor in writing, within thirty days after receipt of the Program, stating the requested modifications and including any justifications it deems appropriate. The Administration and the Contractor will meet as soon as possible in order to study the modifications requested and in order to prepare by mutual agreement the Annual Work Program and the corresponding Budget in their final form.

In any case, the parts of the Annual Work Program for which the Administration did not request modifications are considered approved and must be completed by the Contractor within the initially agreed times.

If the Administration does not address a request for modifications to the Contractor before expiration of the thirty-day period, the Annual Work Program and the corresponding Budget shall be deemed thereby approved.

5.3. If the information acquired as the operations progress or particular circumstances justify certain minor changes in the Petroleum Operations planned in the Annual Work Program which do not affect the pursuit of the primary objectives by the Contractor, the Contractor may make the corresponding changes after approval from the Hydrocarbon Departments, provided that the basic established objectives are not changed.

ARTICLE 6

RELINQUISHMENTS

6.1. Contractor may relinquish all or part of the Delimited Area, subject to application of the provisions of Article 7.

6.2. During the first exploration period defined in Article 3.2, only to the entire Delimited Area may be relinquished, subject to the provisions of Article 6.5.

6.3. During the second exploration period defined in Article 3.2, all or part of the Delimited Area may be relinquished.

6.4. Contractor must inform the Administration in writing of its decision to relinquish acreage, specifying, if applicable, the part of the Delimited Area which is to be relinquished. Said relinquishment becomes effective six15ty days after receipt of the above-mentioned written notice, unless the Administration agrees to the effectiveness of the waiver for an earlier date.

Within thirty days after the effective date of the relinquishment, Contractor must submit to the Administration a detailed report, together with appropriate supporting documentation, on the work performed in the Delimited Area and the corresponding expenses.

6.5. When relinquishing areas held under en exploration contract, Contractor has the right to retain the Exploitation Areas or surface areas for which it has filed an application which is being processed.

6.6. In the event of a partial relinquishment, each of the relinquished areas must be sufficiently large to allow further hydrocarbon operations to be carried out and must be of simple shape and defined by geographic coordinates.

6.7. Partial relinquishment during the second exploration period does not cause the Contractor's work commitments defined in Article 4.3 to be reduced; the part of work not yet completed on the effective date of the partial relinquishment is carried over to the remaining part of the Delimited Area.

ARTICLE 7

INSUFFICIENCY OF EXPLORATION WORK

7.1. In the event of relinquishment of all of the Delimited Area, as described in Articles 6.1 or 6.2, and if Contractor's work commitments as defined in Article 4, have not been met, Contractor is required to pay to the State, within thirty days after the effective date of the relinquishment, on the basis of provisions of Article 6.4, a compensation equal to the cost of the exploration commitments which have not been met at the date of the relinquishment.

7.2. Within thirty days of the expiration of either the first or the second exploration period defined in Article 3, Contractor presents to the Administration a detailed report, with appropriate supporting documents, on the work performed in the Delimited Area and on the corresponding expenditures.

7.3. If at the expiration date of any of the exploration periods, Contractor has failed to meet its work obligations as defined in Article 3, Contractor is required to pay to the State, within thirty days following the date of expiration of the period involved, a compensation corresponding to the value of the work not done, as estimated on that date.

7.4. In the event of a delay in the payment of the compensation due to the State under the terms of Article 7.1 and 7.3 these amounts due will bear interest, calculated from the day the payments were due until the date of payment by Contractor, at the annual discount rate of the Bank of Central African States (B.E.A.C.) plus three percentage points.

7.5. If the compensations estimated in Article 7.1 and 7.3 are less than those actually due, the difference, plus the interest defined in Article 7.6, calculated from the day on which these compensation payments should have been made, is paid to the State as soon as possible.

7.6. The amounts which have not been paid on the dates due are increased by a penalty interest defined by the annual discount rate of the, Bank of Central African States (B.E.A.C.) plus three percentage points.

ARTICLE 8

CONTRACTOR'S OBLIGATIONS DURING THE EXPLORATION PERIODS

8.1. The Contractor furnishes all the necessary funds for the expenses required for the performance of the Petroleum Operations defined in the Annual Work Program.

The Contractor will perform the Petroleum Operations by using either its own materials, equipment and supplies or those acquired or rented to this effect, subject to the provisions of Article 10.3.

8.2. The Contractor is responsible for the performance of the Annual Work Programs. The work must be performed under the best conditions of cost and efficiency; in general, the Contractor will utilize all appropriate means for the execution of the Annual Work Programs under the best economical and technical conditions for the Parties, in accordance with the most appropriate practices generally accepted in the Hydrocarbon industry.

8.3. The Contractor agrees to take all practical measures in order to:

(a) ensure protection of the aquifers encountered:

- while drilling, through proper cementing of the casing in the. wells,

- when abandoning unproductive wells, by applying cement plugs so as to isolate the formations under pressure from other reservoir horizons and from the surface.

(b) carry out the tests necessary to determine the value of the Hydrocarbon shows encountered while drilling and the exploitability of any Fields discovered.

8.4. The facilities erected and work performed by the Contractor offshore under this Contract shall, according to their nature and the circumstances, be built, positioned, marked, buoyed, equipped and maintained in such fashion as to permanently allow free safe passage to navigation at all times in the waters of the Delimited Area.

Independently of the above provisions, in order to facilitate navigation, the Contractor shall install sound or visual devices approved or required by the competent authorities and maintain them to the satisfaction of said authorities.

8.5. At the time of construction and maintenance of the facilities necessary for the performance of the Petroleum Operations, the Contractor shall not disturb any previously installed cemetery or any existing building used for religious purposes. Moreover, Contractor must not in any way cause any problem which may affect normal use of a building without the occupants' consent. The Contractor is required to pay due compensation for damage or disturbance thereby caused to Third Parties.

8.6. In application of the International Convention on the Pollution of Sea Water by Hydrocarbons signed in London on May 12, 1954, its amendments and implementation provisions, the Contractor undertakes to take all the necessary precautions to prevent marine pollution.

To this effect, the State may decide, in agreement with the contractor, on any additional measures it may deem necessary in order to ensure preservation of the marine zone.

8.7. Under similar conditions of price, quality, and delivery, Contractor agrees to use Gabonese companies for its procurement, work and service contracts.

For all contracts that may reach or exceed one million US dollars (US$ 1,000,000), the choice of companies shall be by call for bids.

A copy of all the contracts mentioned in the preceding paragraph concluded by the Contractor and pertaining to the Petroleum Operations will be addressed to the Administration as soon as said contracts are signed.

The Contractor will inform the Departments in charge of Hydrocarbons at least fifteen days in advance of the date, time and place of opening of the bids. The person responsible for these Departments or his representatives may participate in the opening and examination of the bids.

The information made available to the participants in the opening and examination of the bids must be communicated at the same time to the Departments in charge of Hydrocarbons.

A list of all 'the contracts concluded by the Contractor during each calendar quarter for performance of the Petroleum Operations is forwarded for information to the Administration, within fifteen days following the end of said calendar quarter. For each contract, the subject and the amount, together with the name of the co-contracting party will be specified. The Contractor forwards to the Administration copies of the contracts which may be requested by the latter.

ARTICLE 9

RIGHTS IN CONNECTION WITH THE EXPLORATION PERIODS

9.1. Subject to the special provisions of the Contract, Contractor has the rights the exercise whereof affects the performance of the Petroleum Operations in the Delimited Area and to all possible facilities to that end. These rights include specifically:

(a) Full responsibility for the administration, control, and conduct of all the Petroleum Operations;

(b) The option to exercise the rights and powers conferred by the Contract through independent agents and independent contractors whose salaries, expenses, and fees it pays in compliance with the regulations in force in Gabon on financial transactions and subject to the provisions of Article 8.7.

9.2. Subject to the regulations in effect and the provisions of Article 8.5, the Contractor will have the right to clear the land, to excavate, drill, bore, construct, erect, place, procure, operate, administer and maintain ditches, tanks, wells, trenches, excavations, dams, canals, water mains, plants, reservoirs, basins, offshore and onshore storage facilities, primary distillation units, first extraction gasoline separation units, sulfur plants and other facilities for the production of Hydrocarbons, in addition to pipelines, pumping stations, generator sets, power plants, high voltage lines, telephone, telegraph, radio systems and Other communications facilities, factories, warehouses, offices, sheds, houses for employees, hospitals, schools, premises, ports, docks, harbors, dikes, jetties, dredges, breakwaters, underwater piers and other facilities, ships, vehicles, railways, roads, bridges, ferryboats, airlines, airports and other transportation facilities, garages, hangars, workshops, foundries, repair shops and all related auxiliary services and, in general, all that which is necessary for performance of the Petroleum Operations.

The location of these facilities may be selected by the Contractor subject to the regulations and provisions of Articles 8.5, 13 and 14.

9.3. The agents, employees and representatives of the Contractor or of its subcontractors shall be allowed to enter or leave the Delimited Area and to have free access in keeping with their functions to all the facilities installed by the Contractor for performance of the Petroleum Operations.

ARTICLE 10

OWNERSHIP OF THE ASSETS

10.1. The real property such as wells, buildings and associated equipment, piers, roads, bridges, canals, ports, docks, dikes, jetties, water mains, pipelines, reservoirs, basins, railways, land, structures, warehouses, offices, plants and permanently-installed machinery and equipment purchased or built by the Contractor, as well as all movables thereby purchased or manufactured within the framework of the Petroleum Operations are the property of the State.

The Contractor may utilize at no charge said real property and movables within the framework of the Contract. The Contractor may also use said property for other petroleum operations under other contracts to which it is a. party, subject to payment of a properly calculated rental price, approved by the Administration. These proceeds are entered in the Petroleum Costs account and Will reduce said Costs. They are paid to the State if the Petroleum Costs yet to be recovered correspond only to exploitation expenses.

The Contractor will contract, regarding these assets, on behalf of the State, all the necessary insurance policies, according to generally accepted practices. The insurance premiums paid to this effect are included in the Petroleum Costs. The indemnities collected in the event of claim are entered in the Petroleum Costs account and will reduce said Costs. They are paid to the State if the Petroleum Costs yet to be recovered correspond only to exploitation expenses, unless they are allocated to replacement of lost or destroyed assets.

10.2. The provisions of Article 10.1 above are not applicable to assets belonging to Third Parties or Affiliated Companies and leased to Contractor under a lease or simple rental agreement.

10.3. Under equivalent economic conditions, Contractor commits itself to give priority to buying goods instead of leasing or renting.

For major equipment and facilities, before opting for purchase or lease, Contractor shall procure the opinion, suggestions and recommendations of the Technical Consulting Committee and submit its duly justified choice for the Administration's approval. This choice will become final after the approval from the Administration has been obtained.

At the time of review of the Annual Work Program and corresponding Budget, the Administration will designate the major equipment and facilities appearing on said documents, for which the Technical Consulting Committee must be consulted and the Administration's approval requested.

ARTICLE 11

ACTIVITY REPORTS DURING THE EXPLORATION PERIODS

11.1. The State, through the Departments in charge of Hydrocarbons, will have access to all the original data in connection with the Petroleum Operations, such as geological, geophysical, petrophysical, drilling and exploitation reports, in addition to any technical, accounting and financial information which it may deem useful for the exercise of its power of verification.

11.2. Immediately after they have been prepared or obtained, the Contractor shall furnish the following reports or documents to the person responsible for the Departments in charge of Hydrocarbons:

(a) a copy of the geophysical survey and interpretation reports and a complete set of maximum processed seismic profiles on stable transparent material, such as “Mylar”; a copy of the magnetic tapes will be kept by the Contractor and made available to the person responsible for the Departments in charge of Hydrocarbons;

(b) a copy of the daily telexes on the wells being drilled and a copy of the spud-in and end-of-drilling reports for each well drilled, in addition to a complete set of all logs recorded in reproducible form;

(c) a copy of the reports on production tests performed and of any study pertaining to the commencement of production of a well;

(d) a copy of each core sample analysis report,

A representative portion of the cores or cuttings obtained at each well and samples of the fluids produced during the production tests will also be furnished within a reasonable period. Any core samples and cuttings in the Contractor s possession at the time of expiration of the Contract will be delivered to the person responsible for Hydrocarbons.

11.3. During the second half of each month, the Contractor shall furnish to the Departments in charge of Hydrocarbons a report on the Petroleum Operations of the previous month.

11.4. Contractor is required to inform the Departments in charge of Hydrocarbons in the shortest possible time of any discovery of mineral substances and to report on any pertinent observations or information relative thereto.

11.5. The State is the owner of any original documents, reports prepared or obtained by the Contractor or samples relative to the Petroleum Operations, geological, geophysical, and petrophysical work, synthesis reports, well logs, even if in the Contractor’s possession, to be used within the framework of the Petroleum Operations. The Contractor may retain copies of these samples, documents and reports for the requirements of the Petroleum Operations.

Each Party assumes the obligation, each as applicable to it, in its own behalf and in the behalf of the service companies or consultants working for it, to consider these documents, reports, Operations, studies and samples confidential and not to reveal them to Third parties without prior consent from the person responsible for the Departments in charge of Hydrocarbons. This obligation continues, for the State, during the exploration periods defined in Article 3 and, in the event of total surrender, in application of the provisions of Article 6, until the effective date of said surrender, and, for the Contractor, even after the end of the Contract.

Each entity forming the Contractor may, without the consent of the other entities or of the Administration, disclose the following confidential information and data:

(a) To each company interested in good faith in the realization of an eventual transfer or of assistance in the framework of Petroleum Operations, after the undertaking by said company to keep this information confidential and to use it only for the realization of said transfer or assistance; or

(b) To any independent professional consultants operating within the framework of the Petroleum Operations, after obtaining from them a similar confidentiality agreement, provided that the Contractor reports immediately to the Administration the names of said consultants and the information and data disclosed thereto; or

(c) To any bank or financial institution with which the Contractor is attempting to obtain or obtains financing, after obtaining a similar confidentiality agreement from these concerns,

(d) When and insofar as the regulations of a recognized stock exchange require it, unless this is in conflict with the laws of Gabon.

(e) Within the framework of any contentious judicial, administrative or arbitrage procedure.

With prior written consent from the Administration, the Contractor may exchange with any interested party any confidential information or data of this type against other similar information or data.

ARTICLE 12

NATURAL RESOURCES

The Contractor shall have the right, if applicable, in exchange for payment of any applicable royalty and subject to compliance with the regulations in force and the provisions of Article 8.5, to remove and use the topsoil, fully-grown timber, clay, sand, lime, gypsum, stones (other than precious stones) and other similar substances which may be necessary for the performance of the Petroleum Operations.

The Contractor shall make reasonable use of such materials for the performance of the Petroleum Operations.

The Contractor may take or -use the water necessary for the Petroleum Operations provided that existing irrigation or navigation does not thereby suffer and that land, houses or watering points are not thereby deprived of their use.

ARTICLE 13

UTILIZATION OF LAND

13.1. The State will make available to Contractor for the needs of the Petroleum Operations, the State-owned land necessary for said operations. The Contractor may construct and maintain, above and below grade, the facilities necessary for the Petroleum Operations. The Contractor shall not request the use of said land unless it has a real need therefor and it shall refrain from claiming any land occupied by buildings or properties utilized by the Administration. The Contractor shall compensate the State for any damage to the land caused by the construction, maintenance and use of its facilities.

Subject to the regulations in force, the Administration will authorize the Contractor to construct, use and maintain telecommunication systems and pipelines, above and below grade and along land which does not belong to the State, provided the construction, maintenance and use of these systems cause the least possible damage and that they are in accordance with the regulations.

13.2. In the event it is necessary -for the Contractor, in order to perform the Petroleum Operations, to occupy and use land belonging to private parties, the Contractor shall endeavor to reach an amicable agreement with the property owners to determine equitable compensation for the loss of use suffered. In the event of disagreement, the Contractor shall inform the Administration which can:

~ either set a compensation to be paid by the Contractor, if the occupation of the land is of short duration. The amount of the compensation will then take into account the effective use of the land by the landowner at the time of occupation.

~ or expropriate the land, in accordance with the applicable regulations, if the occupation is long-lasting or makes it henceforth impossible to resume the original use of the land. The rights are acquired and recorded by the Government in the latter's name but the Contractor is entitled to free use thereof for the Petroleum Operations for the entire duration of the Contract. The costs, expenses and indemnities resulting from the expropriation procedure will be borne by the Contractor.

ARTICLE 14

UTILIZATION OF FACILITIES

14.1. The Contractor will have the right to utilize, under the provisions of common law, for the needs of the Petroleum. Operations any railway, tramway, road, airport, landing field, canal, river, bridge or waterway and any telecommunication network, whether owned by the State or by private companies, against payment of any royalties in force or to be established by mutual agreement, in exchange for this use and their construction, operation and maintenance. The Contractor will also have the right to use for the Petroleum Operations any means of land, sea or air transportation, subject to the laws and regulations governing the use of such means of transportation.

14.2. The State will have the right in exceptional cases to use any transportation and communication facility installed by the Contractor, such as in case of national necessity due to national catastrophes, disasters, internal or external peril. The Contractor shall make all its facilities available to the State at the latter's simple request or requisition. In such case, the request shall come from the Minister in charge of Hydrocarbons.

14.3. The State can construct, operate and maintain, above and below the land made available to the Contractor or along roads, railways, airports, landing fields, canals, bridges, flood Protection dams, police stations, military installations, pipelines and telecommunication networks, provided this does not compromise or significantly hinder the performance of the Petroleum Operations, except in case of national necessity.

ARTICLE 15

EXPIRATION OF CONTRACT AT THE END OF THE EXPLORATION PERIOD

If, during the exploration periods, Contractor has made no discovery of Hydrocarbon deposits presumed to be commercially exploitable or declared as such and giving entitlement to an Exclusive Exploitation Authorization, the Contract is terminated at expiration of said period.

Expiration of the Contract will not relieve the Contractor of its contractual obligations arisen prior to the date of said expiration and not yet honored, entirely or in part, on said expiration day. The Contractor is required to meet these obligations in accordance with the regulations and the contractual provisions; the validity thereof is extended to this effect.

ARTICLE 16

DISCOVERY AND EXPLOITATION OBLIGATION

16.1. If the Contractor discovers Hydrocarbons, it shall notify the Administration in writing within ten days after completion of the tests making it possible to presume the existence of a field.

16.2. The commercial or presumed commercial nature of a Field is determined by the Parties. The Parties shall meet to this effect and shall record their agreement on this matter in a jointly signed document.

16.3. To this end, Contractor is required to supply all information enabling the Administration to make a detailed review of the data relative to the discovered Field and to make its decisions in full cognizance of the facts as to the commercially exploitable nature of the discovery. This information is to be supplied as it is obtained by Contractor.

16.4. Provided Contractor has met its commitments and obligations under the Contract, and especially Article 16.3, a Field considered to be commercially exploitable in application of the above provisions will entitle it .to an Exclusive Exploitation Authorization on the area involved which will be considered an Exploitation Area after the effective date of this Exclusive Exploitation Authorization and will be limited to the presumed size of the Field, projected to the surface, determined on the basis of available geological and geophysical data.

The Exclusive Exploitation Authorization is granted by official decision of the Minister of Hydrocarbons at Contractor's request, filed in the form and terms of Article 17.1

16.5. If the Contractor makes several commercially exploitable discoveries within the Delimited Area, each of these will entail a separate Exclusive Exploitation Authorization corresponding to a separate Exploitation Area. However, for the requirements of Articles 24, 25 and 26.1, the overall production from the Exploitation Areas of the Delimited Area is taken into account.

16.6. The quantities of Hydrocarbons produced before a Field is declared commercially exploitable in application of the provisions of Article 16.2, will be measured in accordance with the provisions of Article 29 and will be subject to the provisions of Articles 24 to 26, with the exclusion of those used for the needs of the Petroleum Operations or lost, provided, however, that for these quantities the Contractor supplies to the Administration all useful explanations and justifications.

16.7. For any Field declared or presumed commercially exploitable in accordance with the provisions of Article 16.2, the Contractor assumes the obligation to perform all useful and necessary Petroleum Operations for exploitation of said Field.

The Contractor is required to inform the Administration in writing of the starting date of production as soon as this is effective.

After the award of an Exclusive Exploitation Authorization, the State shall not require that the Contractor continue exploitation of the corresponding Field if it provides evidence, on the basis of the technical information acquired on the Field and of accounting and financial justifications, of the non-profitability of the exploitation.

In this case, the Exclusive Exploitation Authorization expires on the date on which the operations or the production are stopped and the corresponding Exploitation Area becomes free on said date. The State has then the right to exploit the Field on its own, without being required to pay any indemnity to the Contractor.

16.8. Except for duly justified exceptional circumstances, if production from a Field has not begun within three years after the date of award of the Exclusive Exploitation Authorization, this authorization is canceled and the Contractor's rights are considered voluntarily relinquished. Cancellation is pronounced by decree from the Minister in charge of Hydrocarbons.

ARTICLE 17

APPLICATION FOR EXCLUSIVE EXPLOITATION AUTHORIZATION AND DELIMITATION OF EXPLOITATION AREAS

17.1. To obtain an Exclusive Exploitation Authorization, Contractor must file an application with the Minister in charge of Hydrocarbons.

The aforementioned application, as well as the attachments and data provided, must be written in French or must be accompanied by a duly certified translation. They are to be dated and signed by the applicant.

The application, as well as the attachments and data provided, must be prepared in triplicate; the first two copies, one of which must have a stamp, are to be filed with the Directorate of Hydrocarbons, the- third is to be filed with the Minister in charge of Hydrocarbons.

The applicant must prove his identity and indicate the elected domicile; if the applicant is acting as a proxy, it must prove its identity, its domicile and its powers.

The applications presented in application of this Article must provide, for all companies making up the Contractor, information concerning their registered offices, authorized capital and the full names, nationalities, titles, and addresses of the persons making up, according to the bylaws, the management, the administration and the board of these companies and persons with signatory power.

Any application filed for a company must include the powers of attorney of the person(s) who signed the application, as well as a certified copy of the bylaws of the company, of the certificate of its incorporation and of the balance sheets of the last three financial years.

The application must include:

- the proposed limits of the Exploitation Area, which must be strictly confined to the presumed size of the Field discovered, as projected to the surface;
- supporting documents (geological and geophysical interpretations, wireline logs, etc.) used as basis for determination of the presumed extent of the Field;
- the provisional estimate of recoverable reserves and the annual production of the Field;
- a plat of map on a scale of 1:200,000 showing the geographic boundaries of the Area of the application;
- a report summarizing the results of the exploration efforts carried out in the Delimited Area and providing the location, a description and the characteristics of the Field;

- a general outline of the development plan for the Field and an estimate of the capital expenditure required for the development and the exploitation of the Field;

- a provisional program for the training of Gabonese Nationals.

17.2. Any later modification in the bylaws, legal form or capital of the companies forming the Contractor, as well as any change of the individuals mentioned in the fifth paragraph of Article 17.1, must be reported without delay to the Minister in charge of Hydrocarbons and to the person responsible for the Departments in charge of Hydrocarbons.

The Contractor is to send annually to the aforementioned copies of its constituent entities' balance sheets and accounting records submitted for approval to their stockholders' meetings and any reports from their management and administration presented at these meetings to this effect.

17.3. The right to obtain an Exclusive Exploitation Authorization will remain in effect only if the application is received by the Administration within six months after the date of the signature of the document specified in Article 16.2 and, in any case, before the expiration date of the second exploration period. If a reply is not received within the above-mentioned time frame after receipt of the application, the latter is considered accepted by the Administration.

17.4. The applications for renewal of the Exclusive Exploitation Authorization mentioned in Article 18.1 must be presented not later than 90 days prior to the expiration date of the previous Exclusive Exploitation Authorization under the same forms as those set forth in Article 17.1.

17.5. If, during the course of the year following the award of an Exclusive Exploitation Authorization, the extensions of the Field appear to be greater than those of the Exploitation Area, the Minister of Hydrocarbons will grant by Edict to the Contractor, at the latter's request, within the framework of the previously granted Exclusive Exploitation Authorization, an additional surface area such that the entire Field may thus be covered, on the condition, however, that said additional surface area is part of the initial Delimited Area. The Contractor may not benefit from such an extension if the surface area in question has already been awarded to a third party or is the subject of an application for award then being reviewed.

ARTICLE 18

TERM OF VALIDITY OF THE EXCLUSIVE EXPLOITATION AUTHORIZATION

18.1. The Exclusive Exploitation Authorization is granted to the Contractor through Edict by the Minister in charge of Hydrocarbons; it will go into effect on the date of the award. Its maximum duration is ten years.

If, at the end of ten-year term, commercial exploitation of an Exploitation Area is still possible, the Exclusive Exploitation Authorization for that Exploitation Area is renewed at the Contractor's request, through Edict from the Minister of Hydrocarbons for a maximum of five years, provided that the Contractor has met its obligations and commitments under this Contract.

The Exclusive Exploitation Authorization is renewed a second time for a maximum of five years, under the same conditions as stated above.

When a renewal is considered and taking into account the financial results obtained by the Parties during the preceding Period, said Parties may agree to new provisions for Articles 24 through 26.

18.2. At any time, the Contractor may relinquish an Exclusive Exploitation Authorization. The Contractor must inform the Administration by letter of its decision to relinquish it and this renunciation will become effective sixty days after receipt of this letter, unless the Administration agrees to a closer date of effectiveness of said renunciation. In the event of relinquishment, the Exploitation Area becomes free on the effective date of the relinquishment.

18.3. The Contract expires on the date of expiration of the last Exclusive Exploitation. Authorization or, when applicable, on the effective date of the above-mentioned relinquishment; however, the Parties are not released from their contractual obligations arisen prior to exploitation of the Contract which may not yet have been honored, entirely or in part, on the date of said expiration. The Parties are required to comply with the regulations and contractual provisions; the validity of these is extended to this effect.

ARTICLE 19

STATE PARTICIPATION

19.1. As soon as a Field is placed on production, the State automatically participates, at a rate of 7.5 percent, in the rights and obligations deriving from the Contract, unless it expressly waives the right to participate within ninety days after the above-mentioned production starting date.

The State participates, at the above-mentioned percentage, in the Petroleum Costs regarding development and exploitation of the Exploitation Area, except for any exploration expense.

If the State wishes to take an additional interest, it will inform the Contractor in writing, specifying the percentage interest which it decides to hold. The conditions for acquisition of the additional interest are mutually agreed upon between the Parties.

19.2. The State may at any time transfer to an entity of its choice all or part of its interest.

This state may, however, transfer its interest only to a company controlled by the State or to a company with a well-established technical and financial reputation; if the assignee is a subsidiary, or a branch office, the State will assure that the parent company guarantees its commitments as per provisions in Article 46.2. The Contractor will be consulted prior to any transfer of interest.

The rights and obligations arising from the partnership agreements binding the entities comprising the Contractor must in no event limit the State's rights or aggravate its obligations under its participation, nor shall they decrease the extent or effects of said participation.

19.3. As from the date on which production begins, the State reimburses, in cash or in kind, its share of the Petroleum Costs incurred for development since the award date of the Exclusive Exploitation Authorization to the companies forming the Contractor, in addition to the sums corresponding to the calls for funds for the Petroleum Costs advanced by the other partners for the exploitation costs.

The above-mentioned choice of payment is exercised by the State through letter addressed to the Contractor within ninety days; failing this, it is considered having opted for payment in kind.

If the State chooses to pay in cash, payment will be made from the net proceeds from the sale of the production share to which it is entitled as a result of its participation, in accordance with the provisions of Article 41.

If the State chooses to pay in kind, payment will be made at the end of each calendar month, by turning over a portion of the production to which it is entitled as a result of its participation.

Whatever the method of payment, the amount to be paid by the State is limited to seventy percent of the net production, or as the case may be, of the portion of the production to which it is entitled as a result of its participation during the calendar month considered. The unpaid balance, if any, is added to the payments owed at the end of the following month; this carrying forward shall not, however, cause the above-mentioned seventy percent limit to be exceeded. Consequently, the total of any balances and of subsequent calls for funds is obligatory only to the above limit, and the surplus will be carried forward and paid under the same conditions defined hereinabove.

Payments made on behalf of the State which have not been recovered by Contractor, constitute a credit due to the Contractor and can be recovered without limitations from the last lifting preceding the expiration of the Contract.

For the purposes of this Article, the quantities of Hydrocarbons turned over as payment by the State will be calculated at the "Fixed Price" defined in Article 27.

19.4. The Contractor will keep up-to-date a "State-Participation" account. This account will be debited with the Petroleum Costs that are attributable to the State by reason of the period prior to its assumption of its participation, as well as at the end of each calendar month, of its monthly share of the Petroleum Costs. The account is credited, at the end of each calendar month, by the Fixed Price of the Hydrocarbons delivered as payment by the State for said month and by the amounts paid by the latter.

The payments owed by the State as reimbursement of its share of Petroleum Costs for development and exploitation, are increased, if applicable, by simple interest calculated at the annual discount rate of the Bank of Central African States (B.E.A.C.).

ARTICLE 20

DEVELOPMENT PROGRAM

20.1. Within one hundred and eighty (180) days after the award of an Exclusive Exploitation Authorization, the Contractor must prepare and submit to the Administration for approval a detailed development and production program specifying notably:

- item by item, the equipment and operations necessary for placement into production, such as the number of development wells, the number of platforms, the pipelines, the production, processing, storage and loading facilities required;
- the corresponding cost estimates;
- the projected schedule for performance of the above-mentioned work, equipment and facilities;
- the estimated production starting date;
- the estimate of recoverable reserves and annual Production.

This development and production program must have been examined by the Technical Consulting Committee. in accordance with Article 2.2, before being submitted to the Administration together with the Committee's advice, suggestions and recommendations.

20.2. If the Administration believes that modifications to the above-mentioned development and production program are necessary or desirable, it must inform the Contractor in writing, specifying the modifications which it requests, supported by those justifications which it may deem useful.

The Administration and the Contractor will then meet, as soon as possible, in order to examine the changes requested and prepare, through mutual agreement, the program in its final form. This program is considered approved on the date of said agreement.

In any case, the parts of the program for which the Administration did not request changes will be considered approved and the Contractor will be able to realize them within the initially planned periods of time.

If, at the time of expiration of the above-mentioned term, the Administration has not presented to the Contractor any request for modifications, the program is considered approved.

ARTICLE 21

OBLIGATIONS OF THE CONTRACTOR DURING THE DEVELOPMENT AND EXPLOITATION PERIODS

21.1. Unless otherwise stipulated, Articles 5, 8, 10, and 11 of the Contract are applicable, *mutatis mutandis*, to Petroleum Operations conducted within the scope of the Exclusive Exploitation Authorizations.

21.2. Upon obtaining an Exclusive Exploitation Authorization, the Contractor agrees to proceed with diligence to drill the necessary development wells with such intervals between wells as to guarantee maximum economic recovery for the Parties, of the Hydrocarbons contained in the Field, in keeping with internationally accepted good practices in the Hydrocarbon industry.

Except for duly evidenced unusual circumstances, the Contractor must start these development operations no later than six months after acceptance by the Administration of the development and production program defined in Article 20.

21.3. In the performance of its production operations, the Contractor is required to observe all the internationally accepted standards and practices of the Hydrocarbon industry which make it possible to obtain optimum economic recovery of Hydrocarbons contained in the Field for the Parties.

21.4. The Contractor is required to proceed, as soon as technically feasible, with enhanced recovery program studies for the Field and to implement at the appropriate time this process if, under economic conditions acceptable to the Parties, it can lead to an improvement in the rate of recovery of the Hydrocarbons contained in the Field.

21.5. The Contractor agrees to provide the Administration with all the reports, studies, results from measurements, tests and trials, and documents which make it possible to verify the proper exploitation of the Fields in order to guarantee that the exploitation is being conducted in the proper conditions, in particular, in the light of the above provisions.

particular, it is required to carry out the following operations on each producing well:

- measurement of the production of Hydrocarbons daily, monthly and annually;
- monthly control of the gas-oil ratio;
- annual measurement of reservoir pressure, on a carefully selected group of wells, representing at least one half of the wells in the Field.

The Contractor is required to implement every recommendations made by the Administration, in agreement with the Contractor, on the subject of conservation of the Fields and to comply with the regulations in effect regarding pollution and the safety of property and persons.

21.6. The Contractor is required to annually produce from each Field quantities of Hydrocarbons in accordance with generally accepted international Hydrocarbon industry practices, in particular in applying the standards for proper conservation of the Fields **making** optimal recovery of the Hydrocarbon reserves possible in minimal economic conditions for the Parties.

21.7. The Contractor contributes annually to a Hydrocarbon Support Fund created for the purpose of developing petroleum research in Gabon. Contractor's contribution to the Hydrocarbon Support Fund is calculated on the basis of the Total Available Production equal to the C.F.A. Franc equivalent of US$ 0.05 per Barrel produced. This contribution will not be included in the Petroleum Costs.

The Hydrocarbon Support Fund will be managed by the Minister of Hydrocarbons.

ARTICLE 22

CONTRACTOR RIGHTS IN CONNECTION WITH EXCLUSIVE EXPLOITATION AUTHORIZATIONS

22.1. Unless otherwise stipulated, Articles 9, 12, 13 and 14 of the Contract are applicable mutatis mutandis to Petroleum Operations conducted within the scope of Exclusive Exploitation Authorizations.

22.2. The Contractor is entitled, subject to regulations in effect, to build, utilize, operate and maintain all the Hydrocarbon production, storage and transportation facilities which are necessary for the production, transportation, delivery and loading of the products extracted, subject to the provisions of Article 10.3.

22.3. If no available or sufficient evacuation means exist, the Contractor can, under the conditions set forth by the regulations, construct a pipeline that will allow it to evacuate the production. To that end, the Contractor will submit for the approval of the Administration, and before the commencement of any work, plans corresponding to the layout it has established and to the projected location of all the pipelines it intends to build. All the pipelines crossing or running along roads or thoroughfares (other than those reserved for the Petroleum Operations) shall be built so as not to obstruct traffic. The conditions of transportation and the safety regulations for these structures will comply with the applicable regulations in force.

22.4. Within the limits of available capacity not used by the Contractor and at normal and nondiscriminatory prices, Contractor is required to allow free use by Third parties of the Hydrocarbon transportation, processing and storage infrastructures set up for the needs of the Petroleum Operations.

The pricing conditions applied shall be duly evidenced and submitted for approval to the Departments in charge of Hydrocarbons. The rate is to be established so that it permits recovery of the cost of operation of the installation, including a portion of the cost price of the facilities at least equal to the fiscal depreciation in effect or usually applied in Gabon and computed on the original acquisition value, plus a reasonable profit margin representing remuneration for the capital invested for the construction of the given infrastructure.

ARTICLE 23

PRODUCTION MARKETING OBLIGATION

23.1. As soon as the production of a Hydrocarbon Field becomes regular, Contractor is required to make every effort to ensure the best valorization of the extracted product such that the marketing of the share of these products to which it is entitled does not unfavorably affect the prices of Gabonese Hydrocarbons on the international market.

23.2. The Contractor is required to make every effort so that the prices obtained for exported Gabonese Hydrocarbons are in agreement with those existing on the international market at the time of the sale, for equivalent duality, quantity, freight and payment terms.

ARTICLE 24

RECOVERY OF PETROLEUM COSTS

24.1. The Contractor is entitled to recover the Petroleum Costs it has defrayed within the Delimited Area, by lifting a portion of the Hydrocarbon production exclusively from that area. The recovery of Petroleum Costs may not in any case be achieved by drawing on the production of Hydrocarbons from Fields outside the Delimited Area.

For the application of the foregoing paragraph, the Contractor shall keep a Petroleum Cost Account, in compliance with Article 26.9 and the Accounting Agreement.

24.2. Contractor is entitled to recover the Petroleum Costs after production begins and as production progresses.

This cost recovery right gives the Contractor the right to lift a portion of the Net Production. These liftings are limited to the balance of the Cost Account, and, for any Calendar Year, shall not exceed seventy (70%) percent of the Net Production obtained during said year.

The Hydrocarbons lifted by Contractor under the provisions of this Article are valued at the “Fixed Price” as defined in Article 27, for the purposes of the Petroleum Cost Account mentioned in Article 26.9.

24.3. The State will enjoy a preference right on the quantities of Hydrocarbons to which the Contractor is entitled within the scope of the recovery of Petroleum Costs, when these quantities are offered to Third Parties.

For the purposes of the application of the above provisions, the quantities of Hydrocarbons that are given over within the scope of exchanges required by technical constraints inherent in the Contractor’s facilities, or that are intended to save time and transportation efforts, will not be considered as sales to Third Parties but on the condition that the quantities exchanged are actually intended for meeting the Contractor’s needs or those of its Affiliated Companies.

In exchange for the quantities of Hydrocarbons that are purchased in application of the above provisions, the State will pay to the Contractor a sum equal to the product of said quantities times the price agreed to by the Parties. This price is determined by reference to prices found on the international market at the time of the sale, for equivalent quality, quantity, freight and payment terms.

The amounts paid by the State to the Contractor within the scope of the preference right stipulated above will be posted to the credit of the Petroleum Cost Account, these therefore being considered as having been recovered in cash.

24.4. When the State exercises its preference right stipulated in Article 24.3, the Contractor will send to the Administration, no later than fifteen days following the date of the loading of the quantity of Hydrocarbons given over to the State, the corresponding invoice made out in United States dollars.

Within ninety days following the reception of that invoice, the State will effect payment in freely exchangeable currency, according to the regulations in force. The amount due will be paid into the Contractor's account in a bank established in Gabon. Should the State not make payment in the above time frame, the amount due will carry an annual interest rate that is at most equal to the discount rate of the Bank of Central African States (B.E.A.C.)? If payment of an invoice is not made by the State within the above mentioned time frame, the preference right of the State is suspended for as long as the last invoice remains unpaid.

Regardless of the means employed to recover Petroleum Costs, by drawing from the Hydrocarbons in conformity with Article 24.2, by cash payments in application of Article 24.3, or by a combination of these two methods, the total recovery, during a Calendar Year, expressed in terms of the quantity of Hydrocarbons, may not, for any reason, exceed the percentage of the Net Production for that Calendar Year set in Article 24.2.

24.5. If in the course of a Calendar Year the Net Production from the Delimited Area fails to permit the Contractor to recover Petroleum Costs in application of the provisions of Articles 24.1 to 24.5, the amount of Petroleum Costs that are not recovered in that Calendar Year will be carried forward to succeeding Calendar Years until full recovery of the Petroleum Costs or expiration of the Contract.

24.6. In the event of the discovery in the Delimited Area of deposits producing Hydrocarbons of differing quality, the recovery of the Petroleum Costs shall be by payment in kind or payment in cash in accordance with this Article, by taking into account each of the qualities, proportionally to the Total Available Production.

ARTICLE 25

PRODUCTION SHARING

25.1. After deduction by the Contractor on a part of the Net Production for the recovery of the Petroleum Costs in application of the provisions of Article 24, the Remaining Hydrocarbon Production is shared between the State and the Contractor in the following terms:

(a) When the average daily Total Available Production from the Delimited Area for a given calendar month is equal to or less than ten thousand (10,000) Barrels, the Remaining Production is shared between:

- the State: fifty (50%) percent
- the Contractor: fifty (50%) percent.

(b) When the average daily Total Available Production from the Delimited Area for a given calendar month is greater than ten thousand Barrels and equal to or less than twenty-five thousand (25,000) Barrels, the Remaining Production is shared between:

- the State: fifty-five (55%) percent
- the Contractor: forty-five (45%) percent.

(c) When the average daily Total Available Production from the Delimited Area for a given calendar month is greater than twenty-five thousand Barrels, the Remaining Production is shared, between:

- the State: sixty (60%) percent
- the Contractor: forty (40%) percent.

In the event of a discovery in the Delimited Area of Hydrocarbons of different qualities, the sharing between the State and Contractor of the Remaining Hydrocarbon Production is made separately for each quality, proportionally to the Total Available Production.

The Contractor is entitled to its share of Hydrocarbons from the start of the production and as it develops.

25.2. The State draws its share of the production as defined in Article 25.1 above, in kind.

However, the Contractor is required, when requested by the State, .to sell all or part of the latter's share of Hydrocarbons under the terms of the above-mentioned Article and reimburse the State. In this case, Contractor will make its best effort to obtain a sales price on the market at least equivalent to the "Fixed Price" defined in Article 27. When this operation occurs, Contractor will receive a sales commission in an amount established by mutual agreement with reference to the applicable customary business practice.

In the event Contractor is unable to sell the State's share of the production at a price at least equal to the "Fixed Price", Contractor will inform the State of the best price proposed. The State will then inform Contractor whether it accepts the sale price Contractor can obtain or prefers to receive the quantities involved in kind.

25.3. The State may request payment of the proceeds from sales of its production share made by the Contractor in the foreign currency of its choice. The choice of payment currency shall be made known to Contractor at the time of the request mentioned in Article 25.2, second paragraph. In the absence of notification, payment shall be made in the currency in which the "Fixed Price" defined in Article 27 is expressed.

25.4. The State has a preference right on the Contractor's share of production defined in Article 25.1, under the same conditions and following the same procedures as those set forth in Articles 24.5 and 24.4.

ARTICLE 26

FISCAL SYSTEM

In connection with the Petroleum Operations performed in the Delimited Area, the Contractor is subject to the following taxes and royalties:

(a) the bonuses specified in Article 28; these are payable in cash;

(b) a proportional mining royalty, during the production phase, the rates of which are defined as follows:

- three percent (3%) when the Total Available Production during a calendar month is equal to or less than five thousand (5,000) Barrels per day;
- six percent (6%) when the Total Available Production during a calendar month is greater than five thousand (5,000) and equal to or less than seven thousand five hundred (7,500) Barrels per day;
- nine percent (9%) when the Total Available Production during a calendar month is greater than seven thousand five hundred (7,500) and equal to or less than ten thousand (10,000) Barrels per day;
- twelve percent (12%) when the Total Available Production during a calendar month is greater than ten thousand (10,000) and equal to or less than fifteen thousand (15,000) Barrels per day;
- fifteen percent (15%) when the Total Available Production durng a calendar month is greater than fifteen thousand (15,000) and equal to or less than twenty-five thousand (25,000) Barrels per day;
- seventeen point five percent (17.5%) when the Total Available Production during a calendar month is greater than twenty-five thousand (25,000) Barrels per day;'

The total Available Production subject to the proportional mining royalty is reduced by the following quantities:

(1) quantities lost or burned at the time of the production tests or at the production, gathering or storage facilities on the Exploitation Area, provided that the Contractor has abided by the applicable regulations and the guidelines and recommendations of the Administration on this matter;

(2) reinjected into the Field of the Exploitation Area;

(3) used for preparation of drilling fluids for the requirements of the Delimited Area;

(4) used for operations performed, after drilling, on wells of the Field of the Exploitation Area;

(5) consumed in the turbine engines providing the energy used:

(i) to drive the necessary pumping units on the wells of the Field of the Exploitation Area,

(ii) to gather the Hydrocarbons on the Exploitation Area,

(iii) to operate the drilling facilities established on the Delimited Area for the requirements of said Area.

The quantities lifted or used downstream from the point where the Total Available Production is discounted for the above-mentioned requirements are acceptable deductions from the proportional mining royalty base only after exceptional authorization from the Administration, issued upon justified request from the Contractor.

The proportional mining royalty is paid either in kind or in cash, at the State's option. If the latter has failed to let its choice be known, it will be considered having opted for payment in cash.

When the proportional mining royalty is paid in cash, it is computed on the FOB value of the Hydrocarbons. For determination of this FOB value, the price adopted is the "Fixed Price" defined in Article 27.

Payment in cash of the proportional mining royalty is made to the office of the tax collector not later than the twenty-eighth of each month, on the basis of the average monthly production of the preceding calendar quarter. Adjustment is made not later than January 28th of each year, for the preceding Calendar Year, on the basis of the taxable Total Available Production of said year and of the corresponding "Fixed Price".

At the start of production and during the period when the above-mentioned average monthly production cannot be determined, the amount of the royalty is calculated on the basis of the effective production of each month considered and is paid within the same above-mentioned periods of time.

If the State wishes to receive in kind all or part of the proportional mining royalty, it advises the Contractor in writing to this effect at least one hundred eighty days in advance, specifying the quantity which it wishes to receive in this form during the period considered.

The proportional mining royalty is not included in the Petroleum Costs.

(c) the annual surface royalty set forth by the regulations in effect. This royalty, included in the Petroleum Costs, is paid in cash, in advance and per full Calendar Year, on the basis of the surface area held on January 1st of each year and, for the first year, on the surface area held on the Effective Date7.

(d) the duties and taxes collected at the time of importation by the Customs Administration, such as defined in Article 34;

(e) The Tax on Profits and Revenues (Corporate Tax), which each entity forming the Contractor has to pay and which is calculated applying the general tax rate in force and in accordance with the provisions of Article 26.1. Payment of the Corporate Tax is made to the appropriate tax administration, by the State, for the account of the above mentioned entities. In accordance with Article 26.3, this quantity is included in the portion due to the State under provisions of Article 25.1.

The Corporate Tax thus due for a given Calendar Year and paid to the State in kind, is determined on the basis, notably, of the gross revenue consisting of the turnover from the quantity of Hydrocarbons available thereto in application of Articles 24 and 25, or their equivalent in cash, as well as from the quantities delivered to the State as payment for the Corporate Tax and, on the other hand, from deductible expenses, including the bonuses as defined in Article 28, the cost of materials, interests, and payments into the Hydrocarbon Support Fund, as defined in Article 21.7, as indicated and defined in the tax laws in effect and in Article 26.1. The pertinent taxable profit is that from the Annual Statistical and Fiscal Declaration mentioned in Articles 26.4 and 26.5.

26.2. In regards to the fiscal and customs regulations, each company which makes up the Contractor is treated as a distinct entity. However, if one of these units does not meet its fiscal obligations resulting from this Contract, the other entities will be substitutes thereof.

26.3. The quantity of Hydrocarbons which the State receives during any Calendar Year in application of Article 25.1 includes:

(a) the part representing the mining rights other than the annual surface royalty and the proportional mining royalty as defined in Article 26.1 above;

(b) and, in accordance with the provisions of the above Article 26.1 e), the part which represents .the corporate tax to be imposed on the companies which make up the Contractor of the Hydrocarbon operations carried out in the Delimited Area, and computed at the rates defined in the tax laws in effect.

26.4. Each company forming the Contractor will keep, by Calendar Year, separate accounting records for the Petroleum Operations, rendering it possible to determine, in particular, the profit and loss balance statement and a detailed balance sheet showing both the results of said operations and the assets and liabilities pertaining and related thereto. This accounting system must be in compliance with the applicable regulations in effect in Gabon, such as the General Accounting Plan for Companies. It has to include, in particular, all the data required for the preparation of the Annual Statistical and Fiscal Statement and its attachments.

26.5. Each of the companies forming the Contractor is required to deliver to the person responsible for the Departments in charge of Hydrocarbons, not later than April 30 of each year, a copy of the tax return regarding the Corporate Tax pertaining to the previous Calendar Year, such as required by the applicable tax regulations.

The profit and loss account and the balance sheet must clearly show the amount of amortization and of write-offs done during the year. As far as the expenditures which have not yet been amortized are concerned, these amortizations are calculated and accounted for as the difference, if it is positive, between the maximum of the Cost Recovery Account as defined in Article 24.2 and the total of the charges debited to the profit and loss account.

26.6. The Tax Administration, after examining the above-mentioned documents, will issue to each one of the companies forming the Contractor, within sixty days after the date of presentation, the originals of the tax statements and all other documents certifying that it has met its fiscal obligations resulting from the applicable regulations, subject to the Administration's rights to audit and recovery set forth by the regulations in force.

Regarding tax regulations, the value of Hydrocarbons available to the Contractor during a Calendar Year, in application of Articles 24 and 25.1 is considered as representing the recovery of Petroleum Costs and the net profit after Corporate Tax:

26.7. Apart from the bonuses defined in Articles 28.1 and 28.2, the taxes, rights and royalties established in Article 26.1, the duties and taxes collected by the Customs Administration, as established in Article 34, the contribution to the Hydrocarbon Support Fund, established in Article 21.7, payments made under Provisions of Article 39 and, with the exception of the property tax on structures due under common law on residential buildings, the Contractor is exempted, in connection with the Petroleum Operations, from any other taxes, royalties, duties, imposts and contributions.

The Contractor's suppliers, subcontractors, service contractors and Affiliated Companies are exempted from the domestic Turnover Tax and the tax on transactions due on sales made, work performed and services rendered within the framework of the Contract.

The profit earned by the companies forming the Contractor within the framework of the Petroleum Operations is exempt from any tax and withholding at the source due in connection with distribution to stockholders or partners or allocation thereof.

When by mistake, one of the companies forming the Contractor has been assessed with taxes, duties, imposts, withholding or royalties from which it is exempted in application of the provisions of this Article, it may charge the amount thereof to the Petroleum Costs, if it is not released from this payment obligation one year after filing a claim to this effect with the proper Administration. This charge is subject to written prior approval from the Minister of Hydrocarbons, so that the grounds thereof may be verified.

The above-mentioned exemptions are not applicable to duties and taxes due for services rendered by Gabonese Administrations, communities and public institutions used by the Contractor. However, the rates applied to the Contractor, its contractors, carriers and clients, and its agents must correspond to the magnitude of the services rendered and be non-discriminatory.

More specifically, the Contractor will still be subject to local, municipal and port charges in effect; however, the rates thereof must not be discriminatory in regards to the Contractor with respect to those applied to companies conducting similar activities.

26.8. Assignments of any nature between the companies signing the Contract and their Affiliates are exempted from all duties and taxes due in this connection to the Registration Administration.

26.9. Concurrently with the obligation to keep an accounting system in accordance with that established by the applicable regulations and the provisions of the Contract, the Contractor will keep a Petroleum Costs Account in which to enter, on one hand, all the recoverable expenses, pursuant to the provisions of the Contract and of the Accounting Agreement, incurred for the requirements of the Petroleum operations, as they are actually incurred and, on the other hand, the recovered amounts of the Petroleum Costs, as this recovery takes place, in addition to receipts and proceeds of any nature to reduce or deduct from the Petroleum Costs, as they are collected.

The Petroleum Costs Account shall be subdivided into subaccounts making it possible specifically to show:

(a) exploration expenses: payments of any nature coru1ected with geological, geophysical, drilling well equipment and production testing operations (as well as all related operations) aimed at discovering Hydrocarbons;

(b) appraisal expenses: payments of any nature connected with geological, geophysical, drilling, well equipment and production testing operations aimed at determining if the Field discovered is commercially exploitable and at determining its boundaries;

(c) development expenses: payments of any nature, such as: drilling, well equipment and production testing, installation of platforms and pipelines and all other operations performed for the production, transportation, processing and storage of Hydrocarbons at the loading terminal;

(d) exploitation expenses: payments of any nature connected with the study, the management and the execution of operations directly or indirectly connected with

Hydrocarbon exploitation and maintenance of production, processing, storage and transport facilities.

In order to be considered as Petroleum Costs, the above-mentioned expenses must be strictly necessary for the requirements of the Petroleum Operations and must meet the criteria stated in the Accounting Agreement.

Expenses incurred in connection with non-deductible costs, those the recovery of which is excluded by express provisions of the Contract or of the Accounting Agreement, those of a sumptuary or exaggerated nature, gratuities not authorized by the regulations and, in general, all those expenses which are not required for proper management of the Petroleum Operations, are not recoverable; consequently, they must not be debited to the Petroleum Costs Account.

At any time, the balance of the Petroleum Costs Account shall show the amount not yet recovered by the Contractor.

The practical methods for application of the provisions of this Article 26 are defined in the Accounting Agreement, Attachment No. II of the Contract.

26.10. The Petroleum Costs account is debited notably for the expenses linked to:

(a) construction, manufacturing, creation, realization, purchase, renting, maintenance and repair of the assets, including consumable materials;

(b) exploration and research;

(c) taxes, rights and duties assessed and paid in Gabon;

(d) personnel and personnel environment;

(e) services rendered by Third Parties, Affiliated Companies and companies constituting the Contractor, including technical assistance;

(f) insurance policies subscribed and settlements of damages;

(g) legal costs;

(h) interest, agios and financial charges paid to creditors, for their real amount and insofar as the loans and debts to which they are linked are necessary for the Petroleum Operations and correspond to a real financing need for these Operations.

However, the expenses of such nature are not chargeable to the Petroleum Costs, giving right to recovery, according to articles 24, 26.9, in the following cases:

- in general, when the loans and debts to which they are linked are not necessary for the financing needs of the Petroleum Operations;

- when they are linked to the loans and debts of the Contractor, which may be contracted for financing prospection and exploration operations;
- when they are linked and up to the portion of the loans and debts which exceeds of the amount of development and production expenses.

The interest paid to shareholders, Affiliated Companies and companies constituting the Contractor for the amounts thereby lent or advanced are admitted within the same limits and under the same conditions as hereinabove, but, moreover, within the maximum limit of the interest computed at the annual discount rate of the Banque des Etats de l'Afrique Centrale plus two points.

(i) the exchange losses incurred in connection with the Contractor's loans and debts, under the same conditions and following the same procedures as those provided in paragraph h) hereinabove.

Moreover, the Contractor should not be covered against exchange losses or loss of profits arising from risks pertaining to the origin of the Contractor's own funds and to self-financing, and the losses which may be thus incurred cannot, in any case, be considered as Petroleum Costs; they can, consequently, neither be entered in the Petroleum Costs account nor give right to recovery. The same provisions are applicable for insurance premiums and costs of policies which the Contractor would have subscribed to cover such risks.

The exchange losses incurred and directly linked to claims concerning Petroleum Operations and directly handled in foreign currency are also chargeable to the Petroleum Costs;

(j) the costs incurred for controls and verifications made by the Administration;

(k) overhead expenses, under the conditions provided in the Accounting Attachment.

Payments made for costs, charges or expenses not directly to the Petroleum Costs. This concerns notably payments made for:

(a) costs of capital increase;

(b) marketing costs;

(c) costs related to the period prior to the Effective Date;

(d) costs of independent audits paid by the Contractor within the framework of particular relations between the companies constituting the Contractor;

(e) bonuses and Hydrocarbons Support Fund provided by articles 21.7 and 28;

(f) costs incurred for meetings, studies and works realized within the Joint Operating Agreement between the companies forming the Contractor;

(g) interest, agios and financial charges which do not meet the conditions set forth in paragraph 1, h) .hereinabove and in Article 1.4;

(h) any exchange losses which may be incurred and which do not meet the conditions set forth in paragraph 1, (i) hereinabove;

(i) exchange losses which constitute losses of arising from risks connected with the origin Contractor's own funds and self-financing, such forth in paragraph 1, (i), 2nd part hereinabove.

The following shall be deducted from the Petroleum Costs:

(a) the proceeds from the quantities of Hydrocarbons which belong to the Contractor according to the provisions of article 24, by the corresponding Fixed Price, such as defined in Article 27;

(b) the amounts which may be received for the recovery of Petroleum Costs, according to the provisions of Article 24.3;

(c) all other related, closely related or accessory receipts, revenues, proceeds and profits, directly or indirectly linked to the Petroleum Operations and such as enumerated in the Accounting Attachment.

26.11. The Accounting Agreement, which is an integral part of the Contract, establishes, although not mentioned in the Contract, the definition and nature of the expenses to be considered as Petroleum Costs, those which do not entail recovery and, limitations of the amount of the expenses which may entail entry in the Petroleum Costs. It establishes the Contractor's obligations regarding procedures and presentation of accounting records for the Petroleum Costs, reports, minutes, statements and information to be furnished to the Administration.

ARTICLE 27

VALORIZATION OF HYDROCARBONS

27.1. The quantities of Hydrocarbons,

- drawn for the recovery of the Petroleum Costs according to provisions of Article 24,
- representing the proportional mining royalty mentioned in Article 26.1, b,

- constituting the Contractor's gross revenue specified in Article 26.1,e, second paragraph,
- representing the State's share of production marketed by the Contractor at the State's request, in application of the provisions of Article 25.2,
- delivered in order to contribute to the satisfaction of the internal consumption needs pursuant to the provisions of Article 35,
- received as payment from the State, in application of the provisions of Article 19.4,

are valorized by application of the price set by the Administration for Gabonese Hydrocarbons, hereinafter referred to as the "Fixed Price".

27.2. The "Fixed Price" is determined by the Administration by reference to the official Hydrocarbon prices defined by the Organization of Petroleum Exporting Countries (OPEC) taking into account the international market prices for Hydrocarbons of similar quality.

It is calculated FOE value every six calendar months for the previous six calendar month period on the basis of pertinent data and information; it is notified to Contractor for application and any necessary adjustments,

If no "Fixed Price" has been provided to Contractor for a given six calendar month period, the "Fixed Price" resulting from the most recent notification will be used provisionally.

27.3. If, for a given period, the "Fixed Price" applied is higher than the market price for sales to Third Parties of Hydrocarbons originating from the Exploitation Area, the difference will be recovered by Contractor by recording a debit in the Petroleum Cost Account. If, conversely, the "Fixed Price" is lower than the above-mentioned market price, the difference is credited to the Petroleum Cost Account.

27.4. The market price mentioned in the above paragraph is determined by the Parties who will meet periodically to this effect, on the basis of the evolution of the international Hydrocarbon market, in accordance with procedures to be defined.

ARTICLE 28

BONUSES

28.1. The Contractor will pay to the State the sum of US dollars five hundred thousand (US$ 500,000) on the Effective Date.

28.2. In addition, the Contractor shall pay to the State the equivalent in CFA francs of:

(a) five hundred thousand (500,000) US dollars at the start of production from the Delimited Area;

(b) two hundred thousand (200,000) US dollars when the rate of Hydrocarbon production in the Delimited Area reached, for the first time, the level of twenty thousand Barrels per day for a period of thirty consecutive days;

(c) two hundred thousand (200,000) US dollars when the rate of Hydrocarbon production in the Delimited Area reached, for the first time, the level of thirty thousand Barrels per day for a period of thirty consecutive days;

(d) Each of the amounts mentioned above will be paid within the next thirty days after the starting date of production, for the first amount, and within thirty days after the end of the corresponding reference period for the other two.

28.3. The payments mentioned in Articles 28.1 and 28.2 hereinabove cannot in any case be considered as Petroleum Costs.

ARTICLE 29

MEASUREMENT AND METERING OF THE HYDROCARBONS

29.1. The Contractor shall measure and meter all the Hydrocarbons produced after extraction of water and foreign substances.

The point where the quantities of Hydrocarbons are measured and metered and the point where the instruments, equipment and facilities to which they are related must mandatorily be approved by the Administration.

The authorized Administration representatives will verify these measurements and counts and check the instruments, facilities and equipment used, at least once every three months. If the Contractor wishes to modify or change said measuring instruments, facilities and equipment, it shall inform the Administration at least fifteen business days in advance in order to enable the Administration representative to be present at the time of said modification or change.

Modifications and changes affecting the points, instruments and equipment mentioned in the above second paragraph must be previously approved by the Administration.

29.2. In order to be deductible, the quantities of Hydrocarbons used for the Petroleum Operations or lost must be the subject of a monthly detailed explanatory statement addressed to the Administration.

29.3. If any measurement errors which would result in shortages or in excesses are detected on the instruments, facilities and equipment used by the Contractor, said errors shall be considered as having existed since the date when the last verifications were or should have been made by the Administration and corrections must be made accordingly.

All expenses and all costs incurred by Contractor, its subcontractors and suppliers and related to the lifting .of natural gas by the State shall not be considered part of the Petroleum Costs but shall be charged to the State which shall reimburse Contractor in accordance with a an agreement to be agreed upon by both parties.

ARTICLE 30

NATURAL GAS

30.1. In the event of a Natural Gas discovery, the Contractor, after carrying out the appropriate studies and after consultation with the Administration, shall determine whether exploitation can be undertaken commercially.

All the provisions of the Contract shall be applicable *mutatis mutandis* and, more specifically, those pertaining to the Set Price defined in Article 27, the recovery of Petroleum Costs defined in Article 24, the Remaining Production sharing regulations defined in Article 25, the bonuses defined in Article 28 and the royalties and taxes defined in Article 26.1 and 26.7, if the discovery is declared commercially exploitable.

However, in order to take the conditions particular to the exploitation of Natural Gas into account and to promote its development, other specific benefits may be granted the Contractor when they are duly justified.

Whenever it is necessary to determine the equivalence between Natural Gas and Crude Oil and, More specifically, especially in order to determine the procedures for lifting the quantities of Hydrocarbons allocated for recovery of the Petroleum Costs defined in Article 24, the sharing of Remaining Production defined in Article 25, and the bonuses defined in Article 28.2, it is agreed that one hundred. Sixty-five cubic meters of Natural Gas are equal to one barrel of Crude Oil. This equivalence shall be stated by mutual agreement.

30.2. If the Contractor does not consider the Natural Gas discovered to be commercial, in this case, the Contractor forfeits any right to this discovery deriving from the Contract. The State is then entitled to exploit this discovery on its own without the obligation to pay any indemnity to the Contractor.

30.3. Any quantity of unmarketed associated Natural Gas, apart from the quantities used for the Petroleum Operations, shall be utilized in order to improve the Crude Petroleum recovery rate through reinjection pursuant to the provisions of Article 21.4. Flaring shall be limited to the hare minimum; the Contractor is required to comply with the applicable regulations in force and the pertinent recommendations from the Administration.

In addition, if the Government wishes to use the associated Natural Gas produced in the Exploitation Area and not marketed or used by the Contractor in the above-defined conditions, the Parties will decide by mutual agreement on any additional technical actions which may be necessary for the shipment and use of said Natural Gas.

ARTICLE 31

CURRENCY EXCHANGE CONTROL

31.1. The Contract will be governed by the currency exchange regulation in force.

31.2. No restriction will be imposed on importation by the Contractor of the funds intended for the performance of the Petroleum Operations.

31.3. The Contractor will be authorized to freely convert its assets in Gabon to convertible currencies; it will also have the right to export the funds it owns in Gabon in excess of its local needs, without being discriminated against.

31.4. In addition, the Contractor will have the right not to import into Gabon the funds intended for performance of the Petroleum Operations requiring payment to be made abroad when due.

ARTICLE 32

EXEMPTION FROM THE OBLIGATION RELATIVE TO EQUIPMENT BONDS AND INVESTMENT CERTIFICATES

In view of the magnitude of the investments to be made by the Contractor, the latter is exempt for the duration of the Contract from any obligations relative to equipment bonds and investment certificates pursuant to Ordinance No. 3/63 dated January 24, 1963, and Ordinance No. 36/67 dated August 1, 1967.

ARTICLE 33

ACCOUNTING METHOD AND MONETARY UNIT USED FOR BOOKKEEPING PURPOSES

33.1. The Contractor's accounting records and books are kept in accordance with the General Accounting Plan of Companies in effect in Gabon and, regarding Petroleum Costs, with the Accounting Agreement even if the provisions of said Agreement do not appear in the Contract The originals of said accounting records and books as well as all supporting documentation shall be kept in Gabon, and presented to the Administration simply at the latter's request.

33.2. The accounting records and books for the Petroleum Operations are kept by the Contractor in French and amounts are expressed in US dollars. These accounting books and records are used in order to determine the gross income, the exploitation expenditures and net Profits and in order to prepare the tax return. These provisions also apply to the Petroleum. Cost Account mentioned in Article 26.9 and in the Accounting Agreement.

The Contractor must indicate and justify the currency of origin and the exchange rates used for keeping the accounting records and books and the Petroleum Costs Account.

33.3. Whenever it is necessary to convert the expenditures and incomes expressed in another currency into CFA Francs, the exchange rates used will be equal to the arithmetic average of the daily closing market sales rates for said currency for the month in which the expenses were paid and the incomes received. Until the arithmetic average of the month considered is known, *the Contractor will temporarily use the arithmetic average of, the previous month.

In the event of official devaluation or revaluation during a given month, two arithmetic averages will be applied, the first calculated on the basis of the daily closing market sales rates for the period from the first of the month up to, but excluding, the date of said devaluation and revaluation, and the second on the basis of the daily closing selling rates for .the period starting and including the day of said devaluation or reevaluation until the last day of the month considered.

ARTICLE 34

CUSTOMS SYSTEM AND IMPORT AND EXPORT DOCUMENTS

34.1. For the duration of the Contract, the Contractor will benefit from the following customs privileges:

(a) Within the scope of the provisions of the Customs Code, importation by the Contractor itself, Third Parties on its behalf and its subcontractors under the temporary admission system (normal or special, depending on the case) of all the equipment, materials, products, machines and tools required for the performance of the Petroleum Operations and not owned by the state pursuant to the provisions of Article 10.1, subject to the provisions of Article 10.3 and provided that these goods are necessary, exclusively intended and actually used for the Petroleum Operations and are to be re-exported after they are used.

(b) Admission with complete exemption from all entry taxes and duties for materials, products, equipment, machines and tools exclusively intended and actually used for petroleum prospecting and exploration in the Delimited Area and appearing on the list provided in Attachment II of Deed no. 13/65-UDEAC-35, dated Dec ember 14, 1965 and subsequent amendments.

This exemption covers imports made directly by the Contractor itself, by Third Parties on its behalf and by its subcontractors, subject to presentation of a final utilization certificate.

(c) Under the same conditions as above, admission at the comprehensive 5% reduced rate of the duties and taxes collected at importation of materials, products, equipment, machines and tools which, although not falling in the category of goods mentioned in the preceding paragraphs a) and b), are nevertheless necessary for, intended and assigned to the production, storage, processing, transportation, shipping and transformation of Hydrocarbons from the Exploitation Area and provided that they appear in an approved development program.

The reduced rate benefit is granted by the Director of Customs and Indirect Taxes at Contractor's request:

- upon presentation of a general importation program,
- or following a special admission request formalities for the reduced rate benefits to be filed at least fifteen days before arrival of the goods involved.

These requests must specify:

- the trade name of the goods and the corresponding customs tariff code,
- quantities and their FOB and CIF values.

(d) Effects and furnishing for personal and household use imported by Contractor's foreign personnel assigned to the Petroleum Operations at the time of their change of residence are admitted tax free pursuant to the provisions and limits established by the Customs Code, such as Articles 17 to 20 of Deed 13/65-UDEAC-35, dated December 14, 1965.

34.2. The Contractor, Third Parties importing on its behalf and its subcontractors agree to import items required for the performance of the Petroleum Operations only insofar as said goods are not available in Gabon under similar price, quality and delivery schedule conditions.

34.3. All the goods not covered by, the above provisions are subject to the taxes and duties levied by the Customs Administration under the common law system.

34.4. Insofar as they-have met all their customs obligations resulting from Articles 34.1 to 34.3 and the regulations in force, the Contractor, Third Party Importers for its account and its subcontractors, may re-export free of all taxes and duties the goods imported pursuant to the provisions of Article 34.1a, and which are no longer necessary for the performance of the Petroleum Operations.

34.5. All importations, exportations and re-exportations made under the Contract are subject to the formalities required by the Customs Administration.

34.6. The Contractor is jointly and severally responsible with Third Parties importing on its behalf and with its subcontractors towards the Customs Administration for any abuse detected in the exercise of the benefits provided by the provisions of this Article. Any fines, penalties and payments of any nature for which it may be liable in this regard do not constitute Petroleum Costs.

34.7. All customs clearing operations performed within the framework of the Contract are subject to the provisions of Ordinance No. 20/87 of October 24, 1987.

ARTICLE 35

CONTRIBUTION TO MEETING THE NEEDS OF TEE DOMESTIC MARKET

35.1. Contractor is required to contribute to meeting the consumption needs of the Gabonese domestic market by delivering to the State or to an organization designated by the State a quantity of Hydrocarbons in proportion to its production share as defined in Articles 24.2 and 25.1 as compared to the total production of Gabon. The quantity to be delivered will be determined prior to the end of each Calendar Year for the subsequent Calendar Year on the basis of the projected production and domestic consumption for the Calendar Year involved. Any necessary adjustments will be made as soon as the actual final data is available.

35.2. The price for the sale by Contractor of the portion of Hydrocarbons intended to meet the needs of the domestic market is equivalent to the Set Price less a twenty-five percent discount. It is payable in CFA Francs. The aforesaid discount is entered in the Petroleum Costs Account.

35.3. The Hydrocarbons sold under the provisions of this Article are to be delivered by Contractor to the place of use or consumption designated by the Administration, using available and customary means of transportation.

ARTICLE 36

EXPORTING, TRANSFER OF TITLE AND REGULATIONS FOR MAKING THE HYDROCARBONS AVAILABLE

36.1. Subject to the regulations in force and for the entire duration of the Contract, the Contractor, its customers and their carriers shall have the right to export through the export point chosen to this effect, the share of Hydrocarbons to which the Contractor is entitled under the terms of this Contract, after deducting all the deliveries made to meet the needs of the Gabonese domestic market pursuant to the preceding Article 35.

36.2. The ownership of the above-mentioned portion of Hydrocarbons is transferred to the Contractor at the time it actually takes such share. However, as the production 'is taken, the Contractor is required to subscribe to any necessary insurance policies in order to cover any damages or losses which may arise and affect the Hydrocarbons.

For the accounting requirements of the Petroleum Costs, lifting of the above-mentioned Hydrocarbons is presumed to take place at the end of each calendar month for quantities having left during that month the storage facilities for the evacuation pipelines or the export loading facilities.

In case of exportation by tanker, the transfer of ownership takes place at the connection point between the tanker and the loading facilities.

The transfer of ownership of the Hydrocarbons assigned by the Contractor as contribution to meeting the needs of the Gabonese domestic market occurs CIF at the utilization site, at entry of the Storage facilities of the entities to which these Hydrocarbons are allotted.

36.3. The Administration appoints a company or experts to monitor, inspect and control the Hydrocarbon lifts and manage the loading terminal and its facilities.

The expenditures entailed by these operations are reimbursed to the Administration by the Contractor, which includes them in the Petroleum Costs Account.

36.4. The Parties will meet periodically to establish a provisional lifting schedule and will make their best effort to load jointly, if this should prove necessary, in order to avoid Overlifting or Underlifting on the part of one Party towards the other.

As soon as a sufficient quantity of Hydrocarbons is stored at the export point to make it possible to load tankers, the first shipments are made for the account of the State. The Hydrocarbons are then available to the Contractor for the next tanker loading operations for its own account, until an Underlifting situation is created for the State.

Each of the subsequent loading operations shall be carried out for the account of the Party which is in an Underlifting situation.

However, if one of the Parties cannot lift its share of production in a timely manner, the other Party will have the option to dispose of it, provided that it later gives an equivalent quantity of products to the defaulting Party.

The practical terms for application of the provisions of this Article can be negotiated at any time by mutual agreement between the Administration and the Contractor, such as within the framework of a lifting and availability agreement.

ARTICLE 37

PROTECTION OF RIGHTS

37.1. The Contractor will take all the necessary action to achieve the objectives of the Contract and give reasonable compensation to Third Parties for any damage which it, its employees, contractors or subcontractors and their employees, while carrying out their activities under the Contract, may cause to the person, property or rights of Third Parties. The Contractor will be civilly liable for all losses or damages suffered by Third Parties due to its or their errors or negligence and shall bear the cost of all compensation and damages payable.

37.2. The State will take all the necessary and possible actions in order to facilitate the implementation of the Petroleum Operations and the achievement of the objectives of the Contract and to protect the property and rights of the Contractor, its employees and agents on the territory of Gabon and its appurtenances.

37.3. At the Contractor’s request and against justification, the Administration will prohibit the construction of residential or commercial buildings in the vicinity of facilities which may be declared dangerous due to the Petroleum Operations and will take the necessary precautions to prevent vessels from mooring or going near submerged pipelines and to prohibit any interference with the use of any other facilities required for the Petroleum Operations, both onshore and offshore.

ARTICLE 38

PERSONNEL

38.1. For the performance of the Petroleum Operations, the Contractor shall employ, insofar as possible, Gabonese national labor in the minimum proportion of seventy-five percent of the total work force. Specialized and qualified personnel may be recruited outside Gabon if not available in Gabon.

The Contractor shall inform the General Hydrocarbons Department of any available positions and of the action taken towards recruitment of Gabonese personnel.

38.2. The competent Administration will issue, in accordance with regulations, the necessary documents for entry of foreign personnel into Gabon, such as visas, work permits and residence cards. The Contractor will take the necessary measures to this effect.

At the Contractor's request, the Administration may assist to facilitate all immigration formalities with the proper authorities at the entry and exit points in Gabon for the Contractor's employees, contractors, subcontractors and agents and their families.

38.3. The employees working for the Petroleum Operations shall be placed under the authority of the Contractor or of its contractors, subcontractors and agents in their capacity as employers. Their work, working hours, salaries and any other conditions related to their employment conditions will be determined by the above-mentioned employers, in accordance with the labor and social laws in force in Gabon.

38.4. The Contractor must train and take the necessary steps to ensure promotion of its Gabonese employees in close cooperation with the Administration. The Technical Consulting Committee is informed of the procedures for application of application of this provision.

ARTICLE 39

TRAINING OF GABONESE NATIONALS OTHER THAN THOSE EMPLOYED BY THE CONTRACTOR

39.1. In addition to the obligation set forth in Article 38, the Contractor must contribute to the training of other Gabonese nationals designated by the Administration by allocating to said training for the entire duration of the Contract:

(a) sixty thousand US dollars per Calendar Year during the period preceding production;

(b) one hundred thousand US dollars per Calendar Year from the start of production.

The contributions defined in the preceding paragraphs (a) and (b) are allocated:

- a portion for the training of Gabonese nationals in higher level schools or universities of international reputation; the corresponding training program will be determined by the Administration in charge of Hydrocarbons;
- a portion for "on-the-job" training of Gabonese nationals. This training will take place at the Contractor's jobsites and major centers of activity. The conditions of this on-the-job training will be defined in each case by the Parties through mutual agreement;
- a portion for training outside the Contractor's structures, in the form of seminars and assignments to other companies, of Gabonese nationals designated by the Administration.

The terms for distribution of the sums mentioned in this Article will be decided by mutual agreement between the Administration and the Contractor, depending on national priorities.

39.2. The contributions mentioned in this Article are included in the Petroleum Costs.

ARTICLE 40

ACTIVITY REPORTS DURING THE DEVELOPMENT AND EXPLOITATION PERIOD

40.1. Unless otherwise specifically stated, the provisions of Article 11 of the Contract pertaining to the documents and data relative to the exploration operations, the activity reports and other information are applicable *mutatis mutandis* to the development, exploitation and transportation operations.

40.2. The activity reports shall also include a statement of the production obtained during the previous month and a statement of the quantities of Hydrocarbons sold during the same month by the Contractor on its own behalf and, if applicable, on behalf of the State in application of the provisions of Article 25.2, specifying the reference data of the sale contract and, especially, the buyer's name, unit price and total amount of the sale, characteristics of the Hydrocarbons sold and country of final destination.

40.3. The monthly activity reports must also include:

(a) data concerning all the exploitation, development, production and exploitation operations performed during the Calendar Year, including the total quantities of Hydrocarbons produced and sold;

(b) data concerning all transportation operations and the location of any major facilities constructed by the Contractor;

(c) a statement specifying the number of employees, their title, nationality and the total amount of their salaries and wages, as well as a report on the medical services and equipment made available to these employees;

(d) a descriptive statement of all the capital assets acquired or created with the indication of the date and price or cost of acquisition.

40.4. Each entity forming the Contractor will also transmit to the Administration in charge of Hydrocarbons by April 30 of each year a copy of its statistical and tax declaration mentioned in Article 26.5 and information and documentation and data to be attached.

40.5. The Contractor will notify the Hydrocarbons Administration in writing, as promptly as possible, of any damage of any nature whatsoever caused to the Fields or to the production facilities and will take all necessary action to terminate and repair said damage.

40.6. The provisions of Article 11.5 are applicable, *mutatis mutandis*, to any document or sample connected with the development, exploitation and transport operations and the Parties are subject to the same obligations.

ARTICLE 41

PAYMENTS

The proceeds from Hydrocarbons sales made by either of the Parties for the account of the other must be remitted within thirty days following the date of the lift, unless otherwise agreed between the Parties in consideration of specific marketing conditions.

Any other payment to the State must be made when due unless otherwise provided in the Contract.

Hydrocarbons transfers to the State made within the framework of contribution to the requirements of the domestic market as mentioned in Article 35 are paid for within thirty days and, in the event of difficulties, within ninety days after the delivery date.

ARTICLE 42

ASSIGNMENT OF INTERESTS

42.1. Each one of the companies forming the Contractor may assign all or part of its interests deriving from the Contract to Third Parties, if their good technical and financial reputation is well-established; the assignees will then become jointly and severally responsible, with the other companies forming the Contractor, for fulfillment of the clauses of the Contract. The assignor’s rights and obligations related to the portion of interest thus assigned are fully transferred to the assignees.

Nevertheless, after start-up of production, the State has a preference right on the above-mentioned assignments under the conditions of and in accordance with the procedures described below. It then replaces Third party buyers at the same terms and conditions.

42.2. Before an assignment to Third Parties goes into effect, the assignor must obtain the approval of the Administration. This approval cannot be withheld without valid reasons. To this effect, it is required to inform the Administration in writing, specifying the names, capacities and nationalities of the buyers, all data regarding their financial and technical capabilities, their legal status in addition to the financial terms and procedures of the assignment-planned, and to deliver a certified copy of the assignment agreement, signed and executed subject to the suspensive condition of approval by the Administration or waiver on the part of the State to exercise the preference right described in Article 42.1.

If the Administration does not oppose the assignment in writing within thirty days after the date of receipt of the above information and if the State does not exercise its preference right stated in Article 42.1 within the same 30-day period, this approval is considered granted.

42.3. If, due to partial assignment of its interest, the assignor earns a financial profit, this will be deducted from the Petroleum Costs. If the assignment pertains to all its interests, the assignor is subject under common law to Corporate Tax on the amount of this profit.

For application of the preceding paragraph, the term “financial profit” refers to the difference, if positive, between the assignment price and the non-reevaluated amount of the Petroleum costs not yet recovered by the assignor and computed, in the case of partial assignment, proportionally to the percentage interests assigned. The assignor communicates to the Administration all information of such nature as to enable the latter to determine this profit.

When, in the case of partial assignment, the price obtained is less than the share of unrecovered Petroleum Costs pertaining to the assigned interest, the assignor records a decrease in its accounting of said share of Petroleum Costs it loses any right to recover the negative difference involved.

The assignee enters in its accounting records the Petroleum Costs not recovered by the assignor pertaining to the interest acquired or the actual acquisition price if this is less than said Petroleum Costs not recovered by the assignor.

The assignee cannot in any case include in the Petroleum Costs the cost thereby incurred, corresponding to this profit and paid to the assignor.

42.4. Each company forming the Contractor may assign freely and at any time all or part of its interests deriving from the Contract, to one or more Affiliates or to other companies forming the Contractor. However, the assignor is required to inform the Administration in writing. These assignments must not in any case be such as to harm the State’s interests, hinder performance of the Petroleum Operations or reduce the technical and financial capabilities of the Contractor. If the Administration deems such to be the case, it may oppose the assignment. Furthermore, the commitment stated in Article 46.2 involves automatically the assignee Affiliated Company.

The provisions of Article 42.3 are applicable to the assignments made within the framework of this Article.

42.5. Any assignments made in violation of the provisions of Articles 42.1 through 42.4 are null and void.

ARTICLE 43

APPLICATION OF THE CONTRACT

43.1. Subject to the provisions of Article 43.4, the State guarantees to the Contractor for the duration of the Contract the stability of the financial and economic conditions, such as these conditions result from the Contract and from the regulations in force on the Effective Date.

The obligations resulting from the Contract shall not be aggravated and the general and overall equilibrium of this Contract shall not be affected in an important and lasting manner for the entire period of validity hereof. However, adjustments and modifications may be agreed upon by mutual consent.

43.2. The Parties agree to cooperate in all possible ways in order .to achieve the objectives of the Contract. The Administration will facilitate the performance of the Contractor's activities by granting it any necessary permit, license and access right and making available to it all the appropriate existing facilities and services, so that the Parties can obtain the best possible profit from sincere cooperation. However, the Contractor shall comply with the customary procedures and formalities and directly contact the competent Administration departments to obtain the approvals and authorizations necessary. It must inform the Departments in charge of Hydrocarbons of the formalities, contacts and correspondence it has and maintains with other administrative departments.

43.3. Total or partial nationalization or expropriation of the Contractor's rights entail just and equitable compensation in accordance with internationally accepted rules and principles.

43.4. The terms and conditions of the Contract shall be modified only in written form and through mutual agreement.

ARTICLE 44

PENALTIES AND TERMINATION

44.1. Violation by the Contractor of the provisions of the Contract may entail termination of the Contract by the Administration if, after notification with acknowledgment of receipt to the Contractor, pursuant to the provisions of Article 48.10., second paragraph to correct said violation and, if applicable, the consequences thereof, the Contractor has not given any follow-up to the Administration's request. Termination is pronounced by Decree.

44.2. Independently of the penalties set forth in the regulations, the following violations of the Contract will lead to termination of this Contract by decree, after formal notice remaining without action fifteen days after its receipt. Contractor will be required to provide some explanations:

(a) refusal to provide to the Administration within the Prescribed periods the information specified in Articles 5, 8.7, 11, 20.1, 21.1, 21.5, 26.5, 26.9, 33, 40 and 48.

(b) refusal to pay the bonuses and royalties-within the required periods of time in the terms and conditions defined by Articles 26.1 b, 26.1 c and 28, as well as the sums stipulated in Article 39.1.

(c) refusal to pay within the required periods of time the Proceeds from sale by the Contractor of the State's share of Hydrocarbons, when the Contractor handles said sale, pursuant to the provisions of, Articles 25.2.

(d) refusal to deliver to the State its share of production in kind, pursuant to Article 25.2 or of the mining royalty pursuant to the provisions of Article 26.1, b;

(e) suspension or serious restriction, without legitimate reason and in a manner prejudicial to the general interest, of the exploitation activity of the Fields discovered in the Delimited Area.

For the application of this paragraph and preceding provisions, modification related to economic factors, such as variations in the international Hydrocarbons market cannot be invoked as constituting a legitimate reason.

44.3. The Administration's decision to terminate the Contract, under the provisions of Articles 44.1 and 44.2, is communicated to the Contractor in writing with return receipt; the latter automatically forfeits all its interests deriving from the Contract and its right to recover its Petroleum Costs.

44.4. Termination of the Contract does not release the Contractor from its contractual obligations arisen prior to termination of the Contract which may not yet have been met on the date of said termination.

ARTICLE 45

OPERATIONS ON BEHALF OF THE STATE

45.1. If, during the exploration periods defined in Article 3, the State wishes to survey and test deeper geological horizons than those proposed by the Contractor or indicated in Article 4 for a given well, it will have the right to ask the Contractor to continue drilling said well until the objectives set by the State have been reached, at its exclusive expense and risk. To do so, the Administration will address a written request to the Contractor insofar as possible prior to the start of said well or, if this is impossible, during the drilling, but in no case after the Contractor has started completion or abandonment operations on the well.

The above-mentioned request will establish the period of time beyond which the Contractor is considered as having refused.

The State can also contract, at its own risk, a third company to deepen a well under conditions that it is free to establish and for the account of the State.

45.2. The Contractor may decide, before the start of the well-deepening operations, to take charge financially of said deepening operations, in which case the corresponding expenses are included in the Petroleum Costs and any Hydrocarbon discovery-resulting from these well deepening operations will be considered made within the framework of fulfillment of the Contract.

45.3. If the deepening of a well at the exclusive expense and risk of the State leads to a discovery of Hydrocarbons, the State alone will have the right to develop and exploit the discovery and dispose of all the Hydrocarbons produced.

ARTICLE 46

JOINT LIABILITY AND GUARANTEES

46.1. The clauses of the Contract are binding for the Parties and their respective successors and assigns. They constitute the only agreement between them, no prior verbal or written promise or agreement between the Parties pertaining to the purpose of the Contract can be invoked in order to modify them or to give them a different interpretation.

The State guarantees that no other agreement exists concerning the Petroleum Operations in the Delimited Area.

46.2. Each of the entities comprising the Contractor will have the option to perform the Petroleum Operations through a subsidiary or 'a branch registered in Gabon and created to this effect. If the signatory of the Contract is a subsidiary thus created, the parent company of the signatory will give to the Administration, prior to signature, a commitment, in accordance with the sample enclosed with the Contract, guaranteeing proper performance by said subsidiary of the obligations under the Contract.

In case of assignment, the commitments thus assumed by the signatories' parent companies will be replaced, regarding the rights assigned, by identical rights of the assignees' parent companies whose good financial and technical reputation is well established; failing this, the assignment is considered null and void.

ARTICLE 47

FORCE MAJEURE

47.1. No delay or failure by one Party to fulfill or comply with any of the clauses, or obligations of this Contract will be considered as a breach of said Contract if said delay, or failure, is due to a case of Force Majeure. The duration of the resulting delay and such period as is necessary to repair any damage caused during or by said delay will be added to the duration set by Contract, if applicable.

47.2. Force Majeure means any unforeseeable, unsurmountable and irresistible event, not due to error or negligence by the Parties, but to circumstances independent of their will.

ARTICLE 48

AUDITS, VERIFICATIONS AND CONTROLS

48.1. The Administration has the authority to exercise overall verification of all the Petroleum Operations; to this effect, it has right to communication of anything which is directly or indirectly connected with said Petroleum Operations.

The Administration's representatives may inspect, check and verify all the phases of the Petroleum Operations and, specifically, they may be present during the well tests. To this effect, the Contractor is required to furnish all the necessary assistance to the persons designated by the Administration and to facilitate their tasks.

After the inspections, checks and controls of the Petroleum Operations, the Administration may require that the Contractor perform any operation which the Administration may deem necessary in order to ensure safety and hygiene at the work sites, in the interest of both Parties.

The State, in its capacity as Contracting Party, and the entities forming the Contractor included under the provisions of Article 19, may undertake, at their cost, through experts of their choice or their own employees, all the accounting, financial or technical examinations, verifications and audits which they may deem necessary or useful for their information on the management and development of the Contractor's activities, on the technical methods thereby employed and on the Petroleum Costs, as well as in the exercise of their right to examine, check and audit these activities and the corresponding Petroleum Costs.

Within the framework of the above-mentioned examination, verifications and audits, the Contractor may be asked, in accordance with the procedure set forth in Article 48.10, to make any adjustments, corrections, amendments or modifications which are deemed necessary, useful or justified.

48.2. The above-mentioned examinations, verifications and audits must take place within a period of two years after the end of the exploration periods specified in Article 3, or, in the development and production phase, for a given Calendar Year, within the same two-year period after the end of said Calendar Year.

The Contractor is notified by the Administration of the conclusions and results of the examinations, verifications and audits thereby conducted.

48.3. A certified copy of the reports and conclusions following these examinations, verifications and audits must obligatorily be delivered to the Administration when these are conducted by the companies forming the Contractor. The Operator or the companies forming the Contractor are required to inform the Administration of the follow-ups given to the conclusions and recommendations of the reports prepared after the examinations, verifications and audits conducted.

48.4. Without any examinations, verifications and audits within the periods specified in Article 48.3, first paragraph, no adjustment may be made later.

48.5. Notwithstanding the above provisions, the Administration may also, within the normal context of its right to verification and repetition, such as set forth by the applicable regulations, conduct at any time examinations, verifications and audits through experts of its choice or its own employees.

48.6. For application of the provisions of this Article, the Contractor shall deliver to the Administration, not later than April 30 of each year, a detailed report on its activities of the preceding Calendar Year. This report shall include specifically, in addition to data of a technical nature, a detailed account of the Petroleum Costs pertaining to that Calendar Year, presented in accordance with the Accounting Agreement. The Contractor' files, as well as the pertinent and necessary records, accounting and technical documents and vouchers shall be available to the interested Parties in compliance with the above provisions, and presented at their request or requisition.

48.7. The expenses incurred by the Administration in connection with examinations, verifications and audits conducted in application of the provisions of the above Articles are borne by or, if applicable, reimbursed by the Contractor and included by the latter in the Petroleum Costs.

48.8. Subject to the prescription periods of time set forth by the applicable regulations and by the Contract, and notwithstanding the provisions of Article 48.2, the Administration may request in writing all information, justifications and clarifications, as well as any documents, reports, studies and accounting, financial, legal and technical records which it may deem necessary or useful for its information on the management and development of the Contractor's activities and on the Petroleum Costs, as well as for the exercise of its right to examine, check and audit these activities and the Petroleum Costs.

48.9. If the Administration considers, on the basis of the data and information available thereto or thereby secured either from the Contractor itself or from Third Parties, that the reports, files, documents and accounting records contain errors, inaccuracies, gaps or missing elements or that the Contractor has made a mistake or committed an irregularity in the fulfillment of its obligations and if it considers that corrections, adjustments, amendments or modifications should be made, the Administration shall notify the Contractor in writing to this effect within the time frame required by law.

The Contractor has then thirty days counted from the date of receipt of the above-mentioned notification, to make the corrections, adjustments, amendments or modifications requested or to present its comments, either in writing or by requesting a meeting to this effect with the Administration. If necessary, the Contractor may obtain, at its request, an additional period for making the corrections, adjustments, amendments or modifications requested by the Administration.

The Administration shall notify the Contractor in writing of its position on the corrections, adjustments, amendments or modifications requested and on the explanations and justifications furnished.

If, after completion of the above procedure, a disagreement still exists between the Administration and the Contractor, the dispute is settled by arbitration in accordance with the provisions of Article 49.

Nevertheless, for differences of a technical nature and prior to the arbitration procedure, the Parties may resort to the opinion of an expert selected through joint agreement. The above-mentioned periods are then extended accordingly.

48.10. The notifications and other communications specified in the Contract are considered as given by a Party when they are delivered into the hands of a qualified representative of the other Party, at its domicile elected in Gabon, sent by telegram, cable, telex or other means of telecommunication, all expenses paid, or placed in an envelope and entrusted, as registered mail with the proper postage, to the Postal Administration of Gabon. The notifications and other communications shall be considered as made on the date of receipt by the addressee.

ARTICLE 49

ARBITRATION

49.1. If, after completion of the procedure set forth in Article 48.10, any disputes still exist between the Parties in connection with the application of the clauses of the Contract or regarding the obligations resulting therefrom shall be resolved through arbitration and, subject to the provisions hereinbelow, pursuant to the Conciliation and Arbitration Regulations of the International Chamber of Commerce.

The arbitration procedure is instituted by request addressed by the applicant Party to the Secretary of the Arbitration Court within sixty days following expiration of the thirty day period defined in Article 48.10; 4th paragraph, plus, if applicable, the additional period defined in the same fourth paragraph of said Article. The starting point of proceedings is the date of receipt of the aforesaid request by the Secretary of the Arbitration Court.

Each Party designates its arbitrator and notifies the other Party and the Arbitration Court of that designation within thirty days after the start of the arbitration proceedings as defined above.

If, at the end of this period, the applicant Party has not designated its arbitrator, it is deemed to have renounced its request. If the defending Party has not designated its arbitrator by the end of the same period, the other Party may directly inform the Arbitration Court of the International Chamber of Commerce and request that it make the said designation within the shortest possible time.

The arbitrators shall not be of the same nationality as that of any of the Parties.

Within forty-five days after the date of designation of the last of them, the arbitrators thus designated select a third arbitrator, who becomes the President of the Arbitration Court. Failing agreement, the Arbitration Court of the International Chamber of Commerce is requested by the more diligent Party to make said designation within the shortest possible time.

The arbitrators are free to choose the procedure they intend to apply.

The decision of the arbitrators is final; it is binding on the Parties and is immediately enforceable.

49.2. The place of arbitration will be Paris, France. The arbitration language will be French, the applicable law will be the law of Gabon, and the clauses of the Contract are interpreted by reference to Gabonese law.

49.3. Each party bears the expenses and the fees of its own arbitrator. The expenses and the fees of the third arbitrator as well as the other expenses related to the arbitration will be borne equally by the Parties.

49.4. The arbitration procedure does not cause the execution of the Parties' contractual obligations to be suspended during the progress of the arbitration.

ARTICLE 50

EFFECTIVE DATE

The Contract will be approved by Decree. The Effective Date will be the date of signature of the Contract. In witness whereof, the Parties have signed the Contract in ten duplicate originals.

Libreville, July 7, 1995

By: /s/ Paul Toungui
Name: PAUL TOUNGUI
Title: The Minister of Mines, Energy and Petroleum

By: /s/ Charles W. Alcorn, Jr.
Name: Charles W. Alcorn, Jr.
Title: Chief Executive Officer for Vaalco Gabon (Etame), Inc. and Vaalco Energy (Gabon), Inc.

By: /s/ Marcel Doupamby Matoka
Name: MARCEL DOUPAMBY MATOKA
Title: The Minister of Finance, Economy, Budget and Joint Ventures

ANNEXE Nº 1

ZONE DELIMITEE

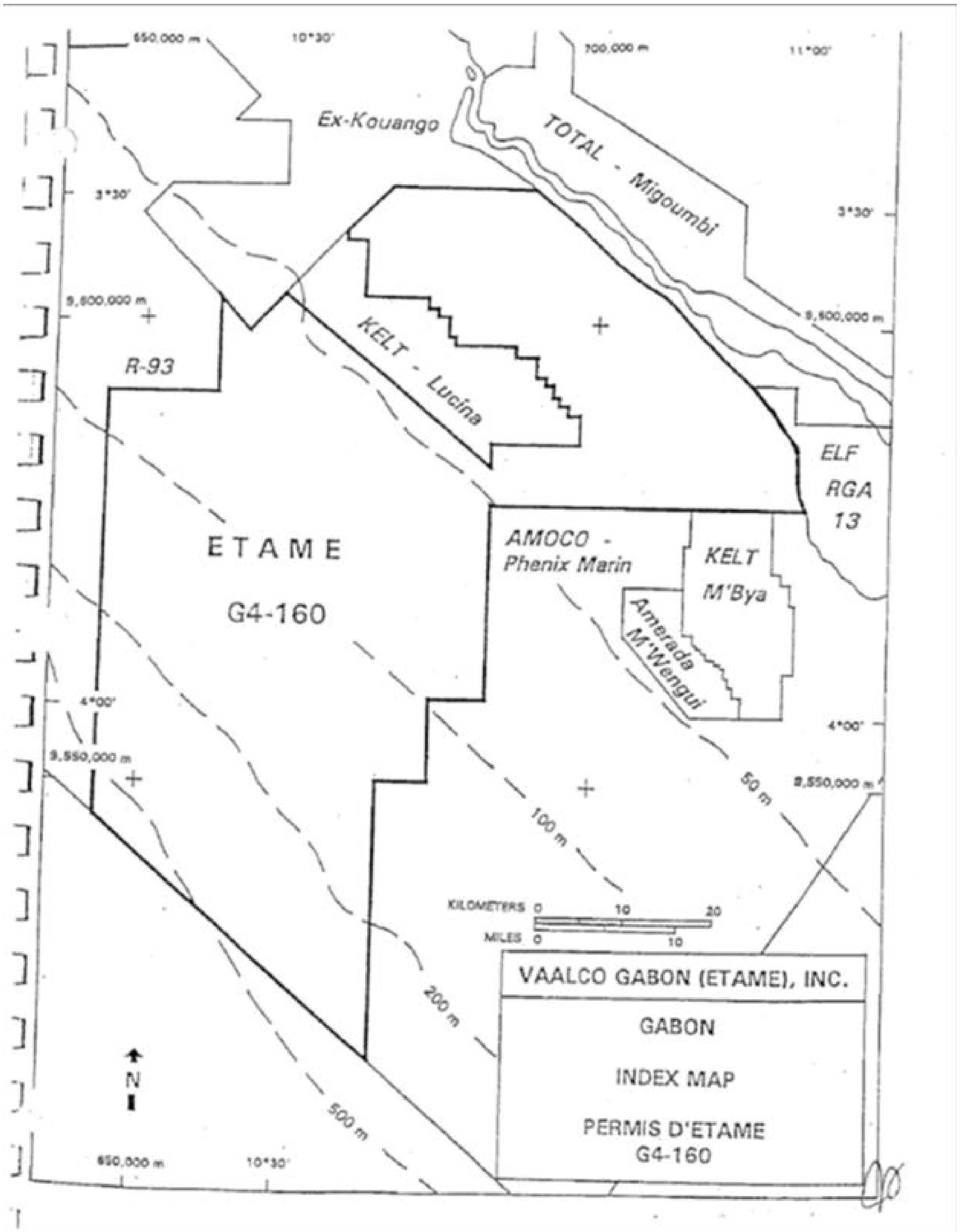
La Zone Délimitée d'ETAME dont les limites sont définies comme suit, les coordonnées étant données dans le système de projection UTM, base sur l'ellipsoïde de Clarke 1880, fuseau 32, ayant pour origine le point M'PORALOKO, avec:

X = 500'000 mètres sur le meridian central 9º 00' 00" EST;

Y – 10'000'000 mètres sur l'équateur

	X	Y		X	Y
A	659,500	9,600,500	W	683,000	9,598,000
B	659,500	9,590,500	X	684,000	9,598,000
C	645,500	9,590,500	Y	684,000	9,597,000
D	645,500	9,546,189	Z	691,000	9,597,000
E	676,500	9,519,916	Z1	691,000	9,596,000
F	676,500	9,550,000	Z2	693,000	9,596,000
G	681,500	9,550,000	Z3	693,000	9,594,000
H	681,500	9,558,500	Z4	694,000	9,594,000
I	688,000	9,558,500	Z5	694,000	9,593,000
J	688,000	9,580,000	Z6	695,000	9,593,000
K	723,600	9,580,000	Z7	695,000	9,592,000
L	690,600	9,614,000	Z8	696,000	9,592,000
M	676,535	9,614,000	Z9	696,000	9,591,000
N	672,000	9,609,429	Z10	697,000	9,591,000
O	672,000	9,608,000	Z11	697,000	9,590,000
P	673,000	9,608,000	Z12	698,000	9,590,000
Q	673,000	9,602,000	Z13	698,000	9,586,000
R	681,000	9,602,000	Z14	688,000	9,586,000
S	681,000	9,601,000	Z15	688,000	9,583,800
T	682,000	9,601,000	Z16	683,000	9,588,000
U	682,000	9,600,000	Z17	665,091	9,602,240
V	683,000	9,600,000	Z18	661,498	9,598,502

La superficie de la Zone Délimitée est donc repute à 3,073.598 km^2



650,000 m
10°30'
700,000 m
11°00'
Ex-Kouango
TOTAL - Migoumbi
3°30'
3°30'
9,600,000 m
9,600,000 m
KELT - Lucina
R-93
ELF
RGA
13
ETAME
G4-160
AMOCO -
Phenix Marin
KELT
M'Bya
Amerada
M'Wengui
4°00'
4°00'
9,550,000 m
9,550,000 m
50 m
100 m
KILOMETERS 0 10 20
MILES 0 10
200 m
500 m
N
650,000 m
10°30'
VAALCO GABON (ETAME), INC.
GABON
INDEX MAP
PERMIS D'ETAME
G4-160

EXHIBIT B
TO
PARTICIPATION AGREEMENT
SUMMARY OF ETAME PERMIT WORK PROGRAM AND BUDGET
EFFECTIVE DATE THROUGH JUNE 30, 1998
(SUMMARY OF ESTIMATED COSTS)

Acquisition and processing of 300 km. 2D and 385 sq. km. 3D seismic survey	$3,000,000
Drilling, logging and testing of one exploratory well in accordance with Article 4 of the Contract	$6,800,000
Geological, geophysical and reservoir engineering studies	$400,000
Reprocessing of existing 2D seismic data	$270,000
General and administrative	$500,000
Overhead	$329,100
TOTAL	$11,299,100

Exhibit 10.6

AMENDMENT No. 5

TO THE

EXPLORATION AND PRODUCTION

SHARING CONTRACT

"ETAME MARIN NO. G4-160" PERMIT

AMENDMENT NO. 5
TO THE EXPLORATION AND PRODUCTION SHARING CONTRACT
"ETAME MARIN NO. G4-160"

BETWEEN

The STATE OF GABON represented by

Mr. **Etienne Dieudonné Ngoubou,** Minister of Oil and Hydrocarbons, and Mr. **Régis Immongault,** Minister of the Economy, the Promotion of Investments and Forecasting,

hereinafter referred to as "the State,"

as the first party

AND

VAALCO GABON (ETAME), Inc., a Delaware (USA) corporation, headquartered in Houston, Texas, 77042, United States of America, 9800 Richmond Avenue, Suite 700, represented by Mr. Cary Bounds, Chief Executive Officer, having full powers for purposes of this Agreement,

as the second party.

The State of Gabon and VAALCO GABON (Etame), Inc. are hereinafter collectively referred to as "Parties" and individually "Party."

Recitals:

The State of Gabon and VAALCO GABON (ETAME), Inc. signed an Exploration and Production Sharing Contract named "Etame Marin No. G4-160," concerning liquid and gas hydrocarbons on July 07, 1995, hereinafter "Contract";

Decree no. 0001513/PR/MMEP/DGEEH of December 12, 1995 established a liquid and gas hydrocarbon exploration permit named "Etame Marin No. G4-160," and approved the related Exploration and Production Sharing Contract;

By Decree No. 00043/MMEPRH of July 17, 2001, an Exclusive Exploitation Authorization liquid and gas hydrocarbons named "Etame Marin No. G5-88" was established and granted to VAALCO GABON (ETAME), Inc., in accordance with the provisions of Article 16.4 of the of Exploration and Production Sharing Contract named "Etame Marin No. G4-160;

By Decree No. 000839/PR/MMEPRH of November 22, 2004, the Exclusive Exploitation Authorization liquid and gas hydrocarbons "Etame Marin G4-160" was renewed for a fourth period of two (02) years;

By Decree No. 0000293/PR/MMEPRH of March 25, 2005, an Exclusive Exploitation Authorization liquid and gas hydrocarbons was established and granted, in accordance with the provisions of article 16.4 of the (EPSC) "Etame Marin no. G4-160," to VAALCO GABON (ETAME), Inc. for a period of ten (10) years known as "AVOUMA No. G5-95," renewable at the request of the Contractor;

By Decree No. 0000623/PR/MMEPRH of June 20, 2006, an Exclusive Exploitation Authorization for liquid and gas hydrocarbons named "EBOURI No. G5-98" was assigned and granted to VAALCO GABON (ETAME), Inc. in accordance with the provisions of Article 16.4 of the "Etame Marin no. G4-160" EPSC;

By Amendment No. 1 dated July 07, 2001, Articles 3.3, 4, 21.7, 28 and 39 of the "Etame Marin G4-160" Exploration and Production Sharing Contract were amended;

By Amendment No. 2 dated April 13, 2006, Articles 3.3, 4, 21.7, 28 and 39 of the "Etame Marin G4-160" Exploration and Production Sharing Contract were supplemented and replace the provisions of Amendment No. 1;

By Amendment No. 3 dated November 26, 2009, Article 14was amended and Articles 4 and 21 were supplemented;

By Amendment No. 4, Article 14 was amended and Article 26.1b was supplemented.

By letter to the State dated January 10, 2015, the Contractor submitted a request for the renewal of "AVOUMA No. G5-95" Exclusive Exploitation Authorization in accordance with Article 16.4 of the "ETAME MARIN No. G4-160" EPSC;

The State wishes to make substantial modifications to the "ETAME MARIN No. G4-160" EPSC;

NOW, THEREFORE, THE PARTIES AGREE AS FOLLOWS:

Article 1: PURPOSE

The purpose of this Amendment is to modify and to supplement the provisions of Articles 21 and 35 of the "Etame Marin no. G4-160" Exploration and Production Sharing Contract.

Article 2: EXPLORATION PERIODS

Article 3.3 of the Contract is modified to read as follows:

"If the Contractor has satisfied its obligations deriving from the Contract, if necessary based on Article 3.2, during the second period, in particular concerning its work commitments as defined in Article 4, the Exclusive Exploration Authorization shall be renewed for a third period of three Contractual Years upon its request.

The third period may also be extended for a maximum of three months for the same reasons and under the same conditions as those stated in Article 3.2.

The Contractor shall submit its renewal request for the third period at least thirty days prior to expiration of the second period. The renewal shall be granted by order of the Minister of Hydrocarbons.

If the Contractor has met its obligations derived from the Contract, in particular with regard to its work commitments, during the third period, which may be extended, the Exclusive Exploration Authorization, upon its request, shall be renewed for a fourth period of two Contractual Years applicable to a surface area of the Delimited Area reduced by 50% of the remaining surface area. The surface area thus released shall be of simple shape and shall have terrestrial lines of latitude and longitude as its limits.

The fourth period may also be extended for a maximum of three months for the same reasons and under the same conditions as those indicated above.

The Contractor shall submit its renewal request for the fifth period at least thirty days prior to expiration of the fourth period. The renewal shall be granted by order of the Minister of Hydrocarbons.

If the Contractor has satisfied its obligations resulting from the Contract, in particular concerning its work commitments during the fourth period, which may be extended, the Exclusive Exploration Authorization, upon its request, shall be renewed for a fifth period of three (03) Contractual Years for a surface area of the Delimited Area.

The fifth period may also be extended for a maximum of three months for the same reasons and under the same conditions as those indicated above.

If the Contractor has satisfied its obligations resulting from the Contract, in particular concerning its work commitments as defined in Article 2 of this Amendment during the fifth period in accordance with this Amendment, the Exclusive Exploration Authorization, upon its request, shall be renewed for a sixth period of five Contractual Years for the entire Delimited Area.

The sixth period may also be extended for a maximum of three months for the same reasons and under the same conditions as those indicated above.

The Contractor shall submit its renewal request for the sixth period at least thirty days prior to expiration of the fifth period.

If the Contractor was granted the extension indicated in Article 2 of this Amendment, the aforesaid thirty-day extension begins as of the end of this extension in order to enable it to examine and evaluate the results of the work and to assess the interest in presenting a renewal request.

The renewal shall be granted by an order of the Minister of Hydrocarbons."

It is acknowledged that all exploration work commitments and periods set forth in Article 3.3 above have already been completed and performed by the Contractor.

Article 3: WORK COMMITMENTS

Article 4.2 of the Contract is amended to read as follows:

"*During the sixth Exploration period defined in Article 3.3 above, the Contractor shall carry out the following minimum work:*

- drill two firm wells;
- acquire 150 km^2 of 3-D seismic.

The Contractor shall invest an amount estimated at USD 17,500,000 in order to carry out this work program under the generally accepted international hydrocarbon industry practices."

It is hereby acknowledged that the obligations set forth in Article 4.2 above have already been completed and performed by the Contractor.

Article 4: SITE REMEDIATION

Article 14 of the Contract is modified by the addition of new paragraphs 14.4, 14.5, 14.6, 14.7, 14.8, 14.9, 14.10, 14.11, 14.12, 14.13, 14.14, 14.15, 14.16, 14.17, 14.18.1, 14.18.2, 14.18.3, 14.18.4, 14.18.5, 14.18.6, 14.18.7, 14.18.8, 14.19, 14.20.

"14.4 For Petroleum Operations having an environmental impact, the Contractor shall ensure the following during these operations:

a. conservation of the natural resources of Gabon and the protection of its environment;

b. the use of methods in accordance with the rules of art in practice in the oil and gas industry intended to prevent or at least to mitigate possible damage to the environment;

c. the application of programs for pollution prevention, waste processing, safeguarding natural resources, restoration, and remediation of land and offshore zones damaged as a result of Petroleum Operations.

14.5 The Contractor shall undertake all appropriate and necessary actions to:

a. *compensate third parties for damages they have sustained or damages caused to their property as a result of Petroleum Operations;*

b. *minimize damage to the environment within the Delimited Area and neighboring areas.*

14.6 If the Contractor does not comply with the terms of paragraph (b) of article 14.5 or violates any environmental protection laws and if this non-compliance or this violation results in damages to the environment, the Contractor shall take the required necessary and reasonable actions to remedy this non-compliance or this violation and the resulting effects.

14.7 If the Hydrocarbons Department determines that the work or the facilities set up by the Contractor exposes or may expose people or their assets to risk, cause environmental pollution or endanger fauna to a degree that the Hydrocarbons Department considers to be unacceptable, it shall order the Contractor to take measures to remedy the damage it has caused as soon as possible and may even require it to completely or partially suspend Petroleum Operations until appropriate actions are taken to remedy the damage it has caused.

14.8 The measures to be taken by the Contractor to comply with the terms of Paragraph (b) of Article 14.5 shall be determined in agreement with the Hydrocarbons Department at the beginning of the operations or upon any change of objectives or work methods. The Contractor shall take account of the applicable international rules and standards in similar circumstances. An impact study shall be performed in accordance with Article 14.9.

The Contractor shall inform the Hydrocarbons Department in writing of the measures ultimately selected and shall ensure that said measures are periodically reassessed according to the prevailing conditions.

14.9 For this purpose, the Contractor shall commission an organization or a company internationally recognized for its knowledge of environmental issues to conduct two environmental impact studies in order to:

- determine the prevailing situation concerning the environment, human beings, land and marine fauna within the Delimited Area and in the neighboring areas at the time the studies are conducted;

- establish the effects on the environment, human beings, land and marine fauna within the Delimited Area as a result of Petroleum Operations performed within the scope of the Contract and propose the measures and methods established in Article 14.8 that may mitigate damage to the environment and restore sites within the Delimited Area.

14.10 The first study shall consist of two parts:

- a preliminary part to be performed before all seismic operations;

- a second part to be performed before all drilling operations.

14.11 The second study shall be completed before the start of production operations and shall be submitted to the Administration by the Contractor at the same time as the development plan.

14.12 The studies mentioned in Article 14.9 shall include instructions regarding environmental protection that are to be undertaken in order to mitigate damages to the environment and shall in particular address the following points:

a. selection of drilling sites;

b. mud and cuttings resulting from drilling;

c. cementing of casings;

d. protection of the water tables;

e. blowout prevention plans;

f. gas flaring during testing and oil well compression phases;

g. relinquishing wells;

h. dismantling rigs;

i. fuel storage and transportation;

j. use of explosives;

k. living accommodations;

l. sites for storing liquid and solid waste;

m. fauna and its habitat;

n. noise control.

14.13 The Contractor shall ensure that:

a. Petroleum Operations are performed under acceptable environmental protection conditions and in accordance with the rule of the and international hydrocarbons industry practices;

b. environmental impact studies of Petroleum Operations are made available to the Contractor's employees and its subcontractors in order to heighten their awareness of the methods and measures to be taken in performing Petroleum Operations;

c. any Contract signed between the Contactor and its subcontractors related to Petroleum Operations takes into account the environmental protection clauses within this Contract;

d. all precautions are taken to prevent ocean pollution in accordance with the International Convention for the Prevention of Pollution from Ships signed on November 2, 1973 and the International Convention for the Prevention of Pollution of the Sea by Oil signed on May 12, 1954, and related amendments and implementing texts. The State may decide on all additional measures to ensure preservation of the offshore area.

14.14 Before undertaking any drilling operations, the Contractor shall prepare a prevention plan and, if necessary, a plan for combating possible oil spills and fires and shall submit it to the Hydrocarbons Department.

14.15 In the event of:

a- an emergency or accident resulting from Petroleum Operations that affects the environment, the Contractor shall promptly inform the Hydrocarbons Department and shall establish appropriate measures commonly allowed in the Hydrocarbons International Industry;

b- fire or an oil spill, the Contractor shall immediately execute the emergency plan it shall have prepared and approved by the Hydrocarbons Department.

14.16 If the Contractor does not comply with the terms in Article 14 of this Contract, the Hydrocarbons Department shall take measures to ensure compliance therewith. In this event, the Contractor shall assume the costs inherent to such measures.

14.17 The Contractor shall perform the following operations upon expiration of the Contract or after relinquishment of the exploited area:

a- remove all the equipment and facilities it has installed within the scope of Petroleum Operations. This removal shall be performed according to a relinquishing schedule and plan accepted by the Hydrocarbons Department as described below;

b- restore the sites in accordance with the rules of art and accepted International Hydrocarbons Industry practices and take any action to prevent all risks to which people, property or the environment may be exposed.

The Operations described in this Article shall hereafter be referred to as "Site Remediation Operations."

The Administration shall issue a decree terminating the contractual obligations of the Contractor and releasing it from liability within six months of performing the Site Remediation Operations and related obligations.

In order to relinquish a Field upon normal expiration of the Exclusive Exploitation Authorization, including the possible renewals thereof, or in the event of its relinquishment for reasons duly justified according to the provisions of Article 18.2 of this Contract, the Contractor shall notify its intention to relinquish the Exploitation Area and shall submit a technical shutdown report in accordance with the terms and conditions described in Article 14.20 herein below to the Hydrocarbons Department at least one hundred and eighty (180) days prior to the end of Petroleum Operations.

14.18.1. In order to cover the expenses for Site Remediation Operations that are incumbent upon it upon normal expiration of the Exclusive Exploitation Authorization, including any renewals, or in the event of relinquishment for duly justified cause according to the provisions of Article 18.2 of this Contract, the Contractor shall establish a fund for each Exploitation Area, when a field begins production, into which it shall annually pay at least five percent (5%) of the estimated cost of relinquishment and dismantling of the facilities that are normally required at the end of exploitation as agreed by the parties for each Exploitation Area (i) with regard to Exclusive Exploitation Authorization G5-88 ("Etame") in progress, renewed for five (5) years as of July 17, 2011, and during any renewal of Exclusive Exploitation Authorization G5-95 ("Avouma") and Exclusive Exploitation Authorization G5-98 ("Ebouri"), and any renewal, and (iii) <sic> *any other Exclusive Exploitation Authorization granted for a renewable term of ten (10) years. At the Contractor's discretion, the amount paid in accordance with this paragraph may exceed the minimum specified in the preceding sentence.*

14.18.2. With regard to the Exclusive Exploitation Authorization effective at the time of this Agreement, the Contractor must pay the following into the account referred to above, in addition to what it agrees to pay annually in accordance with the above Article 14.18.1:

- Each year, between January 1, 2012 and December 31, 2018, i.e. for seven (7) years, an amount equal to one fourteenth (1/14) of the estimated cost of relinquishment and dismantling the facilities, which are normally required to be removed or converted at the end of exploitation as agreed upon by the parties.

14.18.3. Three (03) years before

-(i) expiration of a ten (10) year period beginning on January 1, 2012 and ending on December 31, 2021 concerning the "Etame No. G5-88," "Avouma No. G5-95," and "Ebouri No. G5-98" Exclusive Exploitation Authorizations;

-(ii) expiration of the Authorizations referring to all other Exclusive Exploitation Authorizations.

The additional amounts to be paid during these last three (03) years shall be reduced by the amounts already paid and the accrued interest collected and to be collected on amounts paid in accordance with Article 14, so that the fund established in this way represents an amount in principal and interest equal to one hundred percent (100%) of the estimated cost of relinquishing and dismantling the facilities at the time of performing the Site Remediation Operations.

Article 14.18.4. In the event that an Exclusive Exploitation Authorization is not renewed upon its expiration, the Contractor shall not be required to pay the amounts specified in Articles 14.18.1 and 14.18.2 that have not yet been paid on the aforesaid dates, subject to the provisions of Article 14.20.5 below, and this obligation concerning additional payments shall then be considered to be null and void.

14.18.5. All the amounts paid into the fund in accordance with Article 14 shall be included in the Petroleum Costs account and shall be recoverable as of the date of payment.

14.18.6. The Parties agree to meet in order to determine the methods to calculate the estimated cost of relinquishing and dismantling the facilities that are normally required to be removed or converted at the end of exploitation.

14.18.7. If the facilities of an Exclusive Exploitation Authorization are related to the facilities of one or more other Exclusive Exploitation Authorizations, the Contractor shall create only one fund applying to all these Exclusive Exploitation Authorizations and shall conduct a single relinquishment operation at the end of all production operations.

14.18.8. The Contractor shall submit an updated annual forecast of the Operating Costs for site remediation and shall justify, according to this update and the accrued interest in the account, the annual allocation to the fund in accordance with this Article.

14.19. Said annual payments shall be made in USD to a bank account opened for this purpose with a first-class internationally renowned Gabonese bank designated by the Parties, with the unique credit institution authorization pursuant to regulation No. 1/00/CEMAC/UMAC/COBAC of November 27, 2000 or any similar regulation for banking authorizations within the Economic and Monetary Community of Central Africa (CEMAC) that may replace the aforesaid regulation, to be managed jointly by the Contractor and the State under the conditions specified below. This account shall bear interest, to be credited to the fund and, like all other amounts deposited in the fund, may not be used for any purpose other than Site Remediation Operations according to the provisions of this Article.

In the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Contractor, after having sent the documents justifying the failure of the bank to the Hydrocarbons Department, shall no longer be held liable for the obligation to remediate the sites, which obligation shall be regarded as null and void.

The Contractor and the State shall attempt, within reason, to obtain full or partial reimbursement of the amounts owed by the bank and/or its subrogees.

Nevertheless, if all amounts owed by the bank are not reimbursed, the Contractor may, at its sole discretion and on its own initiative, decide to participate in financing site remediation beyond any amounts it recovered from the defaulting bank and/or its subrogees.

Joint management means that neither the Contractor nor the State can make withdrawals from the account without the written authorization of the other Party that is the co-holder of the account. A joint management agreement specifies the account management conditions. It is negotiated by the Parties at the time of signing this Amendment.

14.20. The terms and conditions for performing the site remediation operations and the use of amounts deposited in accordance with the above provisions are as follows:

1. *For performing the site remediation operations, the Contractor shall notify the Hydrocarbons Department, one hundred eighty (180) days in advance, of its intention to relinquish the Exploitation Area and shall submit a technical report concerning stopping the work.*

2. *If, after examining the aforesaid technical report concerning stopping the work, the State wishes to keep all or part of the facilities or to refurbish them after normal expiration of the Exclusive Exploitation Authorization, including any renewals or, in the event of relinquishment for duly justified reasons according to Article 18.2 of this Contract, the Administration shall inform the Contractor in writing within ninety (90) days following the submission of the technical report concerning stopping the work, which shall release the Contractor from site remediation operations. In this event and as of the publication of the order terminating the current and future obligations of the Contractor and releasing it from any liability, the unused amount of the funds shall be transferred in full to the Treasury.*

3. *If the Administration fails to notify the Contractor according to the terms and conditions described in the preceding subparagraph, the Contractor shall then be required to perform site remediation operations, subject to the withdrawal of the funds specified in item 4 above, and shall submit a relinquishment and dismantling plan for approval by the Hydrocarbons Department within thirty (30) days following the end of the term in item 2 above.*

4. *The approval of the aforesaid relinquishment and dismantling plan by the Administration shall be sent to the Contractor in writing within ninety (90) days, accompanied by the supporting documents provided by the Hydrocarbons Department, enabling it to withdraw the funds for site remediation from the bank. If no response is received within the ninety (90) day term indicated above, the Contractor, according to the power of attorney attached hereto (Annex 1), shall be deemed to be irrevocably authorized by the Administration to unilaterally withdraw the aforementioned funds from the bank account upon simple presentation to the bank of the aforesaid power of attorney, together with a copy of the transmittal letter sending the relinquishment plan, and acknowledgement of receipt. This power of attorney constitutes a valid and irrevocable act by which the Contractor shall be regarded as having received the Administration's authorization to unilaterally withdraw the funds from the bank account. The bank must respond favorably to the Contractor's unilateral request and to remit the funds to the Contractor based upon this power of attorney.*

5. *If the site remediation expenses exceed the amount of the funds deposited as indicated above, the Contractor shall be responsible for providing the balance corresponding to the difference between the amount necessary to perform said site remediation operations and the total of funds deposited (principal and interest).*

6. *If these expenses are lower than the amount of funds deposited as indicated above and insofar as the site remediation operations were performed according to the relinquishment plan previously approved by the Parties, the funds not used for their intended purpose shall be transferred in full to the Treasury as of the date of publication of the decree terminating the Contractor's contractual and future obligations and releasing it from any liability.*

7. *Notwithstanding Article 18.3 of the "Etame Marin No. G4-160" EPSC, should the Contractor be required to perform site remediation operations, the provisions of the aforesaid EPSC shall be applicable throughout the term of said operations and until the publication of the decree indicated in Article 14.20.6 above."*

Article 5: CONTRACTUAL FUNDS

Article 21.7 of the Contract is amended to read as follows:

"The Contractor shall make an annual contribution to a Hydrocarbons Support Fund created in order to advance research and petroleum promotion. This contribution is distributed as follows:

a- payment of one hundred fifty thousand U.S. dollars (USD 150,000) upon execution of Amendment 1;

b- payment of one hundred thousand U.S. dollars (USD 100,000) upon execution of Amendment 2;

c- payment of sixty thousand U.S. dollars (USD 60,000) per calendar year throughout the Exploration Period. This amount shall be paid into an account opened for this purpose, managed by a Joint Committee chaired by the Minister of Hydrocarbons and the Contractor. This Joint Committee shall rule on various petroleum projects prepared by the Petroleum Operations Technical Monitoring Committee, presented by the Hydrocarbons Department, provided by the Technical Secretariat, which submits the files for the final decision. This contribution shall be included in petroleum costs.

d. payment of seventy-five thousand U.S. dollars (USD 75,000) per calendar year and USD 0.05 per barrel of total Available Production throughout the Exploitation Period. This contribution shall be managed by the Minister of Hydrocarbons and shall not be included in petroleum costs.

Article 21.8 of the Contract is amended to read as follows:

“*The Contractor is required to contribute to a Fund intended for Local Community Development.*

This contribution is established as a payment of two hundred fifty U.S. dollars (USD 250,000) per calendar year.

The contribution to the Local Community Development Fund shall be included in the petroleum cost account.”

It is agreed that the payments referenced above in subparagraphs (a), (b) and (c) have already been made by Contractor and these payment obligations have been accomplished already.

With regard to subparagraph (d), this payment obligation remains in effect.

Article 6: RATE OF THE PROPORTIONAL MINING ROYALTY

Article 26.1 of the Contract is amended to read as follows:

“*As of July 17, 2011, until expiration of the second period of validity of the Exclusive Exploitation Authorization applicable to liquid and gas hydrocarbons named “Etame Marin No. G5-88,” the rate of the Proportional Mining Royalty during the hydrocarbons production period is 13% of the Total Available Production.*”

Article 7: CONTRACTOR’S OBLIGATIONS DURING THE DEVELOPMENT AND EXPLOITATION PERIODS

Article 21 of the Contract is amended by the addition of new paragraphs 21.9, 21.10, 21.11, 21.12 to read as follows:

NEW 21.9: ESTABLISHMENT OF A PID CONTRIBUTION

The Contractor shall contribute to the payment of a provision named Provision for Investment Diversification (PID) for purposes of financing the investments or financial commitments in accordance with the diversification objectives of the Gabonese economy within the national territory.

This provision is set at zero point five percent (0.5%) of the revenues of the Contractor related to the Exploitation Area.

The amount of the ETAME PID shall be managed by the Contractor, who shall issue an annual report regarding its management to the Joint Management Committee.

NEW 21.10: ESTABLISHMENT OF A PIH CONTRIBUTION

Contractor shall be responsible for contributing to the payment of a provision known as the Provision for Investments in Hydrocarbons (PIH) for purposes of financing the development of the hydrocarbons industry in the national territory.

This provision is set at zero point five percent (0.5%) of the revenues of the Contractor related to the Exploitation Area.

The amount of the ETAME PIH shall be managed by the Contractor, who shall issue an annual report regarding its management to the Joint Management Committee.

NEW 21.11: GENERAL INFORMATION APPLICABLE TO PID-PIH CONTRIBUTIONS

The amounts the Contractor shall pay into the PID and the PIH in accordance with Articles21.9 and 21.10 above shall be prorated for any calendar year of less than twelve months.

The amounts paid by the Contractor for the PID and the PIH in accordance with Articles21.9 and 21.10 above constitute recoverable Petroleum Costs up to seventy-five percent (75%).

NEW 21.12: PID-PIH MANAGEMENT CONDITIONS

The PID-PIH shall be managed by the Joint Management Committee, whose purpose is to:

- *determine the annual amount of the provision,*
- *establish multi-year programs to be financed by the PID and/or PIH and to track their development,*
- *to establish and, if necessary, modify the program for using the PID and/or PIH and to track the execution of this program.*

This Committee shall be constituted by:

- *1 representative from each member of Contractor,*
- *3 representatives from the State, including one is representative from the Presidency of the Republic, one representative from the Ministry of Hydrocarbons, and one representative from the Ministry of Finance.*

The Joint Management Committee is under the authority of 2 co-chairs, one of which is the Minister of Hydrocarbons on behalf of the State of Gabon and the other the Operator on behalf of Contractor.

The function of secretary shall be performed jointly by the State and the Contractor.

The Joint Management Committee shall meet at the initiative of either Party, at least twice per year. It shall be required to convene one of its meetings in the first half of October in order to establish the amount of the provision for the current fiscal year and the program to use this provision based on an agreement by the parties.

The decisions of the PIH and PID Joint Management Committee are passed by unanimous vote.

Article 8: BONUSES

Article 28 of the Contract shall be supplemented as follows:

"*In addition to the obligations established in Article 28 of the "Etame Marin No. G4-160" Exploration and Production Sharing Contract, the Contactor has paid the State a signature bonus of six hundred thousand U.S. dollars (USD 600,000) on the date of execution of Amendment no. 1."*

"*In addition to the obligations established in Article 28 of the "Etame Marin No. G4-160" Exploration and Production Sharing Contract, the Contactor has paid the State a signature bonus of one million U.S. dollars (USD 1,000,000) on the date of execution of Amendment no. 2."*

"*In addition to the obligations established in Article 28 of the "Etame Marin No. G4-160" Exploration and Production Sharing Contract, the Contactor has paid the State a signature bonus of one million five hundred thousand U.S. dollars (USD 1,500,000) on the date of execution of Amendment no. 4."*

These payments were made on the date of execution of this Amendment by means of a bank check written to the order of Treasury of the Republic of Gabon.

This amount shall not be included in the Petroleum Costs of the "Etame Marin no. G4-160" EPSC.

It is agreed that the payments referenced in this Article 8 have already been made by the Contractor and that these payment obligations have therefore been performed.

Article 9: CONTRIBUTION TO MEET THE NEEDS OF THE DOMESTIC MARKET

Article 35.2 of the Contract is amended to read as follows:

"*The sales price by Contractor of the portion of Hydrocarbons intended to meet the needs of the domestic market is equal to the Fixes Price less a fifteen percent (15%) discount. It is payable in CFA Francs. The aforesaid discount is allocated to the Petroleum Costs Account*"

Article 10: TRAINING OF GABONESE NATIONALS OTHER THAN THOSE EMPLOYED BY THE CONTRACTOR

Article 39 of the Contract is amended by the addition of paragraph 39.1 to read as follows:

"*39.1 In addition to the obligation established in Article 38, the Contractor shall henceforth contribute to training other Gabonese nationals designated by the Administration, by allocating for this training throughout the entire Contract:*

a- One hundred thousand U.S. dollars (USD 100,000) per calendar year for the period preceding the start of production;

b- One hundred eighty thousand U.S. dollars (USD 180,000) per calendar year for the development and exploitation periods.

The contributions defined in Paragraphs (a) and (b) above shall be allocated as follows:

- *in part for training Gabonese nationals in internationally renowned colleges or universities. The training program shall be established by the Hydrocarbons Department;*
- *in part for on-the-job training of Gabonese nationals on the Contractor's sites and its main business centers; the conditions for this training shall be agreed by mutual agreement on a case-by case basis;*
- *in part for training Gabonese nationals chosen by the Administration outside of the Contractor's organization, in the form of participation in seminars or assignments to other companies.*

The amounts established in this Article shall be managed by Contractor and shall be used exclusively for training Gabonese nationals designated by the Hydrocarbons Department. Upon expiration of the Exclusive Exploitation Authorization or at the end of the period of exploitation of the field, the Contractor shall pay the Administration the aforesaid amounts, on a prorated basis.

39.2 The contributions in accordance with the present Article shall be considered Petroleum Costs."

It is agreed that the obligations set forth in this Article 10 have been performed up to and including the date this Amendment is executed and shall continue to be effective.

Article 11:

The "Avouma no. G5-95" Exclusive Exploitation Authorization for liquid and gas hydrocarbons was granted for an initial phase of ten (10) years, from March 25, 2005 through March 24, 2015

It is renewed for a second phase of five (5) years, from March 25, 2015 through March 24, 2020.

It may be renewed for a final phase of five (5) years according to the provisions of Article 18.1 of the Contract, from March 24, 2020 through March 25, 2025.

Article 12:

The State and the Contractor hereby acknowledge that certain adjustments to the Contract as set forth in Amendment no. 5 have been made by mutual agreement, in accordance with the provisions of Article 43 of the Contract, in order to take into account the new provisions of the new petroleum legislation in effect, while endeavoring to preserve the overall equilibrium of the Contract.

Any other provisions of the "Etame Marin no. G4-160" Exploration and Production Sharing Contact not modified under this Amendment shall remain unchanged and continue to remain in full effect.

Article 13:

This Amendment becomes effective on the date it is signed.

It is approved by decree.

This Amendment is signed with ten (10) original counterparts.

Done in Libreville, on April 25, 2016

For the State of Gabon,

By: /s/ Etienne Dieudonne Ngoubou

Name: Etienne Dieudonné Ngoubou

Title: The Minister for Oil and Hydrocarbons

By: /s/ Regis Immongault

Name: Régis Immongault

Title: The Minister for the Economy, the Promotion of Investments and Forecasting

For Vaalco Gabon (Etame)

By: /s/ Cary Bounds

Name: Cary Bounds

Title: Chief Executive Officer

Exhibit 10.7

Deed of Novation

The Bank of New York Mellon, London Branch

as the Trustee and Paying Agent and the Account Bank

and

VAALCO Gabon (Etame), Inc.

as the Original Party and

VAALCO Gabon S.A.

as the New Party

relating to the Etame Field Trustee and Paying Agent Agreement (as amended, supplemented and novated from time to time)

22 June 2017

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THIS DEED is made on 22 June 2017

BETWEEN:

(1) **THE BANK OF NEW YORK MELLON, LONDON BRANCH,** with its registered office at One Canada Square, London E14 5AL, in its capacity as the trustee and paying agent (the **"Trustee and Paying Agent"**);

(2) **THE BANK OF NEW YORK MELLON, LONDON BRANCH,** with its registered office at One Canada Square, London E14 5AL, in its capacity as the Account Bank (the **"Account Bank"**);

(3) **VAALCO GABON (ETAME), INC.,** a company incorporated under the laws of the State of Delaware having its registered office at 1209 Orange Street, Wilmington, Delaware 19801, United States of America (the **"Original Party"**); and

(4) **VAALCO GABON S.A.,** a company incorporated under the laws of Gabon and having its registered office at Port-Gentil, Zone Industrielle OPRAG – Nouveau Port, Libreville/Gabon, B.P. 1335 (the **"New Party"**),

each being referred to individually as a **"Party"** and collectively as the **"Parties"**.

RECITALS:

(A) Certain parties to this deed entered into the Etame Field Trustee and Paying Agent Agreement dated 26 June 2002, as amended on 26 November 2002, 1 February 2006 and 18 June 2014 (the **"TPAA"**).

(B) The Original Party transferred its business in Gabon to the New Party pursuant to the terms of a Business Contribution Agreement dated 29 December 2016 (the **"BCA"**).

(C) The Original Party has agreed to transfer its rights, obligations and liabilities under the TPAA to the New Party as part of the business transfer.

(D) The Original Party and the New Party desire to novate the TPAA such that, with effect from the Effective Date, the Trustee and Paying Agent and the Account Bank shall release the Original Party from its obligations and liabilities in respect of the TPAA and the New Party shall assume all the rights, obligations and liabilities of the Original Party arising under the TPAA on the terms and subject to the provisions set out in this deed.

THE PARTIES AGREE AS FOLLOWS:

1. **DEFINITIONS AND INTERPRETATION**

1.1 In this deed, save where expressly provided in this deed or as the context requires, capitalised terms used but not defined in this deed will have the meanings given to them in the TPAA.

1.2 In this deed:

“Effective Date” has the meaning given in the FPSO Contract Deed of Novation; and

“FPSO Contract Deed of Novation” means the deed of novation dated on or about the date of this deed and entered into between the New Party, the Original Party, Tinworth Pte Limited and Tinworth Limited, in relation to the Contract for the Provision and Operation of an FPSO for the Etame Field dated 20 August 2001 between the Original Party and Tinworth Limited, as amended, supplemented and novated from time to time.

1.3 **Construction**

Section 1.2 of the TPAA shall be deemed to be set out in full in this deed, but as if references in that article to the TPAA were references to this deed.

2. EFFECTIVE DATE

2.1 This deed shall take effect on the Effective Date.

2.2 The Original Party and the New Party shall promptly notify the Trustee and Paying Agent and the Account Bank in writing when the Effective Date occurs.

3. TPAA

The Original Party hereby states to the New Party that the copy of the TPAA is appended to this deed at appendix 1 and is a true and complete copy thereof.

4. NOVATION OF THE TPAA

In consideration of the promises and the mutual covenants and agreements and obligations set out below and to be performed, each Party severally agrees that, with effect on and from the Effective Date:

4.1 the Original Party shall cease to be a party to the TPAA and the New Party shall become a party to the TPAA;

4.2 the New Party undertakes and covenants with the Trustee and Paying Agent and the Account Bank to observe, perform, discharge and be bound by all liabilities, obligations, duties and claims of the Original Party arising under or in connection with the TPAA in the place of the Original Party whether actual, accrued, contingent or otherwise, and whether arising on, before or after the Effective Date, as if the New Party had at all times been a party to the TPAA in place of the Original Party and each act or omission of the Original Party under the TPAA had been an act or omission of the New Party;

4.3 the Trustee and Paying Agent and the Account Bank release and discharge the Original Party from all liabilities, obligations, duties and claims to the extent that those liabilities, obligations, duties and claims are assumed by the New Party in accordance with the provisions of this deed and the Trustee and Paying Agent and the Account Bank hereby accepts the assumption of such liabilities and obligations by the New Party in place of the Original Party, as if the New Party had at all times been a party to the TPAA in place of the Original Party;

4.4 the Trustee and Paying Agent and the Account Bank undertake with the New Party to observe, perform, discharge and be bound by all liabilities, obligations, duties and claims of the Trustee and Paying Agent and the Account Bank arising under or in connection with the TPAA whether actual, accrued, contingent or otherwise, and whether arising on, before or after the Effective Date, as if the New Party had at all times been a party to the TPAA in place of the Original Party; and

4.5 the Original Party releases and discharges each of the Trustee and Paying Agent and the Account Bank from their respective liabilities, obligations and duties arising under or in connection with the TPAA to the extent that those liabilities, obligations and duties are owed to the New Party in accordance with the provisions set out in this deed and the Trustee and Paying Agent and the Account Bank hereby agree that those liabilities, obligations and duties are owed to the New Party in place of the Original Party as if the New Party had at all times been a party to the TPAA in place of the Original Party.

5. AMENDMENTS TO THE TPAA

5.1 Each Party severally agrees that, with effect on and from the Effective Date:

(a) all references to “VAALCO Gabon (Etame), Inc.” in the TPAA shall be replaced with “VAALCO Gabon S.A.”;

(b) in section 9.6(a) (Notices) of the TPAA the Original Party's details shall be deleted and the New Party's details shall be deemed to be inserted as follows:

VAALCO Gabon S.A.
Port-Gentil, Zone Industrielle OPRAG – Nouveau Port, Libreville/Gabon
B.P. 1335
Attention: Managing Director

With a CC to: VAALCO Energy Inc.
9800 Richmond Avenue, Suite 700
Houston, Texas 77042
Attention: General Counsel

Telephone Number: +1 713 623 0801

(c) in the definition of “TINWORTH” in the TPAA the reference to “TINWORTH Ltd., a Bermudian corporation” shall be replaced with “TINWORTH Pte. Limited”; and

(d) the definition of “FPSO Contract” in the TPAA shall be deleted and a new definition shall be deemed to be inserted as follows:

“FPSO Contract” shall mean the Contract for the Provision and Operation of an FPSO for the Field dated August 20, 2001, between the Operator, TINWORTH and TINWORTH Gabon S.A., as the same has been or may be modified, supplemented, amended or novated, including any extension or renewal thereof.”

5.2 Save as herein expressly provided, all provisions of the TPAA shall remain in full force and effect and binding on the Trustee and Paying Agent, Account Bank and New Party on and from the Effective Date.

6. COUNTERPART

6.1 This deed may be executed in any number of counterparts which together shall constitute one agreement and this deed shall not come into force and effect until it is properly executed by or on behalf of each of the Parties and is duly dated.

6.2 Delivery of an executed signature page of a counterpart in Adobe™ Portable Document Format (PDF) sent by electronic mail shall take effect as delivery of an executed counterpart of this deed. If this method is adopted, without prejudice to the validity of such deed, each Party shall provide the other Parties with the original of such page as soon as reasonably practicable thereafter.

7. GOVERNING LAW AND DISPUTES

The provisions of sections 9.4 (*Disputes and Submission to Jurisdiction*) and 9.9 (*Applicable Law*) of the TPAA shall apply to any dispute, controversy or claim arising out of or in connection with this deed, including any question regarding its existence, validity, formation or termination, and shall be deemed to be incorporated into this deed, mutatis mutandis.

IN WITNESS WHEREOF, this deed has been executed and delivered as a deed on 22 June 2017.

The Trustee and Paying Agent

For and on behalf of **THE BANK OF NEW YORK MELLON, LONDON BRANCH.**	)))	**[SIGNED]**

The Account Bank

For and on behalf of **THE BANK OF NEW YORK MELLON, LONDON BRANCH.**	)))	**[SIGNED]**

Original Party

For and on behalf of **VAALCO GABON (ETAME), INC.**	)))	**[SIGNED]**

New Party

For and on behalf of **VAALCO GABON S.A.**	)))	**[SIGNED]**

Acknowledged and consented to by:

For and on behalf of **TINWORTH PTE. LIMITED**	)))	**[SIGNED]**

APPENDIX 1

TPAA

VAALCO GABON (ETAME), INC.

And

J.P. MORGAN TRUSTEE AND DEPOSITARY COMPANY LIMITED

And

JPMORGAN CHASE BANK, LONDON BRANCH

ETAME FIELD
TRUSTEE AND PAYING AGENT AGREEMENT

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THIS AGREEMENT, made as of the 26th day of June, 2002 between **VAALCO GABON (ETAME), INC.**, a Delaware corporation ("**VGEI**"), on behalf of itself, in its capacity as Operator acting under the Operating Agreement and as a Consortium Member and on behalf of each other Consortium Member under the Operating Agreement, J.P. Morgan Trustee and Depositary Company Limited having its registered office at 125 London Wall, London EC2Y 5AJ as Trustee and Paying Agent and JPMorgan Chase Bank, London Branch (the "Bank"), acting through its branch located at Trinity Tower, 9 Thomas More Street, London, England E 1W 1YT as Account Bank (all capitalized terms in the Preface and Recitals are hereinafter defined under Section 1 below).

WITNESSETH:

WHEREAS, **VGEI**, as the Operator and on behalf of the Consortium Members, will be executing Crude Oil Sales Contracts;

WHEREAS, each Crude Oil Sales Contract will provide that the Buyer shall pay Crude Oil Sales Contract Revenues due thereunder to the Etame Revenue Account;

WHEREAS, pursuant to the FPSO Contract between VGEI, as Operator, and TINWORTH, TINWORTH is entitled to receive certain Compensation subject to the terms and conditions thereof secured by the TINWORTH Reserve Account created and funded as provided herein;

WHEREAS, from time to time Consortium Members may enter into financing agreements with Subordinate Secured Parties and assign as security therefor, subject to funding Government Payments, Fees and Expenses and Additional Remuneration of the Trustee and Paying Agent and of the Account Bank and the TINWORTH Reserve Account (as provided herein), their pro rata share of Crude Oil Sale Contract Revenues;

WHEREAS, to secure payment of amounts due to (i) TINWORTH under the FPSO Contract and (ii) the several obligations of the Consortium Members to their Subordinate Secured Parties, VGEI, as the Operator and on behalf of the Consortium Members, wishes to assign its rights and their respective rights to the Crude Oil Sales Contract Revenues in respect of the related Crude Oil Sales Contracts to the Trustee and Paying Agent upon the terms and conditions set forth in this Agreement;

WHEREAS, amounts paid with respect to the Crude Oil Sales Contract Revenues in respect of the Crude Oil Sales Contracts will be received, held, managed and disbursed by the Trustee and Paying Agent (as provided herein);

NOW, **THEREFORE**, in consideration of the mutual agreements contained herein, the Parties hereto agree as follows:

1. DEFINED TERMS

1.1. The following defined terms shall have the meanings set forth below, such meanings to be applicable to both the singular and the plural forms of such expressions:

"Accession Deed" shall have the meaning set forth in Section 2.9.

"Accounts" shall mean the Etame Reserve Account, the Etame Operating Account and the TINWORTH Reserve Account.

"Account Bank" shall mean the JPMorgan Chase Bank or any Successor appointed pursuant to Section 8.7.

"Account Bank's Office" shall mean the office of the Account Bank, the address of the first Account Bank being set out in Section 9.6 or any other office of the Account Bank in London, the address of which is notified to the Operator and TINWORTH, with copies to any Subordinate Secured Parties, by the Account Bank pursuant to Section 9.6 or the office specified in an instrument delivered by any Successor.

"Agreement" shall mean this Etame Field Trustee and Paying Agent Agreement, as modified, supplemented or amended from time to time in accordance with the terms hereof.

"Applicable Law" shall have the meaning set forth in Section 9.9.

"Assigned Property" shall mean the property subject to the Crude Oil Sales Contracts Assignments.

"Authority" any national, supranational, regional or local government or governmental, administrative, fiscal, judicial, or government-owned body, department, commission, authority, tribunal, agency or entity, or central bank (or any person, whether or not government owned and howsoever constituted or called, that exercises the functions of a central bank);

"Authorisation" any consent, registration, filing, agreement, notarization, certificate, license, approval, permit, authority or exemption from by or with any Authority, whether given by express action or deemed given by failure to act within any specified time period and all corporate, creditors' and stockholders' approvals or consents;

"Bank" shall have the meaning set forth in the introduction to this Agreement.

"Beneficiaries" shall have the meaning set forth in Section 2.4.

"Business Day" shall mean any day other than a Saturday, Sunday or other day on which commercial banking institutions in London and New York are authorized or obligated by law to remain closed.

"Buyers" shall mean collectively each of the buyers of Crude Oil under the Crude Oil Sales Contracts and their respective successors and permitted assigns thereunder.

"Charter" the articles of incorporation and bylaws and/or such other constitutive documents, howsoever called;

"Collection Actions" shall have the meaning set forth in Section 2.7(f).

“Compensation” shall mean all charter rate, operating rate and any other compensation whatsoever payable by the Operator to TINWORTH in accordance with their obligations and liabilities under the FPSO Contract.

“Consortium Members” shall mean collectively VGEI, PetroEnergy, Pan African Energy, Sasol, WAAL and NISSHO, and in each case its successors and permitted assigns under the Production Sharing Contract and the Operating Agreement.

“Consortium Member Accounts” shall mean the designated deposit accounts for each Consortium Member as designated on Schedule A hereto.

“Crude Oil” shall mean crude oil produced from the Field.

“Crude Oil Sales Contract Revenues” shall mean each amount payable in ‘U.S. Dollars pursuant to sales of Crude Oil exported from the Project and any amounts payable on account of interest due by reason of the late payment for Crude Oil under the Crude Oil Sales Contracts, in each case net of sales commissions provided for in the Crude Oil Sales Contracts or in any sales agency agreements entered into in connection therewith,

“Crude Oil Sales Contracts” shall mean each and all of the sales contracts for the marketing and sale of Crude Oil from the Project to be entered into either by:

(i) the Operator on behalf of itself, the Consortium Members and the Government of Gabon and its assigns and each of the Buyers thereof; and

(ii) such Consortium Members who elect to take in kind and separately sell its share of Crude Oil from the Project directly and each of the Buyers thereof;

as the same may be modified, supplemented or amended, including any extension or renewal thereof.

“Crude Oil Sales Contracts Assignment” shall have the meaning set forth in Section 2.7 (a).

“Crude Sharing Agreement” shall mean any agreement entered into between the Operator and any Consortium Member under which such Consortium Member elects to take in kind its share of Crude Oil from the Project and to sell it directly under a Crude Oil Sales Contract.

“Eligible Bank” means the Bank or any of the Bank’s affiliates or any other bank or trust company with a registered office or branch in London, England, provided the Bank or its relevant affiliate or such other bank or trust company has capital and surplus of at least US $500,000,000 and whose Long term senior debt is rated at least “A” by Standard & Poor’s Corporation or its successor or at least “A3” by Moody’s Investors Service, Inc. or its successor, or any equivalent rating, issued by such services or successors, as from time to time may be in effect.

“Environmental Law” shall mean all applicable laws, including common law, orders, decrees, permits, rules or regulations pertaining to the environment, health and safety, hazardous substances, or the environmental conditions on, under, or about the Field, the Project or the loading, storage, off-loading and transportation of Crude Oil from the Field.

"Environmental Liability" shall mean any liability under any Environmental Law.

"Etame Operating Account" shall mean the account established and maintained pursuant to Section 4.1 by the Trustee and Paying Agent in the Trustee and Paying Agent's name with the Account Bank, having the designation "JPMTDC Re: Etame Operating Account" and account number 24690601.

"Etame Revenue Account" shall mean the account established and maintained pursuant to Section 2.1 by the Trustee and Paying Agent in the Trustee and Paying Agent's name with the Account Bank, having the designation "JPMTDC Re: Etame Revenue Account" and account number 24690602.

"Fees and Expenses" shall have the meaning set forth in Section 8.2.

"Field" shall mean the Etame Field located offshore Gabon and more particularly described in the Production Sharing Contract and the Operating Agreement.

"Final Compensation Payment" shall mean the final payment for Compensation due and owing to TINWORTH under the FPSO Contract.

"Finance Document" means any agreement or deed relating to the transactions contemplated by this Agreement, other than this Agreement.

"FPSO Contract" shall mean the Contract for the Provision and Operation of an FPSO for the Field dated August 20, 2001, between the Operator and TINWORTH, as the same may hereafter be modified, supplemented or amended, including any extension or renewal thereof.

"Gabon" shall mean the Republic of Gabon.

"**Government"** shall mean the government of Gabon.

"Government Payments" shall mean any funds to be disbursed by the Trustee and Paying Agent to the Government under Section 3.1.

"Investment Designation" shall have the meaning set forth in Section 7.1.

"Letters of Credit" shall mean each irrevocable and transferable letter of credit or any similar payment security provided by a Buyer in favor of the Operator, any Consortium Member or Trustee and Paying Agent to provide for the payment when due of the purchase price of Crude Oil sold pursuant to the Crude Oil Sales Contracts.

"NISSHO" shall mean Nissho Iwai Corporation, a Japanese corporation,

"Operating Agreement" shall mean the joint operating agreement effective as of April 4, 1997 between VGEI, VAALCO Energy (Gabon), Inc., WAAL, Petrofields Exploration & Development Co. Inc. and Alcorn Petroleum and Mineral Corporation, as the same has been and may hereafter be modified, supplemented or amended, including any extension or renewal thereof and any successors of the original parties.

"Operator" shall mean VGEI, the designated Operator pursuant to the Operating Agreement and its successors and permitted assigns under the Operating Agreement and the Production Sharing Contract.

"Pan African Energy" shall mean Pan African Energy Gabon Corporation, (formerly known as VAALCO Energy (Gabon), Inc.), a Delaware Corporation.

"Party" shall mean each of the Trustee and Paying Agent, the Account Bank and the Operator.

"Payment Default" shall have the meaning set forth in Section 5.3.

"Payment Due Date" shall mean the date on which the Buyer must pay the amount due under the relevant Crude Oil Sales Contract to the Operator or, as the case may be, the relevant Consortium Member.

"Permitted Investments" shall mean any of the following investments having a maturity date not later than the Business Day immediately preceding the date on which it is anticipated the proceeds thereof will be required in order to make any payment hereunder and in any event not more than one year from the date the investment is acquired by the Trustee and Paying Agent: (i) Eurodollar time deposits with Eligible Banks, (ii) Eurodollar certificates of deposit of Eligible Banks, (iii) commercial paper, finance company paper or bonds denominated in Eurodollars of any issuer, including Trustee and Paying Agent or any of its affiliates, or (iv) money market funds, provided that in the case of any investments described in either clause (iii) or (iv) above, such investments shall be rated not less than "P-I" by Moody's Bank Credit Report Service or its successors and "A-1 +" by Standard & Poor's Corporation CD Ranking Service or its successors, or any equivalent rating, issued by such services or successors, as from time to time may be in effect, all in accordance with Section 7.1.

"PetroEnergy" shall mean PetroEnergy Resources Corporation, a Philippine corporation.

"Production Sharing Contract" shall mean the Production Sharing Contract executed by VGEI and VAALCO Energy (Gabon), Inc. with the Ministry of Petroleum of Gabon on July 6, 1995, as the same has been and may hereafter be modified, supplemented or amended, including any extension or renewal thereof.

"Project" shall mean the floating production storage and offloading system and the three oil wells existing in the Field and such other wells or facilities as may be added to develop the Field.

"Sasol" shall mean Sasol Petroleum International (Pty) Ltd., a South African Corporation.

"Secured Obligations" shall mean collectively such obligations owed by the Operator, for itself and as agent for and on behalf of the other Consortium Members to TINWORTH under the FPSO Contract and the several obligations, if any, owed by the Consortium Members to their respective Subordinate Secured Parties.

"Security" shall mean the security created or expressed to be created in favour of the Trustee and Paying Agent pursuant to this Agreement.

"Subordinate Secured Parties" shall mean, at any time, the party or parties identified in Schedule A that a Consortium Member has notified in writing to the Operator, the Trustee and Paying Agent and the Account Bank is a secured creditor with respect to such Consortium Member's share of the Crude Oil Sales Contract Revenues and a beneficiary of the Crude Oil Sales Contract Assignment with respect to such share.

"Successor" shall have the meaning set forth in Section 8.7.

"Tax" shall mean all present and future taxes, levies, imposts or duties (including value added and stamp duties) whatsoever and wheresoever imposed.

"TINWORTH" shall mean TINWORTH Ltd., a Bermudian corporation or its successor.

"TINWORTH Draw Notice" shall mean a written notification in form of Schedule D attached hereto as provided in Section 5.3.

"TINWORTH Reserve Account" shall mean the account established pursuant to Section 5.1 by the Trustee and Paying Agent in the Trustee and Paying Agent's name with the Account Bank, having designation "JPMTDC: TINWORTH Reserve Account" and account number 24690603.

"TINWORTH Reserve Account Maximum Balance" shall have the meaning set forth in Section 5.2.

"Trustee Acts" shall mean the Trustee Act 1925 and the Trustee Act 2000 of England and Wales.

"Trustee and Paying Agent" shall mean the person designated as such by the Operator pursuant to Section 2.1 or any Successor appointed pursuant to Section 8.7.

"Trustee and Paying Agent's Office" shall mean the office of the Trustee and Paying Agent, the address of the first Trustee and Paying Agent being set out in Section 9.6 or any other office of the Trustee and Paying Agent in London, the address of which is notified to the Operator and TINWORTH, with copies to any Subordinate Secured Parties, by the Trustee and Paying Agent pursuant to Section 9.6 or the office specified in an instrument delivered by any Successor.

"Trust Funds" shall have the meaning set forth in Section 2.4.

"Trust Property" shall mean the property held by the Trustee and Paying Agent upon the terms of the trusts set out in Section 2.4.

"Underlying Security" shall mean all liens, security interests, Letters of Credit, mortgages or similar rights securing payment by the Buyers of the Crude Oil Sales Contract Revenues.

"US$" and **''U.S. Dollars"** shall mean the lawful currency of the United States of America.

"VGEI" shall have the meaning set forth in the introduction to this Agreement.

"WAAL" shall mean Western Atlas Afrique, Ltd., a Bermuda Corporation.

1.2. Interpretation.

In this Agreement, unless the context otherwise requires:

(a) headings are for convenience only and do not affect the interpretation of this Agreement;

(b) words importing the singular include the plural and vice versa;

(c) a "person" includes any company, corporation, partnership, trust, estate, unincorporated organization, joint venture, association, juridical entity, corporation or other body corporate and any government, state or any political subdivision, authority or agency thereof;

(d) a reference to a party, Schedule or Section is a reference to that Section of, or that party or Schedule to, this Agreement;

(e) a reference to a party to any document includes that party's successors and permitted assigns; and

(f) a reference to a statute or statutory provision shall be construed as a reference to such statute or statutory provision as the same shall have been or may be amended or re-enacted.

2. RECEIPT OF FUNDS

2.1. Designation of Trustee and Paying Agent and Etame Revenue Account.

The Operator hereby appoints J.P. Morgan Trustee and Depositary Company Limited as the Trustee and Paying Agent and J.P. Morgan Trustee and Depositary Company Limited hereby accepts its appointment as Trustee and Paying Agent and its obligations hereunder upon and subject to the terms and conditions of this Agreement. The Trustee and Paying Agent may delegate all or any of the rights, powers and discretions vested in it by this Agreement pursuant to Clause 8.1(k). All Crude Oil Sales Contract Revenues shall be paid to the Trustee and Paying Agent. In the event any Consortium Member sells its share of Crude Oil directly under a Crude Oil Sales Contract such Consortium Member shall, as shall be required by the Operator under the relevant Crude Sharing Agreement, appoint J.P. Morgan Trustee and Depositary Company Limited as the Trustee and Paying Agent to which Crude Oil Sales Contract Revenues under its Crude Oil Sales Contract shall he paid. The Trustee and Paying Agent shall establish and maintain the Etame Revenue Account, to which all Crude Oil Sales Contract Revenues and any other monies which may be payable to Consortium Members in respect of any Crude Oil Sales Contract Revenues shall be paid. The Trustee and Paying Agent shall deposit in the Etame Revenue Account each amount of Crude Oil Sales Contract Revenues and any other monies which may be payable to Consortium Members in respect of any Crude Oil Sales Contract Revenues received by it.

2.2. The Operator shall and shall cause any Consortium Member selling Crude Oil directly to send to the Trustee and Paying Agent (i) any Crude Oil Sales Contract promptly following the execution of the contract and (ii) a copy of each invoice at the same time that such invoice is sent to the relevant Buyer.

2.3. Covenant to Pay.

The Operator on behalf of each of the Consortium Members covenants with the Trustee and Paying Agent on behalf of itself and as trustee for and on behalf of the Beneficiaries (as defined below) that the Operator and such Consortium Members will pay and discharge the Secured Obligations owed to TINWORTH under the FPSO Contract.

2.4. Declaration of Trust Funds.

All amounts received in the Etame Revenue Account pursuant to Section 2.1, and Section 2.1 as applied by Section 2.9, in the Etame Operating Account pursuant to Section 4.2 and the TINWORTH Reserve Account pursuant to Section 5.2, Section 7.1 and Section 7.2 are herein referred to as the "Trust Funds." The Trustee and Paying Agent hereby declares itself trustee of the Trust Funds on trust for itself, the Operator, the Consortium Members, TINWORTH and the Subordinate Secured Parties each as the case may be (being the beneficiaries hereto) the "Beneficiaries" and shall hold the Trust Funds and the benefit of all related rights in trust for the Beneficiaries in accordance with their respective rights hereunder. Such funds shall be held upon trust for the benefit of those having a right to receive disbursements and distributions to the extent provided in this Agreement.

2.5. Amounts Received.

(a) In the event the Trustee and Paying Agent receives any amount from any person which amount is not designated for the Etame Revenue Account or for any other account established or to be established hereunder, or an amount in relation to which it has not received a notification from the Operator, the Trustee and Paying Agent shall request instructions from the Operator as to the proper account designation of the amount received and shall deposit such amount in the account or accounts specified in the designation given by the Operator.

(b) If the Operator receives any sum which, pursuant to this Agreement, should have been paid to the Trustee and Paying Agent, that sum shall be held by the Operator on trust for the Beneficiaries and shall promptly be paid to the Trustee and Paying Agent in accordance with this Agreement.

2.6. Currency Conversion.

If the Trustee and Paying Agent recovers a payment in a currency other than US dollars, the Trustee and Paying Agent may convert the moneys received or recovered by the Trustee and Paying Agent into US dollars at the spot rate at which the Trustee and Paying Agent is able to purchase US dollars with the amount received.

2.7. Crude Oil Sale Contracts Assignment.

(a) To the extent permitted or not prohibited by the Crude Oil Sales Contracts, the Operator on behalf of each of the Consortium Members with full title guarantee and as continuing security for the payment and discharge of the Secured Obligations to the Trustee and Paying Agent for the benefit of TINWORTH and the Subordinate

Secured Parties assigns by way of security absolutely to the Trustee and Paying Agent (the "Crude Oil Sales Contracts Assignment") all the Crude Oil Sales Contract Revenues in respect of the Crude Oil Sales Contracts to which it is a party, and all liens, security interests, Letters of Credit, mortgages or similar rights securing payment by the Buyers of the Crude Oil Sales Contract Revenues pursuant to the related Crude Oil Sales Contracts, including without limitation:

(i) the right to receive all Crude Oil Sales Contract Revenues,

(ii) payments arising from any claims for damages in respect of Crude Oil Sales Contract Revenues, and

(iii) payments received as a result of the Operator, Trustee and Paying Agent or its assignee compelling performance of the payment of such Crude Oil Sales Contract Revenues (all of which shall be held by the Trustee and Paying Agent upon the terms of the trusts set out in Section 2.4 above);

provided however that the Trustee and Paying Agent shall have no right or obligation (unless instructed to do so by the Operator) to consent or agree to any amendment, modification or waiver under or with respect to any such Crude Oil Sales Contract or any such lien, security interest, Letter of Credit, mortgage or similar right. The Trustee and Paying Agent hereby accepts such Crude Oil Sale Contracts Assignment in accordance with the terms hereof.

The Operator shall, contemporaneously with the execution of each Crude Oil Sales Contract to which it is a party, serve a notice of the Crude Oil Sales Contract Assignment, in the form set out in Schedule E on each Buyer thereunder and the Operator shall use its reasonable endeavors to procure that each Buyer promptly executes and delivers to the Trustee and Paying Agent (with a copy thereof to the Operator, TINWORTH and the Subordinate Secured Parties) an acknowledgement of the Crude Oil Sales Contract Assignment in the form set out in Schedule F. The Operator shall use its reasonable endeavors to obtain any relevant consent, waiver or acknowledgement necessary to give full effect to the foregoing assignment to the Trustee and Paying Agent.

(b) The Operator for itself and on behalf of each of the Consortium Members represents, warrants and covenants that:

(i) it has not assigned and will not assign for itself or on behalf of each of the Consortium Members any of its rights or interests hereby assigned to any person other than the Trustee and Paying Agent as aforesaid;

(ii) it has and will have the necessary power to enable it to enter into and perform its obligations under this Agreement;

(iii) this Agreement constitutes and will constitute its legal, valid, binding and enforceable obligation (except as enforcement may be limited by bankruptcy, moratorium, insolvency, reorganisation or similar laws generally affecting creditors' rights as well as the awards by courts of relief in lieu of specific performance of contractual provisions); and

(iv) all necessary authorisations to enable it to enter into this Agreement have been obtained and are, and will remain, in full force and effect.

(c) Anything herein to the contrary notwithstanding, the Operator agrees for the benefit of the Trustee and Paying Agent and for the benefit of each person having an interest in or right at any time to distribution or disbursement of Trust Funds hereunder that:

(i) the Operator shall at all times remain liable to the other party or parties to each Crude Oil Sales Contract to which the Operator is a party to perform all of the duties and obligations of the Operator thereunder as if the Crude Oil Sale Contracts Assignment hereunder had not been made, and

(ii) the Trustee and Paying Agent shall not have any obligation or liability under any Crude Oil Sales Contract or in respect of any Crude Oil Sales Contract Revenue or any lien, security interest, Letter of Credit, mortgage or similar right securing payment by the Buyers of the Crude Oil Sales Contract Revenues pursuant to the related Crude Oil Sales Contracts or any other instrument or agreement securing payment by the Buyers of the Crude Oil Sales Contract Revenues pursuant to the related Crude Oil Sales Contracts by reason of, or arising under, this Agreement or be obligated to perform any of the obligations of the Operator under any thereof or, except as otherwise expressly provided in Section 2.7(t), to make any payment or to make any inquiry as to the sufficiency of any payment received by it or to present or file any claim or to take any other action to collect or enforce any claim for or right to any payment or security therefor assigned hereunder.

(d) The Operator on behalf of each of the Consortium Members does hereby constitute the Trustee and Paying Agent and its respective delegates, the Operator's true and lawful attorney irrevocably, with full power (in the name of the Operator or otherwise on its behalf) to do all acts and all things (including full power to delegate) and to sign, seal, execute, deliver, perfect and do all deeds, instruments and documents, acts and things which may be necessary hereunder and to ask, require, demand, receive, compound and give acquittance for any and all monies and claims for monies due and to become due under or arising out of each Crude Oil Sales Contract to which the Operator is a party and, to endorse any instruments or orders in connection therewith. The Operator ratifies and confirms and agrees to ratify and confirm whatever any attorney appointed hereunder shall do in its capacity as such. Unless and until the Trustee and Paying Agent shall take any action or exercise any right under Section 2.7(t) and shall have notified the Operator to such effect, the Operator may in its discretion take any such action or exercise any such right.

(e) The Operator agrees that, subject to the Operating Agreement, the Operator will, at its own expense, promptly and duly execute and deliver any and all such further notices, instruments and documents and take such further action as the Trustee and Paying Agent may require or consider necessary in order to obtain the full benefits of the Crude Oil Sale Contracts Assignment and the rights and powers herein granted. The Operator shall deliver, and shall cause to be delivered, to the Trustee and Paying Agent all Crude Oil Sales Contracts and Letters of Credit and any other security for performance of the Buyers under the Crude Oil Sales Contracts. The Operator shall provide, and shall cause to be provided, to the Trustee and Paying Agent all amendments, modifications or supplements to the Crude Oil Sales Contracts, the Letters of Credit or any other instruments or agreements securing payment by the Buyers of the Crude Oil Sales Contract Revenues pursuant to the related Crude Oil Sales Contracts or the Letters of Credit; provided however that until the Trustee and Paying Agent shall have received any such amendment, modification or supplement, it may assume and act or not act on the basis that the executed original documentation in its possession is solely authoritative, in effect and binding.

(f) In the event payment is not made in respect of any Crude Oil Sales Contract or Letter of Credit when due, the Trustee and Paying Agent shall have no duty to exercise any right or take any action under any Crude Oil Sales Contract or, except as set forth in Section 2.8, under any Letter of Credit ("Collection Actions"). The Trustee and Paying Agent may, and if instructed in writing by the Operator, shall appoint the Operator or its nominee as the agent of the Trustee and Paying Agent to exercise any such right or take any such action provided that the Trustee and Paying Agent is indemnified and or secured to its satisfaction. In acting (or refraining from acting) as such agent of the Trustee and Paying Agent, the Operator and its assignee shall have all rights, benefits, powers and protections provided to the Trustee and Paying Agent under or pursuant to this Agreement.

(g) Notwithstanding anything to the contrary contained herein, the Trustee and Paying Agent makes no representation as to the collectability of any lien or security interest purported to be created hereby, or as to the sufficiency, validity or genuineness of any instruments or documents at any time assigned or deposited with the Trustee and Paying Agent hereunder, or any liens purported to be created hereunder or under any other document referred to or provided for in this Section. The Trustee and Paying Agent shall have no duty to do, cause to be done or advise with respect to any filing or recording or to the maintenance of any such filing or recording with any governmental agency or office or otherwise. The Trustee and Paying Agent shall, if directed by the Operator or its nominee in accordance with Section 2.7(f), deliver or cause to be delivered to the Operator such instruments, notices or other documents designed to create, protect, perfect or effect the Crude Oil Sales Contracts Assignment, which instruments, notices or other documents shall have been prepared by the Operator or its nominee and delivered to the Trustee and Paying Agent.

2.8. Letters of Credit.

(a) If, as indicated by the relevant invoice, payment for Crude Oil sold pursuant to a Crude Oil Sales Contract is to be effected by a Letter of Credit, the Trustee and Paying Agent shall, but only to the extent that the applicable Letter of Credit (together with all documents required to be presented thereunder) is in the possession of the Trustee and Paying Agent, draw on the applicable Letter of Credit in the manner provided therein and for the amount then due on the applicable payment due date. If any invoice under a Crude Oil Sales Contract is not paid when due in respect of which invoice a Letter of Credit is held by the Trustee and Paying Agent as security for payment of such invoice, the Trustee and Paying Agent shall notify the Operator of such event and the Trustee and Paying Agent shall draw on the applicable Letter of Credit, in the manner provided therein and for the amount then due, after the lapse of five (5) calendar days following the applicable payment due date, but in any event prior to the expiration date of the relevant Letter of Credit. If the applicable Letter of Credit is in favour of the Operator or any Consortium Member, the Trustee and Paying Agent shall request such party to draw on the Letter of Credit and deposit such funds into the Etame Revenue Account.

(b) In the event the issuing bank, advising bank or confirming bank, as the case may be, fails to honor any draw by or on behalf of the Trustee and Paying Agent under a Letter of Credit, the Trustee and Paying Agent shall promptly notify the Operator and shall make prompt written demand on the issuing bank, advising bank or confirming bank. The Trustee and Paying Agent may, and if requested by the Operator shall, provided that the Trustee and Paying Agent is indemnified and/or secured to its satisfaction, take or cause to be taken such other reasonable action as may be specified by the Operator to, cause the issuing bank, advising bank or confirming bank to honor such Letter of Credit, which instructions may be to appoint the Operator or its nominee as the Trustee and Paying Agent's agent pursuant to Section 2.7(f). If the Operator should directly receive any monies from the issuing bank, advising bank or confirming bank as a result of such action such monies shall be held on trust by the Operator and shall immediately be transferred to the Trustee and Paying Agent and shall be treated as Crude Oil Sales Contract Revenues.

2.9. Direct Sales/Crude Sharing Agreements.

In the event that any Consortium Member elects to sell its share of Crude Oil from the Project directly to a Buyer, the Operator shall cause such Consortium Member to enter into a Crude Sharing Agreement with the Operator whereby such Consortium Member shall covenant, among other matters, to perform, with respect to the Crude Oil Sales Contracts and Crude Oil Sales Contract Revenues related to such Consortium Member's share of Crude Oil, the obligations of the Operator under Sections 2.1 (save for the obligation of the Operator referred to in the 4th sentence thereof), 2.2, 2.3, 2.4, 2.5(b), 2.6, 2.7, 2.8, 8.1(a), (i), (m), (p)(iii), and 9.4(c) as more particularly set forth under such Crude Sharing Agreement (including, for avoidance of doubt, an obligation of the Operator to cause any such Consortium Member to duly execute an assignment of such Consortium Member's rights under such Crude Oil Sales Contracts to the Trustee and Paying Agent in accordance with Section 2.5) and to execute an instrument acceding to this Agreement in substantially the form of Schedule I hereto ("Accession Deed"). The Trustee and Paying Agent shall be entitled to Fees and Expenses and Additional Remuneration in connection therewith pursuant to Section 8.2 and 8.3.

2.10. Acceptance of Accession Deeds.

Each of the Parties hereto appoints the Trustee and Paying Agent to receive on its behalf each Accession Deed delivered to the Trustee and Paying Agent pursuant to Section 2.9 and to accept and sign it if the Trustee and Paying Agent has received such documentation from the acceding Consortium Member that it, in its sole discretion, requires in order to comply with all applicable legal and regulatory requirements. No Accession Deed shall be effective unless and until accepted and signed by the Trustee and Paying Agent. The Trustee and Paying Agent shall be entitled to assume, without further enquiry, that any such Accession Deeds are duly executed, authentic, legal, valid, binding and enforceable.

3. DISBURSEMENTS WITH RESPECT TO GOVERNMENT PAYMENTS

3.1. Government Payments.

The Trustee and Paying Agent shall as soon as practicable but not more than three (3) Business Days after receipt of any amount of Crude Oil Sales Contract Revenues, pay over from the Etame Revenue Account to the Government an amount specified by the operator as the Government's share of such amount pursuant to the Production Sharing Contract ("Government Payments"), which amount shall be as specified in the notice received by the Trustee and Paying Agent from the Operator at least three (3) Business Days prior to the due date of each invoice for the sale of Crude Oil under the relevant Crude Oil Sales Contract, failing the receipt of which the Trustee and Paying Agent shall act in accordance with the previous such notice in determining the applicable amount to be paid to the Government. Amounts payable to the Government hereunder shall be paid to such account as shall be specified in writing by the Operator to the Trustee and Paying Agent.

4. ESTABLISHMENT OF ETAME OPERATING ACCOUNT

4.1. Etame Operating Account.

The Trustee and Paying Agent shall establish and maintain the Etame Operating Account.

4.2. Funds to be Deposited.

As soon as practicable but no later than two (2) Business Days after receipt by it of any amount in funds in the Etame Revenue Account, the Trustee and Paying Agent shall deposit in the Etame Operating Account all amounts in the Etame Revenue Account in excess of the amount of Government Payments required to be made pursuant to Section 3.1.

5. DISBURSEMENTS WITH RESPECT TO TRUSTEE COMPENSATION AND THE TINWORTH RESERVE ACCOUNT

5.1. Establishment of TINWORTH Reserve Account.

The Trustee and Paying Agent shall establish and maintain the TINWORTH Reserve Account.

5.2. Payment.

Any time funds are deposited in the Etame Operating Account, the Trustee and Paying Agent shall as soon as practicable after such deposit but in no event more than two (2) Business Days thereafter pay or deposit such funds in the following order:

First, pay Fees and Expenses incurred in accordance with Section 8.2 hereof and Additional Remuneration incurred in accordance with Section 8.3 hereof.

Second, deposit such amounts in the TINWORTH Reserve Account as may be necessary to ensure that the credit balance of the TINWORTH Reserve Account, including the value of any Permitted Investments and accrued interest in accordance with Section 7, is equal to $2,500,000 (the **"TINWORTH Reserve Account Maximum Balance"**).

Third, distribute the balance remaining in the Etame Operating Account, if any, to each of the Consortium Member's Accounts the amounts in accordance with their respective entitlements under Production Sharing Contract and the Operating Agreement, as shall be specified in the notice received by the Trustee and Paying Agent from the Operator at least three (3) Business Days prior to the date of such distribution.

5.3. TINWORTH Reserve Account Draws.

TINWORTH shall be entitled to draw such amounts out of the TINWORTH Reserve Account up to the TINWORTH Reserve Account Maximum Balance in the event Operator fails to pay any Compensation due to TINWORTH under the FPSO Contract on the due date thereof and after the expiration of any applicable grace periods (a **"Payment Default"**), upon five (5) Business Days' written notice from TINWORTH (**"TINWORTH Draw Notice"**) to the Trustee and Paying Agent with copies to the Operator and each of the Subordinate Secured Parties (as designated on the most recent Schedule A delivered to TINWORTH pursuant to Section 6.1(b)), declaring that a Payment Default has occurred under the FPSO Contract and for these purposes the Trustee and Paying Agent can rely without enquiry on a certificate from TINWORTH certifying that TINWORTH has sent such copies of the TINWORTH Draw Notice and the Trustee and Paying Agent shall not be liable for so acting. TINWORTH shall have no obligation to confirm that Schedule A is a complete and current list of Subordinate Secured Parties. The Trustee and Paying Agent shall distribute to TINWORTH such amounts in the TINWORTH Reserve Account up to the TINWORTH Reserve Account Maximum Balance as certified due and owing under the TINWORTH Draw Notice. Trustee and Paying Agent shall liquidate the Permitted Investments to the extent necessary to fund the full amount of the TINWORTH Draw Notice, whether or not such Permitted Investments have matured. Anything herein to the contrary notwithstanding, the Operator on behalf of itself and each of the Consortium Members agrees for the benefit of the Trustee and Paying Agent that the Trustee and Paying Agent shall be under no duty to inquire or seek approval from Operator, any Consortium Member or any Subordinate Secured Party or any other person with respect to the occurrence or not of the Payment Default or the right of TINWORTH to receive the amount requested under the TINWORTH Draw Notice and Trustee and Paying Agent shall have no liability to the Operator, any Consortium Member or Subordinate Secured Party to determine or resolve any claims with respect to their rights under the FPSO Contract, TINWORTH's Compensation, or any other disputes between TINWORTH and the Operator thereunder for payment of such amounts.

5.4. Final Compensation Payment.

After the date of payment of the Final Compensation Payment pursuant to the FPSO Contract as confirmed by notice from the Operator and TINWORTH to the Trustee and Paying Agent, the

Trustee and Paying Agent shall as promptly as practicable convert to cash any Permitted Investments then held in the TINWORTH Reserve Account and promptly pay all amounts remaining in the TINWORTH Reserve Account to the Consortium Members' Accounts in accordance with the instructions as provided by the Operator in the manner described in Paragraph "Third" under Section 5.1, and thereafter close the TINWORTH Reserve Account.

6. PROCEDURES RESPECTING ACCOUNTS AND SECURITY INTERESTS UNDER THIS AGREEMENT

6.1. Beneficial Rights in Trust Funds.

(a) TINWORTH shall have under this Agreement or otherwise no claim or interest in the Etame Revenue Account or Etame Operating Account except to the extent funds deposited in the Etame Operating Account are to be deposited in the TINWORTH Reserve Account as provided in Section 5.2. The funds in the TINWORTH Reserve Account, up to the TINWORTH Reserve Account Maximum Balance, shall be held for the benefit of TINWORTH as security for and payment of the Compensation. Except as provided under Section 7.2, prior to the Final Compensation Payment, neither Operator nor any Consortium Member or any Subordinate Secured Party shall have any security interest in the TINWORTH Reserve Account. TINWORTH has no claim or interest in the Consortium Member Accounts under this Agreement or otherwise.

(b) At any time and from time to time any Consortium Member may give notice to the Trustee and Paying Agent and the Operator that it has assigned with full title guarantee to its Subordinate Secured Party by way of security absolutely all of such Consortium Member's rights in and to the Etame Operating Account funds substantially in the form of Exhibit G hereto. Upon receipt of such notice, (i) the Trustee and Paying Agent and Operator shall amend Schedule A as appropriate and deliver a copy thereof to each of TINWORTH, each of the Consortium Members and each of their respective Subordinate Secured Parties, if applicable (ii) the Trustee and Paying Agent and the Operator shall acknowledge such Subordinate Secured Party's security interest substantially in the form of Exhibit H hereto and (iii) thereafter the Trustee and Paying Agent shall distribute such Consortium Member's share of the Etame Operating Account funds to such Consortium Member's Account as directed in such notice.

6.2. No overdraft.

None of the Accounts may go to into overdraft.

6.3. Accounting for Assets.

All assets under the jurisdiction and control of the Trustee and Paying Agent and held from time to time in the Trust Funds shall be accounted for within the Etame Revenue Account, Etame Operating Account and TINWORTH Reserve Account specifying the designated account to which such assets may be allocated and the place or places at which Permitted Investments may be held in custody for the account of the Trustee and Paying Agent. The Trustee and Paying Agent shall maintain such books of account and other records as may be necessary to ensure full and proper segregation of the funds credited to such accounts as may be established by the Trustee and Paying

Agent hereunder. Such books of account shall be open to inspection by the duly authorized representatives of the Operator, TINWORTH, the Government, the Consortium Members and their respective Subordinate Secured Parties at all reasonable times and upon reasonable notice.

6.4. Reports.

The Trustee and Paying Agent shall furnish to the Operator, TINWORTH and each Subordinate Secured Party the following reports:

(a) Within 20 days after the close of each calendar quarter, a statement prepared by the Trustee and Paying Agent setting forth the amount and source (by category) of funds received pursuant to this Agreement and the disbursements of such funds as disclosed by the records and accounts kept by the Trustee and Paying Agent pursuant to Section 6.3 during such preceding calendar quarter and a statement of the cash and investments held in the accounts under this Agreement as of the end of such period.

(b) As soon as practicable after its receipt or disbursement of any funds pursuant to this Agreement, a statement by facsimile transmission or, if so requested by any party, by e-mail, of such transactions specifying the amount and the source (by category) of the funds received and disbursed and the amounts credited or charged to the Etame Revenue Account, the Etame Operating Account, the TINWORTH Reserve Account and each Consortium Member's Account.

6.5. Tax Considerations.

(a) All payments from the Trust Funds to Consortium Members shall be paid gross except to the extent required by law and the Trustee and Paying Agent shall be entitled to deduct or withhold any sum on account of any Tax required or which in its view is required to be so deducted or withheld or for which it is in its view liable or accountable by law or practice of any relevant revenue authority of any jurisdiction and in each case in accordance with the Trustee and Paying Agent's usual and customary business practice.

(b) The Operator shall use reasonable endeavors to procure, on request from the Trustee and Paying Agent, that each Consortium Member makes such declarations as may be required (including, without limitation, declarations under paragraph 4 of the Income Tax (Paying and Collecting Agents) Regulations 1996 (as amended)) that may be required to avoid any withholding from payments out of the Trust Fund that would otherwise be required by law.

7. INVESTMENT OF FUNDS HELD IN ACCOUNTS UNDER THIS AGREEMENT

7.1. Permitted Investments.

The Trustee and Paying Agent shall invest amounts held by it from time to time in the TINWORTH Reserve Account solely in such Permitted Investments specifically designated by the Operator (as to type, obligor, yield, maturity and other necessary information) from time to time in writing ("Investment Designation"); provided that (a) if the Trustee and Paying Agent has not received an Investment Designation as to any funds required to be invested hereunder it shall invest such funds in an interest bearing deposit account held with the Account Bank and bearing a rate of interest of the JPMorgan Chase Bank overnight bid rate for deposits in US dollars less 50 basis points or such other interest rate as may be agreed from time to time; (b) upon receipt of an Investment Designation, the Trustee and Paying Agent shall to the extent practicable terminate non-designated investments to which such Investment Designation applies and re-invest the proceeds thereof in the Permitted Investments designated therein; and (c) the Trustee and Paying Agent shall in no event have any liability if a Permitted Investment not made performs better than any other investment the Trustee and Paying Agent enters into. For the avoidance of doubt the Trustee and Paying Agent shall not exercise discretion with regard to the selection of Permitted Investment except as directed in 7.1(a). All Permitted Investments shall be and become part of the Trust Funds and shall be included in the credit balance of the TINWORTH Reserve Account for the purpose of meeting the TINWORTH Reserve Account Maximum Balance. The Permitted Investments shall be valued in accordance with the Trustee and Paying Agent's normal banking practice.

7.2. Interest Allocation.

Interest and any other income arising out of the Permitted Investments shall be and become a part of the Trust Funds, allocated to the account for which such investment was made; provided, as of the first Business Day of each calendar quarter during the term hereof, Trustee and Paying Agent shall transfer to the Etame Operating Account quarterly all interest and any other income accruing on amounts in the TINWORTH Reserve Account in excess of the TINWORTH Reserve Account Maximum Balance.

8. CONCERNING THE TRUSTEE AND PAYING AGENT AND ACCOUNT BANK

8.1. In connection with its duties, rights and powers under this Agreement (including in relation to transactions it may enter into pursuant hereto), the Trustee and Paying Agent shall be subject to the following:

(a) *Instructions*. The Trustee and Paying Agent shall, except as otherwise contemplated herein, act solely in accordance with instructions given to it by the Operator for and on behalf of itself and the Consortium Members. The Trustee and Paying Agent shall be entitled to assume that (i) any instruction received by it from the Operator is duly given by or on behalf of the Consortium Members, if applicable, in accordance with the terms of the Operating Agreement and any other applicable Finance Documents, (ii) unless it has received actual written notice of revocation, that any instructions or directions given by the Operator have not been revoked and no revocation of any instructions by the Operator shall affect any action of the Trustee and Paying Agent in reliance upon such instruction or direction prior the actual receipt of the notice of revocation, and (iii) the Operator is entitled under the Operating Agreement and other Finance Documents to give such instructions. The Trustee and Paying Agent shall be entitled to request clarification of any instruction or direction and pending receipt of such clarification to its satisfaction may refrain from acting and shall have no liability for the consequences thereof.

(b) *Reliance on Certificates*. The Trustee and Paying Agent shall be entitled to act upon any notice, certificate, request, direction, waiver, receipt or other document which it in good faith believes to be genuine; and it shall be entitled to rely upon the due execution, validity and effectiveness, and the truth and acceptability of any provisions contained therein.

(c) *Gross Negligence*. The Trustee and Paying Agent shall not be liable for any error of judgment or for any act done or omitted by it in good faith or for any mistake of fact or law, or far anything which it may do or refrain from doing, except for its own gross negligence or willful misconduct.

(d) *Professional Advice*. The Trustee and Paying Agent may consult with, and obtain advice from accounting and legal advisers or such other advisers, consultants and agents as the Trustee and Paying Agent may deem necessary or advisable and it shall incur no liability or loss and shall be fully protected in acting in good faith in accordance with the opinion and advice of any such advisers, consultants or agents, as the case may be.

(e) *No other duties*. The Trustee and Paying Agent shall have no duties other than those specifically set forth or provided for in this Agreement and shall not have any implied duties, obligations or responsibilities. In performing or carrying out its duties, obligations and responsibilities, the Trustee and Paying Agent shall be considered to be acting only in a mechanical and administrative capacity (save as expressly provided in this Agreement).

(f) *Recitals*. The recitals contained herein shall be taken as the statements of the Operator, and the Trustee and Paying Agent assumes no responsibility for their correctness.

(g) *Other agreements*. The Trustee and Paying Agent shall have no obligation to familiarize itself with and shall have no responsibility with respect to any Finance Document, including, without limitation, the Crude Oil Sale Contracts, the Operating Agreement and the Production Sharing Contract, relating to the transactions contemplated by this Agreement nor any obligation to inquire whether any notice, instruction, statement or calculation is in conformity with the terms of any such agreement, except for those irregularities, errors or mistakes apparent on the face of such document or to the knowledge of the Trustee and Paying Agent. If, however, any remittance or communication received by the Trustee and Paying Agent appears erroneous or irregular on its face, the Trustee and Paying Agent shall be under a duty to make prompt inquiry to the person or party originating such remittance or communication in order to determine whether clerical error or inadvertent mistake has occurred.

(h) *Payment in error*. If the Trustee and Paying Agent pays out funds from the Accounts in error, it shall be entitled to recoup such funds from the party to whom it paid such funds.

(i) *Representations, defaults, etc*. The Trustee shall be entitled to assume, unless it has in its capacity as Trustee and Paying Agent for the Beneficiaries received actual notice to the contrary from the Operator, that any representation made or deemed to be made hereunder is true and that neither the Operator nor the Consortium Members are in breach of or default under any of its obligations under this Agreement.

(j) *Agents*. The Trustee and Paying Agent may, in the conduct of its trust business, instead of acting personally, employ and pay an agent on any terms, selected by it whether or not a lawyer or other professional person, to transact or conduct, or concur in transacting or conducting, any business and to do or concur in doing all acts required to be done by the Trustee and Paying Agent (including the receipt and payment of money) and the Trustee and Paying Agent shall not be responsible for any misconduct on the part of any person appointed by it hereunder or be bound to supervise the proceedings or acts of any such person, provided that the Trustee and Paying Agent shall exercise reasonable care in selecting any such person;

(k) *Delegates*. The Trustee and Paying Agent may, at any time, delegate by power of attorney or otherwise to any person for any period, all or any of the rights, powers and discretions vested in it by this Agreement, including without limitation to the Account Bank. The delegation may be made upon any terms and conditions (including the power to sub-delegate) and subject to any restrictions as the Trustee and Paying Agent may think fit in the interest of the Beneficiaries and it shall not be bound to supervise, or be in any way responsible for any loss incurred by reason of any misconduct or default on the part of any delegate or sub-delegate, provided that the Trustee and Paying Agent shall exercise reasonable care in selecting any such delegate.

(l) *Co-trustees*. The Trustee and Paying Agent may at any time appoint (and subsequently remove) any Eligible Bank to act as a separate trustee or as a co-trustee jointly with it (1) if it considers that appointment to be in the interests of the Beneficiaries or (ii) for the purposes of confirming to any legal requirements, restrictions or conditions which the Trustee and Paying Agent deems to be relevant or (iii) for obtaining or enforcing any judgment in any jurisdiction, provided that the Trustee and Paying Agent exercises reasonable care in selecting any such co-trustee and uses reasonable endeavours to consult with the other Beneficiaries in relation thereto, including, without limitation, in respect of any remuneration expected to be paid to such co-trustee. The Trustee and Paying Agent shall give notice to the Operator and the Consortium Members of any appointment. Any person so appointed (subject to the terms of this Agreement) shall have the rights, powers and discretions (not exceeding those conferred on the Trustee and Paying Agent by this Agreement) and the duties and obligations as are conferred or imposed by the instrument of appointment. The remuneration that the Trustee and Paying Agent may pay to any person, and any costs and expenses incurred by that person in performing its functions pursuant to that appointment shall, for the purposes of this Agreement, be treated as costs and expenses incurred by the Trustee and Paying Agent.

(m) *No action without indemnification*. The Trustee and Paying Agent may refrain from acting in accordance with the instructions of the Operator or from taking any other action hereunder unless and until it has received indemnification and/or security as it may in its absolute discretion require (whether by way of advance payment or otherwise) and for all costs, losses, expenses, claims and liabilities which it may incur or expend or to which it may be exposed.

(n) *Expending own fluids*. Nothing contained in this Agreement shall require the Trustee and Paying Agent to expend or risk its own funds or otherwise incur any financial liability and the Trustee and Paying Agent shall not be obliged to do or omit anything, including entering into any transaction or incurring any liability including without limitation any Environmental Liability unless the Trustee and Paying Agent’s liability is limited in a manner satisfactory to it in its absolute discretion. Nor shall the Trustee and Paying Agent in any circumstances be obliged to give its own indemnity to any receiver or delegate or to become a mortgagee in possession.

(o) *Excluded Obligations*. Notwithstanding anything to the contrary expressed or implied hereunder or in any of the Finance Documents, the Trustee and Paying Agent shall not:

(i) be bound to enquire as to the performance, default or any breach by the Operator, any of the Consortium Members, TINWORTH or any of the Subordinate Secured Parties of any of their respective obligations hereunder or under any of the Finance Documents;

(ii) be bound to assess or keep under review the financial condition, creditworthiness, condition, value, affairs, status or nature of the Project;

(iii) except as provided in Sections 6.3 and 6.4, be bound to account to any other Beneficiary for any sum or the profit element of any sum received by the Trustee and Paying Agent for its own account;

(iv) unless ordered to do so by a court of competent jurisdiction, and except as provided in Section 6.3, be bound to disclose to any other person (including any other Beneficiary) any confidential information;

(v) except as specifically set out herein, have or be deemed to have any duty, obligation or responsibility to, or relationship of trust or agency with, the Operator or any Consortium Member;

(p) *Exclusion of Liability*. Unless caused directly by its gross negligence or willful misconduct the Trustee and Paying Agent shall not accept responsibility or be liable for:

(i) the adequacy, accuracy and/or completeness of any information supplied by the Trustee and Paying Agent or any other person in connection with this Agreement or the transactions contemplated in this Agreement, or any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement;

(ii) the legality, validity, effectiveness, adequacy or enforceability of the Agreement, the Security or the Underlying Security or any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement, the security or the underlying security;

(iii) any losses to any person or any liability arising as a result of taking or refraining from taking any action in relation to this Agreement, the Security, the Underlying Security or otherwise, whether in accordance with an instruction from the Operator or otherwise;

(iv) the exercise of, or the failure to exercise, any judgment, discretion or power given to it by or in connection with this Agreement or the Security, the Underlying Security or any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement, the Security or the Underlying Security; or

(v) any shortfall which arises on the enforcement of the Security or the Underlying Security or otherwise.

(q) *Own responsibility*. It is understood and agreed by each Beneficiary (except the Trustee and Paying Agent and Account Bank) that at all times that Beneficiary has itself been, and will continue to be, solely responsible for making its own independent appraisal of and investigation into all risks arising under or in connection with this Agreement including but not limited to:

(i) the financial condition, creditworthiness, condition, affairs, status and nature of the Operator, each of the Consortium Members and each of the Buyers;

(ii) the financial condition, creditworthiness, condition, value, affairs, status and nature of the Project;

(iii) the legality, validity, effectiveness, adequacy and enforceability of this Agreement and the Security and the Underlying Security and any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement, the Security or the Underlying Security;

(iv) whether that Beneficiary has recourse, and the nature and extent of that recourse, against the Operator, any Consortium Member, any Buyer or any other person or any of their respective assets under or in connection with this Agreement, the transactions contemplated in this Agreement or any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement;

(v) the adequacy, accuracy and/or completeness of any information provided by any person in connection with this Agreement, the transactions contemplated in this Agreement or any other agreement, arrangement or document entered into, made or executed in anticipation of, pursuant to or in connection with this Agreement: and

(vi) the right or title of any person in or to, or the value or sufficiency of any part of the Trust Property, the priority of any of the Security, the Underlying Security or the existence of any security interest affecting the Trust Property, and the Operator for and on behalf of itself and the Consortium Members warrants to the Trustee and Paying Agent that it has not relied on and will not at any time rely on the Trustee and Paying Agent in respect of any of these matters.

(r) *No Responsibility to Perfect Security*. The Trustee and Paying Agent shall not be liable for any failure to:

(i) require the deposit with, it of any deed or document certifying, representing or constituting the title of any Beneficiary to any of the Trust Property;

(ii) obtain any license, consent or other authority for the execution, delivery, legality, validity, enforceability or admissibility in evidence of this Agreement, the Security or the Underlying Security;

(iii) register, file or record or otherwise protect any of the Security or the Underlying Security (or the priority of any of the Security or the Underlying Security) under any applicable laws in any jurisdiction or to give notice to any person of the execution of this Agreement or of the Security or the Underlying Security;

(iv) take, or to require any of the Beneficiaries to take, any steps to perfect its title to any of the Trust Property or to render the Security or the Underlying Security effective or to secure the creation of any ancillary security interest under the laws of any jurisdiction; or

(v) require any further assurances in relation to this Agreement, the Security or the Underlying Security.

(s) *Insurance*. Other than as required by applicable law or regulation, the Trustee and Paying Agent shall not be under any obligation to insure any of the Trust Property, to require any other person to maintain any insurance or to verify any obligation to arrange or maintain insurance contained in the Finance Documents. The Trustee and Paying Agent shall not be responsible for any loss which may be suffered by any person as a result of the lack of or inadequacy of any insurance.

(t) *Custodians and Nominees*. The Trustee and Paying Agent may appoint and pay any person to act as a custodian or nominee on any terms in relation to any assets of the trust as the Trustee and Paying Agent may determine, including for the purpose of depositing with a custodian this Agreement and the Trustee and Paying Agent shall not be responsible for any loss, liability, expense, demand, cost, claim or proceedings incurred by reason of the misconduct, omission or default on the part of any person appointed by it under this Agreement or be bound to supervise the proceedings or acts of any person, provided that the Trustee and Paying Agent shall exercise reasonable care in selecting any such custodian or nominee.

(u) *Acceptance of Title*. The Trustee and Paying Agent shall be entitled to accept without enquiry, and shall not be obliged to investigate, the right and title as the Operator or any of the Consortium Members may have to any of the Assigned Property and shall not be liable for or bound to require any Operator or any Consortium Member to remedy any defect in its right or title.

(v) *Illegality*. The Trustee and Paying Agent may refrain from doing anything which in its opinion will or may be contrary to any relevant law, directive or regulation of any jurisdiction which would nor might otherwise render it liable to any person, and the Trustee and Paying Agent may do anything which is, in its opinion, necessary to comply with any law, directive or regulation.

(w) *Powers Supplemental*. The rights, powers and discretions conferred upon the Trustee and Paying Agent by this Agreement shall be supplemental to the Trustee Acts and in addition to any which may be vested in the Trustee and Paying Agent by general law or otherwise.

(x) *Trustee Division Separate*. In acting as trustee for the Secured Parties, the Trustee and Paying Agent shall be regarded as acting through its trustee division which shall be treated as a separate entity from any of its other divisions or departments and any information received by any other division or department of the Trustee and Paying Agent may be treated as confidential and shall not be regarded as having been given to the Trustee and Paying Agent's trustee division.

(y) *Disapplication*. Section 1 of the Trustee Act 2000 shall not apply to the duties of the Trustee and Paying Agent in relation to the trusts constituted by this Agreement. Where there are any inconsistencies between the Trustee Acts and the provisions of this Agreement, the provisions of this Agreement shall, to the extent allowed by law, prevail and, in the case of any inconsistency with the Trustee Act 2000, the provisions of this Agreement shall constitute a restriction or exclusion for the purposes of that Act.

(z) *Protection for Account Bank*. If the Trustee and Paying Agent delegates any of its functions to the Account Bank, then the relevant protective language in this Agreement (including, without limitation, this Section 8 (including, without limitation, Sections 8.2, 8.3 and 8.10)) in favour of the Trustee. Under no circumstances will the Account Bank be liable to any party hereto for any consequential loss (inter alia, being loss of business, goodwill, opportunity or profit) even if advised of such loss or damage).

8.2. Trustee and Paying Agent Fees.

The Trustee and Paying Agent shall be entitled to receive fees as set forth on Schedule B hereto for the services to be performed by it hereunder and to be reimbursed for all properly incurred out-of-pocket expenses incurred by the Trustee and Paying Agent on a full indemnity basis in connection therewith, including properly incurred legal fees and expenses (such fees and expenses payable under this Section 8.2 are referred to herein as **"Fees and Expenses"**). The Trustee and Paying Agent may charge such agreed Fees and Expenses and the Additional Remuneration (referred to in Section 8.3 below) to the Etame Operating Account as an expense to be paid under Section 5 prior to the payment of any other amount thereunder, providing the Operator with such evidence as to the nature and amount of such expenses as the Operator may reasonably require. If the balance in the Etarne Operating Account is insufficient therefor, the Operator, on behalf of each of the Consortium Members, but not TINWORTH or the Subordinate Secured Parties, shall pay such Fees and Expenses and the Additional Remuneration to the Trustee and Paying Agent.

8.3. Exceptional Fees.

In the event of the occurrence of Collection Actions or if payment is not made on any Crude Oil Sales Contract or Letter of Credit when due or the Trustee and Paying Agent is requested by the Operator to undertake duties which the Trustee and Paying Agent, the Operator and the Subordinate Secured Parties agree to be of an exceptional nature or otherwise outside the scope of the normal duties of the Trustee and Paying Agent under this Agreement, the Operator shall pay to the Trustee and Paying Agent any additional remuneration (together with any applicable VAT) as the Operator and the Subordinate Secured Parties shall have consented to, such consent not to be unreasonably withheld. If the Trustee and Paying Agent, the Operator and the Subordinate Secured Parties fail to agree upon the nature of the duties or upon such Additional Remuneration, that dispute shall be determined by an investment bank (acting as an expert and not as an arbitrator) selected by the Trustee and Paying Agent and approved by the Operator and the Subordinate Secured Parties or, failing approval, nominated (on the application of the Trustee and Paying Agent) by the President for the time being of the Law Society of England and Wales (the costs of the nomination and of the investment bank being payable by the Operator) and the determination of any investment bank shall be final and binding upon the Beneficiaries. Such remuneration payable under this Section 8.3 is referred to herein as "Additional Remuneration".

8.4. Stamp Taxes.

The Operator shall pay all stamp, registration, notarial and other taxes or fees to which this Agreement, the security or any judgment given in connection with them, is or at any time may be, subject and shall, from time to time, indemnify the Trustee and Paying Agent on demand against any liabilities, costs, claims and expenses resulting from any failure to pay or any delay in paying any tax or fee.

8.5. Interest on Demands.

If the Operator fails to pay any amount payable by it to the Trustee and Paying Agent under this Agreement on its due date interest shall accrue on the overdue amount (and be compounded with it) from the due date up to the date of actual payment (both before and after judgment and to the extent interest at a default rate is not otherwise being paid on such sum) at the rate which is one per cent. per annum over the rate at which the Trustee and Paying Agent was being offered, by prime banks in the London Interbank Market, deposits in an amount comparable to the unpaid amounts in the currencies of those amounts for such period(s) as the Trustee and Paying Agent may from time to time select.

8.6. Resignation and Termination.

(a) The Trustee and Paying Agent may, at any time, without assigning any reason and without being responsible for the costs and expenses occasioned thereby, by notice to the Operator and TINWORTH tender its resignation as Trustee and Paying Agent under this Agreement.

(b) The Operator may, with consent of TINWORTH and Subordinate Secured Parties, at any time by notice given by it, terminate the Trustee and Paying Agent's appointment hereunder. Such resignation or termination shall be effective as from the appointment of a successor as hereinafter provided and when all the Security has been transferred to such successor.

8.7. Appointment of Successor.

(a) Within 45 days of receipt of a notice of resignation or issuance of a notice of termination, the Operator shall appoint a successor, being an Eligible Bank, acceptable to TINWORTH and the Subordinate Secured Parties. The proposed successor bank (the **"Successor"**) shall promptly give notice of its appointment to the Trustee and Paying Agent and shall execute and deliver to each of the Parties an instrument in writing accepting its appointment hereunder which shall specify the office of the Successor in London which is to be that Trustee and Paying Agent's Office for the purpose of this Agreement.

(b) If in any case a Successor shall not be appointed pursuant to the foregoing provisions of this Section 8.7 within the 45 days aforesaid, the Trustee and Paying Agent may be entitled on behalf of the Operator to appoint a Successor being an Eligible Bank of good standing.

8.8. Successor Vested with Rights.

Upon and from the execution and delivery of the instrument in writing appointing the successor and the transfer of all the Security to the Successor, the Successor without any further act or deed shall become fully vested with all the rights, powers and duties and subject to all the obligations of the Trustee and Paying Agent hereunder, but the retiring Trustee and Paying Agent shall be discharged from any further obligation under this Agreement, but shall retain the benefit of this Section 8.

8.9. Payments After Notice.

Upon and from the date of notification from any Successor, any person required to pay amounts to the Trustee and Paying Agent under this Agreement shall pay the Successor at its office specified as aforesaid all amounts described herein as payable to the Trustee and Paying Agent.

8.10. Indemnification.

The Operator on behalf of itself and the Consortium Members hereby irrevocably and unconditionally agrees to indemnify, and keep fully and effectively (and on an after-Tax basis) indemnified, the Trustee and Paying Agent against all actions, proceedings, claims, demands, losses, damages, liabilities, calls, assessments, costs, charges and expenses, which may be brought or preferred against or incurred by the Trustee and Paying Agent (otherwise than as a result of its gross negligence or willful misconduct) in connection with the Trust Fund, this Agreement or the performance of the Trustee and Paying Agent's obligations hereunder including, without prejudice to the generality of the foregoing, any Tax, other than tax on or attributable to the income earned by the Trustee and Paying Agent for which the Trustee and Paying Agent is or may be liable or accountable in connection with the Trust Fund, this Agreement or the performance of the Trustee and Paying Agent's obligations hereunder.

8.11. Trustee and Paying Agent in Individual Capacity.

The Trustee and Paying Agent, in its individual capacity, or any affiliate thereof shall have the same rights, powers and authority to enter into any deposit agreement, loan agreement or any other banking or business relationship permitted by law with any of the Government, the Operator, the Consortium Members, TINWORTH or the Subordinate Secured Parties as though it were not the Trustee and Paying Agent under this Agreement.

8.12. Set-Off.

The Trustee and Paying Agent is entitled at any time to exercise rights of set-off against (or otherwise make a deduction from) the Trust Fund, in relation to any payment due to the Trustee and Paying Agent under this Agreement in respect of any indemnification, Fees and Expenses or Additional Remuneration.

8.13. Security Procedures.

In the event funds transfer instructions are given (other than in writing at the time of execution of this Agreement), whether in writing, by facsimile or otherwise, the Trustee and Paying Agent is authorized to seek confirmation of such instructions by telephone call-back to the person or persons designated on Schedule C and the Trustee and Paying Agent may rely upon the confirmation of anyone purporting to be the person or persons so designated. In the event Trustee and Paying Agent is unable to obtain a call-back within two (2) Business Days the Trustee and Paying Agent shall proceed on the written instructions as originally received. The persons and telephone numbers for call-backs may be changed only by written instructions actually received and acknowledged by the Trustee and Paying Agent. The Trustee and Paying Agent in any funds transfer may rely solely upon any account numbers or similar identifying numbers provided by the Operator, the Consortium Members, TINWORTH or the Subordinate Secured Parties identifying:

(i) the beneficiary,

(ii) the beneficiary's bank, or

(iii) an intermediary bank.

The Trustee and Paying Agent may apply any of the Trust Funds for any payment order it executes using any such identifying number, even where its use may result in a person other than the beneficiary being paid, or the transfer of funds to a bank other than the beneficiary's bank or an intermediary bank designated. The Parties acknowledge that these security procedures are commercially reasonable.

8.14. Representations and warranties.

Each of the Trustee and Paying Agent and the Account Bank represents and warrants:

(a) It is duly incorporated and validity existing under the laws of its jurisdiction of incorporation, and has the corporate power and has obtained all required Authorisations to enter into, and comply with its obligations under this Agreement;

(b) This Agreement has been duly authorised and executed by it and constitutes a valid and legally binding obligation the Trustee and Paying Agent or, as the case may be, the Account Bank, enforceable in accordance with its terms, except as may be affected by bankruptcy, administration, insolvency and other similar laws affecting creditors' rights generally;

(c) Neither the entering into of this Agreement nor the compliance with its terms will conflict with or result in a breach of any of the terms, conditions or provisions of, or constitute a default or require any consent under, any indenture, mortgage, agreement or other instrument or arrangement to which the Trustee and Paying Agent or, as the case maybe, the Account Bank is a party or by which it is bound, or violate any of the terms or provisions of the Trustee and Paying Agent's or, as the case maybe the Account Bank's Charter or any Authorisation, judgment, decree or order or any statute, rule of regulation applicable to the Trustee and Paying Agent or, as the case maybe, the Account Bank.

9. MISCELLANEOUS

9.1. Remedies and Waivers.

No failure to exercise, or any delay in exercising, on the part of any Secured Party, any right or remedy under this Agreement shall operate as a waiver, nor shall any single or partial exercise of any right or remedy prevent any further or other exercise thereof or the exercise of any other right or remedy. The rights and remedies provided in this Agreement are cumulative and not exclusive of any rights or remedies provided by law.

9.2. Partial Invalidity.

If, at any time, any provision of this Agreement is or becomes illegal, invalid or unenforceable in any respect under any law of any jurisdiction, neither the legality, validity or enforceability of the remaining provisions nor the legality, validity or enforceability of the provision under the law of any other jurisdiction will in any way be affected or impaired.

9.3. Counterparts; Term.

This Agreement may be executed in any number of counterparts and by the Parties on separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts together shall constitute one and the same instrument. Complete sets of counterparts shall be lodged with the Trustee and Paying Agent. This Agreement shall be effective as of the date hereof and shall remain in effect with respect to provisions regarding the TINWORTH Reserve Account until TINWORTH and the Operator have notified the Trustee and Paying Agent that the Final Compensation Payment has been paid and with respect to all other provisions until the Operator and each Subordinate Secured Party shall have notified the Trustee and Paying Agent that this Agreement shall terminate.

9.4. Disputes and Submission to Jurisdiction.

(a) The Parties hereby irrevocably submit to the non-exclusive jurisdiction of the English courts in any legal action or proceedings in relation to any disputes which may arise in connection with the rights and obligations established by this Agreement or otherwise arising in connection with this Agreement. England shall be each of the Trustee and Paying Agent's and the Account Bank's jurisdiction for the purposes of the Uniform Commercial Code as in effect in any jurisdiction. Each of the Trustee and Paying Agent, the Account Bank and the Operator represents that it has not entered into any agreement relating to the Accounts that designates any other jurisdiction as the Trustee and Paying Agent's or the Account Bank's jurisdiction for such purposes and agrees that it will not enter into any such agreement;

(b) Each of Trustee and Paying Agent, the Operator, TINWORTH, the Consortium Members and the Subordinate Secured Parties (with the exception of the International Finance Corporation) irrevocably waives any objections on the ground of venue or forum non conveniens or any similar grounds;

(c) Each of Trustee and Paying Agent, the Operator and TINWORTH irrevocably consents to service of process by mail or in any manner permitted by the relevant law.

9.5. Notice of Trust and Paying Agent Agreement

The Operator hereby undertakes to give notice of the trust created hereby and a copy of this Agreement to the Beneficiaries promptly following the execution of this Agreement.

9.6. Notices

All notices, approvals, instructions, and other communications for purposes of this Agreement shall be in writing, and shall be transmitted by certified or registered airmail, hand, overnight courier, facsimile or e-mail, directed as set forth below:

(a) To the Operator at the following mail, facsimile and e-mail addresses

VAALCO Gabon (Etame), Inc.
4600 Post Oak Place, Suite 309
Houston, Texas 77027

Attention: President or Vice President
Telephone: 713-623-0801
Facsimile No: 713-623-0982
Email address: vaalco@vaalco.com

(b) To TINWORTH at the following mail, facsimile and e-mail addresses:

TINWorth
c/o Fred.Olsen Production A.S.
Fred.Olsen Gate 2
P.O. Box 1159 Sentrum
0152 OSLO
Norway

. Attention: Commercial Manager
Facsimile No: 47 22 42 9946
Email address: fpso@fredolsen.no

(c) To the Trustee and the Paying Agent at the following mail, facsimile and e-mail addresses:

JPMorgan Chase Bank
Trinity Tower
9 Thomas More Street
London E1 W 1YT

Attention: Manager, Escrow Administration
Facsimile No: 44 20 7777 5410
44 20 7777 5450
Email address: will.manns@jpmorgan.com
philip.runciman@jpmorgan.com

(d). To the Account Bank at the following mail, facsimile and e-mail addresses:

JPMorgan Chase Bank
Trinity Tower
9 Thomas More Street
London E1 W 1YT

Attention: Manager, Escrow Administration
Facsimile No: 44 20 7777 5410
44 20 7777 5450
Email address: will.manns@jpmorgan.com
philip.runciman@jpmorgan.com

(e) To each of the Subordinate Secured Parties at the mail and facsimile address specified on Schedule A.

The Parties may designate additional addresses for particular communications as required from time to time, and may change any address, by notice given ten days in advance of such additions or changes. Immediately upon receiving communications by facsimile or e-mail transmission, a Party may request a repeat transmittal of the entire communication or confirmation of particular matters.

All notices and other communications given to any Party in accordance with the provisions of this Agreement shall be deemed to have been given on the date of receipt if delivered by hand or overnight courier service, or the day after the date of receipt if sent by facsimile or e-mail, or on the date seven Business Days after dispatch by certified or registered mail if mailed, in each case delivered, sent or mailed (properly addressed) to such Party as provided in this Section or in accordance with the latest unrevoked direction from such Party given in accordance with this Section.

9.7. Incumbency Certificates; Notices.

(a) The Operator shall furnish the Trustee and Paying Agent, from time to time, with duly executed incumbency certificates showing the names, titles and specimen signatures of the persons authorized on behalf of Operator, TINWORTH and the Subordinate Secured Parties, respectively, to give the notifications and approvals required by this Agreement and such other material in relation to the opening and operating of the Accounts as Trustee and Paying Agent may reasonably request. The Trustee and Paying Agent has a general right, in relation to the receipt of notices, instructions and certificates, to act in accordance with normal banking practice. The Operator shall furnish to the Trustee and Paying Agent from time to time any information as the Trustee and Paying Agent may reasonably specify as being necessary or desirable to enable the Trustee and Paying Agent to perform its functions hereunder.

(b) The Trustee and Paying Agent shall furnish the Operator, from time to time, with notice of the officers of the Trustee and Paying Agent who are authorized to act on its behalf in the performance by the Trustee and Paying Agent of its duties under this Agreement.

9.8. No Amendment Except in Writing.

This Agreement may not be revoked, amended, modified, varied or supplemented except by an instrument in writing signed by the Parties hereto after submission to the Trustee and Paying Agent of the written consent to such amendment of TINWORTH and the Subordinate Secured Parties; provided, however, the Parties agree that Schedule A may be revised and replaced from time to time with a new Schedule A upon receipt of a notification from a Consortium Member as to the identity of such Consortium Member's Subordinate Secured Party or confirmation or change of the respective Consortium Member's Account, accompanied by the written consent of such Subordinate Secured Party.

9.9. APPLICABLE LAW.

THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF ENGLAND AND WALES (the "Applicable Law").

9.10. Benefit of Agreement.

This Agreement shall be binding upon the Parties, and inure to the benefit of, the Parties, each Consortium Member, TINWORTH and each Subordinate Secured Party and their respective successors and assigns.

9.11. Language.

All notices and documents given under this Agreement shall be in English.

9.12. Third Party Rights.

The Parties agree that TINWORTH, the Consortium Members and each of their Subordinate Secured Parties has the right to enforce the terms of this Agreement to the extent necessary to enforce their benefits hereunder, but that no other person has any right under the Contracts (Rights of Third Parties) Act 1999 to enforce or to enjoy the benefit of any term of this Agreement.

9.13. Perpetuity Period.

The perpetuity period under the rule against perpetuities, if applicable to this Agreement, shall be the period of eighty years from the date of this Agreement.

9.14. Winding Up of Trust.

If the Trustee and Paying Agent with the written consent of the Operator, TINWORTH and Subordinate Secured Parties determines that all of the Secured Obligations have been fully and finally discharged then the trust shall be wound up. At that time the Trustee and Paying Agent shall, at the cost and expense of the Operator, release, without recourse or warranty, all of the security held by it hereunder and the Trustee and Paying Agent shall be released from its obligations under this Agreement (save for those which arose prior to such winding-up). The Trustee and Paying Agent shall also reassign to the relevant parties those rights assigned to it pursuant to the Crude Oil Sale Contracts Assignment and shall forthwith instruct the Account Bank to transfer all amounts together with any accrued but uncredited interest, if any, standing to the credit of the Accounts to the Consortium Member Accounts and close the Accounts.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as a deed by their respective duly authorized signatories as of the date first above written.

Executed as a deed by:
VAALCO GABON (ETAME), Inc.,
acting by W. Russell Scheirman and
Robert L. Gerry III acting under the authority of
VAALCO Gabon (ETAME), Inc.

By: **[SIGNED]**
Name:
Title:

By: **[SIGNED]**
Name:
Title:

Executed as a deed by:
JPMORGAN CHASE BANK

[SIGNED]
Authorized Signatory

In the presence of

Signature of Witness: **[SIGNED]**

Name of Witness:

Address of Witness:

Occupation of Witness:

The Common Seal of:
J.P. MORGAN TRUSTEE AND DEPOSITARY COMPANY LIMITED
was hereunto affixed
in the presence of:

[SIGNED]
Authorised Signatory

[SIGNED]
Authorised Signatory

IN WITNESS WHEREOF, TINWORTH acknowledges and consents to the terms of this Agreement, executed by its duly authorized signatory as of the date first above written.

TINWORTH LIMITED

By: **[SIGNED]**
Name:
Title:

By: **[SIGNED]**
Name:
Title:

Schedules

A. Consortium Members Account and Subordinate Secured Party Designations

B. Trustee Fee Schedule

C. Funds Transfer Confirmation Contact Party Designation

D. TINWORTH Draw Notice

E. Notice of Assignment of Crude Oil Sales Contract

F. Acknowledgement of Crude Oil Sales Contract Assignment

G. Notice of Assignment of Consortium Member’s Account

H. Acknowledgement of Assignment of Consortium Member’s Account

I. Appointment Instrument

SCHEDULE A
CONSORTIUM MEMBERS ACCOUNT AND SUBORDINATE SECURED PARTY DESIGNATIONS

SCHEDULE B
TRUSTEE AND PAYING AGENT AND ACCOUNT BANK FEE SCHEDULE

Initial Acceptance Fee:	US$25,000
Etame Revenue Account Administration Fee:	US$7,500 per annum or part thereof
Etame Operating Account Administration Fee:	US$7,500 per annum or part thereof
TINWORTH Reserve Account Administration Fee:	US$7,500 per annum or part thereof

SCHEDULE C
FUNDS TRANSFER CONFIRMATION CONTACT PARTY DESIGNATION

VAALCO Gabon (Etame) Inc.
4600 Post Oak Place Suite 309
Houston, TX 77098 USA
Attn: W. Russell Scheirman
President
Tel: 713-499-1463
Fax: 713-623-0982

PetroEnergy Resources Corporation
7th Floor, JMT Building
ADB Avenue, Ortigas Center
Pasig City, Metro Manila Philippines
Tel: 632-633-8716
Fax: 632-633-8730
Attn: Milagros V. Reyes, President

Nissho Iwai Corporation
3-1, Daiba 2-Chome
Minatoku, Tokyo 135-8655
Japan
Attn: Mr. Shinichi Teranishi
General Manager
Offshore Energy Project Dept.
Tel: 813-3588-2694
Fax: 813-3588-4547

Sasol Petroleum International (Pty) Ltd.
7th Floor, Marble Arch Tower
55 Bryanston Street
London W1H 7AJ
Tel: 44-207-868-2232
Fax: 44-207-868-8600
Attn: Hans Oesterle
Exploration Manager

PanAfrican Energy Gabon Corporation
PanAfrican Energy Corporation Ltd.
PO Box 332, Sir Walter Raleigh House
48-50 Esplanade, St. Helier, Jersey
Channel Islands JE4 9YA
Tel: 44(0) 1534 700900
Fax: 44(0) 1534 700901
Attn: David Lyons
President

Director General de Hydrocaxbures
Ministere des Mines de L'Energie, du
Petrole et des Ressources Hydraulique
B.F. 2199 Libreville Gabon
Attn: Jean KOUMBI GUIYEDI
Directeur de l'Exportation
Tel: 241 76 39 23
Fax: 241 72 49 90

West Atlas Afrique, Ltd.
7th Floor, Marble Arch Tower
55 Bryanston Street
London W1H 7AJ
Tel: 44-207-868-2232
Fax: 44-207-868-8600
Attn: Hans Oesterle
Exploration Manager

TINWORTH
c/a Fred.Olsen Production A.S.
Fred.Olsensgt.2
P.O. Box 1159 Sentrum
0152 OSLO
Norway
Tel: 47-22-34-10-00
Fax: 47-22-42-9946
Attn: Georg S. Onsrud, director

SCHEDULE D
TINWORTH DRAW NOTICE

From: TINWORTH, Ltd
To: Trustee and Paying Agent and the Account Bank
Copy to: The Operator, the other Consortium Members, and the Subordinate Secured Parties
Dated:

TINWORTH DRAW NOTICE

Dear Sirs

Relating to a Trustee and Paying Agent Agreement dated 26 June 2002 between Vaalco Gabon (Etame), Inc., JPMorgan Chase Bank, London Branch and J.P. Morgan Trustee and Depositary Company Limited as from time to time modified, supplemented or amended in accordance with the terms thereof. Terms not otherwise defined herein shall have the meaning given to them in the Trustee and Paying Agent Agreement.

1. We hereby certify that the Operator has failed to pay the Compensation in the amount of US$____________ (the ‘‘Default Amount”) to TINWORTH under the FPSO Contract on the due date thereof and that all applicable grace periods have expired. **TINWORTH hereby declares that a Payment Default has occurred**.

2. We hereby further certify that the Default Amount is now due and owing to TINWORTH under the FPSO Contract. Pursuant to Section 5.3 of the Trustee and Paying Agent Agreement we hereby direct the Trustee and Paying Agent to distribute the lesser of (i) the Default Amount and (ii) the balance of the TINWORTH Reserve Account up to the TINWORTH Reserve Account Maximum Balance to TINWORTH at the following account:

[specify bank account]

3. Our notice details for the purpose of receiving communications under the Trustee and Paying Agent Agreement are as follows:

Address:
Attention:
Telephone No:
Facsimile No:
Email Address:

4. We hereby further certify that a copy of this TINWORTH Draw Notice has been sent by facsimile with an overnight copy sent via international courier to each of the Operator, the other Consortium Members, and the Subordinate Secured Parties as designated on the most recent Schedule A delivered to TINWORTH pursuant to Section 6.1(b) of the Trustee and Paying Agent Agreement.

5. This TINWORTH Draw Notice shall be governed by, and construed in accordance with, English law.

IN WITNESS WHEREOF this TINWORTH Draw Notice has been executed and is intended to be and is hereby delivered on the date first above written.

TINWORTH, Ltd

____

EXECUTED BY [ ])

As attorney for and one behalf of) ____________________

[ ])

Witnessed by:

Name:

Address:

SCHEDULE E
FORM OF NOTICE OF ASSIGNMENT OF CRUDE OIL SALES CONTRACT

(on the Operator's letterhead)

To: [Counterparty to the Crude Oil Sales Contract]

Dear Sirs,

We hereby give you notice that pursuant to the Etame Field Trustee and Paying Agent Agreement dated 26 June 2002 between ourselves and _____________ [name of Trustee and Paying Agent] (the **"Trustee and Paying Agent"**) and _____________ [name of Account Bank] (the **"Account Bank"**) we have assigned to the Trustee and Paying Agent, all our right, to and in respect of each amount payable in U.S. Dollars pursuant to sales of crude oil produced from the Etame Field (as more particularly described in the operating agreement (being the joint operating agreement effective as of April 4, 1997 between Vaalco Gabon (Etame), inc., VAALCO Energy (Gabon), Inc., Western Atlas Afrique Ltd., Petrofields Exploration & Development Co. Inc. and Alcorn Petroleum and Mineral Corporation, as the same has been and may hereafter be modified, supplemented or amended, including any extension or renewal thereof and any successors of the original parties) and exported from the Project (being the floating production storage and offloading system and the three oil wells existing in the Etame Field and such other wells or facilities as may be added to develop the Etame Field) and any amounts payable on account of interest due by reason of the late payment for such crude oil under the Contract, in each case net of sales commissions provided for in the Contract or in any sales agency agreements entered into in connection therewith.(the **"Crude Oil Sale Contract Revenues"**) in respect of [details of contract] (the **"Contract"**) and all liens, security interests, Letters of Credit, mortgages or similar rights securing payment by [name of buyer] (the **"Buyers"**) of the Crude Oil Sales Contract Revenues in respect of the Contract.

With effect from your receipt of this notice we hereby give you notice that we have agreed that:

(a) all Crude Oils Sales Contract Revenues under or arising from the Contract should be made to [specify bank account];

(b) all rights to compel performance of payment of Crude Oils Sales Contract Revenues under or arising from the Contract shall be exercisable by the Trustee and Paying Agent or its nominee and agents (although we shall remain liable to perform all the obligations assumed by us under the Contract); and

(c) all rights, interests and benefits whatsoever accruing to or for the benefit of ourselves for the payment of the Crude Oils Sales Contract Revenues under or arising from the Contract belong to the Trustee and Paying Agent and no changes may be made to the terms of the Contract nor may the Contract be terminated without the Trustee and Paying Agent's consent with respect to the payment of any monies thereunder.

You are hereby authorized and instructed, without requiring further approval from us, to provide the Trustee and Paying Agent with such information relating to the Contract as it may from time to time request and to send copies of all notices issued by you under the Contract to the Trustee and Paying Agent as well as to us.

These instructions may not be revoked, nor may the terms of the Contract be amended, varied or waived without the prior written consent of the Trustee and Paying Agent.

Please acknowledge receipt of this notice by signing and dating the acknowledgement set out on the enclosed copy and returning it to the Trustee and Paying Agent.

Yours faithfully,

for and on behalf of
[the Operator]

SCHEDULE F
FORM OF ACKNOWLEDGEMENT OF CRUDE OIL SALES CONTRACT ASSIGNMENT

To: [Insert name of Trustee and Paying Agent]

[insert address]

Attention:

We acknowledge receipt of the notice dated [ ] (the "Notice"). We confirm that we have not received notice of any previous assignments or charges of or over any of the rights, interests and title in, to or in respect of the Contract and that we will comply with the terms of the Notice.

We further agree and confirm that:

(a) we will not, without your prior written consent, vary, suspend, rescind, discharge or otherwise terminate the Contract or in any way prejudice the rights, titles, benefits and interests assigned to you;

(b) we will not claim any set-off or counterclaim to your prejudice in respect of any moneys payable under the Contract;

(c) we will procure that payments are made to you in accordance with the authority and instruction contained in the Notice; and

(d) we will not withhold consent to the assignment of the Contract by you to another person.

Yours faithfully,

For and on behalf of [ ]

By:

Date:

SCHEDULE G
FORM OF NOTICE OF ASSIGNMENT

(On Consortium Member's letterhead)

To: [Insert Trustee and Paying Agent and Operator's Name and Address]

Dear Sirs,

We hereby give you notice that pursuant to an agreement dated [ ] between ourselves and [Subordinate Secured Party] (the **"Subordinate Secured Party"**) we have assigned with full title guarantee to the Subordinate Secured Party by way of security absolutely all our right, title and interest in, to and in respect of the Etame Operating Account as defined and governed under the Etame Field Trustee and Paying Agent Agreement dated 26 June 2002 (the **"Trust Agreement"**) including all monies which may be payable to us in respect of the Etame Operating Account. We acknowledge that the right, title and interest in, to and in respect of the Etame Operating Account so assigned is subject to the rights of the Trustee and Paying Agent and the Account Bank under the Trust Agreement.

With effect from your receipt of this notice we hereby give you notice that we have agreed that:

(a) all payments to be made to us under or arising from the Etame Operating Account should be made to [specify bank account ("Designated Account")]; and

(b) all rights, interests and benefits whatsoever accruing to or for the benefit of ourselves arising from the Etame Operating Account belong to the Subordinate Secured Party.

We hereby covenant with the Trustee and Paying Agent on behalf of itself and as trustee for an on behalf of the Beneficiaries that we will pay and discharge those Secured Obligations to which we are liable when due.

You are hereby authorized and instructed, without requiring further approval from us, to provide the Subordinate Secured Party with such information relating to the Etame Operating Account as it may from time to time request and to send copies of all notices issued by you under the Trust Agreement to the Subordinate Secured Party as well as to us.

These instructions may not be revoked, nor may the Designated Account be amended or changed without the prior written consent of the Subordinate Secured Party.

Please acknowledge receipt of this notice by signing and dating the acknowledgement set out on the enclosed copy and returning it to Subordinate Secured Party.

Yours faithfully,

Executed as a Deed by:

[Insert relevant execution clause]

[Consortium Member]

SCHEDULE H
FORM OF ACKNOWLEDGEMENT OF ASSIGNMENT

To: [Subordinate Secured Party]

[insert address]

Attention:

We acknowledge receipt of the Notice of Assignment dated [ ] (the "Notice") from [Consortium Member] ("your Consortium Member"). We confirm that we have not received notice of any previous assignments or charges of or over any of the rights, interests and title in, to or in respect of your Consortium Member's interest in and to the Etame Operating Account and that we will comply with the terms of the Notice. Terms defined in the Notice shall have, when used in this acknowledgement, the same meaning herein as therein, unless the context otherwise requires.

We further agree and confirm that:

(a) we will not, without your prior written consent, amend or change the Designated Account or in any way prejudice the rights, titles, benefits and interests assigned to you;

(b) we will procure that payments are made to you in accordance with the authority and instruction contained in the Notice;

(c) we will not withhold consent to the assignment of the Designated Account by you to another person; and

(d) we will not claim any set off or counterclaim to your prejudice in respect of any moneys held in the Designated Account; and

(e) we will not revoke, amend, modify, vary or supplement any of the Trust Agreement without evidence of your consent, except with respect to changes in Schedule A to the extent permitted under Section 9.8 of the Trust Agreement insofar as such changes modify the identity of other Subordinate Secured Parties and/or Consortium Members' Accounts other than your Consortium Member's Account.

Yours faithfully,

For and on behalf of [insert name of Trustee and Paying Agent]

And

For and on behalf of [VAALCO Gabon (Etame), Inc.]

By:

Date:

By: ______________________
Name: ______________________
Title: ______________________

Executed as a deed by:
VAALCO GABON (ETAME), Inc.
acting by [name of person signing] and
[name of person signing] acting under
the authority of VAALCO GABON (ETAME), Inc.

By: ______________________
Name: ______________________
Title: ______________________

By: ______________________
Name: ______________________
Title: ______________________

Executed as a deed by:
VAALCO GABON (ETAME), Inc.
acting by [name of person signing] and
[name of person signing] acting under
the authority of VAALCO GABON (ETAME), Inc.
as attorney for [Retiring Party]

By: ______________________
Name: ______________________
Title: ______________________

By: ______________________________
Name: ______________________________
Title: ______________________________

IN WITNESS WHEREOF, TINWORTH acknowledges and consents to the terms of this Agreement, executed by its duly authorized signatory as of the date first above written.

TINWORTH LIMITED

By: ______________________________
Name: ______________________________
Title: ______________________________

By: ______________________________
Name: ______________________________
Title: ______________________________

SCHEDULE I
FORM OF DEED OF ACCESSION

From: [Consortium Member]

To: Trustee and Paying Agent and the Account Bank

Copy to: The Operator, the other Consortium Members, and the Subordinate Secured Parties

Dated:

Dear Sirs

Consortium Member Accession Deed

Relating to a Trustee and Paying Agent Agreement dated 26 June 2002 between VAALCO Gabon (Etame), Inc., JPMorgan Chase Bank and J.P. Morgan Trustee and Depositary Company Limited as from time to time amended, varied, waived, novated or supplemented. Terms not otherwise defined herein shall have the meaning given to them in the Trustee and Paying Agent Agreement.

6. We hereby confirm that we have elected to sell our share of Crude Oil from the Project directly to a Buyer and have entered into a Crude Sharing Agreement with the Operator.

7. We acknowledge and agree that upon and by reason of our delivering this Accession Deed to the Trustee and Paying Agent and acceptance by the Trustee and Paying Agent of it we will thereby forthwith become a party to the Trustee and Paying Agent Agreement as a Consortium Member thereunder and shall be entitled to those rights and benefits, and be bound by those obligations, of the Operator that are set out in Sections 2.1 (save for the obligation of the Operator referred to in the 4th sentence thereof), 2.2, 2.3, 2.4, 2.5(b), 2.6, 2.7, 2.8, 8.1(a), (i), (m), (p)(iii) and 9.4(c) of the Trust and Paying Agent Agreement.

8. We hereby make the representations, warranties and covenants set out in Sections 2.7(b) and 8.1(q) to the Trustee and Paying Agent Agreement.

9. We confirm and agree that we have been, and will continue to be, solely responsible for making our own independent appraisal of and investigations into the financial condition, creditworthiness, condition, value, affairs, status and nature of the Project and the legality, validity, effectiveness, adequacy or enforceability of the Finance Documents and any documents or other matters delivered pursuant thereto or of any security purportedly granted by or pursuant thereto. We further confirm that we have not relied and will not hereafter rely on any of the Trustee and Paying Agent or any party to the Finance Documents:

(a) to check or enquire on our behalf into the adequacy, accuracy or completeness of any information provided by any person in connection with any of the Finance Documents;

(b) to assess or keep under review on our behalf the financial condition, creditworthiness, condition, value, affairs, status or nature of the Project; or

(c) to assess or keep under review on our behalf the legality, validity, effectiveness, adequacy or enforceability of the Finance Documents or any document or other matter delivered pursuant thereto or of any security purportedly granted by or pursuant thereto.

10. Our notice details for the purpose of receiving communications under the Trustee and Paying Agent Agreement are as follows:

Address:

Attention:

Telephone No:

Facsimile No:

Email Address:

11. This Accession Deed shall be governed by, and construed in accordance with, English law.

IN WITNESS WHEREOF this Accession Deed has been executed as a deed poll and is intended to be and is hereby delivered on the date first above written.

EXECUTED BY [ ])
As attorney for and one behalf of) ____________________
[ ])
Witnessed by:

Name:

Address:

Countersignature by Trustee and Paying Agent:

Vaalco Gabon (Etame) Inc.
4600 Post Oak Place Suite 309
Houston, TX 77098
USA

International Finance Corporation
2121 Pennsylvania Avenue N.W.
Washington D.C. 20433
USA

Tinworth Limited
C/o Fred. Olsen Production A.S.
Fred. Olsensgt.2
PO Box 1159 Sentrum
0152 OSLO
Norway

To: J.P. Morgan Trustee and Depositary Company Limited, 125 London Wall, London, England EC2Y 5AJ (the **"Trustee and Paying Agent")**

26 November 2002

Dear Sirs:

Re: Vaalco

1. We refer to the Etame Field Trustee and Paying Agent Agreement dated 26 June 2002 and made between Vaalco Gabon (Etame), Inc. ("Vaalco"), and the Trustee and Paying Agent and JPMorgan Chase Bank (London Branch) and acknowledged by Tinworth Limited ("TINWORTH") (the "Original Etame Field Trustee and Paying Agent Agreement"). Pursuant to Clause 8.1 (a) of the Original Etame Field Trustee and Paying Agent Agreement, the Trustee and Paying Agent shall act solely in accordance with instructions given to it by Vaalco for and on behalf of itself and the Consortium Members. Pursuant to Clause 9.8 of the Original Etame Field Trustee and Paying Agent Agreement, the Original Etame Field Trustee and Paying Agent Agreement may not be amended without the written consent to such amendment by TINWORTH and the International Finance Corporation, in its capacity as a secured subordinated party (the "Subordinated Secured Party").

2. Accordingly, Vaalco hereby directs and instructs the Trustee and Paying Agent to enter into the First Amendment to the Etame Field Trustee and Paying Agent Agreement (which is attached as an exhibit hereto) and to do anything else required in connection with the foregoing document or the implementation of the transactions contemplated thereby, and the Subordinated Secured Party and TINWORTH irrevocably give their consent to the amendments as set out in the First Amendment to the Etame Field Trustee and Paying Ager

3. So far as permitted by applicable law, we will at all times execute all such further documents and do all such further acts and things as may be necessary at any time or times in the opinion of the Trustee and Paying Agent to give effect to the provisions of this letter and the First Amendment to the Etame Field Trustee and Paying Agent.

4. We acknowledge that the Trustee and Paying Agent has not been responsible for reviewing the First Amendment to the Original Etame Field Trustee and Paying Agent Agreement on our behalf and that it is the commercial intention that the Trustee and Paying Agent should act on the instructions set out in paragraph 2 of this letter and that the parties hereto should make their own assessment of the amendments proposed.

5. Clause 8.10 of the Original Etame Field Trustee and Paying Agent Agreement shall be deemed to be incorporated herein save that any reference to "this Agreement" in such clause shall be construed as a reference to this letter.

6. This letter may be executed in any number of counterparts; all of which shall be deemed to be an original.

7. This letter shall be governed and construed in accordance with the laws of England and Wales.

Yours faithfully,

[SIGNED]
Vaalco Gabon (Etame) Inc.

[SIGNED]
(as acknowledged and agreed to by)

International Finance Corporation

[SIGNED]
(as acknowledged and agreed to by)
Tinworth Limited

FIRST AMENDMENT TO

ETAME FIELD

TRUSTEE AND PAYING AGENT AGREEMENT

AMONG

VAALCO GABON (ETAME), INC.

AND

J.P. MORGAN TRUSTEE AND DEPOSITARY COMPANY LIMITED

AND

JPMORGAN CHASE BANK, LONDON BRANCH

DATED AS OF NOVEMBER 26, 2002

FIRST AMENDMENT TO
ETAME FIELD
TRUSTEE AND PAYING AGENT AGREEMENT

AGREEMENT, dated as of November 26, 2002 among

(1) **VAALCO GABON (ETAME), INC.**, a corporation organised and existing under the laws of the State of Delaware, the United States of America (**"VGEI"**) on behalf of itself, in its capacity as Operator acting under the Operating Agreement, and as a Consortium Member and on behalf of each other Consortium Member and Pan African Energy;

(2) **JPMORGAN CHASE BANK, LONDON BRANCH** (the **"Bank"**), a financial institution organised and existing under the laws of England, acting through its branch located at Trinity Tower, 9 Thomas More Street, London, England EIW IYT; and

(3) **J.P. MORGAN TRUSTEE and DEPOSITARY COMPANY LIMITED** (the **"Trustee and Paying Agent"**), having its registered office at 125 London Wall, London, England EC2Y 5AJ.

WHEREAS:

(A) Pursuant to the Etame Field Trustee and Paying Agent Agreement dated June 26, 2002, (the **"Trustee and Paying Agent Agreement"**), VGEI agreed to (i) enter into Crude Oil Sales Contracts on behalf of Consortium Members (including Pan African Energy, a Jersey Corporation (**"Pan African Energy"**)), and agreed to have Crude Oil Sales Contracts Revenues made subject to the terms of the Trustee and Paying Agent Agreement and (ii) cause Pan African Energy and any Consortium Member that sells its share of Crude Oil directly to a Buyer under a Crude Oil Sales Contract to enter into an Accession Deed and direct that all Crude Oil Sales Contract Revenues under its Crude Oil Sales Contracts be paid to the Trustee and Paying Agent.

(B) Pan African Energy and certain other Consortium Members in the future may desire to sell their share of Crude Oil under contracts or pursuant to contractual arrangements entered into by such entity or on such entity's behalf such that the proceeds of sale are not subject to the Trustee and Paying Agent Agreement (hereinafter referred to as **"Excluded Sales Contracts"**, as more specifically referred to below).

(C) The Parties have agreed to amend the Trustee and Paying Agent Agreement to acknowledge such rights and to contemplate Excluded Sales Contracts subject to certain conditions.

NOW THEREFORE, the parties hereto agree that with effect from the date hereof the Trustee and Paying Agent Agreement shall be amended as follows:

ARTICLE 1.
DEFINITIONS

1.1 Definitions

All capitalised terms used in this Agreement (including the preamble and recitals) and not otherwise defined herein, unless the context otherwise requires, have the respective meanings given to such terms in the Trustee and Paying Agent Agreement.

1.2 Interpretation

In this Agreement, unless otherwise stated or unless the context otherwise requires:

(a) Headings are for convenience only and do not affect the interpretation of this Agreement;

(b) Words importing the singular include the plural and vice versa;

(c) An expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other body corporate and any Authority;

(d) A reference to a Section or party is a reference to that Section or that party to, this Agreement;

(e) A reference to a document includes an amendment or supplement to, or replacement or novation of, that document but disregarding any amendment, supplement, replacement or novation made in breach of this Agreement or the Trustee and Paying Agent Agreement;

(f) A reference to a party to any document includes that party's successors and permitted assigns; and

(g) No rule of construction applies to the disadvantage of a party because that party was responsible for the preparation of this Agreement or any part thereof.

ARTICLE 2.
AMENDMENTS

2.1 Amendment of Section 1.1 (Defined Terms)

Section 1.1 of the Trustee and Paying Agent Agreement is amended as follows:

(a) by inserting the following new definitions in the appropriate alphabetical location:

"Alternate Security Amount" shall mean the aggregate of the Pan African Secured Amount and all amounts secured by any Consortium Members pursuant to any Alternate Security as notified to the Trustee and Paying Agent by TINWORTH from time to time.

"Alternate Security" shall mean a security arrangement entered into by a Consortium Member in order to secure payment to TINWORTH of such Consortium Member's pro-rata share of liabilities under the FPSO Contract, provided that such arrangement is: (i) entered into at least 30 days prior to initial lifting of such Consortium Member's share of Crude Oil (except with respect to Pan African Energy), (ii) TINWORTH has provided such notice as set out in Section 2.9(b), and (iii) to the extent applicable, such Consortium Member's respective Subordinate Secured Parties have provided written notice of their consent to such security arrangement.

"Direct Sales Contracts" shall mean each and all of the sales contracts entered into directly by a Consortium Member (with each Consortium Member's written authorisation if the sales contract purports to be for and on behalf of the other Consortium Members), for the sale of their share of Crude Oil from the Project that are subject to the terms of this Agreement.

"Entitlement" means a quantity of Crude Oil of which a Consortium Member or Pan African Energy has the right and obligation to take delivery pursuant to the Production Sharing Contract, the Operating Agreement and the Crude Sharing Agreement.

"Excluded Sales Contracts" shall mean each and all of the sales contracts or contractual arrangement for the sale of Crude Oil from the Project which satisfy the conditions under Section 2.9(b)(i) or Section 2.9(b)(ii) and are:

(i) direct contracts or contractual arrangements entered into by Pan African Energy or any Consortium Member with any buyer of Pan African Energy's, or such Consortium Member's, share of Crude Oil from the Project;

(ii) contracts or contractual arrangements entered into by any Consortium Member (including the Operator) for and on behalf of Pan African Energy or any other Consortium Member with any buyer of Pan African Energy's, or such Consortium Member's, share of Crude Oil from the Project; or

(iii) contracts or contractual arrangements entered into by any Consortium Member (including the Operator) for and on behalf of Pan African Energy or any other Consortium Member with any Buyer of Pan African Energy's, or such Consortium Member's, share of Crude Oil from the Project, pursuant to the same contractual instrument as, or parallel with, a Crude Oil Sales Contract but only to the extent that provision has been made for separate invoicing and payment thereof to Pan African Energy or such Consortium Member, as the case may be;

as the same may be modified, supplemented or amended, including any extension or renewal thereof, and provided that, for greater certainty, the Parties acknowledge and agree that (i) so long as TINWORTH confirms in writing that Pan African Energy satisfies the condition stipulated in Section 2.9(b)(i) and/ or a relevant Consortium Member satisfies the condition stipulated in Section 2.9(b)(ii), and written notice is not otherwise provided to the Trustee and Paying Agent from the Operator and Pan African Energy and/ or such Consortium Member pursuant to Section 2.9(d), Pan African Energy and/ or such Consortium Member shall be understood and deemed at all times to make any and all sales of its share of Crude Oil from the Project under Excluded Sales Contracts, and (ii) until TINWORTH has confirmed in writing that Pan African Energy satisfies the condition stipulated in Section 2.9(b)(i) and/ or a relevant Consortium Member satisfies the condition stipulated in Section 2.9(b)(ii), and written notice is not otherwise provided to the Trustee and Paying Agent from the Operator, Pan African Energy and/ or such Consortium Member, Pan African Energy and/ or such Consortium Member shall be understood and deemed at all times to make any and all sales of its share of Crude Oil from the Project under Crude Oil Sales Contracts.

"Excluded Sales Contracts Revenues" shall mean each amount payable in any currency pursuant to the valid sale of an Entitlement of Crude Oil exported from the Project, and any amounts payable on account of interest due by reason of the late payment for Crude Oil, under the Excluded Sales Contracts, in each case net of sales commissions provided for in such contracts or in any sales agency agreements entered into in connection therewith, and not subject to the terms of this Agreement.

"Pan African Energy Security" shall mean an irrevocable letter of credit in favour of TINWORTH in the amount of the Pan African Secured Amount securing payment to TINWORTH of Pan African Energy's pro-rata share of liabilities under the FPSO Contract.

"Pan African Secured Amount" shall mean the amount of US$847,500 or as amended in accordance with the Security and Amending Agreement.

"Parent Company Guarantee" shall mean the guarantee dated 6 September 2001 by VAALCO Energy, Inc. to TINWORTH of certain obligations under the FPSO Contract.

"Security and Amending Agreement" shall mean the agreement dated November 7, 2002 between Pan African Energy, TINWORTH, and VGEI, in respect of, *inter alia*, the Pan African Energy Security.

(b) by amending the defined terms below to read as follows:

"Consortium Members" shall mean collectively VGEI, PetroEnergy, Sasol, and NISSHO, and in each case its successors and permitted assigns under the Production Sharing Contract and the Operating Agreement, excluding, for the purposes of this Agreement, Pan African Energy, unless otherwise agreed to in writing by Pan African Energy pursuant to Section 2.9(d) or if TINWORTH has not confirmed to the Trustee and Paying Agent that it is satisfied that the requirements of Section 2.9(b)(i) have been met.

"Crude Oil Sales Contract Revenues" shall mean each amount payable in U.S. Dollars pursuant to sales of Crude Oil exported from the Project, and any amounts payable on account of interest due by reason of the late payment for Crude Oil, under the Crude Oil Sales Contracts, in each case net of sales commissions provided for in such contracts or in any sales agency agreements entered into in connection therewith, and which, for greater certainty, shall not include Excluded Sales Contracts Revenues.

"Crude Oil Sales Contracts" shall mean:

(i) each and all of the sales contracts for the marketing and sale of Crude Oil from the Project entered into by the Operator on behalf of itself, those Consortium Members which have provided express written authorisation for the Operator to so act on their behalf, and the Government of Gabon and its assigns and each of the Buyers thereof; and

(ii) each and all of the Direct Sales Contracts;

as the same may be modified, supplemented or amended, including any extension or renewal thereof, and provided that, for greater certainty, the term "Crude Oil Sales Contracts" shall not include Excluded Sales Contracts and shall be subject to the terms of this Agreement, but a single contractual instrument may consist of an Excluded Sales Contract together with a Crude Oil Sales Contract.

"Crude Sharing Agreement" shall mean the Lifting and Entitlement Scheduling Agreement dated [____] 2002 among VGEI, Pan African Energy, Sasol, PetroEnergy, and NISSHO, as amended.

"NISSHO" shall mean Energy Resources Japan Etame (Gabon) Limited, formed under the laws of England.

"Secured Obligations" shall mean collectively such obligations owed by the Operator, for itself and as agent for and on behalf of the other Consortium Members to TINWORTH under the FPSO Contract (excluding the Alternate Secured Amount) and the several obligations, if any, owed by the Consortium Members to their respective Subordinate Secured Parties.

"Sasol" shall mean SASOL Petroleum West Africa Limited, an Isle of Man corporation.

2.2 Amendment of Sections 2.1 and 2.2 Designation of Trustee and Paying Agent and Etame Revenue Account

Sections 2.1 and 2.2 of the Trustee and Paying Agent Agreement are amended to read as follows:

"2.1 **Designation of Trustee and Paying Agent and Etame Revenue Account**

(a) The Operator hereby appoints J.P. Morgan Trustee and Depositary Company Limited as the Trustee and Paying Agent and J.P. Morgan Trustee and Depositary Company Limited hereby accepts its appointment as Trustee and Paying Agent and its obligations hereunder upon and subject to the terms and conditions of this Agreement. The Trustee and Paying Agent may delegate all or any of the rights, powers and discretions vested in it by this Agreement pursuant to Section 8.1(k).

(b) All Crude Oil Sales Contract Revenues shall be paid to the Trustee and Paying Agent. In the event any Consortium Member sells its share of Crude Oil directly under a Direct Sales Contract such Consortium Member shall, as shall be required by the Operator under the Crude Sharing Agreement, appoint J.P. Morgan Trustee and Depositary Company Limited as the Trustee and Paying Agent to which Crude Oil Sales Contract Revenues under its Direct Sales Contract shall be paid.

(c) Excluded Sales Contract Revenues shall not be paid to the Trustee and Paying Agent. For the avoidance of doubt, each of the Parties acknowledges and agrees that, except as provided for in Section 2.9(d), in no circumstances whatsoever shall any Excluded Sales Contract Revenues be paid to the Operator, its nominees or trustees, including without limitation the Trustee and Paying Agent, or otherwise become subject to the terms of this Agreement, by way of payment into the Etame Revenue Account or Etame Operating Account or otherwise;

(d) The Trustee and Paying Agent shall establish and maintain the Etame Revenue Account, to which all Crude Oil Sales Contract Revenues and any other monies which may be payable to Consortium Members in respect of any Crude Oil Sales Contracts shall be paid. The Trustee and Paying Agent shall deposit in the Etame Revenue Account each amount of Crude Oil Sales Contract Revenues and any other monies which may be payable to Consortium Members in respect of any Crude Oil Sales Contracts received by it.

2.2 The Operator shall and shall cause any Consortium Member selling Crude Oil under a Direct Sales Contract to send to the Trustee and Paying Agent (i) any Direct Sales Contract promptly following the execution of the contract and (ii) a copy of each invoice at the same time that such invoice is sent to the relevant Buyer."

2.3 Amendment of Section 2.7 Crude Oil Sales Contracts Assignment

Section 2.7(a) of the Trustee and Paying Agent Agreement is amended by adding the following language at the end of that provision:

"Excluded Sales Contract Revenues are not subject to the Crude Oil Sales Contracts Assignment under this Agreement except as provided in Section 2.9(d)."

2.4 Amendments to Section 2.9 Direct Sales/Crude Sharing Agreements

Section 2.9 of the Trustee and Paying Agent Agreement is amended to read as follows:

(a) "In the event that any Consortium Member elects to sell its share of Crude Oil from the Project under a Direct Sales Contract, the Operator shall, as applicable, cause such Consortium Member to enter into the Crude Sharing Agreement with the Operator whereby such Consortium Member shall covenant, among other matters, to perform, with respect to the Direct Sales Contracts and Crude Oil Sales Contract Revenues related to such Consortium Member's share of Crude Oil, the obligations of the Operator under Sections 2.1 (save for the obligation of the Operator referred to in the 2nd sentence of 2.1(b)), 2.2, 2.3, 2.4, 2.5(b), 2.6, 2.7, 2.8, 8.1(a), (i), (m), (p)(iii), and 9.4(c) as more particularly set forth under the Crude Sharing Agreement (including, for avoidance of doubt, an obligation of the Operator to cause any such Consortium Member to duly execute an assignment of such Consortium Member's rights under such Direct Sales Contract to the Trustee and Paying Agent in accordance with Section 2.5) and to execute an instrument acceding to this Agreement in substantially the form of Schedule I hereto ("Accession Deed"), in which event, the Trustee and Paying Agent shall be entitled to Fees and Expenses and Additional Remuneration in connection therewith pursuant to Section 8.2 and 8.3.

(b) The Parties agree that during the term of the FPSO Contract TINWORTH shall provide the Trustee and Paying Agent and the Operator with a written notice that:

(i) it is reasonably satisfied that the Pan African Energy Security is in effect prior to the time of payment for initial deliveries under an Excluded Sales Contract of Pan African Energy, and that the Guaranteed Obligations pursuant to and defined under the Parent Company Guarantee have been reduced by an amount equal to the Pan African Secured Amount; or

(ii) it is reasonably satisfied that the Alternate Security of a particular Consortium Member is in effect prior to the time of payment for initial deliveries under an Excluded Sales Contract of that Consortium Member, and that the Guaranteed Obligations pursuant to and defined under the Parent Company Guarantee and the amount of the TINWORTH Reserve Account Maximum Balance are, in each case, reduced by an amount equal to the amount secured pursuant to the Alternate Security, provided by such Consortium Member, in such amount as stated therein;

and the parties acknowledge that the Trustee and Paying Agent shall be entitled to rely upon any such notice from TINWORTH without making any further inquiries or verifying the facts stated therein.

(c) Upon receipt of such written notification, the Trustee and Paying Agent shall disburse from the TINWORTH Reserve Account to such particular Consortium Member an amount equal to the amount of the Alternate Security provided by such Consortium Member.

(d) Upon written notification to the Trustee and Paying Agent from the Operator and Pan African Energy and/ or any Consortium Member, as provided therein, payment of Excluded Sales Contract Revenues in respect of a particular Excluded Sales Contract may be paid into the Etame Revenue Account, or otherwise Pan African Energy's or such Consortium Member's interest under an Excluded Sales Contract may become subject to the terms of this Agreement, and to the application of certain defined terms and provisions under this Agreement, as specifically so consented to in writing by Pan African Energy in respect of its interest in an Excluded Sales Contract or by another Consortium Member in respect of its interest in an Excluded Sales Contract."

2.5 Amendments to Section 5.2 Payment

The third and fourth paragraphs of Section 5.2 of the Trustee and Paying Agent Agreement are amended to read as follows:

"*Second*, deposit such amounts in the TINWORTH Reserve Account as may be necessary to ensure that the credit balance of the TINWORTH Reserve Account, including the value of any Permitted Investments and accrued interest in accordance with Section 7, is equal to $1,652,500, as may be adjusted from time to time pursuant to notification from TINWORTH under Section 2.9(b)(ii) (the **"TINWORTH Reserve Account Maximum Balance"**).

Third, distribute the balance remaining in the Etame Operating Account, if any, to each of the Consortium Member's Accounts the amounts in accordance with their respective entitlements, as shall be specified in the notice received by the Trustee and Paying Agent from the Operator at least three (3) Business Days prior to the date of such distribution."

2.6 Amendment to Schedule D

Schedule D of the Trustee and Paying Agent Agreement is amended to read as set out in Annex 1 to this Agreement.

ARTICLE 3.
MISCELLANEOUS

3.1 Effect

(a) All references in the Trustee and Paying Agent Agreement to "this Agreement", "herein", "hereof", "hereunder", "hereto", or expressions of like meaning shall be references to the Trustee and Paying Agent Agreement as amended by this Agreement.

(b) Except as amended hereby, the Trustee and Paying Agent Agreement shall remain in full force and effect and shall be read and construed as one document with this Agreement.

3.2 Governing Law

This Agreement is governed by, and shall be construed in accordance with, the laws of England and Wales.

3.3 Authority

The Operator represents and warrants to the other Parties hereto that it is duly authorised to act for and on behalf of the Consortium Members in entering into this Agreement.

3.4 Further Assurance

So far as permitted by applicable law, the parties to this Agreement will at all times execute all such further documents and do all such further acts and things as may be necessary at any times in the opinion of the Trustee and Paying Agent to give effect to the provisions of this Agreement

3.5 Indemnification

For the avoidance of doubt, Section 8.10 (Indemnification) of the Trustee and Paying Agent Agreement as amended by this First Amendment to the Etame Field Trustee and Paying Agent Agreement shall apply, *mutatis mutandis*, to this First Amendment to the Etame Field Trustee and Paying Agent Agreement as if set out herein in full.

3.6 Rights of Third Parties

Except in respect of the rights of Pan African Energy or any Consortium Member under an Excluded Sales Contract described herein and as otherwise provided in Section 9.12 of the Trustee and Paying Agent Agreement, none of the terms of this Agreement are intended to be enforceable by any third party under the Contracts (Rights of Third Parties) Act 1999.

3.7 Amendments

This Agreement may not be revoked, amended, modified, varied or supplemented except by an instrument in writing signed by the Parties hereto after submission to the Trustee and Paying Agent of the written consent to such amendment of TINWORTH and the Subordinate Secured Parties, provided that rights of Pan African Energy or any Consortium Member under an Excluded Sales Contract may not be prejudiced or derogated from as described herein without their written consent.

3.8 Counterparts

This Agreement may be executed in several counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same agreement. This Agreement may be executed and delivered by facsimile.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as a deed by their respective duly authorised signatories as of the date first above written.

Executed and delivered as a deed by:
VAALCO GABON (ETAME), INC.
By: **[SIGNED]**
Name: ______________________
Title: ______________________

Executed and delivered as a deed by:
JPMORGAN CHASE BANK

[SIGNED]
Authorised Signatory

In the presence of: ______________

Signature of Witness: **[SIGNED]**

Name of Witness: ______________

Address of Witness: ______________

Occupation of Witness: ______________

The Common Seal of:
J.P. MORGAN TRUSTEE AND
DEPOSITARY COMPANY LIMITED

was hereunto affixed in the presence of:

[SIGNED]
Authorised Signatory

[SIGNED]
Authorised Signatory

IN WITNESS WHEREOF, pursuant to Section 9.8 of the Trustee and Paying Agent Agreement, TINWORTH acknowledges and consents to the terms of this First Amendment to Etame Field Trustee and Paying Agent Agreement, executed by its duly authorised signatory as of the date first above written.

TINWORTH LIMITED

By: **[SIGNED]**
Name:
Title:

**ANNEX 1 TO FIRST AMENDMENT
TO ETAME FIELD TRUSTEE
AND PAYING AGENT AGREEMENT**

FORM OF TINWORTH DRAW NOTICE

From: Tinworth Limited

To: Trustee and Paying Agent and the Account Bank, Barclays Offshore Banking Unit, Mauritius

Copy to: The Operator, the other Consortium Members, the Subordinate Secured Parties, PanAfrican Energy Gabon Corporation, c/o PAE PanAfrican Energy Corporation Ltd.

Dated:

Dear Sirs

TINWORTH DRAW NOTICE

Relating to (i) a Trustee and Paying Agent Agreement dated 26 June 2002 between Vaalco Gabon (Etame), Inc., JPMorgan Chase Bank, London Branch and J. P. Morgan Trustee and Depository Company Limited as from time to time modified, supplemented or amended in accordance with the terms thereof (the **"Trustee and Paying Agent Agreement"**) and (ii) a Security and Amending Agreement dated November 7, 2002 between PanAfrican Energy Gabon Corporation, Vaalco Gabon (Etame), Inc. and Tinworth Limited (the **"Security Agreement"**) and the irrevocable letter of credit arrangement between PAE PanAfrican Energy Corporation, Barclays Bank, Mauritius and Tinworth Limited (the **"Letter of Credit"**) [Drafting Note: further recitations to be added if necessary, to describe Alternate Security provided by other Consortium Members]. Terms not otherwise defined herein shall have the meaning given to them in the Trustee and Paying Agent Agreement.

1. We hereby certify that the Operator has failed to pay the Compensation in the amount of US$[________] (the **"Default Amount"**) to TINWORTH under the FPSO Contract on the due date thereof and that all applicable grace periods have expired. **TINWORTH hereby declares that a Payment Default has occurred.**

2. We hereby further certify that the Default Amount is now due and owing to TINWORTH under the FPSO Contract. We certify that [_______]%[1] ([*number*] per cent) of the Default Amount is now due and owing under the Trustee and Paying Agent Agreement (the **"TPA Default Amount"**) and [_____]%[2] [*number*] percent) of the Default Amount is now due and owing under the Letter of Credit (the **"Letter of Credit Default Amount"**).

Pursuant to Section 5.3 of the Trustee and Paying Agent Agreement we hereby direct the Trustee and Paying Agent to distribute the lesser of (i) the TPA Default Amount and (ii) the balance of the TINWORTH Reserve Account up to the TINWORTH Reserve Account Maximum Balance to TINWORTH at the following account:

[specify bank account]

Pursuant to the Letter of Credit, we hereby direct Barclays Bank, Mauritius to distribute TINWORTH the lesser of (i) the Letter of Credit Default Amount and (ii) US$[______][3] at the following account:

[specify bank account]

[Drafting Note: Additional provision in the event other Consortium Members have provided Alternate Security.]

3. Our notice details for the purpose of receiving communications under the Trustee and Paying Agent Agreement and Letter of Credit are as follows:
Address:
Attention:
Telephone No:
Facsimile No:
Email Address:

4. We hereby further certify that a copy of this TINWORTH Draw Notice has been sent via international courier to each of the Operator, the other Consortium Members, and the Subordinate Secured Parties as designated on the most recent Schedule A delivered to TINWORTH pursuant to Section 6.1(b) of the Trustee and Paying Agent Agreement.

[1] This percentage shall be equal to the difference between 100% and the PanAfrican Percentage Participation and Participation Percentage of any other Consortium Member that have provided Alternate Security as defined in the Security Agreement.

[2] This percentage shall equal to the PanAfrican Percentage Participation, as defined under the Security Agreement. Additional language to be inserted in the event other Consortium Members provide Alternate Security.

[3] This amount shall be equal to the PanAfrican Secured Amount as defined in the Security Agreement.

5. This TINWORTH Draw Notice shall be governed by, and construed in accordance with, English law.

IN WITNESS WHEREOF, this TINWORTH Draw Notice has been executed and is intended to be and is hereby delivered on the date first above written.

______________________________)		
)		
Executed by [ ])		______________________
As attorney for and on behalf of)		
[ ]		

Witness by:

Name:

Address:

VAALCO Gabon (Etame), Inc.
4600 Post Oak Place, Suite 309
Houston, Texas 77027
Tel: (713) 623-0801
Fax: (713) 623-0982

February 1, 2006

Sojitz Etame Ltd.
Kokusai Shin-Akasaka Building
1-20, Akasaka 6-chome,
Minato-ku
Tokyo 107-8655 JAPAN
Attn: Mr. Shinichi Teranishi
General Manager
Offshore Energy Project Dept.

PetroEnergy Resources Corporation
7TH Floor, JMT Condominium Bldg.
ADB Avenue
Ortigas Center, Pasig City
Philippines
Attn: Milagros V. Reyes, President

PanAfrican Etame Inc.
C/O PanAfrican Energy Corporation Ltd.
PO Box 332, Sir Walter Raleigh House
48-50 Esplanade, St. Helier, Jersey
Channel Islands JE4 9YA
Attn: Paul L. Keyes
Chief Executive Officer

Sasol Petroleum West Africa Ltd.
93 Wigmore Street
London W1U 1HJ, United Kingdom
Attn: Hans Oesterle, General Manager

RE: Etame Field Trustee and Paying Agent Agreement Amendment

Ladies and Gentlemen:

Enclosed please find an Amendment to the "Etame Field Trustee and Paying Agent Agreement" fully executed on behalf of all the parties thereto. In connection with our plan to tie other fields into the FPSO it was necessary to modify the definition in the agreement of the term "Field" by deleting it in its entirely and substituting therefore the term "Etame Block Fields" to take into consideration our discovery of the Avouma, South Tchibala and Ebouri fields and any subsequent discoveries that are granted exclusive exploration authorizations by the government.

I would appreciate it if you would acknowledge and consent to this change by executing this letter in the space provided below for your name and returning it to me by either fax or email.

Very truly yours,

[SIGNED]____________________
W. Russell Sheirman
President & Chief Financial Officer

Agreed to and Accepted
This 9th day of February 2006

By: **[SIGNED]**________________
Company:
Name:
Title:

VAALCO Gabon (Etame), Inc.
4600 Post Oak Place, Suite 309
Houston, Texas 77027
Tel: (713) 623-0801
Fax : (713) 623-0982
February 1, 2006

J.P. Morgan Trustee and Depository Company Limited
125 London Wall
London EC2Y 5AJ
("the Trustee and Paying Agent")

JPMorgan Chase Bank
Trinity Tower
9 Thomas More Street
Lonclori E1W 1YT
(the "Account Bank")

Dear Sirs,

We refer to the agreement made between us entitled '"Etame Field Trustee and Paying Agent Agreement" dated 26 June 2002, as amended on 26 November 2002 (together the "Agreement"). Words and expressions defined in the Agreement shall have the same meanings when used herein.

Since the Agreement was entered into, certain fields (in addition to the Elame Field) have been discovered within the area covered by the Production Sharing Contract and Operating Agreement and such fields are expected to be brought into production through the same FPSO (as such term is defined in that certain contract styled FPSO Contract for the Provision and Operation of and FPSO for the Elame Field dated August 20, 2001 between Tinworth Limited and VAALCO Gabon (Etame), Inc.) as is used for the Etame field. It has accordingly been proposed that the arrangements set out In the Agreement should apply with respect to such fields, and to Crude Oil produced therefrom, in the same way as to the Etame field.

Accordingly, it is proposed that, with effect from the date of this letter:

(1) The definition of "Field" set out in Section 1.1 of the Agreement shall be replaced by the following new definition of "Etame Block Fields":

> "Etame Block Fields" shall mean the exploitation areas within the Etame Block (being the area offshore the southern coast of Gabon identified as the "Delimited Area" (Zone Délimitée") in the Production Sharing Contract), including the Etame field in the Avouma and South Tchibila fields, and any other fields that contain hydrocarbon accumulations, and in relation to which one or more exclusive exploitation authorizations shall from time to time have been granted by the State of Gabon":

(2) all references in the Agreement to the "Field" shall be replaced by references to all or any or the "Etame Block Fields" as the context requires.

Except as amended hereby, the Agreement shall remain in full force and effect and shall be read and construed as one document with this letter agreement.

This letter agreement is governed by, and shall be construed in accordance with, the laws of England and Wales.

We represent and warrant to the other parties hereto that we are duly authorized to act for and on behalf of the Consortium Members in entering into this letter agreement.

So far as permitted by applicable law, the parties to this letter agreement will at all times execute all such further documents and do all such further acts and things as may be necessary at any time to give effect to the provisions of this letter agreement.

For the avoidance of doubt, Section 8.10 (Indemnification) of the Agreement (as hereby amended) shall apply, *mutatis mutandis*, to this letter agreement as if set out herein in full.

Except in respect of the rights of Pan African Energy or any Consortium Member under an Excluded Sales Contract and as otherwise provided in Section 9.12 of the Agreement, none of the terms of this letter agreement are intended to be enforceable by any third party under the Contracts (Rights of Third Parties) Act 1999.

This letter agreement may not be revoked, amended, modified, varied or supplemented except by an instrument in writing signed by the parties hereto after submission to the Trustee and Paying Agent of the written consent to such amendment of Tinworth and the Subordinate Secured Parties, provided that the rights of Pan African Energy or any Consortium Member under an Excluded Sales Contract may not be prejudiced or derogated from as described in the Agreement (as hereby amended) without their written consent.

This letter agreement may be executed in several counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same agreement. This letter agreement may be executed and delivered by facsimile.

This letter agreement shall take effect as a deed and is executed as such by each of the parties hereto.

We should be grateful if you would confirm your agreement with the terms set out in this letter by countersigning this letter as indicated below.

Yours faithfully,

VAALCO GABON (ETAME) Inc.

[SIGNED]
W. Russell Scheirman
President & Chief Financial Officer

Acknowledged and agreed

[SIGNED]
JPMorgan Chase Bank, N.A.

[SIGNED]
J.P. Morgan Trustee and
Depository Company Limited

Acknowledged and consented to by:

[SIGNED]
Tinworth Limited

[SIGNED]
International Finance Corporation

VAALCO Energy, Inc.

[SIGNED]
W. Russell Scheirman
President & Chief Financial Officer

AMENDMENT AGREEMENT

DATED 18 JUNE 2014

BETWEEN

VAALCO GABON (ETAME), INC.

AND

THE BANK OF NEW YORK MELLON, LONDON BRANCH as Trustee and Paying Agent and Account Bank

relating to a Trustee and Paying Agent Agreement

dated 26 June 2002 (as amended on 26 November 2002 and as further amended on 1 February 2006)

CONTENTS

Schedule

THIS AGREEMENT is dated 18 June 2014 and made

BETWEEN:

(1) **VAALCO GABON (ETAME), INC.**, a corporation organized and existing under the laws of the State of Delaware, the United States of America (the **Company**);

(2) **THE BANK OF NEW YORK MELLON, LONDON BRANCH**, with its registered office at One Canada Square, London E14 5AL, in its capacity as the trustee and paying agent (the **Trustee and Paying Agent**); and

(3) **THE BANK OF NEW YORK MELLON LONDON BRANCH**, with its registered office at One Canada Square, London E14 5AL, in its capacity as the account bank (the Account **Bank**).

BACKGROUND

(A) This Agreement is supplemental to and amends the Etame Field Trustee and Paying Agent Agreement dated 26 June 2002 (as amended on 26 November 2002 and as further amended on 1 February 2006) between the Company and The Bank of New York Mellon, London branch (the **Trustee and Paying Agent Agreement**).

(B) Pursuant to a debenture dated 30 January 2014 between the Company and International Finance Corporation (**IFC**) (the **Debenture**), the Company has assigned by way of security to IFC its share of all amounts standing to the credit of certain bank accounts (the "Etame Accounts") and the Company's right, title and interest in and to the benefit of the Etame Accounts.

(C) In the event that the Company assigns by way of security its rights in and to the Etame Accounts, the Company must give notice of such assignment to the Trustee and Paying Agent. Upon receipt of such notice, the Company and the Trustee and Paying Agent are obliged to amend schedule A of the Trustee and Paying Agent Agreement pursuant to section 6.1(b) of the Trustee and Paying Agent Agreement.

(D) It is intended that this Agreement takes effect as a deed notwithstanding the fact that a party may only execute this Agreement under hand.

IT IS AGREED as follows:

1. INTERPRETATION

1.1 Definitions

Capitalised terms defined in the Trustee and Paying Agent Agreement have, unless expressly defined in this Agreement, the same meaning in this Agreement.

1.2 Construction

The provisions of sections 1.2 (interpretation), 9.4 (Disputes and Submission to Jurisdiction) and 9.12 (Third Party Rights) of the Trustee and Paying Agent Agreement apply to this Agreement as though they were set out in full in this Agreement except that references to the Trustee and Paying Agent Agreement are to be construed as references to this Agreement.

2. AMENDMENTS

The Trustee and Paying Agent Agreement will be amended from the date of this Agreement by deleting schedule A in its entirety and replacing with a new schedule A as set out in Schedule 1 to this Agreement.

3. REPRESENTATIONS

3.1 The Company represents, warrants and covenants that:

(a) it has and will have the necessary power to enable it to enter into and perform its obligations under this Agreement;

(b) this Agreement constitutes and will constitute its legal, valid, binding and enforceable obligations (except as enforcement may be limited by bankruptcy, moratorium, insolvency, reorganisation or similar laws generally affecting creditors' rights as well as the awards by courts of relief in lieu of specific performance of contractual provisions); and

(c) all necessary Authorisations to enable it to enter into this Agreement have been obtained and are, and will remain, in full force and effect.

4. MISCELLANEOUS

Subject to the terms of this Agreement, the Trustee and Paying Agent Agreement will remain in full force and effect and, from the date of this Agreement, the Trustee and Paying Agent Agreement and this Agreement will be read arid construed as one document.

5. GOVERNING LAW

This Agreement and any non-contractual obligations arising out of or in connection with it are governed by and construed in accordance with English law.

IN WITNESS WHEREOF this Agreement has been executed as a deed on the date stated at the beginning of this Agreement.

SCHEDULE 1

AMENDMENTS TO THE TRUSTEE AND PAYING AGENT AGREEMENT

SCHEDULE A

CONSORTIUM MEMBERS ACCOUNT AND SUBORDINATE SECURED PARTY DESIGNATIONS

Consortium Member	Subordinate Secured Party
VAALCO Gabon (Etame), Inc. United States of America	**International Finance Corporation** 2121 Pennsylvania Avenue, N.W. Washington, D.C. 20433 United States of America Attention: Director, Infrastructure and Natural Resources

SIGNATORIES
Company

Executed as a deed by

VAALCO GABON (ETAME), INC.

By: **[SIGNED]**
Name:
Title:

Trustee and Paying Agent

Executed as a deed by

THE BANK OF NEW YORK MELLON, LONDON BRANCH

Acting by its duly authorized signatory:

By: **[SIGNED]**
Name:
Title:

Account Bank

Executed as a deed by

THE BANK OF NEW YORK MELLON, LONDON BRANCH

Acting by its duly authorized signatory:

By: **[SIGNED]**
Name:
Title:

Exhibit 21.1

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

* Date of Certificate of Incorporation on Change of Name

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

VAALCO Energy, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-218824, 333-197180, 333-183515 and 333-67858) of VAALCO Energy, Inc. of our reports dated March 7, 2018, relating to the consolidated financial statements and financial statement schedule and the effectiveness of VAALCO Energy Inc.'s internal control over financial reporting, which appear in this Form 10-K.

/s/ BDO USA, LLP

Houston, Texas
March 7, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos.333-218824, 333-197180, 333-183515 and 333-67858 on Form S-8 of our report dated March 16, 2016, relating to the consolidated financial statements (before retrospective adjustments to the consolidated financial statements) (not presented herein) and financial statement schedule of VAALCO Energy, Inc. and subsidiaries (the "Company"), (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's recurring losses from operations and insufficient liquidity due to depressed oil and gas prices, raising substantial doubt about its ability to continue as a going concern), appearing in this Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 7, 2018

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

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2017. 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, 201 7, 2016, and 2015 and to the inclusion of our report dated January 23, 2018, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2017. 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, 333-183515 and 333-67858).

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Houston, Texas
March 7, 2018

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 7, 2018

/s/ Cary Bounds
Cary Bounds
Chief Executive Officer

Exhibit 31.2

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

I, Philip F. Patman, Jr., certify that:

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

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

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

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

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

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

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

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

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

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

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

Date March 7, 2018

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

EXHIBIT 32.1

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

In connection with the Annual Report of VAALCO Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2017, 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 7, 2018

/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, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Philip F. Patman, Jr., Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Dated: March 7, 2018

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

Exhibit 99.1

January 23, 2018

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

Dear Mr. Bounds:

In accordance with your request, we have estimated the proved developed reserves and future revenue, as of December 31, 2017, 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, 2017, to be:

	Oil Reserves (MBBL)		Future Net Revenue(1) (M$)	
Category	Gross (100%)	Net(2)	Total	Present Worth at 10%
Proved Developed Producing	6,311.3	1,705.3	7,253.3	8,139.2
Proved Developed Non-Producing	4,974.2	1,344.0	16,099.7	14,350.8
Total Proved Developed	11,285.5	3,049.3	23,353.0	22,490.0

(1) Future net revenue is after deducting estimated abandonment costs.
(2) 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, 2017, 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 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 2017. The average price of $54.42 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $53.49 per barrel of oil is held constant throughout the lives of the properties.

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

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

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

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

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

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

Sincerely,

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

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

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

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

Date Signed: January 23, 2018

Date Signed: January 23, 2018

JRC:BWG

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

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

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

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

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

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

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

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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

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

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

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

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

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

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

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

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

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

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

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

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

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

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

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

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

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

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

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

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

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in

communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

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

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

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

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

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

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

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

(20) *Production costs.*

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

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

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

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

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used

for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example,
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 signif

The extent to which the company has followed a previously adopted development plan (for example, if a co
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
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.