Admission to
London Stock Exchange

VAALCO Energy, Inc.

VAALCO ENERGY, INC.

This document comprises a prospectus relating to VAALCO Energy, Inc. prepared in accordance with the Prospectus Regulation Rules. This Prospectus has been approved by the Financial Conduct Authority in accordance with Part VI of the Financial Services and Markets Act 2000 and has been filed with the FCA and made available to the public in accordance with Rule 3.2 of the Prospectus Regulation Rules. This Prospectus has been approved by the FCA as competent authority under Regulation (EU) 2017/1129. The FCA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by Regulation (EU) 2017/1129. Such approval should not be considered as an endorsement of the issuer that is the subject of this document nor should such approval be considered as an endorsement of the quality of the securities that are the subject of this Prospectus. Prospective investors should make their own assessment as to the suitability of investing in the securities.

Applications have been made to the UKLA and the London Stock Exchange for all of the Common Shares to be admitted to the standard segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities, respectively. Admission to trading on the Main Market constitutes admission to trading on a UK regulated market. It is expected that Admission will become effective and that unconditional dealings in the Common Shares will commence on 26 September 2019. Dealings on the London Stock Exchange before Admission will only be settled if Admission takes place. All dealings before the commencement of unconditional dealings will be of no effect if Admission does not take place and such dealings will be at the sole risk of the parties concerned.

The Company has established arrangements to enable investors to settle interests in the Common Shares through the CREST system. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, the Depositary Interests allow such securities to be dematerialised and settled electronically through CREST. The Depositary Interests will be independent securities constituted under English law, which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interests which will be settled through CREST and not the Common Shares.

The Common Shares are currently listed on the New York Stock Exchange, where they will continue to be listed following Admission. The Company is seeking a secondary listing for the Common Shares on the standard segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities.

The Company and each of the Directors, whose names appear on page 54 of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and does not omit anything likely to affect the import of such information.

This Prospectus is issued solely in connection with Admission. This Prospectus does not constitute or form part of an offer or invitation to sell or issue, or any solicitation of an offer to purchase or subscribe for, any securities by any person. No offer of Common Shares is being made in any jurisdiction.

Prospective investors should read this Prospectus in its entirety. In particular, your attention is drawn to Part 2 (*Risk Factors*) of this Prospectus for a discussion of the risks that might affect the value of your shareholding in the Company. Prospective investors should be aware that an investment in the Company involves a degree of risk and that, if certain risks described in this Prospectus occur, investors may find their investment materially adversely affected. Accordingly, an investment in the Common Shares is only suitable for investors who are particularly knowledgeable in investment matters and who are able to bear the loss of the whole or part of their investment.

VAALCO Energy, Inc.

(incorporated in the State of Delaware, USA with registration file number 2188793)

Admission to the Official List (by way of a Standard Listing under Chapter 14 of the Listing Rules) and to trading on the London Stock Exchange's Main Market for listed securities of 67,478,896 Common Shares

Financial Advisor

GMP FirstEnergy

FirstEnergy Capital LLP (trading as GMP FirstEnergy) is authorised and regulated in the UK by the FCA. GMP FirstEnergy is acting exclusively for the Company as financial adviser (and not as sponsor) and for no other person in connection with Admission and will not regard any other person as its client in relation to Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to Admission. GMP FirstEnergy has not been engaged by the Company as sponsor in connection with Admission and will not be responsible to anyone (including the Company) for providing the protections afforded to its clients for providing advice as sponsor in relation to Admission or any other transaction or arrangement referred to in this Prospectus.

GMP FirstEnergy and/or any of its respective affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for the Company, for which they would have received customary fees. GMP FirstEnergy and/or any of its respective affiliates may provide such services to the Company and any of its respective affiliates in the future.

Apart from responsibilities and liabilities which may be imposed on GMP FirstEnergy by FSMA or the regulatory regime established thereunder, or under the regulatory regime of any other jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, GMP FirstEnergy accepts no responsibility, and makes no representation or warranty, for the contents of this Prospectus, including its accuracy or completeness, or for any other statement made or purported to be made by it, or on behalf of it, the Company or any other person in connection with the Company or the Common Shares. Accordingly, nothing contained in this

Prospectus may be relied upon as any form of promise or representation in this respect. GMP FirstEnergy accordingly disclaims any responsibility or liability (save as referred to above) which it may otherwise have in respect of this Prospectus or any such statement.

GMP FirstEnergy has given and not withdrawn its consent to the issue of this Prospectus with the inclusion of the references to its name.

The application for Admission has been made in compliance with Rule 3 of the Listing Rules.

Information to distributors

The distribution of this Prospectus in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company, the Directors or GMP FirstEnergy to permit possession or distribution of this Prospectus in any jurisdiction where it is believed that this may be unlawful or in contravention of local regulation. Persons into whose possession this Prospectus comes are required by the Company, the Directors and GMP FirstEnergy to inform themselves about and to observe any such restrictions.

Application has been made for the Common Shares to be admitted to the standard segment of the Official List. A Standard Listing affords investors in the Company a lower level of regulatory protection than that afforded to investors in companies whose securities are admitted to the premium segment of the Official List, which are subject to additional obligations under the Listing Rules.

It should be noted that the UKLA does not monitor the Company's compliance with any of the Listing Rules or those aspects of the DTR which the Company has indicated herein that it intends to comply with on a voluntary basis, and is not authorised to impose sanctions in respect of any failure by the Company to so comply.

Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of FSMA or Rule 3.4 of the Prospectus Regulation Rules, the publication of this Prospectus may not be taken to imply that the affairs of the Group at any time subsequent to the date of this Prospectus are not subject to change.

Forward-looking statements

This Prospectus contains "**forward-looking statements**" and "**forward-looking information**" that are based on the Company's expectations, estimates and projections as of the date on which the statements were made. This forward-looking information includes, among other things, statements with respect to the Competent Person's Reports, the Company's business strategy with respect to the Projects, plan, development, objectives, performance, outlook, growth, cash flow, projections, targets and expectations, oil and gas reserves and resources, results of exploration, the price and demand for oil and gas and acts by the Company's partners to the respective Projects. Generally, this forward looking information can be identified by the use of forward-looking terminology such as "*outlook*", "*anticipate*", "*project*", "*target*", "*likely*", "*believe*", "*estimate*", "*expect*", "*intend*", "*may*", "*would*", "*could*", "*should*", "*scheduled*", "*will*", "*plan*", "*forecast*", "*evolve*" and similar expressions. Persons reading this Prospectus are cautioned that such statements are only predictions, and that the Company's actual future results or performance may be materially different.

Forward-looking information is subject to known and unknown risks, uncertainties and other factors that may cause the Company's actual results, level of activity, performance or achievements to be materially different from those expressed or implied by such forward-looking information. These statements speak only as of the date of this Prospectus and do not seek in any way to qualify the working capital statement given by the Company at paragraph 14 of Part 8 (*Information on VAALCO Energy, Inc.*) of this Prospectus. Actual operational and financial results or events may differ materially from the Company's expectations contained in the forward-looking statements as a result of various factors, many of which are beyond the control of the Company.

Statements related to reserves or resources are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and prospective resources can be profitably produced in the future. The forward-looking statements contained in this Prospectus are expressly qualified by this cautionary statement. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Forward-looking statements involve significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct.

Investors are cautioned that forward-looking statements are not guarantees of future performance. The Company makes no representation, warranty or prediction that the results predicted by such forward-looking statements will be achieved and these forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this Prospectus speak only as at the date of this Prospectus, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and the availability of new credit. Investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ. All of the forward-looking statements made in this Prospectus are qualified by these cautionary statements.

Subject to the requirements of the Prospectus Regulation Rules, the DTR and the Listing Rules, or applicable law, the Company explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

Company's website

Information contained on the Company's website or the contents of any website accessible from hyperlinks on the Company's website are not incorporated into and do not form any part of this Prospectus.

Interpretation

A list of defined terms used in this Prospectus is set out in Part 18 (*Definitions*) of this Prospectus. A list of defined technical terms and conversions used in this Prospectus is set out in Part 19 (*Glossary of Technical Terms and Conversions*) of this Prospectus.

References to the singular in this Prospectus shall include the plural and *vice versa*, where the context so requires. References to sections or Parts are to sections or Parts of this Prospectus. All references to time in this Prospectus are to London time unless otherwise stated.

Preferred currency

Unless specifically expressed otherwise, all dollar ($) references in this Prospectus are to U.S. dollars.

Dated 23 September 2019

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PART 1 – SUMMARY

1. INTRODUCTION AND WARNINGS

1.1 ***Introduction warning***

This summary must be read as an introduction to this Prospectus. Any decision to invest in Common Shares should be based on consideration of this Prospectus as a whole by the investor. By deciding to invest in Common Shares, an investor could lose all or part of his invested capital and, where the investor's liability is not limited to the amount of the investment, the investor could lose more than the invested capital. Where a claim relating to the information contained in this Prospectus is brought before a court, the plaintiff investor might, under national law, have to bear the costs of translating this Prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary, including any translation thereof, but only if the summary is misleading, inaccurate or inconsistent when read together with other parts of this Prospectus or it does not provide, when read together with the other parts of this Prospectus, key information in order to aid investors when considering whether to invest in such securities.

1.2 ***The name and ISIN of the securities***

The securities being admitted to trading are the 67,478,896 fully paid Common Shares of $0.10 par value per Common Share, issued as at the date of this Prospectus. The ISIN of the Common Shares is US91851C2017.

1.3 ***The identity and contact details of the issuer***

The issuer is VAALCO Energy, Inc. The contact details for VAALCO are as follows:

Address:	9800 Richmond Avenue, Suite 700, Houston, Texas 77042, United States
Telephone:	+1 (713) 623 0801
Email:	vaalco@vaalco.com

The LEI number for VAALCO is 549300CFHFVIWB8M6T24.

1.4 ***The identity and contact details of the competent authority approving the Prospectus***

UK Listing Authority, Financial Conduct Authority, 12 Endeavour Square, London E20 1JN, United Kingdom.

1.5 ***Date of approval of the Prospectus***

23 September 2019.

2. KEY INFORMATION ON THE ISSUER

2.1 ***Who is the issuer of the securities?***

VAALCO Energy, Inc. is a public company, incorporated in the State of Delaware, USA with registration file number 2188793 and having its registered office, and business address for all of the Directors and Executive Officers, at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. The Company's telephone number is +1 713 623 0801. The principal legislation under which the Company operates is the DGCL. The LEI number for VAALCO is 549300CFHFVIWB8M6T24.

The Company is the holding company of the Group, which is engaged in the acquisition, exploration, development and production of crude oil and natural gas. The Company's primary source of revenue has been from the Etame PSC related to the Etame Marin Block, located offshore Gabon in West Africa. The Company also currently owns an interest in an undeveloped portion of Block P, located offshore Equatorial Guinea in West Africa.

As at the Last Practicable Date, the Company is aware of the following Shareholders that, directly or indirectly, hold interests in five percent or more of the Common Shares or voting rights:

Name	Number of Common Shares	Percentage of Issued and Outstanding Share Capital	Percentage of Issued Share capital
Bradley L. Radoff*	4,494,905	7.7%	6.7%
Tieton Capital Management, LLC	3,008,598	5.1%	4.5%
Renaissance Technologies LLC	3,006,117	5.1%	4.5%

Note

*Based on a Schedule 13D/A filed with the SEC on 5 March 2019 by BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff, Mr. Radoff has sole voting power and sole dispositive power over all 4,494,905 Common Shares. Mr. Radoff directly owns 1,938,905 Common Shares. As the sole shareholder and sole director of each of BLRGP Inc. and Fondren Management, LP and as director of The Radoff Family Foundation, Mr. Radoff may be deemed the beneficial owner of (i) 2,471,000 Common Shares owned by BLR Partners LP; and (ii) 85,000 Common Shares owned by The Radoff Family Foundation.

There are no differences between the voting rights enjoyed by the Shareholders described above and those enjoyed by the other holders of Common Shares.

The Directors and Executive Officers are as follows:

Name	Age	Position	Appointment
Cary M. Bounds	52	Chief Executive Officer and Director	December 2016
Andrew L. Fawthrop	67	Chairman and Director	October 2014
A. John Knapp, Jr.(1)	68	Director	December 2015
Steven J. Pully	59	Director	July 2015
William R. Thomas(2)	63	Director	April 2019
Elizabeth D. Prochnow(3)	61	Chief Financial Officer	April 2019
Jason J. Doornik	50	Chief Accounting Officer and Controller	June 2019
David A. DesAutels(4)	64	Executive Vice President of Corporate Development	July 2017
Michael G. Silver(5)	55	Executive Vice President, Company Secretary and General Counsel	April 2019

Notes

(1) On 31 May 2019, A. John Knapp, Jr. resigned from the Board in accordance with the terms of the Kornitzer Stockholder Agreement. On 6 June 2019, the Board, acting on the recommendation of the Nominating and Corporate Governance Committee, determined to reappoint Mr. Knapp as an independent Director.

(2) William R. Thomas is the nominee Director in accordance with the terms of the Group 42-BLR Group Settlement Agreement.

(3) Elizabeth D. Prochnow first joined the Company in March 2015, where she served as Chief Accounting Officer.

(4) David A. DesAutels served as Vice President for Exploration and Development from his appointment in July 2017 until April 2019.

(5) Michael G. Silver first joined the Company in November 2018 in a non-executive capacity.

BDO USA are the auditors of the Company. BDO USA have been the Company's auditors since financial year ended 31 December 2016. Deloitte & Touche LLP ("**Deloitte**") were the auditors of the Company prior to the appointment of BDO USA. Under the SEC Rules, companies are required to include the auditors' opinion for any comparable years presented in annual audited consolidated financial statements, which under the SEC Rules is the prior two financial years. Deloitte's opinion for financial year ended 31 December 2015 was therefore included for filing with the audited consolidated financial statements of the Group for financial years ended 31 December 2017 and 31 December 2016.

2.2 ***What is the key financial information regarding the issuer?***

The table below sets out (1) summary financial information of the Group as derived without material adjustment from the audited annual consolidated financial statements of the Group for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016; and (2) summary financial information of the Group as derived from the unaudited condensed interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018.

	Year Ended 31 December			Six Months Ended 30 June	
	2018	*2017*	*2016*	*2019*	*2018*
	(in thousands, except per Share amounts)				
Revenues:					
Oil and natural gas sales	$104,943	$77,025	$59,784	$44,995	$52,071
Operating costs and expenses:					
Production expense	40,415	39,697	37,586	18,038	23,777
Exploration expense	14	7	5	–	12
Depreciation, depletion and amortization	5,596	6,457	6,926	3,462	2,159
Gain on revision of asset retirement obligations	(3,325)	–	–	–	–
General and administrative expense	11,398	10,377	9,561	7,167	7,611
Impairment of proved properties	–	–	88	–	–
Other operating expense	–	–	8,853	–	–
General and administrative related to Shareholder matters	–	–	(332)	–	–
Bad debt (recovery) expense and other	(77)	452	1,222	(24)	89
Total operating costs and expenses	54,021	56,990	63,909	28,643	33,648
Other operating income (expense), net	365	(84)	(266)	(4,436)	338
Operating income (loss)	51,287	19,951	(4,391)	11,916	18,761
Other income (expense):					
Derivative instruments gain (loss), net	4,264	(1,032)	(1,711)	(1)	(1,010)
Interest expense, net	(145)	(1,414)	(2,613)	388	(384)
Other, net	68	3,145	(304)	(383)	(145)
Total other income (expense)	4,187	699	(4,628)	4	(1,539)
Income (loss) from continuing operations before income taxes	55,474	20,650	(9,019)	11,920	17,222
Income tax expense (benefit)	(43,254)	10,378	9,248	11,961	7,624
Income (loss) from continuing operations	98,728	10,272	(18,267)	(41)	9,598
Income (loss) from discontinued operations	(496)	(621)	(8,283)	5,509	(395)
Net income (loss)	$98,232	$9,651	$(26,550)	$5,468	$9,203
Basic net income (loss) per Share:					
Income (loss) from continuing operations	$1.65	$0.17	$(0.31)	$0.00	$0.16
Loss from discontinued operations	(0.01)	(0.01)	(0.14)	0.09	(0.01)
Net income (loss) per Share	$1.64	$0.16	$(0.45)	$0.09	$0.15
Basic weighted average Shares outstanding	59,248	58,717	58,384	59,716	58,977
Diluted net income (loss) per Share:					
Income (loss) from continuing operations	$1.63	$0.17	$(0.31)	$0.00	$0.16
Loss from discontinued operations	(0.01)	(0.01)	(0.14)	0.09	(0.01)
Net income (loss) per Share	$1.62	$0.16	$(0.45)	$0.09	$0.15
Diluted weighted average Shares outstanding	59,997	58,720	58,384	59,716	59,358

ASSETS	As at 31 December 2018	2017	2016	As at 30 June 2019	2018
	(in thousands, except per Share amounts)				
Current assets:					
Cash and cash equivalents	$33,360	$19,669	$20,474	$48,557	$40,490
Restricted cash	804	842	741	799	1,029
Receivables:					
Trade	11,907	3,556	6,751	13,828	9,607
Accounts with joint venture owners, net of allowance	949	3,395	3,297	130	–
Other	1,398	100	120	1,239	122
Crude oil inventory	785	3,263	913	553	1,298
Prepayments and other	6,301	2,791	4,040	4,808	3,721
Current assets – discontinued operations	3,290	2,836	2,139	–	3,172
Total current assets	58,794	36,452	38,475	69,914	59,439
Oil and natural gas properties and equipment – successful efforts method:					
Wells, platforms and other production facilities	409,487	389,935	389,231	409,862	390,404
Work-in-progress	519	–	–	1,002	–
Undeveloped acreage	23,771	10,000	10,000	23,771	10,000
Equipment and other	9,552	9,432	9,779	10,903	8,531
	443,329	409,367	409,010	445,538	408,935
Accumulated depreciation, depletion, amortization and impairment	(390,605)	(386,146)	(380,991)	(393,669)	(387,808)
Net oil and natural gas properties, equipment and other	52,724	23,221	28,019	51,869	21,127
Other noncurrent assets:					
Restricted cash	920	967	918	922	918
Value added tax and other receivables, net of allowance	2,226	6,925	5,110	2,742	6,724
Right of use operating lease assets	–	–	–	34,124	–
Deferred tax assets	40,077	1,260	–	30,946	1,260
Abandonment funding	11,571	10,808	8,510	11,550	10,808
Total assets	$166,312	$79,633	$81,032	$202,067	$100,276
LIABILITIES AND SHAREHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	$8,083	$11,584	$19,096	$8,016	$10,876
Accounts with joint venture owners	304	–	–	3,781	9,807
Accrued liabilities and other	14,138	12,991	10,506	19,539	16,893
Operating lease liabilities – current portion	–	–	–	10,500	–
Foreign taxes payable	3,274	–	–	453	5,431
Current portion of long term debt	–	6,666	7,500	–	–
Current liabilities – discontinued operations	15,245	15,347	18,452	4,847	15,186
Total current liabilities	41,044	46,588	55,554	47,136	58,193
Asset retirement obligations	14,816	20,163	18,612	15,214	20,708
Operating lease liabilities – net of current portion	–	–	–	23,624	–
Other long term liabilities	625	284	284	421	892
Long term debt, excluding current portion, net	–	2,309	6,940	–	–
Total liabilities	56,485	69,344	81,390	86,395	79,793
Commitments and contingencies					
Shareholders' equity:					
Preferred Shares, $25 par value	–	–	–	–	–
Common Shares, $0.10 par value	6,717	6,644	6,611	6,745	6,696
Additional paid-in capital	72,358	71,251	70,268	73,059	72,013
Less Treasury Shares, at cost	(37,827)	(37,953)	(37,933)	(37,870)	(37,776)
Retained earnings (deficit)	68,579	(29,653)	(39,304)	73,738	(20,450)
Total Shareholders' equity (deficit)	109,827	10,289	(358)	115,672	20,483
Total liabilities and Shareholders' equity (deficit)	$166,312	$79,633	$81,032	$202,067	$100,276

	Year Ended 31 December			Six Months Ended 30 June	
	2018	2017	2016	2019	2018
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income (loss)	$98,232	$9,651	$(26,550)	$5,468	$9,203
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
(Income) loss from discontinued operations	496	621	8,283	(5,509)	395
Depreciation, depletion and amortization	5,596	6,457	6,926	3,462	2,159
Gain on revision of asset retirement obligations	(3,325)	–	–	–	–
Other amortization	417	369	1,424	121	191
Deferred taxes	(56,907)	(1,260)	–	7,667	–
Unrealised foreign exchange (gain) loss	834	(576)	(32)	21	79
Share-based compensation	2,387	1,098	192	1,620	2,756
Cash settlement paid on exercised SARs	(81)	–	–	(261)	(82)
Commodity derivatives (gain) loss	(4,264)	1,032	1,711	1	1,010
Cash settlements received on matured derivative contracts, net	744	195	–	1,563	(11)
Bad debt (recovery) expense	(77)	452	1,222	(24)	89
Other operating (income) loss, net	(570)	84	266	37	(338)
Operational expenses associated with equipment and other	1,604	1,189	–	(60)	1,739
Impairment of proved properties	–	–	88	–	–
Change in operating assets and liabilities:					
Trade receivables	(8,351)	3,195	(1,050)	(1,921)	(6,051)
Accounts with joint venture owners	2,747	(108)	16,284	4,291	13,203
Other receivables	(1,330)	(43)	(18)	158	(23)
Crude oil inventory	2,478	(2,350)	(192)	232	1,965
Prepayments and other	1,164	1,646	517	(1,175)	(764)
Value added tax and other receivables	(777)	(3,025)	(1,937)	718	(249)
Accounts payable	(3,409)	(7,297)	(15,459)	(730)	(535)
Foreign taxes payable	2,751	–	–	(2,865)	5,431
Accrued liabilities and other	(2,131)	2,050	(4,586)	3,858	1,381
Other long-term assets	–	–	546	–	–
Net cash provided by (used in) continuing operating activities	38,228	13,380	(12,365)	16,672	31,548
Net cash provided by (used in) discontinued operating activities	(1,052)	(4,423)	12,286	(91)	(892)
Net cash provided by (used in) operating activities	37,176	8,957	(79)	16,581	30,656
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions	–	64	(5,692)	–	–
Property and equipment expenditures	(14,127)	(1,813)	(8,705)	(1,163)	(976)
Proceeds from the sale of oil and gas properties	–	250	830	–	–
Premiums paid for put options	–	–	(2,939)	–	–
Net cash used in continuing investing activities	(14,127)	(1,499)	(16,506)	(1,163)	(976)
Net cash used in discontinued investing activities	–	–	–	–	–
Net cash used in investing activities	(14,127)	(1,499)	(16,506)	(1,163)	(976)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from the issuances of Common Shares	544	39	–	107	445
Treasury Shares	(58)	(20)	(51)	(352)	–
Debt issuance costs	–	–	(93)	–	–
Debt repayment	(9,166)	(10,001)	–	–	(9,166)
Borrowings	–	4,167	–	–	–
Net cash used in continuing financing activities	(8,680)	(5,815)	(144)	(245)	(8,721)
Net cash used in discontinued financing activities	–	–	–	–	–
Net cash used in financing activities	(8,680)	(5,815)	(144)	(245)	(8,721)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	14,369	1,643	(16,729)	15,173	20,959
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD	32,286	30,643	47,372	46,655	32,286
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD	$46,655	$32,286	$30,643	$61,828	$53,245

There has been no significant change in the financial performance or financial position of the Group since 30 June 2019, being the end of the last financial period of the Group for which financial information has been published, to the date of this Prospectus. Such financial information, being the Historical Financial Information, is included in Part 12 (*Historical Financial Information*) of this Prospectus.

This Prospectus does not contain pro forma financial information. The auditor's reports on the consolidated financial statements of the Company as at and for the years ended 31 December 2018, 31 December 2017 and 31 December 2016 do not contain any qualifications.

2.3 ***What are the key risks that are specific to the issuer?***

- VAALCO's 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. VAALCO's ability to borrow funds and to obtain additional capital on reasonable terms is also substantially dependent on oil and natural gas prices.

- Unless VAALCO is able to replace the proved reserve quantities that it has produced, its cash flows and production will decrease over time.

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

- VAALCO's 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 VAALCO involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable.

3. KEY INFORMATION ON THE SECURITIES

3.1 ***What are the main features of the securities?***

- The securities being admitted to trading are the Common Shares of the Company. The ISIN of the Common Shares is US91851C2017.

- On Admission, holders of Common Shares will be able to hold and transfer interests in the Common Shares within CREST pursuant to a depositary interest arrangement established by the Company. The Common Shares will not themselves be admitted to CREST; rather, the Depositary will issue the Depositary Interests in respect of underlying Common Shares.

- The Depositary Interests are independent securities constituted under English law, which are held and transferred directly through the CREST system. Depositary Interests have the same ISIN as the underlying Common Shares and do not require a separate admission to trading on the London Stock Exchange. The Depositary Interests were created and issued pursuant to a Deed Poll issued and executed by the Depositary.

- Following Admission, the price of the Common Shares will be quoted on the London Stock Exchange in GBX.

- On Admission, the Company will have an issued share capital of 67,478,896 fully paid Common Shares of $0.10 par value per Common Share.

- The Common Shares rank equally for voting purposes. On a show of hands, each Shareholder present has one vote and on a poll, each Shareholder has one vote per Common Share held.

- The Common Shares rank equally for dividends declared and for any distributions on a winding-up.

- The Common Shares rank equally in the right to receive a relative proportion of the Company's assets upon dissolution and are, as at the Last Practicable Date, the most senior security in the Company's capital structure. If the Company issues any Preferred Shares, the Company will have the ability to determine the rights of those Shares. The Common Shares could rank behind any of Preferred Shares in the payment of any dividend, liquidation, and other matters.

- The Common Shares are freely transferable and there are no restrictions on transfer.

- The Company has never declared or paid dividends on the Common Shares.

3.2 ***Where will the securities be traded?***

In addition to the Common Shares being traded on the NYSE, application has been made to the UKLA and the LSE for all of the Common Shares to be admitted to the standard segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities. It is expected that Admission will become effective and that dealings will commence at 8.00 a.m. on 26 September 2019.

3.3 ***Is there a guarantee attached to the securities?***

No.

3.4 ***What are the key risks that are specific to the securities?***

- Shareholders will not be entitled to the takeover offer protections provided by the UK Takeover Code.

- There is currently no UK market for the Common Shares. An active UK trading market may not develop or be sustained in the future, which would adversely affect the liquidity and price of the Common Shares.

- The market price of the Common Shares could be negatively affected by sales or an additional offering of substantial numbers of Common Shares in the public market, or the perception or any announcement that such sales or an additional offering could occur.

- Substantial future sales of Common Shares, or the perception that such sales might occur, or additional offerings of Common Shares could depress the market price of Common Shares.

4. KEY INFORMATION ON THE ADMISSION TO TRADING ON A REGULATED MARKET

4.1 ***Under which conditions and timetable can I invest in this security?***

It is expected that Admission will become effective and that dealings will commence at 8.00 a.m. on 26 September 2019.

4.2 ***Why is this prospectus being produced?***

Following consultation with its advisers, the Directors have chosen a Standard Listing as they believe that a listing on the Main Market, in addition to VAALCO's NYSE listing, will enable the Company to enhance its awareness among, and allow it to reach, institutional investors in the UK, Europe, Africa and the Middle East, provide the potential to access capital to fund the strategic growth of the Company, increase share trading liquidity and further raise the profile of the Company and the Projects.

PART 2 – RISK FACTORS

The Group's business, financial condition or results of operations could be materially and adversely affected by the risks described below. In such cases, the market price of the Common Shares may decline due to any of these risks and investors may lose all or part of their investment. The Company considers the following risks to be the material risks for potential investors in the Company, but the risks listed do not necessarily comprise all those associated with an investment in the Company.

Any investment in the Common Shares may not be suitable for all recipients of this Prospectus and is subject to a high degree of risk. Prior to investing in the Common Shares, prospective investors should carefully consider the risks and uncertainties associated with any investment in the Common Shares, the Group's business and the industry in which it operates, together with all other information contained in this Prospectus, including, in particular, the risk factors described below. Any of the risks described below, as well as other risks and uncertainties discussed in this Prospectus, could have a material adverse effect on the Group's business and could therefore have a negative effect on the trading price of the Common Shares. Prospective investors should note that the risks relating to the Group, its industry and the Common Shares summarised in Part 1 (*Summary*) of this Prospectus, are the risks that the Company believes to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Common Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in Part 1 (*Summary*) of this Prospectus, but also, among other things, the risks and uncertainties described below.

The following factors are not exhaustive, or an explanation of all of the risk factors involved in investing in the Common Shares, and should be used as guidance only. The factors listed under a single heading may not provide a comprehensive view of all risks relevant to the subject to which the heading relates. Additional risks and uncertainties that are not currently known to the Group or that the Group currently deems immaterial may individually or cumulatively also have an adverse effect on the Group's business, results of operations, financial condition and prospects. In particular, the Group's performance might be affected by changes in market and/or economic conditions and in legal, regulatory and tax requirements. If such changes were to occur the price of the Common Shares may decline and investors could lose all or part of their investment. Prospective investors should also consider carefully whether an investment in the Common Shares is suitable for them in light of the information in this Prospectus and their personal circumstances.

The information contained in this Prospectus is based upon current legislation and tax practice and any changes in the legislation or in the levels and bases of, and reliefs from, taxation may affect the value of an investment in the Common Shares.

RISKS RELATING TO VAALCO'S BUSINESS AND INDUSTRY

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 the Group's financial results

The Group's 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. The Group's ability to borrow funds and to obtain additional capital on reasonable terms is also substantially dependent on oil and natural gas prices.

Historically, worldwide oil and natural gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and decreased further in 2015 and early 2016. During 2016, the spot price per BBL of Brent ranged from a high of $55 to a low of $26. During 2017, the spot price per BBL of Brent ranged from a high of $67 to a low of $44. During 2018, the spot price per BBL of Brent ranged from a high of $86 to a low of $51. The average price at which the Group sold its crude oil in 2018 was $70.32 per BBL compared $52.58 per BBL in 2017 and $40.13 per BBL in 2016. Because the oil price VAALCO uses to estimate its future net cash flows is based on pricing scenarios prior to the date of determination of future net cash flows, the full effect of increasing or falling prices may not be reflected in the Group's estimated net cash flows for several quarters. The Group reviews the carrying value of its properties on a quarterly basis and once incurred, a write-down in the carrying value of its 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 VAALCO's 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.

As operator for the properties producing 100 percent of its production, VAALCO has significant ability to decrease or increase capital expenditures as it sees fit. Cash flows from its operations for the period from July 2019 through June 2020 are partially protected through the commodity swaps at a Dated Brent weighted average of $66.70 per BBL for an approximate quantity of 500,000 BBL.

In extreme economic circumstances, including a very significant decline in oil and gas prices, the Projects may not be economically viable. VAALCO could lower or cease production and delay or reduce its exploration and development activities, which could impact production and reserve growth. Such a curtailment in operations would likely materially adversely affect the Group's business, financial condition and results of operations.

Unless VAALCO is able to replace the proved reserve quantities that it produces, its cash flows and production will decrease over time

VAALCO's future success depends upon its 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. VAALCO may not be successful in exploring for, developing or acquiring additional reserves. Except to the extent that VAALCO conducts successful exploration or development activities or acquires properties containing proved reserves, its estimated net proved reserves will generally decline as reserves are produced.

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, VAALCO's drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including declines in oil or natural gas prices and/or prolonged periods of historically low oil and natural gas prices, title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, failure of wells drilled in similar formations, equipment failures (such as ESPs), delays in the delivery of equipment and availability of drilling rigs.

There can be no assurance that the Group's development and exploration projects and acquisition activities will result in significant additional reserves or that VAALCO will have continuing success drilling productive wells at economic finding costs. If the Group is unable to increase its proved reserve quantities, there will likely be a material impact on the Group's cash flows, business and operations.

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

The Etame Marin Block consists of five fields with 20 production wells, nine of which are currently in production. Production from these fields constituted 100 percent of VAALCO's total production for the financial year ended 31 December 2018. In addition, as at 30 June 2019, 100 percent of VAALCO's total reserves were attributable to the Etame 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 VAALCO's estimated reserves, its results of operations, financial condition, and cash flows could be materially adversely affected.

Because VAALCO's properties are concentrated in the same geographic area, many of VAALCO's rights under the Etame PSC will be affected by the same conditions at the same time, resulting in a relatively greater impact on its results of operations than with respect to companies that have a more diversified portfolio of licences and properties located across diverse geographic areas.

VAALCO's 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 the Group's reserves

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond the Group's 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 Prospectus are based on various assumptions, including non-escalated prices and costs and capital expenditures subsequent to 31 December 2018, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and natural gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Group's reserves.

In addition, the Group's 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 has been calculated using a 10 percent discount rate which is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Group's 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 the Group's net proved reserves are not intended to reflect the fair market value of the Group's reserves.

The Group's proved reserves are in Gabon and are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and natural gas that VAALCO 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.

VAALCO's exploration and development activities are capital intensive

As an oil and gas explorer and producer, the material asset of which is located offshore Gabon, VAALCO's exploration and development activities are capital intensive. To replace and grow the Group's reserves, VAALCO must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and natural gas reserves. VAALCO finances these expenditures primarily with cash flow from operations, debt, asset sales and private sales of equity.

In extreme economic circumstances, including a very significant decline in the oil and gas prices, VAALCO may not be able to access the debt and equity markets, which would likely materially adversely affect the Group's business, financial condition and operations.

The inability of one or more joint venture owners to the Projects to meet their obligations may adversely affect VAALCO's financial results

VAALCO is the operator of the Etame Marin Block and is responsible for contracting on behalf of all the remaining parties participating in the project. VAALCO relies on the timely payment of cash calls by its joint owners to pay for 66.43 percent of the Etame budget.

With respect to Block P, VAALCO is awaiting approval by the EG MMH of its appointment as technical operator. Once VAALCO is appointed, it will rely on the timely payment of cash calls by its joint owners to pay for 61.0 percent of the Block P budget.

If any of VAALCO's partners in the Projects is unable to fund their share of the exploration and development expenses, VAALCO may be liable for such costs. The Etame JOA and Block P JOA require non-defaulting block partners to pay their proportionate share of the defaulting party's costs during the default period, where one of the joint venture owners is unable to meet its costs. Should a default not be cured, VAALCO could be required to pay its share of the defaulting party's costs going forward.

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

Material declines in crude oil prices will cause the estimated quantities and present values of the Group's reserves to be reduced, which may necessitate write-downs. Material declines in crude oil prices could also cause a decline in the estimated fair value and/or the economic viability of projects associated with the Group's undeveloped leasehold costs for the Etame Marin Block and Block P resulting in write-downs of these costs. Such write-downs could have a negative effect on VAALCO's liquidity and financial condition.

VAALCO's drilling activities require it 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 the Group will be productive or that VAALCO will recover all or any portion of the Group's 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. The Group's drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, many of which are beyond the Group's 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.

VAALCO's business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions

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

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

- unauthorised access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on the Group's ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- unauthorised access to and release of personal identifying information of employees and vendors, which could expose the Group to allegations that it did not sufficiently protect that information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations; and

- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent the Group from transporting and marketing its production, resulting in a loss of revenues.

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

VAALCO's operations may be adversely affected by political, social and economic instability

The Group operates in countries that have experienced political, social and economic instability or are in close proximity to areas where such events have and continue to occur.

In Gabon, allegations of voting irregularities were reported after the most recent presidential elections in August 2016. The contested re-election of Ali Bonga triggered protests and violence between supporters of the opposition candidate, Jean Ping, who declared himself the victor, and government security forces. This public unrest included arson of the Lower House of Parliament, damage of private property and damage to the headquarters of the opposition party. On 7 January 2019, a group of five Gabonese soldiers briefly took control of the Gabon Télévision headquarters. Government security forces regained control of the broadcasting headquarters the same day and state operations returned to normal the next day. Mr. Bongo suffered a stroke during an official visit to Saudi Arabia in October 2018 after which he has spent extensive periods recuperating in Morocco.

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

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

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

While the Group monitors the economic and political environments of the countries in which it operates, loss of property and/or interruption of the Group's business plans resulting from civil unrest could have a significant negative impact on the Group's earnings and cash flow. In addition, the Group may not have enough insurance to cover any loss of property or other claims resulting from these risks.

VAALCO operates in countries and regions that are subject to legal and regulatory risk

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

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

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

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

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

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

Competitive industry conditions may negatively affect VAALCO's ability to conduct operations

The oil and natural gas industry is intensely competitive. VAALCO competes with, and may be outbid by, competitors in its 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 the Group's ability to compete in the marketplace include, among other things:

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

VAALCO's competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than it does. 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 the Group's financial or human resources permit; continue drilling during periods of low oil and natural gas prices; contract for drilling equipment; and secure trained personnel. VAALCO's competitors may also use superior technology which VAALCO may be unable to afford or which would require costly investment by VAALCO in order to compete.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact VAALCO's 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 the Group 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.

VAALCO maintains 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 unfavourable event not fully covered by insurance could have a material adverse effect on the Group's financial condition, results of operations and cash flows. Furthermore, VAALCO cannot predict whether insurance will continue to be available at a reasonable cost or at all.

VAALCO may not have enough insurance to cover all of the risks it faces and operators of prospects in which VAALCO participates may not maintain or may fail to obtain adequate insurance

The Group's 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, the Group maintains 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, the Group's insurance coverage may not be sufficient to cover it against 100 percent of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalisation, business interruption, war, terrorism, and piracy, for which VAALCO has limited or no coverage. In addition, VAALCO is not insured against all risks in all aspects of the Group's business, such as hurricanes. The occurrence of a significant event against which VAALCO is not fully insured could have a material adverse effect on the Group's consolidated financial position, results of operations, or cash flows.

VAALCO's results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates and by currency regulations

VAALCO is exposed to foreign currency risk from the Group's foreign operations. While oil sales are denominated in U.S. dollars, portions of the Group's costs in Gabon are denominated in CFA, 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 CFA 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 the Group's control. The Group's financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. In addition, currency devaluation can result in a loss to the Group for any deposits of that currency, such as the Group's deposits in the Etame PSC abandonment account which have been converted from U.S. dollar to CFA. Hedging foreign currencies can be difficult, especially if the currency is not actively traded.

VAALCO is also subject to risks relating to governmental regulation of foreign currency. In particular, on 1 December 2018, the Union Monetaire de L'Afrique Centrale (UMAC) approved new regulation 02/18/CEMAC/UNACCM ("**CEMAC FX Regulations**") effective 1 March 2019, which imposes restrictions on the use of foreign currency accounts within CEMAC and abroad. Governmental regulation of foreign currency, including the CEMAC FX Regulations, may limit the Group's ability to:

- transfer funds from or convert currencies in certain countries;
- repatriate foreign currency received in excess of local currency requirements; and
- repatriate funds held by its foreign subsidiaries to the U.S. at favourable tax rates.

If the Group's assumptions and/or underlying accruals for abandonment costs are too low, VAALCO could be required to expend greater amounts than expected

Almost all of the Group's properties which have future abandonment obligations are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, VAALCO records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and capitalise the related costs as part of the carrying amount of the long-lived assets.

As part of the Etame PSC, VAALCO is subject to an agreed upon cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. Based upon the most recent abandonment study completed in November 2018, the abandonment cost estimate used for this purpose is approximately $61.8 million ($19.2 million, net to VAALCO) on an undiscounted basis. On an annual basis over the remaining life of the Etame PSC (which, following the Etame PSC Extension, will expire in September 2028, with the option for VAALCO to extend for two additional five-year periods), VAALCO must fund a portion of these estimated abandonment costs, which VAALCO estimates to be $0.8 million per year net to VAALCO, as at Admission through September 2028. Future changes to the anticipated abandonment cost estimates could change the Group's asset retirement obligations and increase the amount of future abandonment funding payments VAALCO is obligated to make through the duration of the Etame PSC.

RISKS RELATING TO THE PROJECTS

VAALCO's offshore operations involve special risks that could adversely affect its results of operations

Offshore operations are subject to a variety of operating risks specific to the marine environment. The Group's 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 the Group 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 the Group is increased due to the low number of producing properties it owns. VAALCO could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or licence acquisitions, or result in loss of equipment and licence 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 VAALCO is currently unaware. For example, the production of hydrogen sulphide at certain Etame Marin Block wells could create unexpected production losses, and delay VAALCO's development plans. 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, clean-up 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 clean-up. As a result, a well control incident could result in substantial liabilities for the Group, and have a significant negative impact on the Group's earnings, cash flows, liquidity, financial position, and the price of Common Shares.

VAALCO could incur substantial penalties for not fulfilling the Group's work commitment under the terms of the Etame PSC

VAALCO, along with the Etame Consortium, is required to drill two development wells and two appraisal wellbores as part of the Base Case Work, pursuant to the Etame PSC Extension, by 16 September 2020. VAALCO plans to fulfil this commitment as part of the Work Programme in H1 2020, at an estimated cost of $61.2 million ($20.5 million, net to VAALCO).

If the Base Case Work is not undertaken, the Etame Consortium must pay the difference between the amounts spent on any wells that were drilled and the estimated costs of the wells as set out in the budget approved by the State of Gabon, being an estimated cost of $61.2 million ($20.5 million, net to VAALCO).

VAALCO has less control over its investments in foreign properties than it would have with respect to domestic investments, and added risk in foreign countries may affect VAALCO's foreign investments

The Group's international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalisation, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls, decisions of international financial institutions such as the International Monetary Fund and the Banking Commission of Central Africa, changes in laws and regulations relating to banking institutions and deposit accounts, requirements to hold funds in government-owned banks and the risk of foreign banking institution failure, possible changes in government personnel, the development of new administrative policies, practices and political conditions that may affect the enforcement or administration of laws and regulations, adoption of new or amendments to regulatory regimes for foreign investment, uncertainties as to whether the laws and regulations will be applicable in any particular circumstance, uncertainty as to whether VAALCO will be able to demonstrate to the satisfaction of the applicable governing authorities, compliance with governmental or contractual requirements and foreign governmental regulations that favour 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 licence holders and the Gabonese government is under pressure from the Gabonese labour union to require companies to hire a higher percentage of Gabonese citizens. In addition, VAALCO is subject to periodic routine audits by various government agencies in Gabon, including audits of petroleum costs account, customs, taxes and other operations matters. In 2016, the State of Gabon conducted an audit of the Group's operations in Gabon, covering the years 2013 through 2014. VAALCO received the findings from this audit and responded to the audit findings in January 2017. Since providing the Group's response, there have been changes in the Gabonese officials responsible for the audit. VAALCO is working with the current representatives to resolve the audit findings. The Group does not anticipate that the ultimate outcome of this audit will have a material adverse effect on VAALCO's financial condition, results of operations or liquidity. In addition, if a dispute arises with the Group's foreign operations, VAALCO 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 United States.

Additionally, on 5 March 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account transferred the funds to the CEMAC, of which Gabon is one of the six member states. The U.S dollars were converted to CFA, the local currency, with a credit back to the Gabonese branch. Amendment 5 to the Etame PSC provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, VAALCO shall no longer be held liable for the obligation to remediate the sites.

In the countries in which VAALCO's assets are located, the state generally retains ownership of minerals, and in many cases participates in the exploration and production of hydrocarbon reserves. Accordingly, VAALCO's operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. Beginning in February 2018, Gabon elected to take the portion of their oil attributable to profit oil in-kind rather than VAALCO continuing to market their share of production on their behalf. Gabon took its profit oil in-kind with the September 2018 and April 2019 liftings. The Group anticipates that this will continue to cause fluctuations in the timing of and realised prices for oil sales.

All of VAALCO's proved reserves are related to the Etame Marin Block located offshore Gabon. VAALCO has operated in Gabon since 1995 and believes that it has good relations with the current Government of Gabon. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect the Group's operations or cash flows.

VAALCO could lose its interest in Block P if the terms for lifting the suspension are not met

GEPetrol is the state-owned oil company of Equatorial Guinea, and a member of the Block P Consortium. As a condition of the EG MMH lifting the suspension and granting a two-year extension of the Block P PSC in September 2018 until September 2020 (1) GEPetrol was required to introduce a new investor or joint venture owner to the EG MMH by 28 March 2019, and it has fulfilled this requirement; and (2) the Block P Consortium will be required to drill an exploration well within one year of the EG MMH approving the new joint venture owner.

VAALCO intends to seek a partner on a promoted basis that will cover all or substantially all of the costs to drill the exploratory well. If the Block P Consortium does not drill an exploration well within one year of the EG MMH's approval, VAALCO could lose its interest in the Block P PSC.

While VAALCO would not incur a monetary penalty were it to lose its interest in the Block P PSC, the associated capitalised unproved leasehold costs of $10.0 million, being the total amount recorded in the Historical Financial Information for Block P as of 31 December 2018, would become impaired. The timing of EG MMH's approval of the new joint owner is outside of VAALCO's control. In the event that VAALCO loses its interest in Block P, this would not have an impact on the Group's cash flow.

RISKS RELATING TO VAALCO'S STRATEGY

Commodity derivatives transactions VAALCO enters into may fail to protect it from declines in commodity prices

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of the Group's crude oil and natural gas, VAALCO has entered into derivatives arrangements with respect to a portion of the Group's expected production. The Group's derivative contracts consist of a series of commodity swap contracts and are limited in duration. The Group's derivatives programme may be inadequate to protect it from significant and prolonged declines in the price of crude oil.

Properties that VAALCO buys may not produce as projected, and it 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 the Group's financial condition

One of the Group's growth strategies is to capitalise 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, the Group's 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 the Group's 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 the Group's cash from operations or borrowing capacity to finance acquisitions;
- significant increases in the Group's interest expense or financial leverage if VAALCO incurs additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which VAALCO is not indemnified or for which the Group's indemnity is inadequate;
- an increase in the Group's costs or a decrease in the Group's 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 organisation and adding operations;
- the failure to realise expected profitability or growth;
- the failure to realise expected synergies and cost savings; and
- coordinating or consolidating corporate and administrative functions.

If VAALCO consummates any future acquisitions the Group's capitalisation and results of operations may change significantly.

Acquisitions and divestitures of properties and businesses subject VAALCO to additional risks and uncertainties. The Group may be unable to integrate successfully the operations of any acquisitions with its operations, and it may not realise all the anticipated benefits of any future acquisitions or divestitures. Any sales or divestments of properties VAALCO makes may result in certain liabilities that it is required to retain under the terms of such sale or divestment

Failure to successfully exploit any acquisitions VAALCO engages in could adversely affect the Group's financial condition and results of operations. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and VAALCO may experience unanticipated delays in realising the benefits of an acquisition. If the Group consummates any future acquisition, the Group's capitalisation and results of operation may change significantly, and investors may not have the opportunity to evaluate the economic, financial and other relevant information that VAALCO will consider in evaluating future acquisitions.

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

The distressed financial conditions of one or more hedge providers could have an adverse impact on the Group in the event these hedge providers are unable to pay it amounts owed to it under one or more financial hedge transactions by which it has hedged the Group's exposure to commodity price volatility

From time to time, VAALCO may enter into financial hedge transactions to hedge or mitigate the Group's exposure to the risks of commodity price volatility with respect to the crude oil or natural gas VAALCO produces and sells. In such instances, the hedge provider will be obligated to make payments to VAALCO under such financial hedge transactions to the extent that the floating (market) price is below an agreed fixed (strike) price. Hedging agreements expose the Group to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. This risk of counterparty performance is of particular concern given the disruptions that have occurred in the financial markets that led to sudden changes in counterparty's liquidity and hence their ability to perform under their hedging contracts with the Group. VAALCO is unable to predict sudden changes in counterparty's creditworthiness or ability to perform. Even if VAALCO does accurately predict sudden changes, the Group's ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of the Group's counterparties deteriorates and results in their non-performance, VAALCO could incur a significant loss.

The Group's business could suffer if it loses the services of, or fails to attract, key personnel

VAALCO is highly dependent upon the efforts of the Group's senior management and other key employees. The loss of the services of the Group's Chief Executive Officer and Chief Financial Officer, as well as any loss of the services of one or more other members of the Group's senior management, none of whom are subject to a notice period, could delay or prevent the achievement of the Group's objectives. VAALCO does not maintain any "*key-man*" insurance policies on any of the Group's senior management, and does not intend to obtain such insurance. In addition, due to the specialised nature of the Group's business, VAALCO is highly dependent upon the Group's ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analysing drilling prospects and producing oil and natural gas from proved properties and maximising production from oil and natural gas properties. There is competition for qualified personnel in the areas of the Group's activities, and VAALCO may be unsuccessful in attracting and retaining these personnel.

LEGAL AND REGULATORY RISKS

Significant physical effects of climate change have the potential to damage the Group's facilities, disrupt the Group's production activities and cause it 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, the Group's exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to the Group's facilities from powerful winds or rising waters in low-lying areas, disruption of the Group's production activities because of climate-related damages to the Group's facilities, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on the Group's financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom VAALCO has a business relationship. VAALCO 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.

VAALCO has 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

VAALCO's business subjects it to liability risks from litigation or government actions. From time to time VAALCO may be a defendant or plaintiff in various lawsuits. The nature of the Group's operations exposes it to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavourably against the Group regardless of its belief, opinion, and position, which could have a material adverse effect on the Group's 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 the Group's net income, net cash flows and financial condition. Adverse litigation decisions or rulings may also damage the Group's business reputation.

Often, VAALCO's operations are conducted through joint ventures over which VAALCO may have limited influence and control. Private litigation or government proceedings brought against the Group could also result in significant delays in the Group's operations.

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

The environmental laws and regulations of the U.S., Gabon, and Equatorial Guinea regulate the Group's current business. These laws and regulations may require that VAALCO obtain permits for its development activities, limit or prohibit drilling activities in certain protected or sensitive areas, or restrict the substances that can be released in connection with the Group's operations. VAALCO's 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, VAALCO could be liable for environmental damages caused by, among others, previous property owners or operators of properties that the Group 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, VAALCO may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. The Group could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and the use of hydraulic fracturing fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on the Group's financial condition, results of operations and liquidity.

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

VAALCO operates in international jurisdictions, and it could be adversely affected by violations of the FCPA, UK Bribery Act and similar worldwide anti-corruption laws

The FCPA, UK Bribery 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. The Group's internal policies mandate compliance with these anti-corruption laws. Despite the Group's training and compliance programs, there can be no assurance that these internal control policies and procedures will always protect it from acts of corruption committed by the Group's employees or agents. Any additional expansion, 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 the Group's business and result in a material adverse effect on its financial condition, results of operations and cash flows.

RISKS RELATING TO THE COMMON SHARES

Shareholders will not be entitled to the takeover offer protections provided by the UK Takeover Code

The UK Takeover Code applies to offers for, among other companies, listed public companies which are either (i) considered by the Takeover Panel to be resident in the United Kingdom, the Channel Islands or the Isle of Man; or (ii) incorporated in the United Kingdom, the Channel Islands or the Isle of Man and listed on a Member State's regulated market, traded on a multilateral trading facility in the United Kingdom or traded on a stock exchange in the Channel Islands or the Isle of Man.

Upon Admission, the Common Shares will be listed on the regulated market of the London Stock Exchange. Because VAALCO is not a resident or incorporated within the United Kingdom, the Channel Islands or the Isle of Man, however, Shareholders will not receive the benefit of the takeover offer protections provided by the UK Takeover Code.

There is currently no UK market for the Common Shares. An active UK trading market may not develop or be sustained in the future, which would adversely affect the liquidity and price of the Common Shares

There is currently no UK market for the Common Shares. Therefore, investors cannot benefit from information about prior market history in the UK market when making their decision to invest. VAALCO can give no assurance that an active trading market for the Common Shares will develop in the United Kingdom or, if developed, can be sustained. If an active trading market is not developed or maintained, the liquidity and trading price of the Common Shares could be adversely affected.

Substantial future sales of Common Shares, or the perception that such sales might occur, or additional offerings of Common Shares could depress the market price of Common Shares

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

There may be volatility in the value of an investment in Common Shares and the market price for Common Shares may fluctuate

The market price for the Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Group's control, including the following: (i) actual or anticipated fluctuations in the Group's results of operations; (ii) actual or anticipated changes in the capital markets; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to VAALCO; (v) addition or departure of Executive Officers and other key personnel; (vi) sales or perceived sales of additional Common Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Group or its competitors; (viii) changes in laws, rules and regulations applicable to the Group and its operations; (ix) general economic, political and other conditions; (x) the Group's involvement in any litigation or dispute, or threat of any litigation or dispute; and (xi) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Group's industry or target markets.

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

VAALCO does not currently intend to pay dividends on the Common Shares and its ability to pay dividends in the future may be limited; consequently the only opportunity for investors to achieve a return on their investment is if the price of the Common Shares appreciates

VAALCO has never declared or paid dividends on the Common Shares. VAALCO intends to retain future earnings, if any, to support the development of the business and therefore does not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, would be at the discretion of the Board after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. Consequently, investors must rely on sale of their Common Shares after price appreciation, which may never occur, as the only way to realise a return on their investment.

Certain Shareholders will be issued Depositary Interests in respect of underlying Common Shares and will have to rely on the Depositary or the Custodian to exercise rights attaching to the underlying Common Shares for the benefit of the holders of Depositary Interests

On Admission, holders of Common Shares will be able to hold and transfer interests in the Common Shares within CREST pursuant to a depositary interest arrangement established by VAALCO. The Common Shares will not themselves be admitted to CREST; rather, the Depositary will issue the Depositary Interests in respect of underlying Common Shares. The Depositary will have the power to exercise voting and other rights conferred by the DGCL, Certificate of Incorporation and Bylaws on behalf of the relevant holder through its or the Custodian's DTC account, which will be maintained on the Company's share register via Cede & Co, a nominee of DTC. Consequently, the holders of Depositary Interests must rely on the Depositary to exercise such rights for the benefit of the holders of Depositary Interests. Holders of Depositary Interests may experience delays in receiving any dividends paid by the Company, may receive proxy forms later than other Shareholders and may have to act earlier than other Shareholders when casting votes at general meetings of VAALCO, by virtue of the administrative process involved in connection with holding Depositary Interests.

VAALCO is applying for a Standard Listing and, accordingly, VAALCO will not be required to comply with those protections applicable to a Premium Listing

VAALCO is seeking a Standard Listing and, as a consequence, additional on-going requirements and protections applicable to a Premium Listing will not apply to VAALCO. In particular, the provisions of Chapters 6 to 13 of the Listing Rules (other than Rule 7.2.1), being additional requirements for a Premium Listing of equity securities (Premium Listing principles, sponsors, continuing obligations, significant transactions, related party transactions, dealing in own securities and treasury shares and contents of circulars), will not apply. In addition, a Standard Listing will not permit VAALCO to gain UK FTSE indexation.

Dual-listing on the NYSE and the LSE may lead to an inefficient market in the Common Shares

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

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

The Common Shares are quoted and traded in USD on the NYSE. The Common Shares will be quoted and traded in GBX on the LSE. The market price of the Common Shares on those exchanges may also differ due to exchange rate fluctuations.

VAALCO is a Delaware corporation and a significant portion of its assets are located outside the United Kingdom. As a result, it may be difficult for Shareholders to enforce civil liability provisions available under English law

VAALCO is incorporated under the laws of the State of Delaware, USA and its assets are primarily located in Gabon and Equatorial Guinea. In addition, the Directors are not residents of the UK. As a result, it may be difficult for an investor to effect service of process on that person or to enforce judgments obtained in English courts against VAALCO or that person based on the civil liability provisions available under English law. It is doubtful whether courts in the U.S. will enforce judgments obtained in other jurisdictions, including England and Wales, against VAALCO or the Directors under the securities laws of those jurisdictions or entertain actions in Delaware or the U.S. federal courts against VAALCO or the Directors under the securities laws of other jurisdictions.

Similarly, there are no reciprocal recognition or enforcement agreements in place between the UK, Gabon or Equatorial Guinea. This means a UK judgment cannot be automatically enforced in Gabon or Equatorial Guinea. However, arbitral awards made in either the U.S., UK or Gabon in relation to commercial disputes can be enforced in each country as they are all party to the New York Convention. Equatorial Guinea is not party to the New York Convention and therefore there is no automatic right to enforce an arbitral award made in the UK or Equatorial Guinea in either country.

The rights afforded to Shareholders are governed by laws of the State of Delaware and non-U.S. Shareholders may have difficulties exercising rights which are governed by U.S. law

As VAALCO is incorporated under the laws of the State of Delaware, USA the rights of Shareholders are governed by the DGCL and the Certificate of Incorporation and Bylaws. The rights of Shareholders under the laws of the State of Delaware may differ from the rights of shareholders of companies incorporated in other jurisdictions. Not all rights available to Shareholders under English law will be available to the Shareholders. Shareholders must follow the State of Delaware's legal requirements in order to exercise their rights which may be difficult for Shareholders outside of the United States.

The Certificate of Incorporation and Bylaws do not contain any rights of pre-emption in favour of existing Shareholders, which means that Shareholders may be diluted if additional Common Shares are issued

Shareholders do not have pre-emptive rights and VAALCO, without Shareholder consent, may issue additional Common Shares, Preferred Shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, working capital, capital expenditures, investments, acquisitions and repayment or refinancing of borrowings. VAALCO actively seeks to expand its business through complementary or strategic acquisitions, and may issue additional Common Shares in connection with those acquisitions. VAALCO also issues Common Shares to its Executive Officers, Employees and independent Directors as part of their compensation. This may have the effect of diluting the interests of existing Shareholders. Additionally, to the extent that pre-emptive rights are granted, Shareholders in certain jurisdictions may experience difficulties or may be unable to exercise their pre-emptive rights.

Any issue of Preferred Shares will rank in priority to the Common Shares

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

PART 3 – PRESENTATION OF FINANCIAL AND OTHER INFORMATION

1. General

This document comprises a prospectus for the purpose of Article 6 of the Prospectus Regulation and is issued in compliance with the Listing Rules. Investors should only rely on the information in this Prospectus. No person has been authorised to give any information or to make any representations in connection with Admission, other than those contained in this Prospectus and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company or the Directors. The Company does not accept any responsibility for the accuracy or completeness of any information reported by the press or other media, nor the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media regarding the Company. The Company makes no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication other than this Prospectus.

Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to FSMA, the delivery of this Prospectus shall not under any circumstances, create any implication that there has been no change in the business or affairs of the Group since the date of this Prospectus, or that the information contained herein is correct as of any time subsequent to its date.

The contents of this Prospectus or any subsequent communications from the Company, the Group or any of their respective affiliates, directors, officers, advisers, employees or agents, are not to be construed as legal, business or tax advice. Each prospective investor should consult its, his or her own lawyer, financial intermediary or tax adviser for legal, financial or tax advice. In making an investment decision, each investor must rely on its, his or her own examination, analysis and enquiry of the Company, including the merits and risks involved.

This Prospectus is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation by any of the Company or the Directors or any of its representatives that any recipient of this Prospectus should subscribe for or purchase Common Shares. Prior to making any decision as to whether to subscribe for or purchase Common Shares, prospective investors should read this Prospectus. Investors should ensure that they read the whole of this Prospectus carefully and not just rely on key information or information summarised within it. In making an investment decision, prospective investors must rely upon their own examination of the Company and the terms of this Prospectus, including the risks involved.

2. Presentation of financial information

The financial information presented in this Prospectus includes audited annual consolidated financial statements for the Group as at and for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016 and unaudited condensed interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018.

The audited annual consolidated financial statements for the Group have been prepared in accordance with U.S. GAAP. For full details of the basis of preparation and significant accounting policies, please refer to Note 2 (Summary of Significant Accounting Policies) to the Group's audited annual consolidated financial statements for the each of the financial years ended 31 December 2018, 31 December 2017 and 31 December 2016 as set out in the Appendix to this Prospectus.

For financial year ended 31 December 2018, the Company adopted the new standard under Accounting Standards Codification Topic 606 – 'Revenue from Contracts with Customers' on 1 January 2018 on a modified retrospective transition method basis. The standard requires enhanced disclosure of revenue from contracts with customers, including categories that depict the nature, amount, timing and uncertainty of revenue and cash flows that are affected by economic factors. The Company reviewed its revenue streams and major contracts with customers and concluded that there were no material impacts on the Company's revenues or cash flows as a result of adopting the new standard.

Unless otherwise stated in this Prospectus, financial information in relation to the Group referred to in this Prospectus has been extracted without material adjustment from the Historical Financial Information in the

Appendix to this Prospectus. Unless otherwise indicated, none of the financial information relating to the Group in this Prospectus has been audited.

3. Unaudited financial information

In this Prospectus, the Group presents certain financial measures and other metrics that are unaudited. The Directors believe that each of these measures provides useful information with respect to the performance of the Group's business and operations. Unaudited financial measures and other metrics in relation to Group have been derived from (i) management accounts for the relevant accounting periods presented; (ii) internal financial reporting systems supporting the preparation of the Historical Financial Information contained in Part 12 (*Historical Financial Information*) of this Prospectus; and (iii) the Group's other business operating systems and records. Management accounts are prepared using information derived from accounting records used in the preparation of the Historical Financial Information contained in Part 12 (*Historical Financial Information*) of this Prospectus, but may also include certain other assumptions and analyses.

4. Oil data

Unless expressly stated otherwise, all estimates of proved, probable and possible reserves and related future net revenue and contingent and prospective resources disclosed in this Prospectus have been prepared in accordance with the PRMS. As presented in the PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Unless otherwise noted, reserves estimates are presented on a "*company gross*" basis, representing the Group's working interest share before deduction of royalties.

5. Currencies

In this Prospectus, references to "**GBX**" or "**£**" are to the lawful currency of the UK, references to "**U.S. dollars**" or "**USD**" or "**$**" are to the lawful currency of the United States, references to "**CFA**" are to the lawful currency of Gabon and Equatorial Guinea, and references to "**Euro**" or "**€**" are to the lawful currency of 19 Member States of the European Union. The basis of translation of any foreign currency transactions and amounts in the financial information set out in the Appendix to this Prospectus are set out in the Appendix.

6. Rounding

Percentages and certain amounts in this Prospectus, including financial, statistical and operating information, have been rounded to the nearest thousand whole number or single decimal place for ease of presentation. As a result, the figures shown as totals may not be the precise sum of the figures that precede them. In addition, certain percentages and amounts contained in this Prospectus reflect calculations based on the underlying information prior to rounding, and, accordingly, may not conform exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

7. Third party information

The Company confirms that all third party information contained in this Prospectus has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this Prospectus, the source of such information has also been identified.

Statements regarding the oil and gas industry which are not based on published statistical data or information obtained from independent third parties, are based on the Group's and/or the Directors' experience, the Group's internal studies and estimates, and the Group's own investigation of market conditions. The Company cannot assure prospective investors that any of these studies or estimates are accurate, and none of the Group's internal surveys or information has been verified by any independent sources. While the Directors are not aware of any misstatements regarding the Group's own estimates presented herein, those estimates involve risks, assumptions and uncertainties and are subject to change based on various factors, including those set out in Part 2 (*Risk Factors*) of this Prospectus.

8. Forward-looking statements

This Prospectus contains "**forward-looking statements**" and "**forward-looking information**" that are based on the Company's expectations, estimates and projections as of the date on which the statements were made. This forward-looking information includes, among other things, statements with respect to the Competent Person's Reports, the Company's business strategy with respect to the Projects, plan, development, objectives, performance, outlook, growth, cash flow, projections, targets and expectations, oil and gas reserves and resources, results of exploration, the price and demand for oil and gas and acts by the Company's partners to the respective Projects. Generally, this forward looking information can be identified by the use of forward-looking terminology such as "*outlook*", "*anticipate*", "*project*", "*target*", "*likely*", "*believe*", "*estimate*", "*expect*", "*intend*", "*may*", "*would*", "*could*", "*should*", "*scheduled*", "*will*", "*plan*", "*forecast*", "*evolve*" and similar expressions. Persons reading this Prospectus are cautioned that such statements are only predictions, and that the Company's actual future results or performance may be materially different.

Forward-looking information is subject to known and unknown risks, uncertainties and other factors that may cause the Company's actual results, level of activity, performance or achievements to be materially different from those expressed or implied by such forward-looking information. These statements speak only as of the date of this Prospectus and do not seek in any way to qualify the working capital statement given by the Company at paragraph 14 of Part 8 *(Information on VAALCO Energy, Inc.)* of this Prospectus. Actual operational and financial results or events may differ materially from the Company's expectations contained in the forward-looking statements as a result of various factors, many of which are beyond the control of the Company.

Statements related to reserves or resources are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and prospective resources can be profitably produced in the future. The forward-looking statements contained in this Prospectus are expressly qualified by this cautionary statement. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Forward-looking statements involve significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct.

Investors are cautioned that forward-looking statements are not guarantees of future performance. The Company makes no representation, warranty or prediction that the results predicted by such forward-looking statements will be achieved and these forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this Prospectus speak only as at the date of this Prospectus, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and the availability of new credit. Investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ. All of the forward-looking statements made in this Prospectus are qualified by these cautionary statements.

Subject to the requirements of the Prospectus Regulation Rules, the DTR and the Listing Rules, or applicable law, the Company explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

9. Basis of presentation of Competent Person's Reports

The Competent Person's Reports have been prepared in accordance with the PRMS. The Competent Person's Reports are compliant with the Competent Person's Report requirements as published in the ESMA update of the Committee of European Securities Regulators' recommendations of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

In preparation of the Competent Person's Reports, NSAI relied upon, without independent verification, information furnished by, or on behalf of, the Company with respect to the property interests being evaluated, production from such properties, current cost of operations and development, current prices for production, agreements related to current and future operations and sale of production, estimation of taxes, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of the Competent Person's Reports.

10. No incorporation of website

The contents of the Company's website, any website mentioned in this Prospectus or any website directly or indirectly linked to these websites have not been verified and do not form part of this Prospectus and investors should not rely on such information.

11. Definitions and technical terms

A list of defined terms used in this Prospectus is set out in Part 18 (*Definitions*) of this Prospectus. A list of defined technical terms and conversions used in this Prospectus is set out in Part 19 (*Glossary of Technical Terms and Conversions*) of this Prospectus.

PART 4 – CONSEQUENCES OF A STANDARD LISTING

After careful consideration, the Directors have concluded that in order to promote liquidity in the Common Shares through a public listing on the London Stock Exchange while allowing a sufficient degree of flexibility for a company of its size and type, it is appropriate for the Common Shares to be admitted to listing on the standard segment of the Official List. In particular, the following are key considerations for the Company's proposed Standard Listing:

- a Standard Listing as compared to a Premium Listing will generally facilitate more cost efficient administration. In this regard, the Company wishes to align its regulatory responsibilities and the associated cost consequences with the Company's size;
- the proposed Standard Listing of the Company will mean that the Company will not be required to comply with the super-equivalent provisions of the Listing Rules that apply to companies with a Premium Listing, which will have a direct cost saving for the Company; and
- the Listing Rules for securities with a Standard Listing are far less demanding and stringent than those applicable to securities with a Premium Listing.

A Standard Listing affords Shareholders and investors in the Company a lower level of regulatory protection than that afforded to investors in companies whose securities are admitted to the premium segment of the Official List, which are subject to additional obligations under the Listing Rules.

It should be noted that the UKLA will not have the authority to (and will not) monitor the Company's compliance with any of the Listing Rules or any of the DTR, nor to impose sanctions in respect of any failure by the Company to so comply.

Application has been made for the Common Shares to be admitted to listing on the standard segment of the Official List pursuant to Chapter 14 of the Listing Rules, which sets out the requirements for Standard Listings and does not require the Company to comply with, among other things, the provisions of Chapters 6 to 13 of the Listing Rules (excluding Listing Principles 1 and 2). As a result, the Company's securities will not be eligible for inclusion in the UK series of the FTSE indices.

1. Listing Rules which are not applicable to a Standard Listing

The following Listing Rules are not applicable to a Standard Listing:

- Chapter 6 of the Listing Rules regarding, among other things, the content of the Historical Financial Information, provisions pertaining to, control of the business, working capital, constitutional arrangements of the Company and Shares in public hands;
- Chapter 7 of the Listing Rules other than the listing principles relating to (i) taking reasonable steps to establish and maintain adequate procedures, systems and controls to enable the Company to comply with its obligations; and (ii) dealing with the FCA in an open and co-operative manner;
- Chapter 8 of the Listing Rules regarding the appointment of a listing sponsor to guide the Company in understanding and meeting its responsibilities under the Listing Rules in connection with certain matters. In particular, the Company is not required to appoint a sponsor in relation to the publication of this Prospectus or Admission;
- Chapter 9 of the Listing Rules relating to further issues of shares, issuing shares at a discount in excess of 10 percent of market value, notifications and contents of financial information;
- Chapter 10 of the Listing Rules relating to significant transactions which requires Shareholder consent for certain acquisitions;
- Chapter 11 of the Listing Rules regarding related party transactions;
- Chapter 12 of the Listing Rules regarding purchases by the Company of its Common Shares; and
- Chapter 13 of the Listing Rules regarding the form and content of circulars to be sent to Shareholders.

2. Listing Rules with which the Company must comply under a Standard Listing

There are, however, a number of principles and continuing obligations set out in Chapter 7 and Chapter 14, respectively, of the Listing Rules that will be applicable to the Company. These include requirements as to:

Chapter 7 – Listing Principles

- the taking of reasonable steps to establish and maintain adequate procedures, systems and controls to enable it to comply with its obligations; and
- the dealing with the FCA in an open and co-operative manner.

Chapter 14 – Continuing Obligations

- the forwarding of circulars and other documentation to the UKLA for publication through the document viewing facility and related notification to a regulatory information service;
- the provision of contact details of appropriate persons nominated to act as a first point of contact with the UKLA in relation to compliance with the Listing Rules and the DTR;
- the form and content of temporary and definitive documents of title;
- the appointment of a registrar;
- the making of regulatory information service notifications in relation to a range of debt and equity capital issues; and
- at least 25 percent of the Common Shares being held by the public in the European Economic Area or the jurisdiction in which the Common Shares are listed.

In addition, as a company whose securities are admitted to trading on a regulated market, the Company will be required to comply with the DTR.

3. Disclosure Guidance and Transparency Rules

Under Rule 5 of the DTR (*Vote Holder and Issuer Notification Rules*) ("**DTR5**"), a person must notify the Company and the FCA of the percentage of the Company's voting rights he or she holds as a Shareholder (or holds or is deemed to hold through his or her direct or indirect holding of financial instruments) if, as a result of an acquisition or disposal of Common Shares or financial instruments, or as a result of any event changing the breakdown of voting rights of the Company (for example, a buy-back of Common Shares by the Company), the percentage of those voting rights in which he is interested reaches, exceeds or falls below 5 percent, 10 percent, 15 percent, 20 percent, 25 percent, 30 percent, 50 percent and 75 percent.

The form in which such notification must be made is provided by the FCA on its website at:

https://www.fca.org.uk/markets/ukla/regulatory-disclosures/submit-investor-notification

Such notification must be made no later than four trading days after the date upon which the person making the notification (1) learns of the acquisition or disposal or of the possibility of exercising voting rights, or on which, having regards to the circumstances, should have learned of it, regardless of the date on which the acquisition, disposal or possibility of exercising voting rights takes effect, or (2) is informed about the event changing the breakdown of voting rights of the Company.

Any person who is in breach of their obligations under DTR5 is liable to a fine and/or public censure by the FCA and the FCA may apply to court to have such person's voting rights suspended.

4. Exchange Act

Sections 13(d) and 13(g) of the Exchange Act require any person or group of persons who directly or indirectly acquires or has beneficial ownership of more than 5 percent of a class of an issuer's securities to report such beneficial ownership on Schedule 13D or Schedule 13G, as appropriate. These reports are filed with the SEC electronically on EDGAR. Both Schedule 13D and Schedule 13G require background information about the reporting persons, including the name, address, and citizenship or place of organisation of each reporting person, the amount of the securities beneficially owned and aggregate beneficial ownership percentage, and whether voting and investment power is held solely by the reporting persons or shared with others.

PART 5 – EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Prospectus published	23 September 2019
Admission and commencement of dealings in Common Shares on the London Stock Exchange	8.00 am on 26 September 2019

These dates and times are indicative only, subject to change and may be brought forward as well as moved back, in which case new dates and times will be announced. The times referred to above are references to the time in London.

PART 6 – ADMISSION STATISTICS AND DEALING CODES

Number of Common Shares in issue on Admission	67,478,896
Number of Treasury Shares in issue on Admission	8,883,929
Number of Common Shares in issue and outstanding on Admission	58,594,967
Number of Options in issue on Admission	2,973,488
Number of Common Shares on a fully diluted basis	70,452,384
Percentage of issued share capital represented by Options outstanding at Admission	4.14%
Expected market capitalisation of the Company on Admission	\$123.14 million £98.75 million
ISIN	US91851C2017
LEI	549300CFHFVIWB8M6T24
Tickers	LSE: EGY NYSE: EGY

PART 7 – DIRECTORS, SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors	Cary M. Bounds	*Chief Executive Officer and Director*
	Andrew L. Fawthrop	*Chairman and Director*
	A. John Knapp, Jr.	*Director*
	Steven J. Pully	*Director*
	William R. Thomas	*Director*
Company Secretary	Michael G. Silver	
Registered Office and Head Office	9800 Richmond Avenue Suite 700 Houston Texas 77042 United States	
Financial Adviser	FirstEnergy Capital LLP (trading as GMP FirstEnergy) 85 London Wall London EC2M 7AD United Kingdom	
Legal Advisers as to English Law	Memery Crystal LLP 165 Fleet Street London EC4A 2DY United Kingdom	
Legal Advisers as to U.S. Law	Shearman & Sterling LLP 1100 Louisiana Street, Suite 3300 Houston Texas 77002 United States	
Legal Advisers as to Gabonese and Equatorial Guinean Law	Miranda & Associados Av. Engenheiro Duarte Pacheco, 7 1070-100 Lisbon Portugal	
Reporting Accountants	BDO LLP 55 Baker Street London W1U 7EU United Kingdom	
Auditors	BDO USA LLP 2929 Allen Parkway 20th Floor Houston Texas 77019 United States	
Competent Person	Netherland, Sewell & Associates, Inc. 1301 McKinney Street #3200 Houston Texas 77010 United States	

Financial PR	Buchanan Communications Limited 107 Cheapside London EC2V 6DN United Kingdom
Registrar	Computershare Inc. 8742 Lucent Blvd., Suite 225 Highlands Ranch Colorado 80129 United States
Depositary	Computershare Investor Services plc The Pavilions Bridgwater Road Bristol BS13 8AE United Kingdom

PART 8 – INFORMATION ON VAALCO ENERGY, INC.

1. Overview

VAALCO is an independent energy company based in Houston, Texas, USA engaged in the production of crude oil and the exploration and development of oil properties in West Africa.

The Group's flagship asset is a 31.1 percent working interest in the Etame Marin Block, located offshore Gabon, which has produced more than 110 MMBBL to date. Under the Etame PSC, which the Group entered into in July 1995, VAALCO will hold an interest in Etame until September 2028, with an option to extend for two additional five-year periods.

VAALCO is designated as the operator on behalf of the Etame Consortium. The Etame Consortium consists of four companies, being (1) VAALCO Gabon; (2) Addax; (3) Sasol; and (4) PetroEnergy. Etame is subject to a 7.5 percent back-in carried interest by the State of Gabon, which is currently held by Tullow. VAALCO's working interest will decrease to 30.3 percent in June 2026, when the back-in carried interest increases to 10 percent.

VAALCO's interest in Etame accounts for substantially all of the Group's revenue and 100 percent of its reserves. In addition to its interest in the Etame Marin Block, VAALCO owns a 31.0 percent working interest in an undeveloped portion of Block P, located offshore Equatorial Guinea.

As of 31 March 2019, VAALCO has estimated proved reserves of 5.6 MMBBL, probable reserves of 4.5 MMBBL and contingent resources (3C) of up to 11.9 MMBBL, pursuant to its interests in the Etame Marin Block. Its interests in Block P are estimated to be contingent resources (3C) of up to 8.2 MMBBL.

VAALCO was founded in 1985 and its Common Shares are currently listed, and will remain listed after Admission, on the NYSE under the symbol EGY.

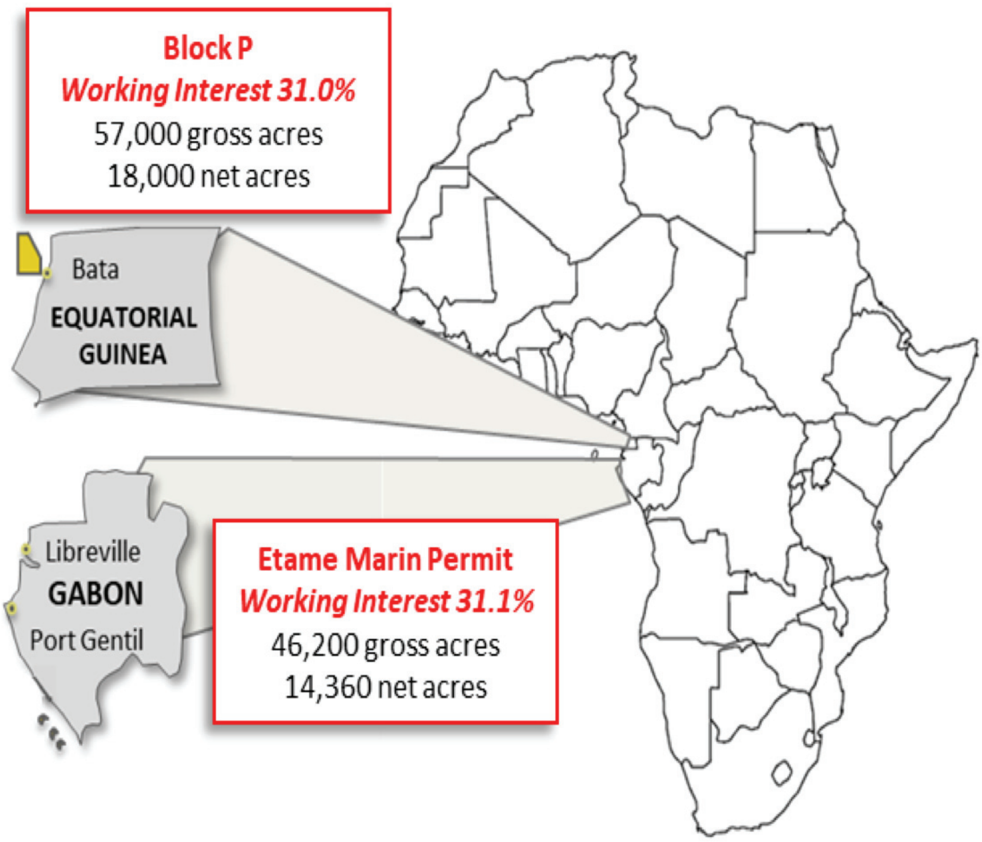


Figure 1 – Map of the Projects.

2. Competitive strengths

Established operator with a proven track record in West Africa

The Group acquired its interest in Etame in July 1995. Since acquiring its interest, VAALCO has acted as operator and has produced more than 110 MMBBL of oil to date, including from deep and over pressured reservoirs. In addition to the Etame Marin Block, the Group has a working interest in the prospective Block P, which it has owned since November 2012 and which the Directors believe has the potential to significantly increase the Group's reserves.

Strong management team with extensive industry experience

The Directors, Executive Officers and the Group's technical teams have experience of working in international and national oil companies, independents and service companies and have global experience in hydrocarbon exploration, development and production operations. They have extensive experience in the African oil and gas market.

Profitable free cash flow from low risk reserve base

VAALCO's operations in Etame have provided the Group with a profitable basis of free cash flow with operating income from the Etame Marin Block in the financial year ended 31 December 2018 of $51.3 million. The Directors believe that, following the Etame PSC Extension and based on the reserves and resources evaluated by NSAI in the Etame Marin Block CPR, it can leverage these strengths to continue to benefit Shareholders.

Material upside from existing Etame Field

VAALCO's proved reserves are estimated at 5.6 MMBBL, probable reserves at 4.5 MMBBL and contingent resources (3C) at up to 11.9 MMBBL, as set out in the Etame Marin Block CPR, as at 31 March 2019.

As a result of improved oil pricing, positive production performance and the Etame PSC Extension, VAALCO's estimated proved reserves increased by 3.7 MMBBL (76 percent) during 2018. This increase was a result of (i) the Etame PSC Extension (adding 2.2 MMBBL); (ii) better-than-forecasted results for production (adding 1.1 MMBBL); and (iii) increased crude oil prices (adding 0.4 MMBBL). The total proved reserves replacement at Etame for 2018 was 270 percent of the total net production.

Fully funded Work Programme providing multiple catalysts

VAALCO is fully funded to pursue the Work Programme, which commenced in September 2019, through H1 2020, exploring, developing and potentially upscaling the known reserves and resources at the Etame Marin Block. VAALCO commenced the Work Programme on 13 September 2019, by beginning the drilling of its first appraisal wellbore of the programme in the Etame Field, to evaluate the Dentale Formation, with a further appraisal wellbore, to evaluate the Gamba Formation in the Southeast Etame Field, and up to three development wells, to follow. The Directors believe that the Work Programme is the first step in realising the full potential now opened to VAALCO following the extension of the Etame PSC.

Solid foundation to pursue opportunistic inorganic growth

VAALCO's goal is to achieve transformational growth both organically and through potential value-accretive acquisitions or mergers of similar properties or assets to diversify the Group's portfolio.

3. Strategy

Following the Etame PSC Extension, VAALCO's financial position has improved and the Group has no debt. The Directors believe that the Group will generate sufficient operating cash flow to sustain current operations and fund development projects in the Etame Marin Block.

VAALCO is seeking to further increase production and reserves by undertaking the fully funded Work Programme and pursuing accretive growth opportunities where it can leverage proven technical and operational capabilities.

The cornerstone of VAALCO's strategy to create long-term value for all stakeholders is to focus on profitable growth from low-risk reserve development while maintaining financial discipline. In addition, over the next 12 months, VAALCO seeks to:

- undertake the Work Programme;
- focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalise on an increase in prices;
- manage capital expenditures related to the Work Programme so that expenditures can be funded by cash on hand and cash flow from operations;
- continue to focus on operating safely and complying with internationally accepted environmental operating standards;
- optimise production through careful management of wells and infrastructure, including minimising downtime;
- maximise cash flow and income generation;
- continue planning for additional development in Etame as well as future exploration and development in Equatorial Guinea;
- preserve a strong balance sheet by maintaining conservative leverage ratios and exhibiting financial discipline;
- opportunistically hedge against exposures to changes in oil prices; and
- actively pursue strategic, value-accretive mergers and acquisitions of similar properties to diversify the Company's portfolio of producing assets.

4. Summary of reserves and resources

Etame Marin Block

NSAI has produced the Etame Marin Block CPR, dated 20 September 2019, on VAALCO's reserves and resources at Etame, as at 31 March 2019.

The estimated gross oil reserves, working interest oil reserves and estimated future net revenue to VAALCO in the Etame Marin Block, as at 31 March 2019, are detailed in Table 1.

Table 1 – Etame Marin Block reserves and probable resources

	Oil Reserves (MBBL)		***Future Net Revenue (M$)***	
Category	***Gross (100%)***	***Working Interest****	***Total***	***Present Worth at 10%***
Proved Developed Producing	8,461.3	2,627.8	$30,545.0	$29.944.0
Proved Developed Non-Producing	1,837.5	570.7	8,222.8	7,069.2
Proved Undeveloped	7,654.2	2,377.1	19,805.0	14,399.8
Total Proved (1P)	17,953.0	5,575.6	58,572.8	51,413.0
Probable	14 479.1	4,485.7	62,989.6	47,774.4
Proved + Probable (2P)	32,432.1	10,061.4	121,562.4	99,187.4
Possible	11,643.2	3,573.9	52,175.7	36,138.3
Proved + Probable + Possible (3P)	44,075.3	13,635.3	$173,738.1	$135,325.7

Note

*Working interest reserves are prior to deductions for government royalties and "*income tax barrels*".

The unrisked gross and working interest contingent oil resources in the Etame Marin Block, as at 31 March 2019, are detailed in Table 2.

Table 2 – Etame Marin Block contingent resources

Category	Unrisked Contingent Oil Resources (MMBBL) Gross (100%)	Working Interest
Low Estimate (1C)	15.6	4.8
Best Estimate (2C)	25.5	7.9
High Estimate (3C)	38.3	11.9

The gross and working interest prospective oil resources for the Etame Marin Block, shown for each of the respective Etame Fields, as at 31 March 2019, are detailed in Table 3.

Table 3 – Etame Marin Block prospective resources

	Unrisked Gross (100%) Prospective Oil Resources (MMBBL)			*Unrisked Working Interest Prospective Oil Resources (MMBBL)*			
Prospect	*Low Estimate (1U)*	*Best Estimate (2U)*	*High Estimate (3U)*	*Low Estimate (1U)*	*Best Estimate (2U)*	*High Estimate (3U)*	*Pg (%)*
East Ebouri	1.6	3.6	8.6	0.5	1.1	2.7	73
Northeast Avouma	1.5	4.4	15.1	0.5	1.4	4.7	73
South Etame	1.9	4.6	12.3	0.6	1.4	3.8	64
Southwest Avouma	2.2	5.1	13.0	0.7	1.6	4.0	73
Southwest Etame	2.1	5.2	14.3	0.7	1.6	4.4	64
West Etame	0.4	1.0	2.4	0.1	0.3	0.8	56

Block P

NSAI has produced the Block P CPR, dated 20 September 2019, on VAALCO's resources at Block P, as at 31 March 2019.

The unrisked gross and working interest contingent oil resources in Block P, as at 31 March 2019, are detailed in Table 4.

Table 4 – Block P contingent resources

Category	Unrisked Contingent Oil Resources (MMBBL) Gross (100%)	Working Interest
Low Estimate (1C)	11.1	3.4
Best Estimate (2C)	16.5	5.1
High Estimate (3C)	26.5	8.2

The gross and working interest prospective oil resources for Block P, shown for each of the respective prospects at Block P, as at 31 March 2019, are detailed in Table 5.

Table 5 – Block P prospective resources

Prospect	Unrisked Gross (100%) Prospective Oil Resources (MMBBL) Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Unrisked Working Interest Prospective Oil Resources (MMBBL) Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Pg (%)
Marte	11.1	40.6	131.9	3.4	12.6	40.9	19
Marte North	23.8	66.9	136.8	7.4	20.7	42.4	17
Saturno	3.5	10.9	25.7	1.1	3.4	8.0	23
Southwest Grande M-3	9.1	28.1	69.5	2.8	8.7	21.5	19
Southwest Grande O-1	11.0	32.9	76.5	3.4	10.2	23.7	16
Southwest Grande Oligocene	7.1	29.0	114.2	2.2	9.0	35.4	13
Southwest Grande OM-1	15.4	43.0	85.9	4.8	13.3	26.6	19
Southwest Grande OM-2	11.8	31.4	64.7	3.7	9.7	20.1	23

5. Etame Marin Block

The Etame Marin Block lies approximately 23 km northwest of the Gabon-Congo international boundary and 140 km southeast of Sette Cama, Gabon, in water depths ranging from 75 m to 85 m. It is separated into three EEAs in the permit area, which comprise approximately 187 km^2 located around the five producing Etame Field areas. The Ebouri EEA comprises 14.86 km^2, the Avouma EEA comprises 77.81 km^2 and the Etame EEA comprises 94.44 km^2.

The Etame Fields consist of five separate producing fields, being the (i) Avouma/South Tchibala Field; (ii) Ebouri Field; (iii) Etame Field; (iv) North Tchibala Field; and (v) Southeast Etame Field, details of which are set out in Table 6.

Table 6 – Etame Fields

Licence/Field	*Operator*	*VAALCO Working Interest (%)*	*Status*	*Licence Expiration Date*	*Licence Area (km^2)*
Etame PSC	VAALCO Gabon	31.057	–	16 September 2028	187
Avouma/South Tchibala Field			Production		
Ebouri Field			Production		
Etame Field			Production		
North Tchibala Field			Production		
Southeast Etame			Production		

Elf, the original licence holder of the Etame PSC, drilled several wells during the 1970s and 1980s when the South Tchibala and North Tchibala Fields were discovered. VAALCO acquired the Etame PSC in July 1995 and conducted a 385 km^2 3-D seismic survey in 1997 and drilled the discovery well for the Etame Field in 1998.

On 22 November 2016, the Group completed the acquisition of an additional 2.98 percent working interest (3.23 percent participating interest) in the Etame Marin Block from Sojitz, which had an effective date of 1 August 2016. The Etame PSC Extension, which the Group entered into on 17 September 2018, extended the Etame PSC through September 2028, with an option to extend for two additional five-year periods.

Geology of the Etame Marin Block

The coastal sedimentary basin of Gabon started forming during the Upper Jurassic period with the onset of rifting and breakup of the Gondwana supercontinent. Rifting started with the formation of a series of tilted horst and graben blocks and fluviodeltaic deposition that ended with deposition of the Dentale Formation. The rift phase was terminated by major uplift of the western margin of Africa that caused an erosional event that planed off topographic highs and deposited the sediments in the lows, creating a surface with little or no topographic relief.

The rift phase was followed by an Aptian transition phase initiated by transgression of marine waters into the basin with deposition of the transgressive Gamba Sandstone and Vembo Shale. Later deposition of the Ezanga Salt occurred in the restricted seaway that formed and then was cut off from the main body of the ocean.

The transition phase was succeeded by the drift phase in which Albian oceanic crust started to form and the Madiela carbonates were deposited. These carbonates and the clastics of the Cenomanian Cap Lopez were deformed by basinward block faulting caused by a slight westward tilt of the basin and the mobility of the underlying salt.

From the Cenomanian age onward, a large prograding wedge of marine and marginal marine clastics has been deposited along the west coast of Gabon. This sediment wedge has been broken up into large fault blocks formed by listric faulting that soles out into the Ezanga Salt.

The Dentale Formation contains a thick sequence of fluviodeltaic and fluviolacustrine sandstones and shales of Barremian age. The source rock for much of the offshore area is found in this formation. It is also one of the more prolific oil-producing zones in Gabon. The Dentale Formation is productive in offshore Etame, North Tchibala and Tchibala Fields.

The Gamba Formation unconformably overlies the Dentale Formation and was deposited during the transgressive event after erosion of the Dentale Formation. The Gamba Formation is composed of a basal sandstone and an upper carbonate. The reservoir is usually contained in the sandstone since the carbonate is typically very tight unless a dolomite zone is developed. The Gamba Sandstone exhibits excellent reservoir properties, with porosity generally between 20 to 30 percent and permeability often greater than 1 darcy.

Capping the Gamba Formation are the Vembo Shale and the Ezanga Salt. The Vembo is a dark-coloured, restricted marine shale. The Ezanga Salt varies in thickness from 500 to over 1,500 m. The drastic change in thickness is caused by the mobility of the salt that has resulted in much of the structuring observed in the post-salt sequence. The Vembo Shale and Ezanga Salt make an excellent seal for the underlying Gamba and Dentale Formations.

Wells in the Etame Marin Block

There are 20 wells across the Etame Fields, of which nine are currently in production: the (i) Avouma/South Tchibala Field has three producing wells; (ii) Ebouri Field has one producing well; (iii) Etame Field has three producing wells; (iv) North Tchibala Field has one producing well; and (v) Southeast Etame Field has one producing well.

Details of each of the wells in Etame are set out in Table 7.

Table 7 – Summary of production wells in the Etame Marin Block*

Well Name	***Field***	***Well Type***	***Artificial Lift Type***	***First Production Date***	***Current Status***	***Cumulative Oil (MBBL)***
EAVOM-2H	Avouma	Platform	ESP	01-2007	Active	14,701.4
EAVOM-3H	Avouma	Platform	ESP	04-2013	Shut-In	757.1
ETBSM-1H	Avouma	Platform	ESP	01-2007	Abandoned	4,474.5
ETBSM-1HB	Avouma	Platform	ESP	05-2014	Active	1,060.0
ETBSM-2H	Avouma	Platform	ESP	01-2011	Active	4,185.0
EEBOM-2H	Ebouri	Platform	ESP	01-2009	Active	10,191.9
EEBOM-3H	Ebouri	Platform	ESP	04-2009	Shut-In	1,586.3
EEBOM-4H	Ebouri	Platform	ESP	05-2010	Shut-In	1,124.6
ETAME-1VA	Etame	Subsea	Gas Lift	09-2002	Shut-In	6,274.0
ETAME-3H	Etame	Subsea	Gas Lift	09-2002	Shut-In	5,728.4
ETAME-4H	Etame	Subsea	Gas Lift	09-2002	Shut-In	17,080.3
ETAME-5H	Etame	Subsea	Gas Lift	08-2004	Shut-In	5,305.5
ETAME-6HST1	Etame	Subsea	Gas Lift	07-2005	Active	18,485.6
ETAME-7H	Etame	Subsea	Gas Lift	12-2010	Active	7,551.5
ETAME-8H	Etame	Platform	ESP	N/A	Shut-In	0.0
ETAME-10H	Etame	Platform	ESP	02-2015	Shut-In	1,683.3
ETAME-12H	Etame	Platform	ESP	04-2015	Active	3,531.1
ETBNM-1H	North Tchibala	Platform	Natural Flow	09-2015	Active	1,491.3
ETBNM-2H	North Tchibala	Platform	Natural Flow	12-2015	Shut-In	534.9
ETSEM-2H	Southeast Etame	Platform	ESP	07-2015	Active	3,693.7

Note

* Figure 5 in the Etame CPR (*Summary of Production Wells*) details each of the wells in Etame as at 31 March 2019. The ETAME-4H, ETAME-10H and ETBNM-2H wells are not currently producing, as detailed in this paragraph 5 of this Part 8 (*Information on VAALCO Energy, Inc.*) under the heading '*Production*'.

Development of the Etame Fields

General

Following the installation of the platform for the Etame Field and the platform for the Southeast Etame/North Tchibala Fields in 2014, the Group commenced a multi-well drilling campaign which resulted in five new wells being brought into production in 2015. In February 2016, due to the continuing low commodity prices, the Group released the rig and incurred net expenses of $7.9 million related to its demobilisation and early release.

The Etame PSC Extension requires the Etame Consortium to complete the Base Case Work by 16 September 2020, which VAALCO commenced on 13 September 2019 as part of the Work Programme.

Avouma/South Tchibala Field

The discovery well for the South Tchibala Field was drilled in 1978, followed by the drilling of four more appraisal wellbores. The Avouma-1 exploration well was drilled in July 2004 to the southwest of the existing South Tchibala Field wells and confirmed a structure in a fault block adjacent to the South Tchibala Field. This field is now referred to as the Avouma/South Tchibala Field. The Avouma-1 well drillstem tested at a rate of 6.6 MBOPD, so the decision was made to commercially develop this field.

Two horizontal development wells were drilled in the second half of 2006. The ETBSM-1 well was drilled to the South Tchibala structure and the EAVOM-2H well was drilled to the Avouma structure. An unmanned production facility was installed and tied in by a subsea pipeline to the Etame Field during 2006. ESPs installed in the two production wells provided the artificial lift mechanism for production. Production started from the two horizontal wells in January 2007. The field production rate in February 2007 was approximately 4.6 MBOPD; however, this rate was artificially restricted because of overall licence processing limitations. The field production rate gradually increased throughout the year as the rate from Etame Field decreased. The field production rate reached a peak of 11.4 MBOPD in April 2008.

The ETBSM-2H well, which targeted a central portion of the South Tchibala area, was drilled in October 2010 and put online in December 2010. The EAVOM-3H well was drilled in the southern portion of the Avouma structure and put online in April 2013. In 2014, the ETBSM-1 well was side-tracked to the ETBSM-1HB location to mitigate a mechanical issue in the original well. All of the Avouma/South Tchibala wells are produced using ESPs, and pump replacement workovers are a significant component of the ongoing operations in the field. Future development plans in this field include the ETBSM-3H well, which will target a structural high to the north and west of the existing producing wells.

Ebouri Field

The Ebouri Field is located along the boundary of the Etame Marin Block, on a separate structure approximately 18 km northwest of the Etame Field. The field was discovered in December 2003 with the drilling of the EBO-1 well. The EBO-1 well was drilled to 2,026 m measured depth (1,901 m true vertical depth subsea) and encountered approximately 14 m of oil pay in the Gamba Formation near the centre of the structure. The oil discovery was confirmed by the drilling of two side-tracks, the EBO-1 ST1 well on the east side of the structure and the EBO-1 ST2 well to the west of the discovery well. The Ebouri development was then approved and the Ebouri platform was installed.

At the end of 2008, renewed appraisal and development began with the drilling of the EEBOM-2HP1 well. The EEBOM-2HP1 well came in high to prognosis and pushed the oil-water contact further west. A second pilot hole, EEBOM-2HP2, was then drilled from the platform to the north end of the structure and also came in high to prognosis. A horizontal drainhole, the EEBOM-2H, was drilled from this pilot hole in the north part of the field. A third well, the EEBONM 1, was drilled to the northeast in late 2008 to test a possible separate closure. This well came in slightly low to prognosis with the same oil-water contact as seen in the Ebouri Field. The EEBONM-1 well was then side-tracked to the southwest of the original hole and encountered good-quality reservoir sands oil-filled to base. A second producing well, the EEBOM-3H, was drilled in early 2009 to produce the northeast area of the field.

The EEBOM-2H well began producing in January 2009 and the EEBOM-3H came online in April 2009. Initial field rates were 7 MBOPD. In early 2010, the EEBOM-4 pilot was drilled in the southwest portion of the Ebouri structure. This well helped define the extent of the structure in this area before being side-tracked to the EEBOM 4H producing location in the eastern part of the field. In May 2010, the well was brought online with initial rates of over 3.5 MBOPD. Peak production rates of over 9 MBOPD from the three producing wells occurred in June 2010.

In July 2012, it was found that hydrogen sulphide (H_2S) was being produced from the EEBOM-3H and EEBOM-4H wells. All production prior to this event was sweet crude; because the facilities and wellbores were not designed to handle sour production, the wells were shut-in. Although these wells have been shut-in since, the EEBOM-2H well has continued to produce with low levels of H_2S, which are able to be treated by chemical injection. Discussions about a crude sweetening project are ongoing and, at some point, facilities modifications could be made in order to restore the sour crude production from the EEBOM-3H and EEBOM-4H wells.

Etame Field

The Etame Field was discovered in 1998 with the drilling of the ETAME-1V well, which discovered oil in the Gamba Formation. After the ETAME-2V well was drilled in 1999, the 3-D seismic data were reprocessed. The ETAME-3V well was drilled in February 2001 and the ETAME 4V well was drilled in May 2001. From April to July 2002, the ETAME-3V and ETAME-4V wells were re-entered and drilled as the ETAME-3H and ETAME-4H horizontal production wells. Production from the field commenced in September 2002 from the ETAME-1V, ETAME-3H, and ETAME-4H wells. It became apparent that the field is divided into two regions separated by a northeast-to-southwest trending sealing fault. Fluid properties, particularly the gas-oil ratio, differ across this fault. The regions are known as the 1V FB, which contains the ETAME-1V well, and the main fault block, which contains all other wells.

Additional reprocessing of the 3-D seismic data was performed in 2003. The ETAME-5H-Pilot and ETAME 5H wells were drilled into the main fault block in June and July 2004, and the ETAME-5H well was placed on production. The ETAME-6H and ETAME-6HST wells were drilled into the main fault block in mid-2005, and the ETAME-6H ST was placed on production. Production from the ETAME-3H well ceased in September 2005 because of water production and subsequent loss of flowing tubing pressure. The ETAME-7H well was drilled into the 1V FB during August and September 2010 and commenced production in December 2010. Subsequent to the ETAME-7H coming online, the production rate from the ETAME-1V well went on a significantly steeper decline and the well stopped producing in April 2012. The ETAME-5H, ETAME-6HST, and ETAME-7H wells are fitted with gas-lift valves.

Production from Etame had always been sweet crude with no H_2S. However, after the discovery of H_2S in two of the three Ebouri wells in July 2012, additional monitoring of all wells in the Etame Marin Block was implemented. In early 2014, H_2S was discovered on the ETAME-5H well and it was subsequently shut-in.

Installation of a four-pile platform was completed in Q3 2014. The platform has the capability to serve as a first stage processing facility for up to eight dry tree ESP-lifted wells. Three wells have been drilled from this platform to Etame Field: the ETAME-8H into the main fault block and the ETAME-10H and ETAME-12H into the 1V FB. ETAME-8H was drilled in 2014 but encountered H_2S and, as a result, the well has remained shut. ETAME-10H was drilled near the end of 2014, completed in January 2015, and started production in February 2015. ETAME-12H was drilled in Q1 2015 and was completed and started production in April 2015.

Future development plans for the Etame Field include a workover of the ETAME-6HST well in 2020 and the drilling of at least one additional horizontal production well in the main fault block as part of the Work Programme, further details of which are set out in this paragraph 5 of this Part 8 (*Information on VAALCO Energy, Inc.*) under the heading '*Work Programme*'. The ETAME-6HST workover plan is to use a light intervention vessel to replace and relocate the existing gas-lift valves in an attempt to improve gas lift efficiency. The new production well will be the ETAME-9H and may also be ETAME-11H, both infill horizontal wells in the Gamba Formation.

North Tchibala Field

A complex of stacked Dentale sands known as the North Tchibala Field is located southeast of the Southeast Etame Field and northwest of the Avouma/South Tchibala Field. The North Tchibala structure is a presalt anticlinal feature in which several sandstones within the Dentale Formation were found to be hydrocarbon-bearing. Gulf Oil of Gabon drilled a discovery well and two appraisal wellbores during the 1970s. Elf drilled an additional appraisal wellbore in 1980 that further defined the field.

In Q3 2014, VAALCO completed the installation of a four-pile fixed-leg platform to develop the Southeast Etame and the North Tchibala Fields. Two wells have been drilled from this platform into the North Tchibala Field. ETBNM-1H was drilled in 2015, and was completed and started production in September 2015. It is a horizontal well completed in the commingled D-9 and D-10 intervals in the Dentale Formation. ETBNM-2H was drilled in 2015, completed in November 2015, and started production in December 2015. It is a horizontal well completed in the commingled D-18 and D-19 intervals in the Dentale Formation. The ETBNM-1H and ETBNM-2H wells are both fitted with upper and lower ESPs which are operational, if needed, but both wells currently flow naturally.

Southeast Etame

The Southeast Etame Field was identified as a southern extension to the Etame Field on a separate anticlinal structure. During 2010, the ETSEM-1 exploration well was drilled and encountered oil pay in the Gamba Formation. The deposit was further defined by two appraisal side-tracks, the ETSEM-1 ST1 and the ETSEM-1 ST2. The discovery well encountered a reservoir in the Gamba that was 5 m thick; this reservoir was oil-bearing and filled-to-base.

Following the installation of the SEENT platform, the ETSEM-2H development well was drilled in 2015. The well was completed and started production in July 2015 and is fitted with upper and lower ESPs that are operational and in use. If the appraisal wellbore drilling conducted as part of the Work Programme into the Gamba Formation is successful, VAALCO anticipates drilling a development well as soon as practicable after.

Production

In 2018, VAALCO's net production at Etame averaged approximately 3,751 BOPD, decreasing from 4,159 BOPD average for fiscal year 2017, reflecting natural decline. The average net production for Q2 2019 was 3,664 BOPD, increasing from an average of 3,549 BOPD in Q2 2018 and 3,496 BOPD in Q1 2019.

During Q2 2019, the ETAME-4H well produced an average of approximately 350 BOPD gross (95 BOPD, net to VAALCO); however, in July 2019, this well stopped producing. In September 2019, the ETAME-10H well, which had produced an average of approximately 735 BOPD gross (200 BOPD, net to VAALCO) during Q2 2019, stopped producing. VAALCO is currently undertaking a technical analysis of cost effective remedial work with a view to re-establishing production at each of ETAME-4H and ETAME-10H.

In July 2019, the Company performed an acid simulation job on the ETBNM-2H well. Subsequent to this work, the well would not flow naturally, and VAALCO was unable to restore production. VAALCO is currently planning on performing remedial work in Q4 2019 with a view to re-establishing production. During Q2 2019, this well produced an average of approximately 420 BOPD gross (113 BOPD, net to VAALCO).

In August 2019, VAALCO performed a planned maintenance turnaround for the FPSO Petroleo Nautipa, which included a nine-day full field shut down which will impact Q3 2019 production. This was taken into consideration in determining the full year guidance for 2019, which remains at between 3,300 BOPD net to VAALCO and 3,900 BOPD net to VAALCO. Taking into consideration the combination of the planned turnaround, as well as the impact of deferred production from the three wells that are not producing, VAALCO expects average production for Q3 2019 to be between 3,000 BOPD net to VAALCO and 3,300 BOPD net to VAALCO.

Production operations in the Etame Marin Block currently comprise of seven platform wells and two subsea wells across the nine producing wells in the Etame Fields. Dry tree wells are used to develop the Etame Fields from four manned production platforms. The Avouma, Ebouri, Etame, and SEENT platforms are 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 the FPSO Petroleo Nautipa anchored to the seabed on the block. Some of the original wells in the Etame Field have subsea trees, which are tied directly back to the FPSO Petroleo Nautipa. Production from seven of the wells is aided by ESPs.

The FPSO Petroleo Nautipa has production limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day.

For the financial years ended 31 December 2018, 31 December 2017 and 31 December 2016, aggregate production from the Etame Marin Block was approximately 5.1 MMBBL (1.4 MMBBL, net to VAALCO), 5.6 MMBBL (1.5 MMBBL, net to VAALCO) and 6.2 MMBBL, (1.5 MMBBL, net to VAALCO), respectively. VAALCO's net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13 percent.

A summary of the key production facilities and their various production capacities is shown at Table 8.

Table 8 – Summary of key production facilities at the Etame Marin Block

		Capacity (BBL/Day)		
Facility Name	***Producing Field***	***Total Liquid***	***Oil***	***Water***
FPSO Petroleo Nautipa	All	30,000	25,000	20,000
Avouma platform	Avouma/South Tchibala	16,000	16,000	15,000
Ebouri platform	Ebouri	17,500	15,000	14,000
Etame platform	Etame	26,000	25,000	22,500
SEENT platform	North Tchibala/Southeast Etame	26,000	25,000	22,500

Work Programme

Under the terms of the Etame PSC, the Etame Consortium is required to drill two development wells and two appraisal wellbores at the Etame Marin Block by 16 September 2020 ("**Base Case Work**").

Base Case Work appraisal wellbores

VAALCO commenced the Work Programme on 13 September 2019, by beginning the drilling of an appraisal wellbore at ETAME-9P, in the Etame Field, to evaluate the Dentale Formation. In addition, VAALCO will drill a second appraisal wellbore in the Southeast Etame Field, to evaluate the Gamba Formation.

Base Case Work development wells

Following completion of the first appraisal wellbore at ETAME-9P, in the Etame Field, VAALCO will drill two development wells in the Etame Field, targeting the Gamba Formation, the first of which will be ETAME-9H.

Expansive Work

In addition to and following the Base Case Work, VAALCO anticipates drilling at least one further development well at the Etame Marin Block in H1 2020 ("**Expansive Work**", together with the Base Case Work, the "**Work Programme**").

The Expansive Work is subject to approval by the other members of the Etame Consortium and the State of Gabon.

The location of the Expansive Work development well will depend on the success of the Gamba appraisal wellbore in the Southeast Etame Field:

- if the appraisal wellbore is successful, an additional development well may be drilled in the Southeast Etame Field (Option A); or
- if the appraisal wellbore is unsuccessful, an additional development well may be drilled in the South Tchibala Field (Option B).

Cost of the Work Programme

VAALCO estimates that the Base Case Work will cost approximately $61.2 million ($20.5 million, net to VAALCO) and that the Expansive Work will cost approximately $25.0 million – $30.0 million ($8.5 million – $10.0 million, net to VAALCO).

If the Base Case Work is not undertaken, the Etame Consortium must pay the difference between the amounts spent on any wells that were drilled and the estimated costs of the wells as set out in the budget approved by the State of Gabon, being an estimated cost of $61.2 million ($20.5 million, net to VAALCO).

Further technical studies

Under the Etame PSC, the Etame Consortium is also required to complete two technical studies by 16 September 2020, at an estimated cost of $1.3 million gross ($0.4 million, net to VAALCO).

6. Block P

VAALCO Mauritius has a 31.0 percent working interest in an undeveloped portion of Block P, located offshore Equatorial Guinea, that the Group acquired in 2012. For a number of years, the Block P interest under the Block P PSC was in suspension; however, in September 2018, the EG MMH lifted the suspension.

Geology of Block P

Block P is located in the Rio Muni Basin, offshore Equatorial Guinea. The rift between South America and Africa began 126 million years ago in the early Cretaceous with a series of basins that would resemble the lakes in East Africa today. As Brazil continued to pull away from West Africa, faulting and sliding associated with the rift formed the early Rio Muni basin. The Rio Muni Basin contains a thick wedge of Cretaceous to Tertiary sediments deposited over an early Cretaceous rifted terrain. Deposition of this wedge was interrupted by low stands in sea level and tectonic uplift in the Aptian and Santonian stages. During the regional Santonian tectonic episode and associated uplift, valleys were incised into the underlying lower Cretaceous syn-rift, transitional, and early drift deposits in the prospect area. Subsequently, stacked Upper Cretaceous channels and fans were deposited as valley fill on the Santonian unconformity. Continued opening of the Atlantic Ocean accommodated the deposition of Tertiary and younger shale and sands that buried the Santonian unconformity and related valley fill deposits to their current depths.

During the Barremian and Aptian rifting, deep, anoxic, lacustrine systems developed, resulting in the deposition of important synrift source rocks. These permanently stratified lakes did not experience seasonal overturn. During humid episodes, when lake level was high, the lakes were highly productive and anoxia was widespread, resulting in the accumulation of thick sequences of organic-rich, laminated shale. During arid episodes, when evaporation rates were high and thus lake level was low, organic shale and carbonate mudstone or marl was deposited in shallow, aerated water. These source rocks are a key part of the hydrocarbon system within the basin.

The Upper Cretaceous sequence of sedimentation is important as it relates to prospectivity within the basin. This was a period of sand-rich deposition as incised valleys were filled and stacked channels systems and fans were formed. Some of these features are imaged on 3D seismic data and are the subjects of potential future exploration.

During the early Tertiary, thick sections of sediment were deposited but were subsequently eroded during the Oligocene when sea level dropped. Valleys were cut into the existing sediments during the period of erosion that were later filled in by sediments of varying lithology. The sand members within the valley fill are potential exploration targets.

Development of Block P

Historical development of Block P

The first well on Block P, the P-1, was drilled in 2004 targeting Campanian and Santonian channel sands within the Jupiter complex. This well demonstrated a viable hydrocarbon system was present in the area finding 17 feet of low permeability pay as well as numerous hydrocarbon shows.

In 2005, Devon Energy Corporation made the Venus discovery with the P-2 well, which targeted a stratigraphic trap in the Venus Channel complex. The P-2ST and P-3 wells were subsequently drilled in 2005 and 2006, further delineating this discovery in the Green Sand. The P-4 well, drilled in 2007 to test AVO anomalies in the Europa field, made another discovery in the Europa channel system.

Since this time, the data have been studied and various development plans have been evaluated by VAALCO. However no development activity has commenced to date. Currently, VAALCO is considering additional exploration activity in order to optimise the commerciality of a development on the block.

Future development of Block P

VAALCO is awaiting the EG MMH to approve VAALCO Mauritius' appointment as technical operator for Block P on behalf of the Block P Consortium. There is no prescribed criteria for the EG MMH to consider for reaching a decision. The Block P Consortium consists of four companies, being (1) VAALO Mauritius; (2) GEPetrol; (3) Atlas; and (4) Crown.

Each of the Block P Consortium are party to the Block P PSC. GEPetrol will act as the administrative operator. Under the terms of lifting of the suspension of the Block P PSC, GEPetrol was required to introduce a new investor or joint venture owner of Block P by 28 March 2019, and it has fulfilled this requirement.

Once the joint owner is approved by the EG MMH, the Block P Consortium will be required to drill an exploration well within one year. VAALCO intends to seek a partner on a promoted basis that will cover all or substantially all of the costs to drill the exploratory well.

While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, VAALCO would lose its interest in the licence, and the associated capitalised unproved leasehold costs of $10.0 million, being the total amount recorded in the Historical Financial Information for Block P as of 31 December 2018, would become impaired. While the Company is unable to opine on when it expects the EG MMH to approve or reject the new joint owner, were the Block P Consortium unable to meet the terms of the lifting of the suspension, this would have no impact on the Group's cash flow.

The Block P Consortium is evaluating the timing and budgeting for development and exploration activities under a development and production area in Block P, including the approval of a development and production plan. The Block P PSC provides for a development and production period of 25 years from the date of approval of a development and production plan.

7. Block 5 (discontinued operations)

In November 2006, VAALCO signed the Block 5 PSA in respect of Block 5, a 1.4 million-acre oil exploration concession off the coast of Angola. VAALCO's working interest was 40 percent and it carried Sonangol

P&P, the operating subsidiary of Sonangol E.P., the national concessionaire. On 30 September 2016, VAALCO notified Sonangol P&P that it was withdrawing from the Block 5 joint operating agreement with effect from 31 October 2016. On 30 November 2016, VAALCO notified Sonangol E.P. that it was withdrawing from the Block 5 PSA. Further to VAALCO's decision to withdraw from Angola, it closed its local offices with no intention of conducting future activities in Angola.

On 28 June 2019, the State of Angola approved by executive decree the Block 5 Settlement Agreement entered into on 26 February 2019. In consideration for the payment of $4.5 million by VAALCO to the Angola National Agency of Petroleum, Gas, and Biofuels ("**ANAPGB**"), as national concessionaire, and the elimination of the $3.3 million outstanding receivable from Sonangol P&P, the Group was released in full and final settlement from its outstanding obligations and liabilities arising under the Block 5 PSA. On 16 July 2019, VAALCO made the final settlement payment to ANAPGB.

8. History

VAALCO was founded in 1985 and was registered and incorporated in the State of Delaware, USA under the name Gladstone Resources Limited in 1989. The name of the company was changed to VAALCO Energy, Inc. in 1997.

In July 1995 the Group entered into the Etame PSC, pursuant to which it acquired an interest in the Etame Marin Block. Elf, which had held an interest in Etame prior to VAALCO's entry into the Etame PSC, had drilled several wells during the 1970s and 1980s, leading to the discovery of the South Tchibala and North Tchibala Fields. VAALCO conducted a 385 km^2 3-D seismic survey in 1997 and drilled the discovery well for Etame Field in 1998.

The first sale of oil lifted from Etame occurred in November 2002. The Group continued to explore the Etame Fields, leading to the discovery of the Avouma and Ebouri Fields in 2004. The first oil was lifted from Avouma Field in 2007 and from Ebouri Field in 2009. In 2011, the Group discovered the Southeast Etame Field.

In 2006, VAALCO entered into the Block 5 PSA, acquiring a 40 percent working interest in Block 5, offshore Angola, from which it has now withdrawn.

In November 2012, VAALCO acquired its 31.0 working interest in an undeveloped portion of Block P from Petronas.

In 2014 the Group installed Etame and SEENT platforms to further increase the production capability of Etame.

In September 2018, VAALCO entered into the Etame PSC Extension, pursuant to which VAALCO will hold an interest in Etame until September 2028, with an option to extend for two additional five-year periods.

9. Group structure

VAALCO is the holding company of the Group, of which each subsidiary is a wholly-owned direct or indirect subsidiary. VAALCO Gabon is party to the Etame PSC, while VAALCO Mauritius is party to the Block P PSC. The structure of the Group is shown at Figure 2.

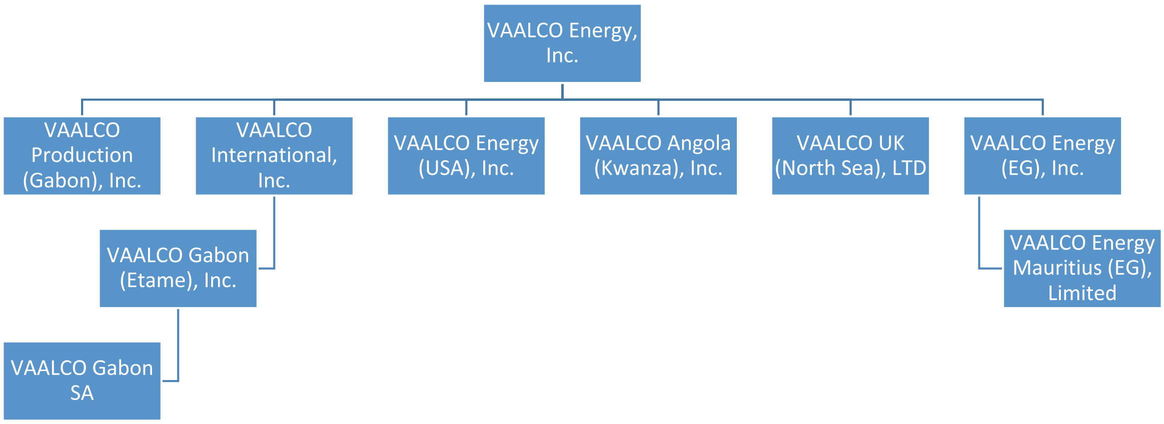


Figure 2 – Group structure chart.

10. Market overview

Industry value chain

The oil and gas industry value chain consists of two key segments, namely the E&P or upstream segment, and the refining and processing or downstream segment. In the upstream segment, E&P operating companies extract oil and gas resources and conduct basic processing, allowing for the resources to be transported and stored. Downstream, operating companies refine and process the produced resources into products usable in a wide range of applications, such as transportation, power generation, and chemicals.

Three primary types of companies operate within the upstream segment: (i) operating companies; (ii) oilfield services companies; and (iii) equipment manufacturers. Operating companies acquire oil and gas resource exploration leases with the objective of finding and extracting oil and gas. Operating companies can also be roughly classified into three different categories: (i) national oil companies, which are majority state-owned oil companies that have grown out of large domestic reserves; (ii) international oil companies ("**IOCs**"), which are typically large, North American and European listed oil companies usually participating across the oil and gas value chain; and (iii) independents, which are typically exploration and production focused companies. Oilfield services companies provide operating companies with a wide range of specialised services and technologies across the life cycle of an oil and gas field. Equipment manufacturers build equipment to support operating companies and oilfield service providers.

Field lifecycle

The oil and gas field lifecycle consists of three stages, namely (i) exploration; (ii) development; and (iii) production. Each presents its own set of challenges, risks and cost structure, and therefore each has different implications in terms of financial profitability and sustainability for operating companies and oilfield services companies. The exploration stage requires significant capital investments by the operating company and the chance of declaring commercial fields at this stage is low. Consequently, exploration activity is highly sensitive to oil prices and return on capital calculations. The development stage involves building the infrastructure to produce the resource. The production stage involves producing the resource and maintaining the infrastructure.

Industry global trends

The oil and gas industry was subject to volatility in 2015 and 2016 where the price of oil plummeted to a range between the mid-$40s and $50s/BBL but recovered to $85/BBL (Brent) before sliding to $50/BBL in Q4 2018. Oil prices as at the Last Practicable Date were $64/BBL (Brent). This stems from the sustained success of the production restraint agreement between OPEC and non-OPEC countries in force since the beginning of 2017 and to which OPEC has agreed to extend until March 2020, the growing demand for gas (in particular LNG especially from developing economies, China and India) and evidence suggesting that world oil demand growth remains solid. Although the pace of growth is substantially slowing, the International Energy Agency anticipates a 30 percent increase in the global energy demand by 2040.

Global upstream capital expenditure, which dropped nearly 45 percent between 2014 and 2016 is now forecast to rise 6 percent year-on-year in the medium term. Oil and gas rig activity levels are rising, in particular, driven by the North American market, and major projects are being approved such as Mad Dog

Phase 2 (Gulf of Mexico), ACG (Caspian Basin), Tortue (offshore Senegal and Mauritania) and Bonga Southwest (offshore Nigeria). Furthermore, investment in deepwater production and exploration is starting to show signs of recovery following a significant drop from over $300 billion in 2014 to a low of $155 billion in 2018, with many of the major IOCs opening new leases offshore the Gulf of Mexico, West Africa and other global locations.

Recent oil and gas developments in Gabon and Equatorial Guinea

Gabon is a small country with a long history of oil exploration and production. It is the eighth largest producer of oil in sub-Saharan Africa, with production of approximately 225 MBOPD in Q2 2019 (193 MBOPD in 2018). Petroleum is the primary source of public revenue in Gabon. Currently, the country's licensed deepwater plays cover an area of 128,000 km^2, representing around half of the country's acreage. In 2018, Gabon had proven crude oil reserves of 2.0 BBBL, proven natural gas reserves of 26 BCF and petroleum exports of $4.2 billion.

In Equatorial Guinea, petroleum production now dominates the economy. Oil revenues account for over 70 percent of national income; the petroleum sector is the driving force behind the ongoing growth of the country's GDP. In 2018, Equatorial Guinea had proven crude oil reserves of 1.1 BBBL. Production was 114 MBOPD in Q2 2019 (120 MBOPD in 2018). In April 2019, the State of Equatorial Guinea, Noble Energy and Marathon Oil signed definitive agreements to develop the Alen field, which is expected to become a major gas hub for the country. Furthermore, the State of Equatorial Guinea has been pushing to attract greater foreign investment with the EG MMH launching the 'Year of Energy' initiative for 2019.

11. Legal and arbitration proceedings

The Company confirms that, other than the Etame Audit Agreement described at paragraph 18.11 of Part 17 (*Additional Information*) of this Prospectus, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the issuer is aware), during a period covering at least the previous 12 months which may have, or have had in the recent past significant effects on the Company and/or the Group's financial position or profitability.

12. Employees

As at the Last Practicable Date, the Company had 120 full-time employees, 81 of whom were located in Gabon. The Company is not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the National Organisation of Petroleum Workers union (NEOP). The Company believes relations with the employees are satisfactory.

For the Historical Financial Information Period, the Group has employed, on average, the numbers of people as detailed in Table 9.

Table 9 – Employees for the Historical Financial Information Period

	30 June		***31 December***	
Category of Location	***2019***	***2018***	***2017***	***2016***
Houston, USA	37	26	27	24
Gabon – Nationals	75	75	75	78
Gabon – Expatriates	6	7	7	4
Angola	–	–	–	2
Total number of employees	118	108	109	108

As at the Last Practicable Date, the Company retained the services of 32 contractors, seven of whom are located in Houston and 25 of whom are located in Gabon.

13. Incentives

As at the Last Practicable Date, the Compensation Committee was authorised to issue up to 47,973 Common Shares under the 2014 LTIP and the following securities were outstanding:

Options

The number of outstanding Options at the Last Practicable Date was as detailed in Table 10.

Table 10 – Outstanding Options as at the Last Practicable Date

Number of Shares Underlying Options (in thousands)	*Weighted Average Exercise Price per Share ($)*	*Weighted Average Remaining Contractual Term (in years)*	*Aggregate Intrinsic Value (in thousands)*
2,973	$1.53	3.05	$1,507

Restricted Shares

The number of outstanding Restricted Shares at the Last Practicable Date was as detailed in Table 11.

Table 11 – Outstanding Restricted Shares as at the Last Practicable Date

Restricted Shares (in thousands)	*Weighted Average Grant Price*
418	$1.44

Share Appreciation Rights

The number of outstanding SARs at the Last Practicable Date was as detailed in Table 12.

Table 12 – Outstanding SARs as at the Last Practicable Date

Number of Shares Underlying SARs (in thousands)	*Weighted Average Exercise Price per Share ($)*	*Term (in years)*	*Aggregate Intrinsic Value (in thousands)*
3,726	$1.29	3.48	$2,291

Further details of the Incentive Plans are set at paragraph 16 of Part 17 (*Additional Information*) of this Prospectus.

14. Working capital

In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this Prospectus.

15. Reasons for listing

Following consultation with its advisers, the Directors have chosen a Standard Listing as they believe that a listing on the Main Market, in addition to VAALCO's NYSE listing, will enable the Company to enhance its awareness among, and allow it to reach, institutional investors in the UK, Europe, Africa and the Middle East, provide the potential to access capital to fund the strategic growth of the Company, increase share trading liquidity and further raise the profile of the Company and the Projects.

Positioning against key peers

Of the possible international listing venues, the Directors believe that the London Stock Exchange represents the most logical venue given the presence of several other independent exploration and production companies with oil and gas assets in West Africa, which the Directors consider to be key peers.

Many of these key peers benefit from broad, international shareholder bases. The Directors believe that listing on the London Stock Exchange will enhance VAALCO's capital markets profile among the international investment community and therefore provide support for the continued development of VAALCO.

Increased research coverage

The Directors anticipate that the number of analysts providing independent investment research on VAALCO will increase following Admission, in line with the level of analyst coverage that VAALCO's London-listed peers currently attract. The Directors believe that an increased level of analyst coverage will enhance VAALCO's profile with potential new investors in Europe, North America and internationally and benefit VAALCO's existing Shareholders.

Broader access to institutional investors

VAALCO benefits from a diverse and supportive Shareholder base from its NYSE listing. However, the Directors believe there are a number of European investment funds and specialist international oil and gas investors that are currently unable to hold Common Shares due to their listing outside of a European regulated market.

The Directors therefore believe that admission to trading on the London Stock Exchange will allow VAALCO to broaden its international investor base.

Notwithstanding Admission, the Common Shares will continue to be listed on the NYSE.

16. Environmental and social

The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which the Group operates. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of oil and natural gas and various substances produced concurrently with oil and natural gas. These regulations can have an impact on the selection of drilling locations and facilities, potentially resulting in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. VAALCO is committed to complying with environmental and operation legislation wherever the Group operates.

17. Insurance

For protection against financial loss resulting from various operating hazards, VAALCO maintains insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker's compensation and employer's liability. VAALCO maintains insurance at levels that it believes to be customary in the industry to limit its 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. VAALCO is not fully insured against all risks associated with its 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 VAALCO's financial position, results of operations or cash flows.

18. Dividend policy

VAALCO has never declared or paid dividends on the Common Shares. The Company intends to retain future earnings, if any, to support the development of the business and therefore does not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, would be at the discretion of the Board after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results, restrictions in any debt agreements and current and anticipated cash needs.

19. Taxation

Further details relating to taxation are set out in Part 16 (*Taxation*) of this Prospectus.

PART 9 – DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

1. Directors

The Board is responsible for, and has the authority to determine, all matters relating to the strategic direction, policies, practices, goals for the Executive Officers and the operations of the Group.

The following table lists the names, positions and ages of the Directors and the date that they were each appointed:

Name	***Age***	***Position***	***Appointment***
Cary M. Bounds	52	Chief Executive Officer and Director	December 2016
Andrew L. Fawthrop	67	Chairman and Director	October 2014
A. John Knapp, Jr.(1)	68	Director	December 2015
Steven J. Pully	59	Director	July 2015
William R. Thomas(2)	63	Director	April 2019

Notes

(1) On 31 May 2019, A. John Knapp, Jr. resigned from the Board in accordance with the terms of the Kornitzer Stockholder Agreement. On 6 June 2019, the Board, acting on the recommendation of the Nominating and Corporate Governance Committee, determined to reappoint Mr. Knapp as an independent Director.

(2) William R. Thomas is the nominee Director in accordance with the terms of the Group 42-BLR Group Settlement Agreement.

The management expertise and experience of each of the Directors is set out below. Further information on the Directors, including the companies of which each Director has been a director at any time in the past five years, is set out in paragraph 10 of Part 17 (*Additional Information*) of this Prospectus.

1.1 *Cary M. Bounds (Chief Executive Officer and Director)*

Mr. Bounds was appointed Chief Executive Officer on 29 December 2016 after having served as the Chief Operating Officer for VAALCO since July 2015, as well as interim Chief Executive Officer since 1 September 2016. Mr. Bounds has held a variety of technical and management positions of increasing responsibility with major energy companies as well as independent E&P companies.

Prior to joining the Company, Mr. Bounds was Business Unit Manager and Vice President, Noble Energy Equatorial Guinea Limited from May 2013 until July 2015. Earlier in his tenure with Noble, Mr. Bounds held the position of North Sea Country Manager from April 2010 until May 2013. Prior to Noble, Mr. Bounds was the Engineering and Planning Manager, Worldwide for Terralliance Technologies, Inc. from 2007 to 2010 and served as their Country Manager in Mozambique from 2007 to 2010. Mr. Bounds was with SM Energy from 2004 to 2007 and held the position of Engineering Manager for their Gulf Coast and Permian regions. Mr. Bounds spent five years with Dominion E&P serving in corporate development, planning and reservoir engineering positions. Mr. Bounds began his career with ConocoPhillips in 1991 where he held a variety of reservoir and production engineering positions in U.S. onshore regions.

Education: Mr. Bounds holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University.

1.2 *Andrew L. Fawthrop (Chairman & Director)*

Mr. Fawthrop has served on the Board since October 2014 and as the Chairman of the Board since December 2015. Mr. Fawthrop has deep and broad-based experience in the oil and gas industry, including in West Africa, having served for 37 years with Unocal Corporation and Chevron Corporation (following its acquisition of Unocal in 2005) in a vast number of international leadership positions. Most recently, from January 2009 until his retirement in 2014, Mr. Fawthrop served as Chairman and Managing Director for Chevron Nigeria. Prior to his assignment in Nigeria, Mr. Fawthrop served as President and Managing Director for Unocal/Chevron Bangladesh from 2003 until 2007.

In his professional career, Mr. Fawthrop held various positions of increasing responsibility for exploration activities around the world in geographies including China, Egypt, Indonesia, South America, Africa, Latin America and Europe. Mr. Fawthrop served as a Member of the Advisory Board of Eurasia Group. He served as a Director of Hindustan Oil Exploration Co. Ltd. from 2003 to 2005. He was an active member of the United States Azerbaijan Chamber of Commerce, the Asia Society of Texas and the Houston World Affairs Council.

Education: Mr. Fawthrop holds a Bachelor of Science in Geology and Chemistry and a Masters degree in Marine Geology from the University of London.

1.3 ***A. John Knapp, Jr. (Director)***

Mr. Knapp has served on the Board since December 2015. On 31 May 2019, Mr. Knapp resigned from his position as a member of the Board in accordance with the terms of the Kornitzer Stockholder Agreement, pursuant to which Mr. Knapp, as designee of the Kornitzer Group, was required to resign as a member of the Board following such time that the Kornitzer Group, collectively with its affiliates, beneficially held less than five percent of the outstanding Common Shares. On 6 June 2019, the Board, acting upon the recommendation of the Nominating and Corporate Governance Committee, determined to reappoint Mr. Knapp as a member of the Board and each of the Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee, as well as reappoint Mr. Knapp as Chairman of the Audit Committee.

Mr. Knapp is a Partner at CCM Opportunistic Advisors, LLC, an investment fund in Houston, Texas, a position he has held since March 2011. He also serves as the President, Chief Executive Officer, and principal shareholder of Andover Group, Inc., a real estate investment and development company he founded in 1978. Mr. Knapp currently serves on the board of directors of ATRM Holdings, Inc. (NASDAQ: ATRM) which he joined in April 2015, and previously served on from January 2013 until March 2013. He also serves as a director of On Track Innovations Ltd. (NASDAQ: OTIV), and has served since December 2012.

Previously, Mr. Knapp served as the Chief Executive Officer and a director of ICO, Inc. (NASDAQ: ICOC), from October 2005 to April 2010. Mr. Knapp is a Chartered Financial Analyst and is currently a trustee of Transylvania University in Lexington, Kentucky.

Education: Mr. Knapp holds a Bachelor of Arts from Williams College.

1.4 ***Steven J. Pully (Director)***

Mr. Pully has served on the Board since July 2015. Mr. Pully has over 34 years of experience in capital markets, finance, investing and legal matters. He also has extensive board participation and leadership experience. He is currently on the board of publicly-traded Harvest Oil & Gas, a U.S. oil and gas producer. Within the past five years, he has also served on the public boards of Energy XXI Gulf Coast, Titan Energy, Bellatrix Exploration and Goodrich Petroleum. He also serves on a number of private company boards.

From 2008 until 2014, Mr. Pully served as General Counsel and Partner of the investment firm, Carlson Capital, L.P. Mr. Pully previously was an investment banker, serving as a Managing Director in the energy and power investment banking division of Bank of America and as a Senior Managing Director in the natural resources investment banking department of Bear Sterns & Company. Mr. Pully began his career as an attorney with Baker Botts LLP in Houston.

Education: Mr. Pully holds a Bachelor of Science in Accounting from Georgetown University and a J.D. from The University of Texas School of Law. Mr. Pully is a Chartered Financial Analyst, a Certified Public Accountant in the State of Texas and a member of the State Bar of Texas.

1.5 ***William R. Thomas (Director)***

Mr. Thomas joined the Board in April 2019, pursuant to the terms of the Group 42-BLR Group Settlement Agreement. Mr. Thomas has over 30 years of experience in the international energy industry as a senior executive, investment banker and entrepreneur. In 1982, Mr. Thomas joined the International Division of Pennzoil Company. In 1986, Mr. Thomas entered investment banking with the Mergers & Acquisitions Department at Bankers Trust Company where he represented energy clients in major transactions. Mr. Thomas later served as Chief Executive Officer and in other senior executive capacities for companies with petroleum operations in Russia and Kazakhstan.

During his career, Mr. Thomas has successfully built, managed and monetised several emerging-market oil companies. In 2001, he was a founder and appointed Chief Executive Officer of Urals Energy N.V. which became Russia's largest independent oil company. He later was a founder and Chief Executive Officer of Urals Energy Public Company Ltd. and led the company to a successful IPO on AIM in 2005. Since 2010, through his wholly-owned entity, Texas Oceanic Petroleum Co., Mr. Thomas has negotiated transactions involving exploration and production companies around the world including in West Africa.

Education: Mr. Thomas graduated from the University of Texas at Austin with a B.A. in Economics.

2. Executive Officers

The Executive Officers are responsible for the day-to-day management of the business, operations and implementation of the Group's strategy.

The following table lists the names, positions and ages of the Executive Officers in addition to the CEO and the date that they were each appointed:

Name	***Age***	***Position***	***Appointment***
Elizabeth D. Prochnow(1)	61	Chief Financial Officer	April 2019
Jason J. Doornik	50	Chief Accounting Officer and Controller	June 2019
David A. DesAutels(2)	64	Executive Vice President of Corporate Development	July 2017
Michael G. Silver(3)	55	Executive Vice President, Company Secretary and General Counsel	April 2019

Notes

(1) Elizabeth D. Prochnow first joined the Company in March 2015, where she served as Chief Accounting Officer.

(2) David A. DesAutels served as Vice President for Exploration and Development from his appointment in July 2017 until April 2019.

(3) Michael G. Silver first joined the Company in November 2018 in non-executive capacity.

The management expertise and experience of each of the Executive Officers is set out below. Further information on the Executive Officers, including the companies of which each Executive Officer has been a director at any time in the past five years, is set out in paragraph 10 of Part 17 (*Additional Information*) of this Prospectus.

2.1 *Elizabeth D. Prochnow (Chief Financial Officer)*

Ms. Prochnow was appointed Chief Financial Officer on 1 April 2019 after having served as the Company's Chief Accounting Officer since March 2015. Ms. Prochnow has held a variety of finance management positions primarily with publicly traded companies including a number of companies in the energy sector.

Prior to joining the Company, Ms. Prochnow served as Controller and Chief Accounting Officer for Total Safety, U.S., Inc. from August 2014 to March 2015. Prior to that, she served as a director of Carrtegra, LLC, a financial advisory consulting firm, from June 2013 to August 2014 with a focus on E&P companies and as Executive Vice President, Chief Financial Officer of Sterling Construction Company, Inc. (NASDAQ: STRL) from November 2011 to May 2013. Before beginning with Sterling in February 2011, Ms. Prochnow was Vice President, Finance and Chief Financial Officer of Bristow Group Inc. (NYSE: BRS) from May 2009 to June 2010 and Vice President, Chief Accounting Officer and Controller from 2005 to 2009. From 1997 to 2005, Ms. Prochnow served in positions of increasing responsibility at MAXXAM Inc., ultimately as the company's Vice President and Controller. Before MAXXAM, Ms. Prochnow served as the Controller and Chief Accounting Officer of GulfMark Offshore, Inc. (formerly GulfMark International, Inc. (NYSE: GLF)) from 1990 to 1996. Ms. Prochnow began her career as a public accountant at Arthur Andersen LLP in 1981.

Education: Ms. Prochnow holds a Bachelor of Arts and a Masters of Accounting from Rice University and is a certified public accountant in the State of Texas.

2.2 ***Jason J. Doornik (Chief Accounting Officer and Controller)***

Mr. Doornik joined the Company on 11 June 2019 as Chief Accounting Officer and Controller. Mr. Doornik has over twenty years of diversified accounting and finance experience, balanced among large companies and emerging companies as well as public accounting and industry experience.

Prior to joining the Company, Mr. Doornik served as Chief Accounting Officer and Controller of Fairway Energy, a Houston based midstream company, as Corporate Controller for BPZ Resources, Inc. and as a consultant for Sirius Solutions. Mr. Doornik has held a variety of other senior finance roles such as Financial Reporting Manager of Grant Prideco, Inc. and its successor company, National Oilwell Varco, Inc. and Senior Associate for The Siegfried Group. Mr. Doornik began his career with Ernst & Young in the Assurance and Advisory practice starting as a staff level associate and ending as a manager in the assurance practice. From 1987 through 1991, Mr. Doornik served as a Unit Supply Specialist in the U.S. Army.

Education: Mr. Doornik holds a Bachelor's degree in Business Administration and a Master's degree of Professional Accountancy from the University of Texas at Austin and is a certified public accountant in the State of Texas.

2.3 ***David A. DesAutels (Executive Vice President of Corporate Development)***

Mr. DesAutels joined the Company in July 2017 as Vice President for Exploration and Development and assumed the role of Executive Vice President for Corporate Development on 1 April 2019.

Mr. DesAutels is an oil and gas industry executive with over 40 years upstream experience in development and exploration. He has worked on over 100 development projects worldwide, both conventional and unconventional. Mr. DesAutels gained senior executive experience by working for Noble Energy (Director, Development Geoscience, 2008 to 2016) and Occidental Oil and Gas (Chief of Production Geoscience and Vice President of Geoscience, 2000 to 2007) and founding Synertia Energy, LLC and Seregon Energy, LLC, two oil and gas consulting companies. In addition, he has international experience from working in Colombia, Indonesia, Equatorial Guinea, Qatar, Oman, Argentina, Israel, UK, Ecuador, Peru, Russia, Canada, and the UAE. Mr. DesAutels is also a published author of two books, one fiction and one non-fiction.

Education: Mr. DesAutels holds an M.S. and BA in Geology from the University of Minnesota-Twin Cities.

2.4 ***Michael G. Silver (Executive Vice President, Company Secretary and General Counsel)***

Mr. Silver joined the Company in November 2018 and has served as Executive Vice President and General Counsel since 1 April 2019. He has nearly 30 years of experience in the energy industry.

Prior to joining the Company, from 2009 to 2018, Mr. Silver served as Managing Counsel for the Petroleum Division of BHP Group plc where he supported the company's international upstream activities, including major acquisitions and divestments. From 2007 to 2009, Mr. Silver held the position of Senior Counsel at Constellation Energy Commodities Group, Inc. with responsibilities for U.S. upstream and LNG operations. Mr. Silver began his career with ExxonMobil Corporation in the law department in 1990 and during the next 17 years served in multiple roles of increasing responsibility.

Education: Mr. Silver holds a Bachelor of Arts degree in International Affairs from Lafayette College, an M.B.A. from the Duke University Fuqua School of Business and a J.D. from the Duke University School of Law. Mr. Silver is a member of the State Bar of Texas.

3. Corporate Governance

3.1 ***The Board***

The Board currently comprises five Directors, four of which are non-executive Directors.

It is the policy of the Board that a majority of the members of the Board be independent. The Board has affirmatively determined that, as to each non-executive Director, no material relationship exists that, in the opinion of the Board, would interfere with the exercise of his independent judgement in carrying out his responsibilities as Director, and that each non-executive Director qualifies as independent in accordance with the Corporate Governance Principles.

Any Director appointed to the Board by the Directors will be subject to election by the Shareholders at the next annual meeting of Shareholders after his/her appointment.

The composition of the Board will be reviewed regularly to ensure that the Board has the appropriate mix of expertise and experience. The Certificate of Incorporation provides that the number of Directors serving on the Board cannot be fewer than three or greater than 15.

The Board is responsible for the corporate governance of the Company, and has developed policies to ensure that an appropriate level of corporate governance is in place. The Company's corporate governance system is reviewed regularly by the Board to ensure that it fulfils the needs of Shareholders.

The Common Shares are currently quoted on the NYSE and the Company is therefore required to comply with the NYSE Listed Company Manual, which is the comprehensive rulebook for listed companies, including publishing an annual confirmation statement. Section 303A.09 of the NYSE Listed Company Manual requires issuers to adopt and disclose corporate governance guidelines covering certain issues including director qualifications and responsibilities, director compensation, responsibilities of key board committees, management succession and evaluation of the board's performance. In accordance with this provision, the Corporate Governance Policies are available under the '*Governance'* link on VAALCO's website at www.vaalco.com. The information on the website is not incorporated by reference into this Prospectus. The Company will disclose any amendments to the Corporate Governance Policies on its website at www.vaalco.com.

3.2 *Committees*

The Company's committees are constituted as follows:

Committee	***Chair***	***Members***
Audit Committee	A. John Knapp Jr.	Steven J. Pully Andrew L. Fawthrop William R. Thomas
Compensation Committee	William R. Thomas	A. John Knapp Jr. Andrew L. Fawthrop Steven J. Pully
Nominating and Corporate Governance Committee	Steven J. Pully	A. John Knapp Jr. Andrew L. Fawthrop William R. Thomas
Strategic Committee	Andrew L. Fawthrop	A. John Knapp Jr. Steven J. Pully William R. Thomas

The deliberations of the various committees do not reduce the individual and collective responsibilities of the Directors with regard to their fiduciary duties and responsibilities, and they must continue to exercise due care and judgement in accordance with their statutory obligations.

Audit Committee

The Audit Committee is principally responsible for (1) the integrity of the financial statements of the Company; (2) the independent auditor's qualifications and independence; (3) the performance of the Company's internal audit function and independent auditors; and (4) the compliance by the Company with legal and regulatory requirements. The Audit Committee shall oversee the appointment, qualification, independence and performance of the Company's independent auditors and the performance of the Company's internal auditing function and shall prepare the report required by the SEC Rules to be included in the Company's annual proxy statement.

The Audit Committee is comprised of no fewer than three Directors, all of whom are required to meet the independence and experience requirements of the NYSE and the Exchange Act.

The Audit Committee must meet at least quarterly and shall meet periodically in separate executive sessions with management, internal auditors and the independent auditor. The Audit Committee has the sole authority to appoint or replace the independent auditor; pre-approves all auditing services, internal control related services and permitted non-audit services; and is empowered to conduct any investigation appropriate to fulfilling its responsibilities.

The Audit Committee must make regular reports to the Board, including an annual review of the Audit Committee's own performance and the adequacy of the Audit Committee's charter.

Compensation Committee

The Compensation Committee is responsible for (1) reviewing and approving the corporate goals and objectives relevant to the compensation for the CEO and the Executive Officers; (2) evaluating the CEO's and Executive Officers' performance in light of their goals and objectives; (3) determining and approving the CEO's and Executive Officers' incentive compensation plans and equity based plans; (4) overseeing the Company's compensation philosophy, incentive compensation plans, equity based plans for Executive Officers and the senior management of the Company; (5) preparing an annual report on executive compensation to be included in the Company's annual proxy statement; and (6) reviewing the Company's compensation discussion & analysis, required by the SEC Rules to be included in the Company's annual proxy statement.

The Compensation Committee must be comprised of three of more independent Directors, in accordance with, among other things, the NYSE and the Exchange Act.

The Compensation Committee must meet at least twice a year or in accordance with the NYSE. The Compensation Committee annually reviews all Director, Executive Officer, CEO and non-executive Employee compensation, and administers the Company's incentive compensation plans which the CEO and Executive Officers may participate in. The Compensation Committee at least annually reviews incentive compensation arrangements to confirm that such arrangements do not encourage unnecessary risk-taking and reports the results to the Board.

Nominating and Corporate Governance Committee

The Nominating and Corporate Governance Committee is responsible for (1) identifying, evaluating, recruiting and recommending to the Board individuals qualified to be nominated for election to the Board; (2) recommending to the Board the members and chairperson for each of the committees; (3) periodically reviewing and assessing the Corporate Governance Principles and the Code of Business Conduct and Ethics and making recommendations for changes thereto to the Board; (4) overseeing the annual self-evaluation of the performance of the Board and the evaluation of the Company's management; (5) assisting the Board in succession planning; and (6) considering any other corporate governance issues that arise and discharging all other duties and responsibilities imposed on the Nominating and Corporate Governance Committee by the Board from time to time.

The Nominating and Corporate Governance Committee must consist of three or more Directors, all of whom shall meet the independence requirements of the NYSE and the SEC.

The Nominating and Corporate Governance Committee must meet as often as is necessary to carry out its responsibilities. The Nominating and Corporate Governance Committee annually self-assesses its performance and the adequacy of its charter and reports the results to the Board. The Nominating and Corporate Governance Committee oversees an assessment of the Board's and management's performance and is responsible for establishing the evaluation criteria and implementing the process for such evaluation.

Strategic Committee

The Company formed the Strategic Committee in January 2016 to explore a range of strategic alternatives to further enhance Shareholder value. The strategic alternatives process explores options for the future of the Company including, but not limited to securing additional investment to support growth opportunities, joint ventures, asset sales or farm outs, mergers or acquisitions or continuing to pursue the Company's existing operation plan.

3.3 ***Corporate Governance Policies***

Corporate Governance Principles

The Company is committed to good corporate governance practices, which promote the long-term interests of Shareholders and strengthens the Board and management accountability. The Company is subject to the governance rules and guidelines for public companies established by securities regulators in the United States, including the NYSE. All Directors, Executive Officers and Employees are subject to the Code of Business Conduct and Ethics, which sets out the Company's expectations and standards of behaviour. No waivers from the Code of Business Conduct and Ethics have been granted to date. In addition, the governance practices of the Company are set out in the Corporate Governance Principles, which establish good governance practices including (i) establishing the functions reserved to the Board and setting out the composition of the Board; (ii) setting the frequency of meetings of the Board; (iii) establishing the Company Committees and the responsibility for such committees' charters; and (iv) communicating with security holders.

Code of Business Conduct and Ethics

The Company has a formal written code of business conduct and ethics. The purpose of the Code of Business Conduct and Ethics is to maintain the highest level of integrity in all corporate dealings and is applicable to all Directors, Executive Officers, contractors, consultants and employees. The Code of Business Conduct and Ethics provides an explanation as to the Company's position on matters such as confidentiality, fair disclosure, environmental concerns and conflicts of interest. All new employees are required to read and sign a copy of the Code of Business Conduct and Ethics.

Code of Ethics for the Chief Executive Officer and Senior Financial Officers

The Company has a formal written code of ethics for the CEO, chief financial officer and senior financial officers that is supplemental to the Code of Business Conduct and Ethics and applies to the CEO and senior financial officers. The code details the standards that the applicable Executive Officers are expected to conduct their roles with respect to the Company. Each of the applicable Executive Officers are required to reach and sign a copy of the code.

Insider Trading Policy

The Company has an insider trading policy which applies to all PDMRs and their associates, Employees and consultants of the Company, and the family members of all such individuals. The insider trading policy outlines the U.S. federal laws which prohibit insider trading and the Company's policy on (i) securities trading; (ii) the blackout period; (iii) short sales and options trading; and (iv) the compliance programme for officers and directors. With effect from Admission, the Company has adopted an amended insider trading policy that is also compliant with MAR and the DTR.

The insider trading policy prohibits any Employees or parties retained by the Company (and their family members) from buying or selling Common Shares in the Company when such person has or is aware of material, non-public information relating to the Company. Under U.S. federal securities law, material non-public information is information about a company which is not known by the general public and which could or may affect the market price of a security, or is of a nature which a reasonable investor would attach importance in deciding whether to buy, sell or hold a security.

The Company further restricts trading in its Common Shares during the quarterly blackout period, which begins on the fifteenth day of the third calendar month in any fiscal quarter (i.e. 15 March, 15 June, 15 September and 15 December), and ends after the second full trading day following the public release of such earnings. The Company may also determine that additional blackout periods exist where a material event occurs, however such blackout period shall only be known by, and apply to, such persons as have awareness of the event. Cash exercise of vested Options are permitted during a blackout period, as the purchase price is fixed.

The insider trading policy outlines the prohibited and limited transactions in Common Shares, in addition to the compliance programme operated by the Company which is applicable only to Directors, Executive Officers, and certain designated Employees, whereby such persons can only trade in Common Shares during specified window periods and by following the Company's procedure.

Information Disclosure Policy

The Company has adopted, with effect from Admission, an information disclosure policy to ensure that the Company complies with its continuous disclosure obligations under U.S. securities laws, MAR and the DTR. The policy sets out the procedures for how the Company will treat material, non-public information, as well as providing Shareholders and the market with timely, direct and equal access to information issued by the Company; and promoting investor confidence in the integrity of the Company and Common Shares.

Anti-Bribery and Anti-Corruption Policy

The Company has adopted, with effect from Admission, a new anti-bribery and anti-corruption policy. The Company has developed its anti-bribery and anti-corruption policy to be consistent with the FCPA and the UK Bribery Act. The policy is designed to ensure that the Directors, Executive Officers, Employees and agents understand the requirements of the UK Bribery Act and the FCPA and adhere to the Company's policy to comply with the FCPA and the UK Bribery Act and all anti-bribery legislation wherever the Company conducts its business.

The policy specifically addresses facilitation payments or gifts and hospitality, dealings with public officials, political donations, lobbying and advocacy and charitable donations, and includes provisions dealing with notification, as well as provisions regarding disciplinary action in the event that any part of the anti-bribery and anti-corruption policy has been breached. New and existing staff are required under the policy to be trained and the Company's approach to anti-bribery and anti-corruption must be communicated to its business partners.

PART 10 – GABON LEGAL AND REGULATORY FRAMEWORK

1. Petroleum law regime of Gabon

1.1 *Overview*

The Ministère du Pétrole, du Gaz et des Hydrocarbures regulates the upstream oil and gas industry in Gabon, while the Directeur Générale des Hydrocarbures is responsible for the upstream sector on a day-to-day basis.

Two separate types of contract have been used by the State of Gabon for the exploration and production of hydrocarbons.

Older fields operate under the terms of a concession agreement and an establishment convention, where the tax terms were agreed between the State of Gabon and the signatory. Since 2014, however, establishment conventions have been expressly prohibited.

The second type of contract is a PSC, which was first introduced in Gabon in 1977. Since the adoption of Law No. 14/82 of 24 January 1983, any new contracts to be entered into between independent contractors and the State of Gabon for the exploration and production of hydrocarbons are required to be structured through a PSC or service contract. In practice, however, only PSCs have been signed.

1.2 *2014 Hydrocarbons Law*

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

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

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

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

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

1.3 *2019 Hydrocarbons Law*

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

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

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

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

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

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

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

1.4 *Exclusive exploration permits*

The 2019 Hydrocarbons Law provides that the exploration period has a duration of eight years and that the duration of each of its phases is determined by the relevant contract. The exploration period can only be extended by a period of up to one year.

The 2019 Hydrocarbons Law further provides that each separate exploration phase can be extended by a period of up to 12 months and that the entire duration of the exploration period, including its extension and the extension of any of its phases, cannot exceed 10 years in aggregate.

1.5 *Exclusive development and production authorisations*

Under the 2019 Hydrocarbons Law, the duration of development and production authorisation periods vary according to the respective area and type of hydrocarbons concerned as follows:

(i) in the case of liquid hydrocarbons:

  (a) in conventional areas: 10 years, plus three renewals, each of five years; and

  (b) in deep offshore or ultradeep offshore areas: 15 years, with a first renewal of eight years and a second of seven years.

(ii) in the case of gaseous hydrocarbons:

  (a) in conventional areas: 15 years, plus three renewals, each of five years; and

  (b) in deep offshore or ultradeep offshore areas: 20 years, with a first renewal of eight years and a second of seven years.

1.6 *Downstream licences*

The 2019 Hydrocarbons Law provides that the duration of downstream authorisations and conditions for renewal of those authorisations is set out in the administrative document granting them. There is no prescribed minimum or maximum duration provided for in the 2019 Hydrocarbons Law.

2. Environmental law regime of Gabon

2.1 *Overview*

Oil and gas exploration and production activities are currently regulated by the 2019 Hydrocarbons Law, which states that general legislation currently in force stipulating obligations pertaining to environmental matters shall apply to the hydrocarbons sector, including, notably, as regards to the (i) preservation of the environment and waste management; (ii) pollution prevention; (iii) conduct of impact studies, and the related environmental and social management; and (iv) site abandonment and rehabilitation plans.

2.2 ***Environment Law***

The primary environmental legislation in Gabon is Law No. 007-2014, of 1 August 2014, relating to the Protection of the Environment ("**Environmental Law**").

The Environmental Law aims to foster a sustainable use of resources and development, limit pollution and nuisances, and improve the environment. The implementation of these principles under the Environmental Law is the responsibility of the Minister of Environment. Implementing regulations adopted under the previous Law No. 16/93, of 26 August 1993, relating to the Protection and Improvement of the Environment are applied in practice.

Under the Environmental Law, any works carried out by private companies which may have a negative impact on the environment are subject to an EIS, and require authorisation from the Minister of Environment. Additional studies, audits and risk assessment studies may also be required.

Under the Environmental Law, the discharge of any substances which may harm the maritime environment is subject to the prior authorisation of the Minister of Environment. In addition, any special facilities (including facilities the operation of which may harm the environment or public health) are subject to (i) the prior notification to the Minister of Environment if the operation of the facility does not present material risks but must be carried out in compliance with the environmental regulations in force; and (ii) the prior approval from the Minister of Environment if the operation of the facility presents material risks to human health, the environment or the well-being of communities.

The Environmental Law provides for a strict (civil) liability regime, according to which regardless of fault or negligence, whoever causes environmental damages or injury, as a result of its activities, will be liable for repairing such damages. This is applicable to national parks as well. In addition, the standard liability regime for tortious and contractual liability under the Civil Code will also apply. The 2019 Hydrocarbons Law clarifies that the statute of limitations for a liability claim is 30 years counted as of the damage becoming known.

2.3 ***Other environmental laws***

Decree No. 541, of 15 July 2005, regulates the elimination of wastes and requires from all waste producers and owners to dispose of these wastes if they are potentially harmful to the environment. Decree No. 542, of 15 July 2005, regulates the dumping of some products in superficial, underground and marine waters and Decree No. 543, of 15 July 2005, determines classified installations subject to either a declaration or an authorisation. Oil and gas extractive installations, in particular, are subject to an authorisation.

Decree No. 545, of 15 July 2005, regulates the recovery of used oil, its collection and recycling, while oil spill risks and relative emergency response arrangements are governed by Law No.21/04, of 2 February 2004, and Decree No. 653, of 21 May 2003; offshore response measures are the responsibility of the Merchant Navy, whereas onshore response measures are to be coordinated by the "*Ministère de l'Intérieur*" via the "*Direction de la Protection Civile*", although other State agencies can also be involved.

Order No.000937/MEFEDD/SG/DGFAP, of 11 July 2018, also established a Fauna Protection Plan on Petroleum Sites.

Law No. 003/2007, of 27 August 2007, on National Parks, as amended, prohibits activities likely to negatively impact National Parks environment within their boundaries and a buffer and peripheral zones, which limits are to be specified in implementing regulations. Only human activities not impacting the environment can be authorised. This authorisation must be provided by the relevant minister after consultation with the organism in charge of the National Park. The beneficiary of the authorisation must pay a fee according to applicable modalities and rates.

3. State of Gabon

Gabon gained independence from France on 17 August 1960. The constitution of 21 February 1961, adopted under the first President, Mr. Leon Mb'a, established a presidential regime. Following Mr. Mb'a's death in 1967, his Vice-President, Mr. Omar Bongo Ondimba, became and remained President up until his death in 2009. Following political and civil unrest in Gabon in the 1990s, a multiparty regime was established.

Gabon is currently a multiparty republic, with a president elected by popular vote for a seven-year term. After presidential elections, the President appoints the Prime-Minister and the Council of Ministers. The current President of Gabon is Mr. Ali Bongo Ondimba, of the majority party, Parti Démocratique Gabonais ("**PDG**"), who is currently serving his second term, which began in 2016.

The latest presidential elections in Gabon were held on 27 August 2016, and the then-incumbent President, Mr. Bongo Ondimba, presented himself as a candidate for another seven-year term, against his principal opponent, the former African Union Commission Chairman and ex-minister, Mr. Jean Ping. 59.5 percent of voters cast their ballot. Mr. Bongo Ondimba was declared the winner with 49.8 percent of the votes, but allegations of fraud surfaced soon after, especially in Mr. Bongo Ondimba's home province, where turnout was calculated at 99.93 percent and Mr. Bongo Ondimba won 98 percent of the votes.

The announcement of the election results by the interior minister was followed by acts of unrest, notably the arson of the Lower House of Parliament, damage of private property and the military assault on the election headquarters of the presidential candidate, Mr. Jean Ping. Curfews and lockdowns were common during the month of September until the Constitutional Court validated the election results on 23 September 2016. However, unlike the 2009 elections, where crowds stormed private offices in Port-Gentil, no such incidents were reported this time, and although most non-essential expatriate staff left the country during this period, essential operations were not disrupted.

To resolve the resulting political fallout from the elections, the State of Gabon organised a National Dialogue from March to May 2017 bringing together members from the PDG and the opposition as well as members of the civil society and non-governmental organisations to discuss their concerns. This political dialogue led to a constitutional revision through the adoption of Law No. 001/2018 of 12 January 2018. The legislative elections were held in November 2018, and were resoundingly won by members of the majority party PDG.

Mr. Bongo Ondimba suffered from a stroke on 24 October 2018 while on an official trip to Saudi Arabia. There were calls for the Constitutional Court to rule on a temporary power vacancy, which would have led to the President of the Senate assuming power in the interim, but the Constitutional Court did not do so. Following Mr. Bongo Ondimba's convalescence in Morocco, he returned to Gabon on 25 March 2019. However, he has made few a public appearance since, although, he has met with several members of the State of Gabon and the administration in private. A petition was recently filed by the *Appel à Agir* movement before the Libreville Court requesting it to order medical exams evaluating the President's health condition, however the case still remains pending before the Appellate Court.

An armed uprising was attempted by five Gabonese soldiers on 7 January 2019 through the takeover of the *Gabon Télévision* headquarters. The subsequent counterattack by government forces resulted in two deaths and multiple arrests. Business was disrupted on the day of the uprising and foreign embassies asked their nationals to stay home. However, oil operations still continued offshore. A peaceful state of affairs resumed the next day.

In June 2016, political opponent Roland Aba'a Minko declared to TV channels that he had laid mines in several government buildings, subject to Mr. Ali Bongo Ondimba stepping down from power. However, he was apprehended by the authorities on the same day and arrested. In December 2017, two Danish reporters from National Geographic were wounded in a knife attack in the local market, which led to the arrest of a 53-year old Nigerian national. No more incidents have been publically reported since.

The Gabonese administration has experienced a succession of strikes since 2017, notably the judges' strike from December 2017 – February 2018, and the Court Clerks' strike from February 2018 – August 2018. Different employee unions at the tax administration and other financial institutions have also gone on strike on several occasions since August 2017. These strikes have led to the paralysis of the justice system as well as cumbersome administrative delays.

Gabon had a 40-year border dispute with Equatorial Guinea concerning the Mbanié, Cocotiers and Congas islands, which was forwarded to the International Court of Justice through the signature of an agreement on 15 November 2016. Gabon also has border disputes with Congo and Cameroon.

No wars have taken place on Gabonese territory, although Gabon was involved in the Congolese civil war of 1997. Gabon is also involved in missions abroad of the African Union (the latest being in the Central African Republic).

The Gulf of Guinea, covering Gabon, is often presented as a high risk zone for piracy. In August 2018, a tanker went missing for a week off the coast of Gabon but was subsequently found. A new maritime centre for piracy monitoring has been built for Gabon by the United States Navy and was inaugurated in May 2019.

The 2016 Gallup Poll of the most dangerous countries in the world ranked Gabon in the 7th position. Gabon is ranked 113th in press freedom by Reporters Without Borders. The latter have criticised the recent suspension of several online media sites by the Haute Autorité de la Communication (HAC).

PART 11 – EQUATORIAL GUINEA LEGAL AND REGULATORY FRAMEWORK

1. Petroleum law regime of Equatorial Guinea

1.1 *Hydrocarbons Law and Petroleum Regulations*

Until 2006, the legal framework governing the upstream petroleum industry in Equatorial Guinea was set out in Decree Law No. 7/1981, dated 16 June 1981, which was amended by Law No. 6/2000, of 20 March 2000.

This legislation was superseded by Law No. 8/2006, dated 3 November 2006 ("**Hydrocarbons Law**"), which incorporates not only the regime applicable to the exploration, appraisal, development and production of hydrocarbons, but also rules on the transportation, distribution, storage, preservation, decommissioning, refining, marketing, sale and other disposal of hydrocarbons. In addition, the Hydrocarbons Law contains provisions on a number of aspects concerning upstream operations and contracts, such as national content obligations, unitisation, transfers and abandonment.

In September 2013, the Petroleum Operations Regulations ("**Petroleum Regulations**"), containing provisions for the implementation of the Hydrocarbons Law, approved by Ministerial Order No. 4/2013, dated 20 June 2013, came into force.

On 26 September 2014, the Ministry of Mines, Industry and Energy also approved Order No. 1/2014, containing the National Content Regulations, and, in 2018, the EG MMH issued Order No. 1/2018, dated 18 May 2018, on authorisations for companies performing activities in the mining and hydrocarbons sectors in Equatorial Guinea. While these orders were not published in the State Official Gazette, as required, provisions from each of these have each been enforced in Equatorial Guinea, although not exhaustively.

1.2 *Ministries of Equatorial Guinea*

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

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

Until June 2016, the Ministry responsible for petroleum operations was the Ministry of Mines, Industry and Energy, whose organisation and authority was laid down in Decree No. 170/2005, of 15 August 2005.

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

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

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

1.3 *GEPetrol and Sonagas*

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

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

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

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

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

1.4 *Exploration and production periods*

As prescribed by the Hydrocarbons Law, activities related with petroleum operations are divided into two different phases: (i) the exploration period (which includes the exploration phase and the appraisal phase); and (ii) the production period (which includes both the development and the production phases).

The exploration period is further divided into: (i) an initial exploration period, which is delineated into two sub-periods, with a duration between four and five years; and (ii) a maximum of two extension periods, of one year each. However, the Hydrocarbons Law and Petroleum Regulations entitle the Ministry responsible for petroleum operations to change the duration of such periods in the contract if the Ministry deems it appropriate.

The Hydrocarbons Law does not define the duration of the development and production phases; it states that the phase shall be specified in the relevant contract, while the Petroleum Regulations state that the duration of the development and production period shall be 25 years from the date of approval of the field development and production plan.

The Petroleum Regulations further allow the Ministry to grant an extension of up to five years, and extensions beyond this five year period, in the Ministry's sole discretion, if it serves the State of Equatorial Guinea's interest.

1.5 *Taxation*

The Hydrocarbons Law contains a non-limited list of the taxes and equivalent charges which apply or may apply in connection with petroleum operations, and also refers to a windfall profit tax. This tax, however, is not set forth in the 2014 General Tax Law currently in force, which contains a chapter on the taxation of the hydrocarbons sector, and has not been established to date.

2. Environmental law regime of Equatorial Guinea

2.1 *Environmental Law*

Law No. 7/2003, of 27 November 2003 ("**Environmental Law**") incorporates primarily general principles, rules and guidelines which are to be complemented by and implemented through ancillary legislation covering specific provisions in respect of, for example, environmental protected areas, endangered species, atmosphere protection and soil pollution controls.

While the only legislation enacted to date for implementation of the law is Decree No. 173/2005, of 8 September 2005, on environmental inspections, the provisions of the Environmental Law on environmental licensing and related obligations are sufficiently clear to be enforceable and have been enforced to a certain extent by the Ministry in charge of environment.

2.2 *Environmental conventions*

Equatorial Guinea is a member of the International Maritime Organisation (IMO) and party to a number of conventions adopted that impact petroleum activities. These conventions include: (i) the 1974 International Convention for the Safety of Life at Sea and Protocols 78 and 88 thereto (SOLAS); (ii) the 1973 International Convention for the Prevention of Pollution from Ships, as modified by the 1978 Protocol (MARPOL 73/78); (iii) the 1972 London International Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter; (iv) the 1969 International Convention relating to Intervention on the High Seas in Cases of Oil Pollution Casualties; (v) the 1969 International Convention on Civil Liability for Oil Pollution Damage ("**CLC Convention**"); and (vi) the 1976 International Convention on Limitation of Liability for Maritime Claims.

Equatorial Guinea is not bound by certain provisions of the CLC Convention and is also not a party to the 1990 International Convention on Oil Pollution Preparedness, Response and Co-Operation ("**OPRC**"). However, certain requirements and provisions of the CLC Convention and the OPRC have been incorporated by reference into the CEMAC's Merchant Navy Code, of which Equatorial Guinea is a signatory. While the treaties and conventions have not, to the Company's knowledge, been published in the Official Gazette, the enforceability of such provisions has not been publically challenged.

2.3 *Hydrocarbons Law and Petroleum Regulations*

The Hydrocarbons Law contains few provisions on environmental matters, however, the Petroleum Regulations address these matters with some detail; it specifies that contractors shall undertake a comprehensive EIS prior to, during and after major drilling operations. An EIS must also be completed prior to undertaking any seismic work in any areas of particular environmental sensitivity specified by the State of Equatorial Guinea.

The Petroleum Regulations further provide that contractors shall take all prudent and necessary steps in accordance with (a) the Environmental Law; (b) the Hydrocarbons Law and its regulations; (c) generally accepted practices in the international petroleum industry; and (d) the terms of their contracts with the State of Equatorial Guinea to (i) prevent pollution and protect the environment and living resources; (ii) ensure that hydrocarbons discovered or produced are handled in a manner that is safe for the environment; (iii) avoid damage to formations trapping hydrocarbon reserves; (iv) prevent the ingress of water through wells into strata containing hydrocarbon reservoirs; and (v) ensure prompt, fair and full compensation for injury to persons or property caused by the effects of exploration and production operations.

Additionally, the Petroleum Regulations provide that if a contractor's actions result in any pollution or damage to the environment, any person, living resources, property or otherwise, the contractor shall immediately take all prudent and necessary measures to remedy such damages and consequences and/or any additional measures as may be directed by the Ministry responsible for petroleum operations. If the pollution or damage is caused as a result of the negligence or wilful misconduct of the contractor, its subcontractors or any persons acting on their behalf, all related costs incurred shall not be cost recoverable nor tax deductible. Furthermore, if the contractor does not act promptly so as to control or clean-up pollution, or make good any damage caused, the Ministry may, after giving the contractor reasonable notice, carry out the actions which are prudent or necessary and all reasonable costs and expenses of such actions shall be borne by the contractor and shall not be cost recoverable.

If the Ministry determines that any works or installations built by a contractor or any of its activities threatens the safety of any person or property or the environment, the Ministry can require the contractor to take all appropriate mitigating measures consistent with generally accepted practices in the international petroleum industry, to repair any damage and to suspend totally or partially the affected operations until the measures are taken or the damage is repaired.

With respect to liability, the Petroleum Regulations state that a contractor shall indemnify, hold harmless and compensate any person, including the State of Equatorial Guinea, for any damage or loss which the contractor, its affiliates, its subcontractors and their respective directors, officers, employees, agents or consultants and any other person acting on their behalf may cause in the conduct of exploration and production operations, regardless of whether or not any environmental authorisations have been obtained. In case of negligence or wilful misconduct, costs shall not be recoverable nor tax deductible.

3. State of Equatorial Guinea

Equatorial Guinea became independent from Spain in 1968. Since its independence, and until 1979, the country was ruled by President Francisco Macias Nguema, who was deposed by his nephew, Teodoro Obiang Nguema Mbasogo. President Obiang has been the Head of State since 1979, having won all presidential elections held in the country (1996, 2002, 2009 and 2016).

Equatorial Guinea is a constitutional multiparty presidential republic. Since its adoption in 1968, the constitution has been amended numerous times, most notably in 1973, 1982 and 1991 and more recently in 2012.

Pursuant to the constitution, the President is the Head of State and of the State of Equatorial Guinea, leader of the executive branch, and responsible for defining the nation's policies. The President can be elected for a maximum of two consecutive seven-year terms. The same person can only be elected for a third term after a seven-year break. President Obiang is currently serving his second term after the 2012 revision of the constitution. This term started in 2016 and will end in 2023.

Under the constitution, the Vice President will assume the powers of the President in case of his removal, permanent physical or mental disability, or death until elections are held. Currently Mr. Teodoro Nguema Obiang Mangue, the current President's eldest son, holds the office of Vice President.

In April 2016, President Obiang was re-elected with 93.7 percent of the votes. In November 2017, the country held legislative and municipal elections. The ruling PDGE party (the Democratic Party founded by the President in 1991) and its 14 coalition parties won 92 percent of the vote, taking all 70 seats in the Senate, 99 of 100 seats in the lower chamber, and all except one seat in the municipal councils. In 2018, the President and the ruling PDGE further solidified their position after a court dissolved the political party that held the sole seat belonging to the opposition in the 170 member bicameral parliament. No civil unrest was noted during the elections or the days that followed.

There have been several attempted coups in Equatorial Guinea in the past 20 years, notably in 2002, 2004 and 2009, when the Presidential Palace allegedly came under attack. Several arrests, deportations and the exile of opposition members, mercenaries and foreigners allegedly involved in the coups have followed each occasion. In January 2018, the authorities reported an attempted coup in December 2017. In May 2018, the Supreme Court upheld a ban on the country's main opposition party, the CI Party, which was accused of involvement in acts of violence ahead of last year's elections.

In 2006 and 2008, mass resignation of the Government of Equatorial Guinea was accepted by the President on the basis of corruption and mismanagement. In subsequent years, the Government of Equatorial Guinea has been changed by the President after intervals of two or three years.

There are no unions in the country, demonstrations are very rare and there have been no strikes in recent years.

Equatorial Guinea has had generally cordial relations with its neighbours. It is a member of the CEMAC, the Organisation for the Harmonisation of Corporate Law in Africa (OHADA), the African Union, the Community of Portuguese Language Countries (CPLP) and other organisations. It had a minor border dispute with Cameroon that was resolved by the International Court of Justice in 2002, and a dispute with Gabon over the Corisco border, which was solved by an agreement signed with the help of United Nations mediation, in January 2004. The dispute persisted concerning the Mbanié, Cocotiers and Congas islands, but was forwarded to the International Court of Justice and resolved through the signature of an agreement on 15 November 2016.

PART 12 – HISTORICAL FINANCIAL INFORMATION

Please refer to the Appendix to this Prospectus which contains the audited consolidated financial statements of the Group for the three years ended 31 December 2018, 31 December 2017 and 31 December 2016, and the unaudited condensed interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018, together with the independent auditor's report therein.

PART 13 – OPERATING AND FINANCIAL REVIEW

The following discussion and analysis is intended to assist in the understanding and assessment of the trends and significant changes in the Group's results of operations and financial condition during the Historical Financial Information Period. Historical results may not be indicative of future financial performance. Forward-looking statements contained in this review that reflect the current view of the Directors and Executive Officers involve risks and uncertainties and are subject to a variety of factors that could cause actual results to differ materially from those contemplated by such statements. Factors that may cause such a difference include, but are not limited to, those discussed in paragraph 8 of Part 3 (*Presentation of Financial and Other Information*) and Part 2 (*Risk Factors*) of this Prospectus.

In this Prospectus the consolidated financial statements presented are those of the Group. This discussion is based on the audited annual consolidated financial statements of the Group for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016 and unaudited condensed interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018, and should be read in conjunction with its consolidated financial statements and the accompanying notes contained in the Appendix to this Prospectus, as referred to in Part 12 (*Historical Financial Information*) of this Prospectus, and with the information relating to the business of the Group included elsewhere in this Prospectus. Unless otherwise indicated, all of the financial data and discussions thereof are based upon financial statements prepared in accordance with U.S. GAAP. Investors should read the whole of this Prospectus and not rely just on summarised information.

1. Key highlights for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016

During 2017 through Q3 2018, the global oil supply and demand were close to being balanced; however, late in Q4 2018, prices were adversely impacted by concerns about oversupplies in the markets. ICE Dated Brent crude oil prices fluctuated between $44 and $67 per BBL from January 2017 through December 2017. During financial year ended 31 December 2018, ICE Dated Brent crude oil prices fluctuated between $51 and $86 per BBL with financial year ended 31 December 2018 price of $51 per BBL, 24 percent lower than financial year ended 31 December 2017 price of $67 per BBL.

On 22 May 2018, the Company terminated the Amended Term Loan Agreement with the IFC by prepaying the outstanding principal and accrued interest. The Company did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

On 17 September 2018, the Company entered into the Etame PSC Extension, providing for the extension of the Company's three EEAs for the Etame Marin Block through 16 September 2028, with the right for two additional five-year extension periods.

At 31 December 2018, the Company reported a 76 percent increase in estimates for proved reserves over reserves reported at 31 December 2017.

Effective as of September 2018, the Block P PSC has been lifted and the Company is awaiting the EG MMH to approve GEPetrol's introduction of a new joint venture owner and VAALCO's appointment as technical operator for Block P. Once the joint owner is approved, the Block P Consortium will be required to drill an exploration well within one year. VAALCO intends to seek a partner on a promoted basis that will cover all or substantially all of the costs to drill the exploratory well.

2. Highlights and selected financial information for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016

The following table sets forth, as of the dates and for the periods indicated, selected financial information. The financial information for each of the three financial years ended 31 December 2018, 31 December 2017 and 31 December 2016 has been derived from the Company's audited annual consolidated financial statements, filed in the annual report with the SEC on Form 10-K for each year.

	Year Ended 31 December		
	2018	2017	2016
	(in thousands, except per Share amounts)		
Total revenues	$104,943	$77,025	$59,784[1]
Income (loss) from continuing operations	98,728[2]	10,272	(18,267)[2]
Basic income (loss) from continuing operation per Share attributable to Shareholders	1.65	0.17	(0.31)
Diluted income (loss) from continuing operations per Share attributable to Shareholders	1.63	0.17	(0.31)
Balance Sheet Data:			
Net property, plant and equipment	52,724	23,221	28,019
Total assets	166,312[3]	79,633	81,032
Total long-term liabilities	15,441	22,756	25,836

Notes

(1) The lower total revenues in 2016 is tied to the decrease in oil and natural gas prices that began in the second half of 2014 and continued through 2016.

(2) Income from continuing operations in 2018 was primarily impacted by a $56.9 million deferred tax benefit primarily related to the re-evaluation of the realisability of certain tax assets. The loss from continuing operations in 2016 was primarily impacted by decreased revenues due to prevailing low oil and natural gas prices.

(3) Total assets increased substantially in 2018 due to the recognition of certain deferred tax benefits.

3. Liquidity, financing and capital resources for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016

The Company's cash flows for the financials years ended 31 December 2018, 31 December 2017 and 31 December 2016 were as follows:

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

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

Property and equipment expenditures have historically been the Company's most significant use of cash in investing activities. These expenditures were significantly lower in financial years ended 31 December 2016 and 2017 than financial year ended 31 December 2018. No drilling activities were conducted during these two years as the Company conserved cash during the recent period of low crude oil prices. For 2018, the cash basis expenditures of $14.1 million, were primarily related to the $11.8 million signing bonus paid in connection with the Etame PSC Extension and $2.3 million paid for equipment and enhancements. For 2017, the cash basis expenditures of $1.8 million for property and equipment was primarily related to equipment and other enhancements. During 2016, these expenditures on a cash basis (including expenditures attributable to discontinued operations) were $8.7 million.

There were no other significant investing activities in 2018 and 2017. For 2016, other significant investing activities included $5.7 million for the November 2016 acquisition of Sojitz's interest in the Etame Marin Block and $2.9 million to purchase oil puts used to mitigate the potential impact of price declines in 2016 and 2017.

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

Capital expenditures

At 31 December 2018, pursuant to the Etame PSC Extension, the Company had commitments for capital expenditures related to the Base Case Work at an estimated cost of approximately $61.2 million ($20.5 million, net to VAALCO), by 16 September 2020. The Company estimates that the Expansive Work will cost $25.0 million — $30.0 million ($8.5 million — $10.0 million, net to VAALCO).

The Company anticipates completing the Work Programme in H1 2020 and that the Work Programme and any other capital expenditures will be funded by cash on hand and cash generated from operations. The Expansive Work is subject to approval by the joint venture owners and the State of Gabon.

During 2018, the Company had accrual basis capital expenditures attributable to continuing operations of $20.0 million compared to $1.7 million and $(4.1) million accrual basis capital expenditures in 2017 and 2016, respectively. The difference between capital expenditures and the property and equipment expenditures reported in the consolidated statements of cash flows is attributable to changes in accruals for costs incurred but not yet invoiced or paid on the report dates. Capital expenditures in 2018 were attributable to the Etame PSC Extension signing bonus, equipment and enhancements. Capital Expenditures in 2017 and 2016 were mainly for equipment and enhancements.

Capital resources

Credit facility

On 29 June 2016, the Company executed a supplemental agreement with the IFC which, among other things, amended and restated the Company's existing loan agreement to convert $20.0 million of the revolving portion of the credit facility, to the Amended Term Loan Agreement with $15.0 million outstanding at that date. On 22 May 2018, the Company terminated the Amended Term Loan Agreement by prepaying the outstanding principal and accrued interest. The Company did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

Cash on hand

At 31 December 2018, the Company had unrestricted cash of $33.4 million. The unrestricted cash balance included $0.3 million of cash attributable to non-operating joint venture owner advances. As operator of the Etame Marin Block, the Company entered into project related activities on behalf of the Etame Consortium. The Company generally obtains advance cash from joint owners prior to significant funding commitments.

The Company currently sells its crude oil production from Gabon under the Mercuria COSPA, that began in February 2019 and ends in January 2020. Pricing under the contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Liquidity

The Company's revenues, cash flow, profitability, oil and gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. The Company's ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices.

The Company generally seeks to fund its capital programme through cash flows from operations and expects this to be the case for its capital programme through the medium term, including the Work Programme. The Company has commitments under the Etame PSC Extension for capital expenditures to undertake the Base Case Work, being the drilling of two development wells and two appraisal wellbores by 16 September 2020, which the Company commenced on 13 September 2019. The Company estimates that the Base Case Work will cost approximately $61.2 million ($20.5 million, net to VAALCO). The Expansive Work, comprising of a third development well that will follow completion of the Base Case Work and is expected to be completed in H1 2020 and is estimated to cost approximately $25.0 million – $30.0 million ($8.5 million – $10.0 million, net to VAALCO), is subject to approval by the joint venture owners and the State of Gabon. Based on drilling results and other factors, the Company's drilling plans may change.

The Company's capital programme for 2019 – 2020 does not include the cost of any potential acquisitions or exploration activity with respect to Block P. In line with the Company's general policy, the Group expects to finance its 2019 – 2020 capital programme fully through cash on hand and cash flows from operations.

The Company expects any capital expenditures during the Working Capital Period to be funded by cash on hand and cash flow from operations. The Company believes that at current prices, cash generated from continuing operations, together with cash on hand at 30 June 2019, are adequate to support its operations and cash requirements during 2019 and through 30 September 2020.

At 31 December 2018, the Company had 5.4 MMBBL of estimated net proved reserves (increased to 5.6 MMBBL as at 31 March 2019), all of which are related to the Etame Marin Block. The current term for exploitation of the reserves in the Etame Marin Block ends in September 2028 with rights for two five-year extension periods. Except to the extent that the Company conducts successful exploration or development activities or acquires properties containing proved reserves, the Company's 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, the Company's long-term liquidity also depends upon the Company's ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable.

4. Results of operations for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016

The Company's results of operations for the financials years ended 31 December 2018, 31 December 2017 and 31 December 2016 was as follows:

	Year Ended 31 December		
	2018	*2017*	*2016*
	(in thousands, except per Share amounts)		
Revenues:			
Oil and natural gas sales	$104,943	$77,025	$59,784
Operating costs and expenses:			
Production expense	40,415	39,697	37,586
Exploration expense	14	7	5
Depreciation, depletion and amortization	5,596	6,457	6,926
Gain on revision of asset retirement obligations	(3,325)	–	–
General and administrative expense	11,398	10,377	9,561
Impairment of proved properties	–	–	88
Other operating expense	–	–	8,853
General and administrative related to Shareholder matters	–	–	(332)
Bad debt (recovery) expense and other	(77)	452	1,222
Total operating costs and expenses	54,021	56,990	63,909
Other operating income (expense), net	365	(84)	(266)
Operating income (loss)	51,287	19,951	(4,391)
Other income (expense):			
Derivative instruments gain (loss), net	4,264	(1,032)	(1,711)
Interest expense, net	(145)	(1,414)	(2,613)
Other, net	68	3,145	(304)
Total other income (expense)	4,187	699	(4,628)
Income (loss) from continuing operations before income taxes	55,474	20,650	(9,019)
Income tax expense (benefit)	(43,254)	10,378	9,248
Income (loss) from continuing operations	98,728	10,272	(18,267)
Loss from discontinued operations	(496)	(621)	(8,283)
Net income (loss)	$98,232	$9,651	$(26,550)
Basic net income (loss) per Share:			
Income (loss) from continuing operations	$1.65	$0.17	$(0.31)
Loss from discontinued operations	(0.01)	(0.01)	(0.14)
Net income (loss) per Share	$1.64	$0.16	$(0.45)
Basic weighted average Shares outstanding	59,248	58,717	58,384
Diluted net income (loss) per Share:			
Income (loss) from continuing operations	$1.63	$0.17	$(0.31)
Loss from discontinued operations	(0.01)	(0.01)	(0.14)
Net income (loss) per Share	$1.62	$0.16	$(0.45)
Diluted weighted average Shares outstanding	59,997	58,720	58,384

The Company reported net income for the financial year ended 31 December 2018 of $98.2 million, compared to a net income of $9.7 million for the same period of 2017. These amounts of income were inclusive of a loss from discontinued operations for the financial year ended 31 December 2018 of $0.5 million, and loss from discontinued operations for the financial year ended 31 December 2017 of $0.6 million.

The reported net income for the financial 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 a loss from discontinued operations for the financial year ended 31 December 2017 of $0.6 million, and loss from discontinued operations for the financial year ended 31 December 2016 of $8.3 million.

The Company's net production, sales volumes and realised prices for the financials years ended 31 December 2018, 31 December 2017 and 31 December 2016 was as follows:

	Year Ended 31 December		
	2018	***2017***	***2016***
	(in thousands, except prices)		
Gabon net oil production (MBBL)	1,369	1,518	1,515
International net oil sales (MBBL)	1,442	1,423	1,485
U.S. net oil sales (MBBL)	–	–	3
Net oil sales (MBBL)	1,442	1,423	1,488
Net natural gas sales (MMCF)	–	–	124
Net oil equivalents (MBOE)	1,442	1,423	1,509
Average realised oil price ($/BBL)	$70.32	$52.58	$40.13
Average realised natural gas price ($/MCF)	–	–	1.95
Weighted average realised price ($/BOE)	70.32	52.58	39.62
Average Dated Brent spot* ($/BBL)	71.34	54.10	43.67

Note

*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 Petroleo Nautipa, and thus crude oil sales do not always coincide with volumes produced in any given quarter. The Company made fifteen liftings for financial year ended 31 December 2018 and twelve liftings for financial years ended 31 December 2017 and 31 December 2016. Volumes in 2017 were adversely impacted because the last lifting of 2017 was not completed until 1 January 2018. Net revenues of $6.5 million associated with these net volumes were reported as revenue in 2018. The Company's share of oil inventory aboard the FPSO Petroleo Nautipa, excluding royalty barrels, was approximately 34,811, 122,076 and 46,700 barrels at financial years ended 31 December 2018, 31 December 2017 and 31 December 2016, respectively.

The revenue changes between financial year ended 31 December 2018 and financial year ended 31 December 2017 and changes between financial year ended 31 December 2017 and financial year ended 31 December 2016 identified as related to changes in price or volume are shown in the table below.

	Change from 2017 to 2018	***Change from 2016 to 2017***
	(in thousands)	
Price	$25,578	$17,716
Volume	999	(2,850)
Other	1,341	2,375
	$27,918	$17,241

Oil and natural gas revenues

Oil and natural gas revenues increased $27.9 million during financial year ended 31 December 2018 compared to financial year ended 31 December 2017. Based on the average realised oil prices, a substantial portion of the increase in revenue is related to realised oil prices, which are due to increases in the Dated Brent market price.

Oil and natural gas revenues increased $17.2 million during financial year ended 31 December 2017 compared to financial year ended 31 December 2016. A substantial portion of the increase in revenue is related to higher realised oil prices as well as higher revenue attributable to the Group's acquisition of Sojitz's

2.98 percent working interest (3.23 percent participating interest) in the Etame Marin Block on 22 November 2016. This was offset in part by an overall decrease in sales volumes. Revenues in 2017 were adversely impacted because the last lifting in 2017 was not completed until 1 January 2018. Net revenues of $6.5 million associated with net volumes delivered to the buyer on 1 January 2018 of 95,525 barrels are reported as revenue in 2018.

Production expenses

Production expenses were substantially unchanged increasing $0.7 million in financial year ended 31 December 2018 compared to financial year ended 31 December 2017. Workover costs increased $0.7 million and the Company saw increases in fuel and personnel costs. These increases were offset by lower FPSO Petroleo Nautipa charter fees and customs costs.

Production expenses increased $2.1 million in financial year ended 31 December 2017 compared to financial year ended 31 December 2016, primarily as a result of the Company's increased ownership in the Etame Marin Block after the acquisition in November 2016 from Sojitz, 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

Depreciation, depletion and amortization decreased $0.9 million in financial year ended 31 December 2018 compared to financial year ended 31 December 2017 due to the favourable impact of depleting the Company's costs over a higher reserve base as a result of improvements in estimated reserves identified at 31 December 2018.

Depreciation, depletion and amortization decreased $0.5 million in financial year ended 31 December 2017 compared to financial year ended 31 December 2016 due to the favourable impact of depleting the Company's costs over a higher reserve base as a result of improvements in estimated reserves identified at financial year ended 31 December 2016 and financial year ended 31 December 2017 as well as lower lifting volumes.

Gain on revision of asset retirement obligations

Gain on revision of asset retirement obligations for financial year ended 31 December 2018 resulted from the downward revisions of $6.5 million to the liability for asset retirement obligations which exceeded the net book value of the related assets by $3.3 million.

General and administrative expenses

General and administrative expenses increased $1.0 million in financial year ended 31 December 2018 compared to financial year ended 31 December 2017. Share-based compensation expense increased by $1.3 million during financial year ended 31 December 2018 as compared to financial year ended 31 December 2017. This increase was primarily related to fair value adjustments associated with SARs. Other increases in personnel costs were offset by lower professional services and other taxes in financial year ended 31 December 2018 compared to financial year ended 31 December 2017.

General and administrative expenses increased $0.8 million in financial year ended 31 December 2017 compared to financial year ended 31 December 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 Share-based compensation as 2016 included the benefit related to employee forfeitures.

Bad debt (recovery) expense

Bad debt (recovery) expense is primarily associated with accounts receivable balances with the joint venture owners 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 the Company. Portions of the costs in Gabon (including the VAT receivable) are denominated in CFA. For the financial year ended 31 December 2018 the Company recovered $0.1 million from payments associated with the VAT receivable.

For the financial years ended 31 December 2017 and 31 December 2016, the Company recorded bad debt expense of $0.5 million and $1.2 million, respectively.

Other operating expenses

Other operating expenses for financial year ended 31 December 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labour provided to the Company over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilisation and release of the contracted drilling rig. In June 2016, the Company reached an agreement with the drilling contractor to pay less than the Company's originally estimated maximum day rate, plus demobilisation costs, in seven equal monthly instalments beginning in July 2016. In January 2017, the Company resolved the Gabon payroll tax obligation. The Company did not incur such expenditures for the financial years ended 31 December 2018 and 31 December 2017.

Derivative instruments gain (loss), net

Derivative instruments gain (loss), net for the financial year ended 31 December 2016 and 2017 consisted of the Company's oil put contracts, which provided for settlement based upon reported the Brent price, expired as of financial year ended 31 December 2017. The Company's derivative instruments at financial year ended 31 December 2018 consisted of oil swaps, which require the Company to pay a counterparty when the price of oil exceeds $74.00 per BBL, and where the price of oil falls below $74.00, the Company received a payment from the counterparty. Derivative instruments gain (loss), net consisted of realised gains or losses upon the settlement of the derivative instrument and the change in the fair value during the period of derivative assets and liabilities of the Company resulting from commodity risk management activities.

The Company received net cash settlements of $0.7 million during the financial year ended 31 December 2018 related to matured derivative contracts. The Company received cash settlements of $0.2 million during the financial year ended 31 December 2017 related to matured derivative contracts. The Company did not receive any cash settlements during the financial year ended 31 December 2016 related to matured derivative contracts.

Interest expense

Interest expense for financial years ended 31 December 2018, 31 December 2017 and 31 December 2016 related to the Amended Term Loan Agreement with the IFC to the consolidated financial statements and to interest on taxes other than income taxes. On 22 May 2018, the Company terminated the Amended Term Loan Agreement by prepaying the outstanding principle and accrued interest. Financial year ended 31 December 2018 includes interest expense related to the Amended Term Loan Agreement prior to the May 2018.

Other, net

Other, net for the financial year ended 31 December 2018 consisted primarily of other income offset by foreign currency losses of $0.1 million. In 2017 Other, net consisted primarily of $2.6 million related to the reversal of accruals for liabilities the Company was no longer obligated to pay as well as $0.5 million in foreign currency gains. Other, net consisted of foreign currency losses in financial year ended 31 December 2016

Income tax expense (benefit)

Income tax expense (benefit) for the financial year ended 31 December 2018 includes a $56.9 million deferred tax benefit primarily related to the recognition of deferred tax assets and the reversal of valuation allowances on deferred tax assets. In addition to the deferred tax benefit, the Company had a current tax provision of $13.7 million during the financial year ended 31 December 2018.

As a result of the 2017 tax legislation enacted in the U.S., the Company expects to realise the benefit from the Alternative Minimum Tax ("**AMT**") credit carryforwards. The valuation allowance recorded related to AMT credits in previous periods was reversed in 2017 with the exception for a reserve for the possible sequestration of the credits. The $1.3 million reversal was recorded as a deferred income tax benefit during the fourth quarter of 2017.

In addition to the deferred tax benefit, the Company had a current tax provision of $11.6 million during the financial year ended 31 December 2017. The current tax provision in both periods is primarily attributable to the Company's operations in Gabon and is higher in 2018 than income tax for the comparable 2017 period as a result of higher revenues. Income tax expense increased $1.1 million in the financial year ended 31 December 2017 compared to the same period of 2016. Income tax expense in both periods is primarily attributable to the Company's 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 in the financial year ended 31 December 2017 was offset by a $1.3 million benefit from the reversal of valuation allowances on deferred tax assets attributable to 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

Loss from discontinued operations for financial years ended 31 December 2018, 2017 and 2016 were attributable to the discontinued operations in Angola. For financial year ended 31 December 2016 the Company reported loss from discontinued operations related to Angola 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.

5. Key operating highlights for six months ended 30 June 2019 and 30 June 2018

During the six months ended 30 June 2019 and 30 June 2018 production from the Etame PSC was approximately 2,399 MBBL (648 MBBL, net to VAALCO) and 2,398 MBBL (648 MBBL, net to VAALCO), respectively.

On 20 June 2019, the Board authorised and approved the Share Repurchase Programme for up to $10.0 million of the currently issued and outstanding Common Shares, over a period of 12 months. Under the Share Repurchase Programme, the Company intends to repurchase Common Shares through open market purchases, privately-negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the Exchange Act.

During Q2 2019, the ETAME-4H well produced an average of approximately 350 BOPD gross (95 BOPD, net to VAALCO); however, in July 2019, this well stopped producing. In September 2019, the ETAME-10H well, which had produced an average of approximately 735 BOPD gross (200 BOPD, net to VAALCO) during Q2 2019, stopped producing. VAALCO is currently undertaking a technical analysis of cost effective remedial work with a view to re-establishing production at each of ETAME-4H and ETAME-10H.

In July 2019, the Company performed an acid simulation job on the ETBNM-2H well. Subsequent to this work, the well would not flow naturally, and VAALCO was unable to restore production. VAALCO is currently planning on performing remedial work in Q4 2019 with a view to re-establishing production. During Q2 2019, this well produced an average of approximately 420 BOPD gross (113 BOPD, net to VAALCO).

In August 2019, VAALCO performed a planned maintenance turnaround for the FPSO Petroleo Nautipa, which included a nine-day full field shut down which will impact Q3 2019 production. This was taken into consideration in determining the full year guidance for 2019, which remains at between 3,300 BOPD net to VAALCO and 3,900 BOPD net to VAALCO. Taking into consideration the combination of the planned turnaround, as well as the impact of deferred production from the three wells that are not producing, VAALCO expects average production for Q3 2019 to be between 3,000 BOPD net to VAALCO and 3,300 BOPD net to VAALCO.

As part of the Work Programme, the Company has contracted a drilling rig to undertake the Base Case Work. The contract includes options to drill the Expansive Work and three further additional wells at the Etame Marin Block. The Company believes that there is significant reserve upside associated with the two appraisal wellbores being drilled as part of the Base Case Work.

The Company anticipates completing the Work Programme in H1 2020 and that the Work Programme will be funded by cash on hand and cash generated from operations. VAALCO estimates that the Base Case Work will cost approximately $61.2 million ($20.5 million, net to VAALCO) and that the Expansive Work will cost approximately $25.0 million – $30.0 million ($8.5 million – $10.0 million, net to VAALCO).

6. Highlights and selected financial information for six months ended 30 June 2019 and 30 June 2018

The following table sets forth, as of the dates and for the periods indicated, selected financial information. The financial information for each of the six months ended 30 June 2019 and 30 June 2018 has been derived from the Company's unaudited financial statements filed with the SEC in the quarterly report on Form 10-Q for each quarter.

	Six Months Ended 30 June	
	2019	***2018***
	(in thousands, except per Share amounts)	
Total revenues	$44,995	$52,071
Income (loss) from continuing operations	(41)	9,598
Basic income (loss) from continuing operation per Share attributable to Shareholders	0.00	0.16
Diluted income (loss) from continuing operations per Share attributable to Shareholders	0.00	0.16
Balance Sheet Data:		
Net property, plant and equipment	51,869	21,127
Total assets	202,067	100,276
Total long-term liabilities	39,259	21,600

7. Liquidity, financing and capital resources for six months ended 30 June 2019 and 30 June 2018

	Six Months Ended 30 June		
	2019	***2018***	***Increase (Decrease)***
	(in thousands)		
Net cash provided by operating activities before change in operating assets and liabilities	$14,106	$17,190	$(3,084)
Net change in operating assets and liabilities	2,566	14,358	(11,792)
Net cash provided by continuing operating activities	16,672	31,548	(14,876)
Net cash used in discontinued operating activities	(91)	(892)	801
Net cash provided by operating activities	16,581	30,656	(14,075)
Net cash used in continuing investing activities	(1,163)	(976)	(187)
Net cash used in discontinued investing activities	–	–	–
Net cash used in investing activities	(1,163)	(976)	(187)
Net cash used in continuing financing activities	(245)	(8,721)	8,476
Net cash used in discontinued financing activities	–	–	–
Net cash used in financing activities	(245)	(8,721)	8,476
Net change in cash, cash equivalents and restricted cash	$15,173	$20,959	$(5,786)

The decrease in net cash provided by the Company's operating activities for the six months ended 30 June 2019 compared to the same period of 2018 includes a $3.1 million decrease in cash generated by continuing operations before change in operating assets and liabilities, which was mainly due to lower revenue, and a decrease in the Company's operating assets and liabilities of $11.8 million. The net change in operating assets and liabilities of $2.6 million for the six months ended 30 June 2019 included a $3.2 million decrease in trade and other receivables, and an increase in "*Accrued liabilities and other*" of $3.9 million offset by a $2.8 million decrease in "*Foreign taxes payable*," and a $0.7 decrease in "*Accounts payable*" and an increase of $1.2 million in "*Prepayments and other*". The net change in operating assets and liabilities of $14.4 million for the six months ended 30 June 2018 included $13.2 million in payments made by joint venture owners partially offset by a pay down of "*Accounts payable*" and "*Accrued liabilities and other*" of $0.8 million.

Property and equipment expenditures have historically been the Company's most significant use of cash in investing activities. During the six months ended 30 June 2019, these expenditures on a cash basis were

$1.2 million, primarily related to equipment purchases. This compares to $1.0 million in property and equipment expenditures included in capital expenditures for the six months ended 30 June 2018.

Net cash used in financing activities during the six months ended 30 June 2018 included $9.2 million in principal payments on debt which was extinguished in May 2018.

Capital expenditures

During the six months ended 30 June 2019, the Company made accrual basis capital expenditures of $2.3 million. Pursuant to the Etame PSC Extension, the Company has commitments for capital expenditures related to the Base Case Work at an estimated cost of approximately $61.2 million ($20.5 million, net to VAALCO), by 16 September 2020. The Company estimates that the Expansive Work will cost $25.0 million — $30.0 million ($8.5 million — $10.0 million, net to VAALCO). The Company anticipates completing the Work Programme in H1 2020. The Expansive Work is subject to approval by the joint venture owners and the State of Gabon.

Capital resources

Credit facility

Historically, the Company's primary sources of capital have been cash flows from operating activities, borrowings under the Amended Term Loan Agreement with the IFC and cash balances on hand. On 22 May 2018, the Company terminated the Amended Term Loan Agreement by prepaying the outstanding principal and accrued interest. The Company did not incur any termination or prepayment penalties as a result of the early termination of the Amended Term Loan Agreement.

Cash on hand

At 30 June 2019, the Company had unrestricted cash of $48.6 million. The unrestricted cash balance includes $3.8 million of cash attributable to non-operating joint venture owner advances. As operator of the Etame Marin Block, the Company enters into project related activities on behalf of the Etame Consortium. The Company generally obtain cash advances from the joint venture owners prior to significant funding commitments. The Company's cash on hand will be utilised, along with cash generated from operations, to fund operations for the Working Capital Period.

The Company currently sells the crude oil production from Gabon under the Mercuria COSPA that began in February 2019 and ends in January 2020. Pricing under the contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Liquidity

The Company's revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. VAALCO's ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices.

The Company generally seeks to fund its capital programme through cash flows from operations and expects this to be the case for its capital programme through the medium term, including the Work Programme. The Company has commitments under the Etame PSC Extension for capital expenditures to undertake the Base Case Work, being the drilling of two development wells and two appraisal well bores by 16 September 2020, which the Company commenced on 13 September 2019. The Company estimates that the Base Case Work will cost approximately $61.2 million ($20.5 million, net to VAALCO). The Expansive Work, comprising of a third development well that will follow completion of the Base Case Work and is expected to be completed in H1 2020 and is estimated to cost approximately $25.0 million – $30.0 million ($8.5 million – $10.0 million, net to VAALCO), is subject to approval by the joint venture owners and the State of Gabon. Based on drilling results and other factors, the Company's drilling plans may change.

The Company's capital programme for 2019 – 2020 does not include the cost of any potential acquisitions or exploration activity with respect to Block P. In line with the Company's general policy, the Group expects to finance its 2019 – 2020 capital programme fully through cash on hand and cash flows from operations.

The Company expects any capital expenditures during the Working Capital Period to be funded by cash on hand and cash flow from operations. The Company believes that at current prices, cash generated from continuing operations, together with cash on hand at 30 June 2019, are adequate to support its operations and cash requirements during 2019 and through 30 September 2020.

At 31 December 2018, the Company had 5.4 MMBBL of estimated net proved reserves (increased to 5.6 MMBBL as at 31 March 2019), all of which are related to the Etame Marin Block. The current term for exploitation of the reserves in the Etame Marin Block ends in September 2028 with rights for two five-year extension periods. Except to the extent that the Company conducts successful exploration or development activities or acquire properties containing proved reserves, the Company's 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, the Company's long-term liquidity also depends upon the Company's ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable.

8. Results of operations for six months ended 30 June 2019 and 30 June 2018

The Company's results of operations for the six months ended 30 June 2019 and 30 June 2018 was as follows:

	Six Months Ended 30 June	
	2019	***2018***
	(in thousands, except per Share amounts)	
Revenues:		
Oil and natural gas sales	$44,995	$52,071
Operating costs and expenses:		
Production expense	18,038	23,777
Exploration expense	–	12
Depreciation, depletion and amortization	3,462	2,159
General and administrative expense	7,167	7,611
Bad debt (recovery) expense	(24)	89
Total operating costs and expenses	28,643	33,648
Other operating income (expense), net	(4,436)	338
Operating income	11,916	18,761
Other income (expense):		
Derivative instruments gain (loss), net	(1)	(1,010)
Interest income (expense), net	388	(384)
Other, net	(383)	(145)
Total other income (expense), net	4	(1,539)
Income from continuing operations before income taxes	11,920	17,222
Income tax expense	11,961	7,624
Income (loss) from continuing operations	(41)	9,598
Income (loss) from discontinued operations, net of tax	5,509	(395)
Net income (loss)	$5,468	$9,203
Basic net income (loss) per Share:		
Income (loss) from continuing operations	$0.00	$0.16
Income (loss) from discontinued operations, net of tax	0.09	(0.01)
Net income (loss) per Share	$0.09	$0.15
Basic weighted average Shares outstanding	59,716	58,977
Diluted net income (loss) per Share:		
Income (loss) from continuing operations	$0.00	$0.16
Income (loss) from discontinued operations, net of tax	0.09	(0.01)
Net income (loss) per Share	$0.09	$0.15
Diluted weighted average Shares outstanding	59,716	59,358

The Company reported net income for the six months ended 30 June 2019 of $5.5 million compared to net income of $9.2 million for the same period of 2018. The net income for the six months ended 30 June 2019 is inclusive of the income from discontinued operations for the same period of $5.5 million. The net income for the six months ended 30 June 2018 was inclusive of the loss from discontinued operations for the same period of $0.4 million. Substantially all of the Company's operations are attributable to the Company's interest in Etame.

The table below shows net production, sales volumes and realised prices for the six months ended 30 June 2019 and 30 June 2018.

	Six Months Ended 30 June	
	2019	2018
	(in thousands, except prices)	
Gabon net oil production (MBBL)	648	648
International net oil sales (MBBL)	654	712
Average realised oil price ($/BBL)	$66.60	$71.23
Average Dated Brent spot* ($/BBL)	$66.07	$70.67

Note

*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 Petroleo Nautipa, and thus, crude oil sales do not always coincide with volumes produced in any given quarter. The Company made seven liftings during both of the six month periods ended 30 June 2019 and 30 June 2018. The Company's share of oil inventory aboard the FPSO Petroleo Nautipa, excluding royalty barrels, was approximately 21,526 and 52,900 barrels at 30 June 2019 and 30 June 2018, respectively. Production volumes for the six months ended 30 June 2019 were consistent with the comparable 2018 period. Sales volumes were lower between the periods because sales volumes for the six months ended 30 June 2018 included 95,525 barrels associated with the last lifting in 2017 which was not completed until 1 January 2018. Net revenues of $6.5 million associated with these net volumes were reported as revenue in the six months ended 30 June 2018.

The revenue changes between the six months ended 30 June 2019 and 30 June 2018 identified as related to changes in price or volume are shown in the table below.

	(in thousands)
Price	$(3,029)
Volume	(4,131)
Other	84
	$(7,076)

Oil and natural gas revenues

Oil and natural gas revenues decreased $7.1 million during the six months ended 30 June 2019 compared to the six months ended 30 June 2018. The decrease in revenue was attributable to lower sales volumes and to a lesser extent lower prices.

Production expenses

Production expenses decreased $5.7 million in the six months ended 30 June 2019 compared to the same period of 2018. The Company recorded $0.1 million in workover costs in 2019 compared to $4.8 million in workover costs during the comparable period. The lower workover costs were offset by higher transportation ($0.6 million), FPSO ($0.2 million), customs and other costs ($0.3 million) during 2019 compared to 2018.

Depreciation, depletion and amortization costs

Depreciation, depletion and amortization costs increased $1.3 million due to higher depletable costs associated with the PSC Extension for the six months ended 30 June 2019 and 30 June 2018.

General and administrative expenses

General and administrative expenses decreased $0.4 million in the six months ended 30 June 2019 compared to the same period of 2018. The decrease in expense was related to a $1.2 million decrease in SARs expense. SAR liability awards are fair valued. The primary driver to changes in the fair value of these awards is changes in the price of Common Shares. The decrease in SARs expense was offset by higher professional fees ($0.3 million), accounting and audit fees ($0.2 million), personnel related costs ($0.2 million) and other costs ($0.1 million) during the six months ended 30 June 2019 compared to the same period in 2018.

Bad debt (recovery) expense

Bad debt (recovery) expense for the six months ended 30 June 2019 reflected recoveries from payments associated to the VAT receivable. For the six months ended 30 June 2018, the Company recorded a bad debt expense of $0.1 million.

Other operating income (expense), net

Other operating income (expenses), net for the six months ended 30 June 2019 is related to the Etame Audit Agreement which the Company entered into in September 2019 to resolve a legacy issue related to findings from Etame joint ventures owners' audits for the periods from 2007 through 2016 for $4.4 million net to VAALCO. During the six months ended 30 June 2018, the Company recorded a reduction in inventory obsolescence.

Interest income (expense), net

Interest income (expense), net for the six months ended 30 June 2019 relates to interest income on cash balances as compared to 30 June 2018 which relates to interest expense on the Amended Term Loan Agreement with the IFC and interest expense on taxes other than income taxes.

Derivative instruments gain (loss), net

Derivative instruments gain (loss), net for the six months ended 30 June 2019 is attributable to the Company's swaps and is a result of an increase in the price of Dated Brent crude oil during each of the six months ended 30 June 2019 and 30 June 2018.

Other, net

Other, net for the six months ended 30 June 2019 and 30 June 2018 consisted primarily of foreign currency losses.

Income tax expense

Income tax expense for the six months ended 30 June 2019 was $12.0 million. This is comprised of $7.7 million of deferred tax expense and a current tax provision of $4.3 million and was impacted by the above referenced $4.4 million related to the Etame Audit Agreement. Income from continuing operations, excluding the $4.4 million, was $16.3 million. At an effective tax rate of 79 percent (which was impacted by items associated with operations and foreign taxes for which no U.S. tax benefit was recognised), income taxes would have been $12.9 million. The $12.9 million of income tax expense is reduced by the tax benefit of the $4.4 million expense (taxed at the U.S. income tax rate of 21 percent) or $0.9 million; thus, the expected tax is $12.0 million and consistent with the actual income tax expense recorded of $12.0 million.

For the six months ended 30 June 2018, the Company had a current provision of $7.6 million and no amounts related to the deferred provision. The decrease in the current provision is primarily attributable to Gabon income taxes which were impacted by the decline in revenues between periods as well as an increase in the Cost Recovery percentage from 70 percent to 80 percent under the Etame PSC Extension. With respect to deferred income tax, for periods prior to the three months ended 30 September 2018, the Company had full valuation allowances on its net deferred tax assets, and deferred income tax was zero.

Gain (loss) from discontinued operations

Gain (loss) from discontinued operations for the six months ended 30 June 2019 and 30 June 2018 are attributable to the Angola operations. The gain from discontinued operations for the six months ended 30 June 2019 is primarily related to recording a $5.7 million after tax gain on the finalised Block 5 Settlement Agreement. The loss from discontinued operations for the six months ended 30 June was related to Angola administration costs.

9. Business combination

On 22 November 2016, the Company completed the acquisition of an additional 2.98 percent working interest (3.23 percent participating interest) in the Etame Marin Block from Sojitz, which represented all of the interest owned by Sojitz in the concession. The acquisition had an effective date of 1 August 2016 and was funded with cash on hand.

The actual impact of the Sojitz acquisition was an increase to "*Total revenues*" in the consolidated statement of operations of $0.2 million for financial year ended 31 December 2016 and a minimal decrease to "*Net loss*" in the consolidated statement of operations for financial year ended 31 December 2016.

PART 14 – CREST AND DEPOSITARY INTERESTS

1. The Company has established arrangements to enable investors to settle interests in the Common Shares through the CREST system. CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another without the need to use share certificates or written instruments of transfer. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, Depositary Interests allow such securities to be dematerialised and settled electronically through CREST. Where investors choose to settle interests in the Common Shares through the CREST system, and pursuant to depositary arrangements established by the Company, the Custodian will hold the Common Shares and issue dematerialised Depositary Interests representing the underlying Common Shares, which will be held on trust for the holders of the Depositary Interests. The Depositary Interests will be independent securities constituted under English law which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interests which will be admitted to and settled through CREST and not the Common Shares.

2. The Bylaws are consistent with CREST membership in respect of Depositary Interests and the holding and transfer of Depositary Interests in uncertified form. Under the DGCL, companies are not prohibited from issuing shares in book-entry form, but shareholders have the right to require the companies to issue physical certificates. The Board has passed a resolution authorising the issuance of Shares in book-entry form.

3. The Company and the Depositary entered into a depositary agreement on 10 September 2019, the principal terms of which are summarised below.

4. The Depositary Interests have been created pursuant to and issued on the terms of a deed poll that was executed on 9 September 2019 by the Depositary in favour of the holders of the Depositary Interests from time to time. Holders of Depositary Interests should note that they will have no rights against Euroclear UK & Ireland (the operators of CREST) or its subsidiaries in respect of the underlying Common Shares or the Depositary Interests representing them.

5. If a holder of Common Shares so requests, its Common Shares will be transferred to an account of the Depositary or the Custodian maintained on the Company's share register via Cede & Co, a nominee of DTC, in accordance with the applicable DTC rules, and the Depositary will issue Depositary Interests to participating CREST members.

6. Each Depositary Interest will be treated as one Common Share for the purposes of determining, for example, eligibility for any dividends. The Depositary will pass on to holders of Depositary Interests any share or cash benefits received by it as holder of Common Shares on trust for such Depositary Interest holder. Depositary Interest holders, through the Depositary, will also be able to receive notices of meetings of holders of Common Shares and other notices issued by the Company to its Shareholders.

7. The Depositary Interests have the same security code (ISIN) as the underlying Common Shares and will not require a separate admission to the Main Market. The Depositary Interests can then be traded and settled within the CREST system in the same way as any other CREST securities. Application will be made for the Depositary Interests to be admitted to CREST with effect from Admission.

8. If a holder wishes to cancel its Depositary Interest, it will either directly or through its broker instruct the applicable CREST participant to initiate a CREST withdrawal (where such withdrawal is sent to the Depositary) for the name that appears on the Register. The Depositary Interest will then be cancelled by the Depositary and the related Common Shares will be credited to the account on the Register by the Registrar. The Registrar will then send the holder a new Common Share certificate.

9. The information included within this section relating to the obtaining and cancellation of Depositary Interests by a holder is intended to be a summary only and is not to be construed as legal, business or tax advice. Each investor should consult his or her own lawyer, financial adviser, broker or tax adviser for legal, financial or tax advice in relation to Depositary Interests.

Deed Poll

The Deed Poll executed by the Depositary prior to Admission contains the following provisions:

10. The Depositary will hold (itself or through the Custodian), as bare trustee, the underlying Common Shares in its DTC account (which will be maintained on the Company's share register via Cede & Co, a nominee of DTC) and all and any rights and other securities, property and cash attributable to the underlying Common Shares pertaining to the Depositary Interests for the benefit of the holders of the relevant Depositary Interests as tenants in common. The Depositary will re-allocate securities or Depositary Interests distributions allocated to the Depositary or Custodian *pro rata* to the Common Shares held for the respective accounts of the holders of Depositary Interests, but will not be required to account for fractional entitlements arising from such re-allocation.

11. Holders of Depositary Interests agree to give such warranties and certifications to the Depositary as the Depositary may reasonably require. In particular, holders of Depositary Interests warrant, among other things, that the securities in the Company transferred or issued to the Depositary or Custodian on behalf of the Depositary for the account of the Depositary Interest holder are free and clear of all liens, charges, encumbrances or third party interests and that such transfers or issues are not in contravention of the Company's constitutional documents or any contractual obligation, or applicable law or regulation binding or affecting such holder, and holders of Depositary Interests agree to indemnify the Depositary against any liability incurred as a result of any breach of such warranty.

12. The Depositary and any Custodian shall pass on to the Depositary Interest holders and, so far as they are reasonably able, exercise on behalf of the Depositary Interest holders all rights and entitlements received or to which they are entitled in respect of the underlying Common Shares which are capable of being passed on or exercised. Rights and entitlements to cash distributions, to information, to make choices and elections and to call for, attend and vote at meetings shall, subject to the Deed Poll, be passed on in the form in which they are received, together with amendments and additional documentation necessary to effect such passing-on, or, as the case may be, exercised in accordance with the Deed Poll. If arrangements are made which allow a holder to take up rights in the Company's securities requiring further payment, the holder must put the Depositary in cleared funds before the relevant payment date or other date notified by the Depositary if it wishes the Depositary to exercise such rights.

13. The Depositary will be entitled to cancel Depositary Interests and treat the holders thereof as having requested a withdrawal of the underlying securities in certain circumstances, including where a Depositary Interest holder fails to furnish to the Depositary with such certificates or representations as to material matters of fact, including his identity, as the Depositary deems appropriate.

14. The Depositary warrants that it is an authorised person under the FSMA and is duly authorised to carry out custodian and other activities under the Deed Poll. It also undertakes to maintain that status and authorisation.

15. The Deed Poll contains provisions excluding and limiting the Depositary's liability. For example, the Depositary shall not be liable to any Depositary Interest holder or any other person for liabilities in connection with the performance or non-performance of obligations under the Deed Poll or otherwise except as may result from its negligence or wilful default or fraud or that of any person for whom it is vicariously liable, provided that the Depositary shall not be liable for the negligence, wilful default or fraud of any Custodian or agent which is not a member of its group unless it has failed to exercise reasonable care in the appointment and continued use and supervision of such Custodian or agent. Except in the case of personal injury or death, any liability incurred by the Depositary to a holder under the Deed Poll is limited to the lesser of:

    (a) the value of the Common Shares that would have been properly attributable to the Depositary Interests to which the liability relates; and

    (b) that proportion of £5 million which corresponds to the portion which the amount the Depositary would otherwise be liable to pay to the holder bears to the aggregate of the amounts the Depositary would otherwise be liable to pay to all such holders in respect of the same act, omission or event which gave rise to such liability or, if there are no such amounts, £5 million.

16. The Depositary is entitled to charge holders of Depositary Interests fees and expenses for the provision of its services under the Deed Poll.

17. Each holder of Depositary Interests is liable to indemnify the Depositary and any Custodian (and their agents, officers and employees), and hold each of them harmless, from and against all liabilities arising from or incurred in connection with, or arising from any act related to, the Deed Poll so far as they relate to the property held for the account of that holder, other than those caused by or resulting from the wilful default, negligence or fraud of: (i) the Depositary; or (ii) the Custodian or any agent if such Custodian or agent is a member of the Depositary's group or if, not being a member of the same group, the Depositary shall have failed to exercise reasonable care in the appointment and continued use of such Custodian or agent.

18. The Depositary is entitled to make deductions from the deposited property or any income or capital arising therefrom, or to sell such deposited property and make deductions from the sale proceeds thereof, in order to discharge the indemnification obligations of Depositary Interest holders.

19. The Depositary may terminate the Deed Poll by giving not less than 30 days' notice. During such notice period, Depositary Interest holders may cancel their Depositary Interests and withdraw their deposited property and, if any Depositary Interests remain outstanding after termination, the Depositary shall, as soon as reasonably practicable and amongst other things: (i) deliver the deposited property in respect of the Depositary Interests to the relevant Depositary Interest holder; or at the Depositary's discretion; (ii) sell all or part of such deposited property. It shall, as soon as reasonably practicable, deliver the net proceeds of any such sale, after deducting any sums due to the Depositary, together with any other cash held by it under the Deed Poll, *pro rata* to the Depositary Interest holders in respect of their Depositary Interests.

20. The Depositary or the Company may require from any holder: (i) information as to the capacity in which Depositary Interests are owned or held by such holders and the identity of any other person with any interest of any kind in such Depositary Interests or the underlying Common Shares and the nature and amounts of such interests; (ii) evidence or declaration of nationality or residence of the legal or beneficial owner(s) of Depositary Interests and such information as is required to transfer the relevant Depositary Interests or Common Shares to the holder; and (iii) such information as is necessary or desirable for the purposes of the Deed Poll or CREST system, and holders are bound to provide such information requested. The holders of Depositary Interests consent to the disclosure of such information by the Depositary, Custodian or Company to the extent necessary or desirable to comply with their respective legal or regulatory obligations.

21. Furthermore, to the extent that the Company's constitutional documents, applicable laws or regulations, the Ground Rules for the Management of the FTSE UK Index Series (if applicable), or any court or legal or regulatory authority may require or the Company deems it necessary or desirable in connection therewith (including in response to requests for information), the disclosure to the Company of, or limitations in relation to, beneficial or other ownership of, or interests of any kind whatsoever in the Company's securities, the Depositary Interest holders are to comply with such provisions and with the Company's instructions with respect thereto, and consent to the disclosure of such information for such purposes.

22. It should also be noted that holders of Depositary Interests may not have the opportunity to exercise all of the rights and entitlements available to holders of Common Shares, including, for example, the ability to vote on a show of hands. In relation to voting, it will be important for holders of Depositary Interests to give prompt instructions to the Registrar or its nominated Custodian, in accordance with any voting arrangements made available to them, to vote the underlying Common Shares on their behalf or, to the extent possible, to take advantage of any arrangements enabling holders of Depositary Interests to vote such Common Shares as a proxy of the Registrar or its nominated Custodian.

Depositary Agreement

The Depositary Agreement entered into between the Company and the Depositary prior to Admission contains the following provisions:

23. Under the Depositary Agreement, the Company appoints the Depositary to constitute and issue from time to time, upon the terms of the Deed Poll, a series of Depositary Interests representing Common

Shares and to provide certain other services (including depositary services, custody services and dividend services) in connection with such Depositary Interests.

24. The Depositary agrees that it will comply with the terms of the Deed Poll and that it will perform its obligations with reasonable skill and care. The Depositary assumes certain specific obligations, including, for example, to arrange for the Depositary Interests to be admitted to CREST as participating securities and provide copies of, and access to, the register of Depositary Interests.

25. The Company acknowledges that it shall be its responsibility and undertakes to advise the Depositary promptly of any securities laws or other applicable laws, rules or regulations in the State of Delaware, USA with which the Depositary must comply in providing the services.

26. The Company agrees to provide such assistance, information and documentation to the Depositary as is reasonably required by the Depositary for the purposes of performing its duties, responsibilities and obligations under the Depositary Agreement.

27. The Depositary is to indemnify the Company and its officers and employees from and against any loss (excluding indirect, consequential or special loss) which any of them may incur in any way as a result of or in connection with the fraud, negligence or wilful default of the Depositary (or its officers, employees, agents or sub-contractors).

28. Subject to earlier termination, the appointment of the Depositary shall continue for a fixed period of one year and thereafter until terminated in accordance with the terms of the Depositary Agreement. Should the Depositary Agreement be terminated for any reason, other than arising from the Depositary's fraud, negligence, wilful default or material breach of a term of the Depositary Agreement, the Company shall within 30 days of termination pay to the Depositary the Depositary's reasonable costs and expenses of transferring the Depositary Interest register to its new registrar. Either party may terminate the Depositary Agreement by giving not less than three months' notice in writing. Either party may terminate the Depositary Agreement with immediate effect by notice in writing if the other party: (i) shall be in persistent or material breach of any material term (of the Depositary Agreement) and such breach is not remedied within 21 days of a request for such remedy; (ii) goes into insolvency or liquidation or administration or a receiver is appointed over any part of its undertaking or assets, subject to certain provisos; or (iii) shall cease to have the appropriate authorisations which permit it lawfully to perform its obligations under the Depositary Agreement.

29. The Depositary will be entitled to employ agents for the purposes of carrying out certain of its obligations under the Depositary Agreement which the Depositary reasonably considers to be of a specialist nature.

30. The Company is to pay to the Depositary an annual fee for the services. The Company shall pay a fixed fee for the deposit, cancellation and transfer of the Depositary Interests and the compilation of the initial Depositary Interests register. The Company shall in addition reimburse the Depositary within 30 days of the Depositary's invoice for all network charges, CREST charges, money transmission and banking charges and other out-of-pocket expenses incurred by it in connection with the provision of the services under the Depositary Agreement.

31. The Company will indemnify the Depositary from and against all loss suffered by the Depositary as a result of or in connection with the performance of its obligations under the Depositary Agreement.

32. The aggregate liability of the Depositary to the Company over any 12-month period under the Depositary Agreement will not exceed twice the amount of the Fees (as defined in the Depositary Agreement) payable in any 12-month period in respect of a single claim or in the aggregate.

PART 15 – CAPITALISATION AND INDEBTEDNESS

The tables below set out the Group's unaudited capitalisation and indebtedness as at 30 June 2019 and its unaudited net current financial indebtedness and noncurrent financial indebtedness as at 30 June 2019. The capitalisation and indebtedness figures as at 30 June 2019 have been extracted without material adjustment from the Historical Financial Information set out in the Appendix to this Prospectus.

CAPITALISATION AND INDEBTEDNESS

The table below sets out the Company's total capitalisation and indebtedness as at 30 June 2019.

	30 June 2019 (in thousands)
Total current debt	
Guaranteed	$–
Secured	–
Unguaranteed/Unsecured	–
Total current debt	–
Total noncurrent debt (excluding current portion of long-term debt)	
Guaranteed	–
Secured	–
Unguaranteed/Unsecured	–
Total noncurrent debt	–
Total debt	$–

	30 June 2019 (in thousands)
Shareholders' Equity	
Share capital	$6,745
Share premium	73,059
Other reserves	(37,870)
Total Shareholders' equity	$41,934

There has been no significant change in the Company's total capitalisation and indebtedness since 30 June 2019 to the date of this Prospectus.

NET FINANCIAL INDEBTEDNESS

The table below sets out the Company's total net current financial indebtedness and noncurrent financial indebtedness as at 30 June 2019.

		30 June 2019 (in thousands)
A.	Cash	$48,557
B.	Cash equivalent	–
C.	Trading securities	–
D.	**Liquidity (A) + (B) + (C)**	48,557
E.	Current financial receivable	15,197
F.	Current bank debt	–
G.	Current portion of noncurrent debt	–
H.	Other current financial debt	–
I.	**Current financial debt (F) + (G) + (H)**	–
J.	**Net current financial indebtedness (D) + (E) – (I)**	63,754
K.	Noncurrent bank loans	–
L.	Bonds Issued	–
M.	Other noncurrent loans	–
N.	Noncurrent financial debt (K) + (L) + (M)	–
O.	**Net financial indebtedness** (J) + (N)	$63,754

There has been no significant change in the Company's total net current financial indebtedness since 30 June 2019 to the date of this Prospectus.

PART 16 – TAXATION

The information set out below describes the principal UK and U.S. tax consequences of the acquisition, holding and disposal of the Common Shares and is included for general information only. It is not intended to be, nor should it be construed to be, legal or tax advice to any prospective investors. This section does not take into account the individual circumstances of any prospective investors and should not be relied upon by any prospective investor or any other person. Each prospective investor should obtain, and only rely upon, their own professional tax advice regarding the tax consequences of acquiring, holding and disposing of the Common Shares under the laws of their country and/or state of citizenship, domicile or residence. This summary is based on tax legislation in force as at the Last Practical Date, without prejudice to any amendments introduced at a later date and implemented with retroactive effect.

1. UK taxation

The following statements are intended only as a general guide to current UK tax legislation and to the current practice of HMRC and may not apply to certain Shareholders, such as dealers in securities, insurance companies and collective investment schemes. They relate (except where stated otherwise) to persons who are resident, and in the case of individuals, domiciled in (and only in) the UK for UK tax purposes, who are beneficial owners of Common Shares (and any dividends paid on them) and who hold their Common Shares as an investment (and not as employment-related securities and other than via an individual savings account). They are based on current UK legislation and what is understood to be the current practice of HMRC as at the Last Practical Date, both of which may change, possibly with retroactive effect. The tax position of certain categories of Shareholders who are subject to special rules (such as persons acquiring their Common Shares in connection with employment, dealers in securities, insurance companies and collective investment schemes or those who hold 10 percent or more of the Common Shares or those who are non-UK domiciled individuals) is not considered.

Any person who is in any doubt as to his or her tax position, or who is subject to taxation in any jurisdiction other than that of the UK, should consult his or her own professional advisers immediately.

1.1 *Taxation of dividends – individual Shareholders*

UK resident individual Shareholders will be liable to income tax in respect of dividends or other income distributions of the Company. A UK resident individual Shareholder will generally benefit from an allowance in the form of an exemption from tax for the first £2,000 of dividend income received in the 2018/19 tax year ("**Dividend Allowance**"). Any dividends above the Dividend Allowance will be taxable at 7.5 percent (to the extent it falls within an individual's basic rate band), 32.5 percent (to the extent it falls within an individual's higher rate band) or 38.1 percent (to the extent it falls within an individual's additional rate band) for the 2018-19 tax year.

1.2 *Taxation of dividends – corporate Shareholders*

Dividends paid to a UK resident corporate Shareholder will be taxable income of the UK corporate Shareholder unless the dividends fall within an exempt class and certain other conditions are met. It is likely that most dividends paid to UK resident corporate Shareholders would fall within one or more of the classes of dividend qualifying for exemption from corporation tax. However, it should be noted that the exemptions are not comprehensive and are also subject to anti-avoidance rules.

To the extent that dividends are not exempt, UK resident corporate Shareholders may be able to obtain credit for any withholding tax and any underlying tax paid by the Company, subject to certain conditions. The UK has complex double tax relief where UK resident companies receive dividends from non-UK resident companies and therefore UK resident corporate Shareholders should seek further advice on these issues.

1.3 *Taxation of dividends – trustees*

The annual dividend allowance available to individuals will not be available to UK resident trustees of a discretionary trust. Generally, dividends received by UK resident trustees of a discretionary trust are liable to income tax at a rate of 38.1 percent (save the first £1,000 of trust income which may attract a lower rate of 7.5 percent). The £1,000 dividend allowance for trustees must divided by the total number of trusts which the settlor has settled. However, if the settlor has set up five or more trusts, the standard rate band for each trust is £200.

1.4 *Taxation of dividends – UK pension funds and charities*

UK pension funds and charities are generally exempt from tax on dividends, which they receive.

Other Shareholders who are not resident in the UK for tax purposes should consult their own advisers concerning their tax liabilities on dividends received.

1.5 *Chargeable gains*

Shareholders who are resident in the UK for tax purposes and who dispose of their Common Shares at a gain will ordinarily be liable to UK taxation on chargeable gains, subject to any available exemptions or reliefs. The gain will be calculated as the difference between the sale proceeds and any allowable costs and expenses, including the original acquisition cost of the Common Shares.

Shareholders who are not resident in the UK for tax purposes but who carry on business in the UK through a branch, agency or permanent establishment with which their investment in the Company is connected may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains.

If an individual Shareholder ceases to be resident in the UK and subsequently disposes of Common Shares, in certain circumstances any gain on that disposal may be liable to UK capital gains tax upon that Shareholder becoming once again resident in the UK.

For UK resident individual Shareholders, capital gains tax at the rate of 10 percent (for basic rate taxpayers) or 20 percent (for higher or additional rate tax payers) will be payable on any gain. UK resident individual Shareholders may benefit from certain reliefs and allowances (including a personal annual exemption allowance, which for 2018-19 tax year exempts the first £11,850 of gains from tax) depending on their circumstances.

For UK resident corporate Shareholders any chargeable gain will be within the charge to corporation tax. UK corporate Shareholders can benefit from indexation allowance up to 31 December 2017 (which, in general terms, increases the chargeable gains tax base cost of an asset in accordance with the rise in the retail prices index up to 31 December 2017), but indexation allowance for corporate Shareholders no longer applies post 31 December 2017. Accordingly, any new (post 31 December 2017) UK tax resident corporate Shareholder holding any rolled over tax base cost pre 31 December 2017 may claim indexation allowance on a subsequent disposal on the Common Shares, but such indexation allowance will only be up to 31 December 2017.

1.6 *Stamp duty and stamp duty reserve tax ("SDRT")*

The statements below are intended as a general guide to the current position under UK tax law. They do not apply to certain intermediaries who may be eligible for relief from stamp duty or SDRT, or to persons connected with depositary arrangements or clearance services (or, in either case, their nominees or agents), who may be liable to stamp duty or SDRT at a higher rate.

1.7 *Treatment of the transfer of Common Shares into CREST and the trading of Depositary Interests within CREST*

Admission of the Common Shares to the standard segment of the Official List should not give rise to a liability to stamp duty or SDRT on the basis that the Admission does not involve a change in title or beneficial ownership in the Common Shares for consideration.

Where there is a transfer of Common Shares into CREST (where Depositary Interests are issued) there should be no SDRT or stamp duty provided that there is no change in beneficial ownership of the Common Shares.

Where there is a transfer of Common Shares into CREST (where Depositary Interests are issued) and there is a change in beneficial ownership of the Common Shares, no charge to SDRT should arise on the basis that:

(a) the central management and control of the Company currently takes place, and will continue to take place outside the UK;

(b) the register of members of the Company is, and will be, maintained outside the UK; and

(c) the underlying Common Shares are, and will continue to be, listed on a recognised stock exchange (such as the NYSE).

Assuming that no document of transfer is executed for such a transfer there should be no stamp duty either.

Where Depositary Interests are traded (wholly within CREST), no charge to SDRT should arise on the basis that:

(a) the central management and control of the Company currently takes place and will continue to take place outside the UK;

(b) the register of members of the Company is, and will be, maintained outside the UK; and

(c) the underlying Common Shares are, and will continue to be, listed on a recognised stock exchange (such as the NYSE).

Since any transfer of the Depositary Interests will be wholly within CREST, and no documents of transfer will be executed, no charge to stamp duty should arise on the transfer of Depositary Interests (wholly within CREST).

1.8 *Treatment of the transfer of Common Shares out of CREST and trading of the underlying Common Shares*

Where there is a transfer of Common Shares out of CREST (which may involve a collapse of the Depositary Interests) and there is a change in beneficial ownership of the Common Shares, no charge to SDRT should arise, provided that:

(a) the register of members of the Company continues to be maintained outside the UK; and

(b) the Common Shares are not paired with shares or marketable securities in UK-incorporated companies.

Provided that the register of members of the Company continues to be maintained outside the UK, and the Common Shares are not paired with shares or marketable securities in UK incorporated companies, there should be no SDRT on any agreement to transfer the Common Shares themselves.

However, any document transferring title to the Common Shares will be technically within the scope of UK stamp duty (at the rate of 0.5 percent, rounded to the nearest £5) if it is executed in the UK or relates (wheresoever executed) to any matter or thing done or to be done in the UK. Where stamp duty arises, this is generally payable by the purchaser.

Stamp duty is not a directly enforceable tax. As such, any stamp duty which may arise should not generally be required to be paid in respect of transfers of Common Shares, unless the document of transfer is required to be relied upon as evidence in a UK court or for other official purpose in the UK. However, where the stamp duty is paid late, interest and penalties may arise.

1.9 *Inheritance tax*

If any individual Shareholder is regarded as domiciled in the UK for inheritance tax purposes, inheritance tax may be payable in respect of the Common Shares on the death of the Shareholder or on certain gifts of the Common Shares during their lifetime, subject to any allowances, exemptions or reliefs.

Non-UK domiciled individual Shareholders may be regarded as deemed domiciled for inheritance tax purposes following a long period of residence in the UK. Further advice should be sought in these circumstances.

Individual Shareholders who are in any doubt about the impact of this change on their tax position should obtain detailed tax advice from their own professional advisers.

UK inheritance tax is a complex area and individuals should obtain their own advice in respect of this.

2. U.S. taxation

The following is a summary of the material U.S. federal income and estate tax consequences to non-U.S. holders (as defined below) of their ownership and disposition of the Common Shares, but does not purport to be a complete analysis of all the potential U.S. tax considerations relating thereto. This summary is based upon the provisions of the Code, Treasury regulations promulgated thereunder, administrative rulings and judicial decisions, all as of the date hereof. These authorities may be changed, possibly retroactively, so as to result in U.S. federal income and estate tax consequences different from those set forth below. The Company has not obtained, and does not intend to obtain, any opinion of counsel or ruling from the IRS with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions.

Moreover, this discussion does not address all of the tax considerations that may be relevant to non-U.S. Holders in light of their particular circumstances, nor does it discuss special tax provisions, which may apply to holders subject to special treatment under U.S. federal income tax laws, such as certain financial institutions or financial services entities, insurance companies, tax-exempt entities, dealers in securities, entities or arrangements that are treated as partnerships for U.S. federal income tax purposes, "controlled foreign corporations," "passive foreign investment companies," former U.S. citizens or long-term residents, persons owning, directly, indirectly or constructively, 5 percent of the Company's equity by vote or value and persons that hold the Common Shares as part of a straddle, conversion transaction, or other integrated investment. Furthermore, this discussion does not address any tax considerations arising under the Medicare contribution tax or the alternative minimum tax, nor does it address any tax considerations arising under the laws of any state, local or foreign jurisdiction, or under any U.S. federal laws other than those pertaining to income or estate taxes.

2.1 *Non-U.S. holder definition*

For purposes of this discussion, a Non-U.S. holder is a Shareholder other than:

(a) a partnership or other entity or arrangement classified as a partnership for U.S. federal income tax purposes; or

(b) an individual citizen or resident of the United States (for tax purposes); or

(c) a corporation or other entity taxable as a corporation created or organised in the United States or under the laws of the U.S. or any political subdivision thereof; or

(d) an estate the income of which is subject to U.S. federal income taxation regardless of its source; or

(e) a trust: (i) whose administration is subject to the primary supervision of a U.S. court and which has one or more U.S. persons (within the meaning of section 7701(a) (3) of the Code) who have the authority to control all substantial decisions of the trust; or (ii) which has made a valid election to be treated as a U.S. person.

If a partnership holds Common Shares, the tax treatment of a partner generally will depend on the status of the partner and upon the activities of the partnership. Accordingly, partnerships that hold Common Shares, and partners in such partnerships, should consult their tax advisers.

2.2 *Taxation of dividends*

The Company does not anticipate paying any cash dividends or other distributions on its Common Shares in the foreseeable future. However, if the Company does make distributions on the Common Shares, those payments will constitute dividends for U.S. tax purposes to the extent paid from the Company's current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those distributions exceed both the Company's current and the Company's accumulated earnings and profits, the excess will constitute a return of capital and will first reduce a holder's basis in their Common Shares, but not below zero, and then will be treated as a gain from the sale of Shares as described below.

Subject to the discussions below on effectively connected income and the Foreign Account Tax Compliance Act ("**FATCA**"), any dividend paid to a Non-U.S. holder generally will be subject to U.S. withholding tax either at a rate of 30 percent of the gross amount of the dividend or such lower rate as may be specified by an applicable income tax treaty. Under the U.S.-UK income tax treaty, subject to certain conditions applying, the maximum withholding tax rate is 15 percent.

In order to receive a reduced treaty rate, a Non-U.S. holder must provide the Company with an IRS Form W-8BEN, IRS Form W-8BEN-E or other appropriate version of IRS Form W-8 (or successor form), which may require a U.S. taxpayer identification number, certifying qualification for the reduced rate. A Non-U.S. holder of Common Shares eligible for a reduced rate of U.S. withholding tax pursuant to an income tax treaty may obtain a refund of any excess amounts withheld by filing an appropriate claim for refund with the IRS.

Dividends received by a Non-U.S. holder that are effectively connected with a Non-U.S. holder's conduct of a U.S. trade or business (and, if required by an applicable income tax treaty, that are attributable to a permanent establishment or a fixed base maintained by a Non-U.S. holder in the United States), are exempt from such withholding tax if the Non-U.S. holder satisfies certain certification and disclosure requirements. In order to obtain this exemption, a Non-U.S. holder must provide the Company with an IRS Form W-8ECI (or successor form) or other applicable IRS Form W-8 (or successor form) properly certifying such exemption. Such effectively connected dividends, although not subject to withholding tax, generally are taxed at the same graduated U.S. federal income tax rates applicable to U.S. persons, net of certain deductions and credits. In addition, if a Non-U.S. holder is a corporate Non-U.S. holder, dividends they receive that are effectively connected with the Non-U.S. holder's conduct of a U.S. trade or business may also be subject to a branch profits tax at a rate of 30 percent or such lower rate as may be specified by an applicable income tax treaty. Each Non-U.S. holder should consult their own tax advisor regarding any applicable tax treaties that may provide for different rules.

2.3 *Taxation of capital gains*

Subject to the discussion below regarding backup withholding and foreign accounts, a Non-U.S. holder generally will not be required to pay U.S. federal income tax on any gain realised upon the sale, exchange or other disposition of Common Shares unless:

(a) the gain is effectively connected with the Non-U.S. holder's conduct of a U.S. trade or business (and, if required by an applicable income tax treaty, the gain is attributable to a permanent establishment or a fixed base maintained by the Non-U.S. holder in the United States); or

(b) the Non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met; or

(c) the Common Shares constitute a U.S. real property interest by reason of the Company's status as a "United States real property holding corporation", or USRPHC, for U.S. federal income tax purposes at any time within the shorter of the five-year period preceding the Non-U.S. holder's disposition of, or the Non-U.S. holder's holding period for, the Company's Common Shares.

The Company believes that it is not currently, was not in the past five years and will not become a USRPHC and the remainder of this discussion so assumes.

If a Non-U.S. holder is described in (a) above, the Non-U.S. holder will be required to pay tax on the net gain derived from the sale under regular graduated U.S. federal income tax rates, and a corporate Non-U.S. holder described in (a) above also may be subject to the branch profits tax at a 30 percent rate, or such lower rate as may be specified by an applicable income tax treaty. If an individual Non-U.S. holder is described in (b) above, the Non-U.S. holder will be required to pay a flat 30 percent tax (or such lower rate specified by an applicable income tax treaty) on the gain derived from the sale, which gain may be offset by U.S.-source capital losses for the year (provided the Non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses). A Non-U.S. holder should consult the Non-U.S. holder's own tax advisor regarding any applicable income tax or other treaties that may provide for different rules.

2.4 *U.S. federal estate tax*

Common Shares beneficially owned by an individual who is not a citizen or resident of the United States (as defined for U.S. federal estate tax purposes) at the time of their death will generally be includable in the decedent's gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise. Investors are urged to consult their own tax advisors regarding the U.S. federal estate tax consequences of the ownership or disposition of Common Shares.

2.5 *Backup withholding and information reporting*

Generally, the Company must report annually to the IRS the amount of dividends paid to Non-U.S. holders, the Non-U.S. holder's name and address, and the amount of tax withheld, if any. Pursuant to applicable income tax treaties or other agreements, the IRS may make these reports available to tax authorities in a Non-U.S. holder's country of residence.

Payments of dividends on or of proceeds from the disposition of Common Shares made to a Non-U.S. holder may be subject to additional information reporting and backup withholding at a current rate of 24 percent unless they establish an exemption, for example, by properly certifying their non-U.S. status on an IRS Form W-8BEN, IRS Form W-8BEN-E or another appropriate version of IRS Form W-8 (or successor form). Notwithstanding the foregoing, backup withholding and information reporting may apply if either the Company or the Company's paying agent has actual knowledge, or reason to know, that they are a U.S. person.

Backup withholding is not an additional tax; rather, the U.S. income tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund or credit may generally be obtained from the IRS, provided that the required information is furnished to the IRS in a timely manner.

2.6 *FATCA*

FATCA imposes a U.S. federal withholding tax of 30 percent on dividends on Common Shares that are paid to a "*foreign financial institution*" (as specifically defined under these rules), unless such institution enters into an agreement with the U.S. government to, among other things, withhold on certain payments and to collect and provide to the U.S. tax authorities substantial information regarding the U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are foreign entities with U.S. owners) or otherwise establishes an exemption. FATCA also generally imposes a U.S. federal withholding tax of 30 percent on dividends on Common Shares that are paid to a "non-financial foreign entity" (as specifically defined for purposes of these rules) unless such entity provides the withholding agent with a certification identifying certain substantial direct and indirect U.S. owners of the entity, certifies that there are none or otherwise establishes an exemption. Under certain circumstances, a non-U.S. holder might be eligible for refunds or credits of such taxes. An intergovernmental agreement between the U.S. and an applicable foreign country may modify the requirements described in this paragraph 2.6 of this Part 16 (*Taxation*). Prospective investors are encouraged to consult with their own tax advisors regarding the possible implications of these rules on their investment in Common Shares.

PART 17 – ADDITIONAL INFORMATION

1. Responsibility statement

The Company and each of the Directors, whose names appear on page 54 of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and this Prospectus makes no omission likely to affect its import.

2. NSAI responsibility statement

NSAI accepts responsibility for the Competent Person's Reports contained in Part 20 (*Etame Marin Block Competent Person's Report*) and Part 21 (*Block P Competent Person's Reports*) of this Prospectus. To the best of the knowledge and belief of NSAI, the information contained in the Competent Person's Reports, including estimates of reserves and resources contained therein, as well as references to them, and statements and information attributed to NSAI or extracted from the Competent Person's Reports and included in this Prospectus, is in accordance with the facts and contains no omissions likely to affect the import of such information.

3. The Company

3.1 On 28 February 1989, Gladstone Resources Limited was registered and incorporated in the State of Delaware, USA under the DGCL with registration file number 2188793. On 15 September 1997, the certificate of incorporation of Gladstone was restated under the name VAALCO Energy, Inc. and was subsequently amended on 24 June 1998. The certificate of incorporation of VAALCO Energy, Inc. was further restated and amended on 3 June 2009 and filed with the SEC on 7 May 2014.

3.2 VAALCO Energy, Inc. is a public company, incorporated in the State of Delaware, USA with registration file number 2188793 and having its registered office, and business address for all of the Directors and Executive Officers, at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. The Company's telephone number is +1 713 623 0801.

3.3 The principal legislation under which the Company operates with conformity is the DGCL.

3.4 The Company operates in conformity with its Bylaws and Certificate of Incorporation and is duly authorised by its Bylaws and Certificate in respect of Admission.

3.5 The Company has all necessary statutory consents in connection with Admission.

4. Share capital of the Company

4.1 As at the Last Practicable Date, the Company has an:

(a) authorised share capital of 100,000,000 Common Shares, par value $0.10 per Share and 500,000 Preferred Shares, par value $25.00 per Share; and

(b) issued share capital of 67,478,896 Common Shares of which 8,883,929 are Treasury Shares, resulting in 58,594,967 Common Shares issued and outstanding.

4.2 The issued share capital of the Company immediately after Admission is expected to be 67,478,896 Common Shares of which 8,883,929 are Treasury Shares, resulting in 58,594,967 Common Shares issued and outstanding.

4.3 On Admission, it is expected that approximately 78.67 percent of the Common Shares will be held in public hands (within the meaning of Rule 14.2.2(4) of the Listing Rules).

4.4 The Common Shares will be registered, and may be held in either certificated or uncertificated form (by way of Depositary Interests on the London Stock Exchange).

4.5 During the Historical Financial Information Period, there have been the following changes to the Company's issued share capital:

	Common Shares Issued	***Treasury Shares***	***Common Shares Outstanding***
Balance at 1 January 2016	65,621,450	7,514,169	58,107,281
Shares issued – Share-based compensation	488,115	–	–
Treasury Shares acquired	–	40,926	–
Balance at 31 December 2016	66,109,565	7,555,095	58,554,470
Shares issued – Share-based compensation	334,406	–	–
Treasury Shares acquired	–	26,000	–
Balance at 31 December 2017	66,443,971	7,581,095	58,862,876
Shares issued – Share-based compensation	724,023	(35,265)	–
Treasury Shares acquired	–	26,421	–
Balance at 31 December 2018	67,167,994	7,572,251	59,595,743
Shares issued – Share-based compensation	284,391	–	–
Treasury Shares acquired	–	123,899	–
Balance at 30 June 2019	67,452,385	7,696,150	59,756,235
Shares issued – Share-based compensation	26,511	–	–
Treasury Shares acquired	–	1,187,779	–
Balance as at Last Practicable Date	67,478,896	8,883,929	58,594,967

4.6 The Company is authorised to issue up to 500,000 Preferred Shares. For the Historical Financial Information Period and as at the Last Practicable Date, there were no Preferred Shares issued.

4.7 In the financial years ended 31 December 2018, 31 December 2017 and 31 December 2016, the Company withheld 26,421, 26,000 and 40,926 Treasury Shares, respectively. This withholding was in connection with cashless Option exercises and Restricted Shares vesting to satisfy withholding obligations related to Option exercises. In financial year ended 31 December 2018, the Company issued 35,265 Treasury Shares in respect of Restricted Shares vesting.

4.8 On 20 June 2019, the Company announced that the Board had authorised the Share Repurchase Programme, pursuant to which the Company could repurchase up to $10.0 million of the outstanding Common Shares over a period of 12 months, through open market purchases, privately-negotiated transactions or otherwise in compliance with Rule 10b-18 of the SEC Rules. In conjunction, the Board resolved to establish a Rule 10b5-1 trading plan, allowing the Company to repurchase Common Shares at times when it might otherwise be prevented from doing so by securities laws or because of self-imposed trading blackout periods. Under the Rule 10b5-1 trading plan, the Company's third-party broker, subject to SEC Rules regarding certain price, market, volume and timing constraints, would have authority to purchase Common Shares in accordance with the terms of the plan. During the period from the implementation of the programme through 30 June 2019, the Company purchased 141,686 Common Shares at an average price of $1.73 per Share. Subsequent to 30 June 2019 and up to the Last Practicable Date, the Company purchased 1,187,779 Common Shares at an average price of $1.74 per Share for $2.1 million.

5. U.S. takeover provisions

5.1 Tender offers in the U.S. are subject to federal rules and regulations under the Exchange Act that require a bidder to comply with detailed disclosure and procedural requirements (including withdrawal rights for target company shareholders through the offer period and certain timing and offer extension requirements). A bidder must also comply with general anti-fraud and anti-manipulation rules that apply to all tender offers in the U.S. These rules prohibit the use of materially misleading statements or omissions in the conduct of any offer, prohibit market purchases of the target company's securities outside the offer, and mandate a minimum offer period of at least 20 business days in the U.S.

5.2 Acquisitions completed by merger are governed by the law of the state of incorporation of the target company, which in the Company's case is the DGCL. The solicitation of votes to approve a merger by the target company shareholders must comply with rules and regulations on proxy statements under the Exchange Act. If a bidder offers securities as consideration to the target company shareholders, the registration requirements of the Securities Act will also apply, unless an exemption is available.

6. Minority Shareholders

6.1 The Company is incorporated and registered in the State of Delaware, USA and is subject to the DGCL. Section 253 of the DGCL permits a parent company that owns at least 90 percent of the outstanding shares of each class of the share of a Delaware corporation to merge the subsidiary corporation with and into the parent company without the approval of such subsidiary's shareholders. Section 262 of DGCL provides minority shareholders with appraisal rights and generally permits shareholders who dissent from the shareholder approval for a merger, if such approval is required for the merger, to request an appraisal of the fair value of their shares from the Delaware Chancery Court. A shareholder is accordingly entitled to dissent from, and request payment of the fair value of such shareholder's share in the event of, among other things, a merger or consolidation, in each case requiring shareholder approval.

6.2 Notwithstanding the foregoing, the DGCL does not confer appraisal rights on a shareholder receiving shares that are either (i) listed on a national securities exchange; or (ii) held of record by more than 2,000 shareholders, provided that the consideration received by such shareholder in the merger or consolidation for which such shareholder is seeking appraisal consists solely of shares in the acquiring corporation.

7. Substantial holdings

7.1 Sections 13(d) and 13(g) of the Exchange Act require any person or group of persons who directly or indirectly acquires or has beneficial ownership of more than 5 percent of a class of an issuer's securities to report such beneficial ownership on Schedule 13D or Schedule 13G, as appropriate.

7.2 These reports are filed with the SEC electronically on EDGAR. Both Schedule 13D and Schedule 13G require background information about the reporting persons, including the name, address, and citizenship or place of organisation of each reporting person, the amount of the securities beneficially owned and aggregate beneficial ownership percentage, and whether voting and investment power is held solely by the reporting persons or shared with others.

8. NYSE disclosure requirements

In addition to the numerous ongoing reporting requirements for reporting issuers pursuant to applicable corporate and securities legislation in the U.S., the NYSE imposes certain disclosure and notification requirements on listed companies. The NYSE's timely disclosure policy requires listed companies to immediately disclose any material information, with limited exceptions for confidentiality.

9. Certificate of Incorporation and Bylaws

The following is a non-exhaustive summary of the provisions of the Certificate of Incorporation and Bylaws. Please see paragraph 28 of this Part 17 (*Additional Information*) for details on how to obtain a full copy of the Certificate of Incorporation and Bylaws.

9.1 *Purpose*

Pursuant to the Certificate of Incorporation, the purpose of the Company is to engage in any lawful act or activity for which corporations may be organised under the DGCL.

9.2 *Authorised Share Capital*

The Company is authorised to issue up to 100,500,000 Shares consisting of (a) 100,000,000 Common Shares; and (b) 500,000 Preferred Shares.

9.3 ***Rights attaching to Common Shares***

(a) *Voting rights*

Unless otherwise provided by the Certificate of Incorporation, each outstanding Common Share entitles the Shareholder to one vote on each matter properly submitted to Shareholders for their vote. Cumulative voting is not permitted for the election of individuals to the Board or for any other matters brought before any meeting of Shareholders, regardless of the nature thereof.

Each Shareholder may vote in person or by proxy, but no proxy shall be voted after three years from the date of its creation, unless such proxy provides for a longer period. A Shareholder may revoke any proxy which is not irrevocable by attending the meeting and voting in person, or by filing with the person recording the proceedings of the meeting an instrument in writing revoking the proxy or another duly executed proxy bearing a later date.

(b) *Dividends, redemption and preferences*

The Board may from time to time declare, and the Company may pay, dividends on its outstanding Common Shares in the manner and on the terms and conditions provided by law.

All Common Shares have the same rights and preferences.

All Common Shares when issued shall be fully paid and non-assessable.

Shareholders shall not be entitled to any pre-emptive or preferential rights to acquire additional Common Shares.

9.4 ***Transfer of Common Shares***

Neither the Certificate of Incorporation nor the Bylaws contain any restrictions on the free transferability of the Common Shares. The Common Shares are transferable upon the Company's books by holders thereof in person or by their duly authorised attorney or legal representatives and upon such transfer, the old certificates (in the case of certificated shares) shall be surrendered to the Company.

9.5 ***Rights attaching to Preferred Shares***

Preferred Shares may be issued from time to time in one or more series, and Shares of each series will have such designations, powers, preferences, rights, qualifications, limitations, and restrictions as may be fixed by the Board in the resolution(s) authorising the issuance of that particular series.

In designating any series of Preferred Shares, the Board has the authority, without further action by the holders of Common Shares, to fix the voting rights, dividend rate, conversion rights, rights and terms of redemption (including any sinking fund provisions), and the liquidation preferences of that series of the Preferred Shares.

The Board will make any determination to issue such Shares based on its judgement as to the Company's best interests and the best interests of Shareholders.

If Preferred Shares are issued, the Shares will fully be paid and non-assessable and will not have, or be subject to, any pre-emptive or similar rights.

9.6 ***Amendment of the Certificate of Incorporation and Bylaws***

The Company has reserved the right to amend, alter, change or repeal any provision in the Certificate of Incorporation in any manner prescribed by the laws of the State of Delaware. The Board has the power to make, adopt, alter, amend and repeal, from time to time, the Bylaws (except as so far as the bylaws adopted by the Shareholders otherwise provide). However, the affirmative vote of the Shareholders holding at least 66⅔ percent of the voting power of all the Shares entitled to vote generally in the election of Directors, voting together as a single class, shall be required to amend the provision in the Bylaws relating to the maximum and minimum number of Directors.

9.7 ***Shareholder meetings***

(a) *Annual meetings and special meetings of Shareholders*

Annual meetings of Shareholders may be held at such place, either within or outside of the State of Delaware, and at such time and date as the Board may by resolution determine and as set forth in the notice of meeting. The Board may, in its sole discretion, determine that a meeting of Shareholders will be held solely by means of remote communication as authorised by section 211(a)(2) of the DGCL, as amended from time to time. At each annual meeting, the Shareholders entitled to vote shall elect a Board and may transact such other corporate business as stated in the notice of meeting.

A special meeting of Shareholders may be called by the chairman of the Board or president and shall be called by the chairman, president or secretary at the request of a majority of the Directors or by the secretary upon the written request of holders of record owning a majority of the outstanding Common Shares.

(b) *Notice of meeting*

Written notice of Shareholder meetings shall be delivered by the Company not less than 10 days nor more than 60 days before the date of the meeting to each Shareholder of record entitled to vote at such meeting. Only such business shall be conducted at a special meeting of Shareholder as shall have been brought before the meeting pursuant to the Company's notice of meeting and as shall have been accompanied by a timely notice setting forth the information required by the Bylaws.

(c) *Quorum*

The holders of a majority of the issued Shares and outstanding and entitled to vote thereat, present in person or represented by proxy, shall constitute a quorum at all meetings of the Shareholders for the transaction of business except as otherwise provided by statute or by the Certificate of Incorporation.

(d) *Action without a meeting*

Unless otherwise provided in the Certificate of Incorporation, any action required to be taken at any annual or special meeting of Shareholders, or any action which may be taken at any annual or special meeting of such Shareholders, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, shall be signed by the Shareholders having not less than the minimum number of votes that would be necessary to authorise or take such action at a meeting at which all Shares entitled to vote thereon were present and voted. Prompt notice of the taking of the corporate action without a meeting by less than unanimous written consent shall be given to those Shareholders who have not consented in writing and who, if the action had been taken at a meeting, would have been entitled to notice of the meeting if the record date for such meeting had been the date that written consents signed by a sufficient number of Shareholders to take the action were delivered to the Company as provided herein.

9.8 ***Directors***

The business and affairs of the Company shall be managed by or under the direction of the Board. In addition to the powers and authorities conferred on the Board by the Bylaws, the Board may exercise all such powers of the Company and do all such lawful acts and things as are not by the DGCL, the Certificate of Incorporation or the Bylaws required to be exercised or done by the Shareholders.

(a) *Number and qualifications*

Except as otherwise fixed pursuant to the provisions of article four of the Certificate of Incorporation relating to the rights of Shareholders of any class or series of Shares having a preference over the Common Shares as to dividends or upon liquidation to elect additional Directors under specified circumstances, the number of Directors shall be fixed from time to time by or pursuant to the Bylaws; provided that such number shall not be less than three nor more than 15. Directors are elected at each annual meeting for a one-year term expiring at the next annual meeting.

Nominations of persons for election to the Board and the proposal of other business to be considered by the Shareholders may be made at an annual meeting of Shareholders:

(i) as specified by the Company's notice of meeting by or at the direction of the Board; or

(ii) by or at the direction of the Board; or

(iii) by any Shareholder who:

  (A) was a Shareholder of record at the time of giving of notice provided for in the Bylaws and at the time of the annual meeting;

  (B) is entitled to vote at the meeting; and

  (C) complies with the notice procedures set forth in the Bylaws as to such business or nomination,

with (iii) being the exclusive means for a Shareholder to make nominations or submit other business (other than matters properly brought under Rule 14a-8 under the Exchange Act and included in the Company's notice of meeting) before an annual meeting of Shareholders.

Without qualification, for any nominations or any other business to be properly brought before an annual meeting by a Shareholder, the Shareholder must have given timely notice thereof in writing to the secretary and such other business must otherwise be a proper matter for Shareholder action. To be timely, a Shareholder's notice shall be delivered to the secretary at the principal executive offices of the corporation not earlier than the close of business on the 120th day and not later than the close of business on the 90th day prior to the first anniversary of the preceding year's annual meeting; provided, however, that in the event that the date of the annual meeting is more than 30 days before or more than 60 days after such anniversary date, notice by the Shareholder to be timely must be so delivered not earlier than the close of business on the 120th day prior to the date of such annual meeting and not later than the close of business on the later of the 90th day prior to the date of such annual meeting or, if the first public announcement of the date of such annual meeting is less than 100 days prior to the date of such annual meeting, the 10th day following the day on which public announcement of the date of such meeting is first made by the corporation. In no event shall any adjournment or postponement of a meeting or the announcement thereof commence a new time period for the giving of a Shareholder's notice as described above.

To be in proper form, a Shareholder's notice must:

(i) set forth, as to the Shareholder giving the notice and the beneficial owner, if any, on whose behalf the nomination or proposal is made (including any affiliate or associate (each within the meaning of Rule 12b-2 under the Exchange Act) of such Shareholder or beneficial owner):

  (A) the name and address of such Shareholder, as they appear on the Company's books;

  (B) and of such beneficial owner, if any:

    i. the class or series and number of Shares which are, directly or indirectly, owned beneficially or of record (within the meaning of Rule 13d-3 under the Exchange Act) by such Shareholder and such beneficial owner, if any (except that any such person shall in all events be deemed to beneficially own any Shares of any class or series of the corporation as to which such person has a right to acquire beneficial ownership at any time in the future);

    ii. any Option, Warrant, convertible security, SAR, or similar right with an exercise or conversion privilege or a settlement payment or mechanism at a price related to any class or series of Shares or with a value derived in whole or in part from the value of any class or series of Shares, whether or not such instrument or right shall be subject to settlement in the underlying class or series of Shares of the Company or otherwise ("*Derivative Instrument*") directly or indirectly owned beneficially by such Shareholder and such beneficial owner, if any, any other direct or indirect opportunity to profit or share in any profit derived from any increase or decrease in the value of Shares;

iii. any proxy, contract, arrangement, understanding, or relationship pursuant to which such Shareholder and such beneficial owner, if any, has a right to vote any Shares or any security of the Company;

iv. any short interest of such Shareholder or beneficial owner, if any, in any security of the Company (for purposes of these Bylaws a person shall be deemed to have a short interest in a security if such person directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise, has the opportunity to profit or share in any profit derived from any decrease in the value of the subject security);

v. any rights to dividends on the Shares owned beneficially by such Shareholder or beneficial owner, if any, that are separated or separable from the underlying Shares;

vi. any proportionate interest in Shares or Derivative Instruments held, directly or indirectly, by a general or limited partnership in which such Shareholder or beneficial owner, if any, is a general partner or, directly or indirectly, beneficially owns an interest in a general partner; and

vii. any performance-related fees (other than an asset-based fee) that such Shareholder or beneficial owner, if any, is entitled to, based on any increase or decrease in the value of Shares or Derivative Instruments, if any, as of the date of such notice, including without limitation any such interests held by members of such Shareholder's or beneficial owner's immediate family sharing the same household,

(C) any other information relating to such Shareholder and beneficial owner, if any, that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for, as applicable, the proposal and/or for the election of directors in a contested election pursuant to section 14 of the Exchange Act and the rules and regulations promulgated thereunder; and

(D) a representation:

i. that the Shareholder is a holder of record of the Shares entitled to vote at such annual meeting and intends to appear in person or by proxy at the annual meeting to propose such business or nomination; and

ii. whether the Shareholder or the beneficial owner, if any, intends or is part of a group which intends:

1. to deliver a proxy statement and/or form of proxy to holders of at least the percentage of the Company's outstanding Shares required to approve or adopt the proposal or elect the nominee; and/or

2. otherwise to solicit proxies from Shareholders in support of such proposal or nomination;

(ii) if the Shareholder notice relates to any business other than a nomination of a Director or Directors that the Shareholder proposes to bring before the meeting, the notice must set forth:

(A) a brief description of the business desired to be brought before the meeting, the reasons for conducting such business at the meeting and any material interest of such Shareholder and beneficial owner, if any, in such business;

(B) the text of the proposal or business (including the text of any resolutions proposed for consideration); and

(C) a complete and accurate description of all agreements, arrangements and understandings between or among such Shareholder and such beneficial owner, if any, and any other person or persons (including their names and addresses) in connection with the proposal of such business by such Shareholder; and

(iii) set forth or provide, as to each person, if any, whom the Shareholder proposes to nominate for election or re-election to the Board:

(A) the name, age, business address and residence address of such person;

(B) the principal occupation or employment of such person (present and for the past five years);

(C) the class or series and number of Shares which are owned beneficially and of record by such person;

(D) a completed and signed questionnaire, and written representation and agreement, each as required by article II, section 12(A)(4) of the Bylaws;

(E) all information relating to such person that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of directors in a contested election pursuant to section 14 of the Exchange Act and the rules and regulations promulgated thereunder (including such person's written consent to being named in the proxy statement as a nominee and to serve as a director if elected); and

(F) a complete and accurate description of all direct and indirect compensation and other material monetary agreements, arrangements and understandings during the past three years, and any other material relationships, between or among such Shareholder and beneficial owner, if any, and their respective affiliates and associates, or others acting in concert therewith, on the one hand, and each proposed nominee, and his or her respective affiliates and associates, or others acting in concert therewith, on the other hand, including, without limitation, all information that would be required to be disclosed pursuant to Rule 404 promulgated under Regulation S-K if the Shareholder making the nomination and any beneficial owner on whose behalf the nomination is made, if any, or any affiliate or associate thereof or person acting in concert therewith, were the "*registrant*" for purposes of such rule and the nominee were a director or executive officer of such registrant.

(b) *Tenure*

Directors shall be elected by a plurality of the votes cast at a meeting of Shareholders at which a quorum is present. Directors shall hold office until the next meeting of Shareholders for the purposes of electing the Board or until their successors have been duly elected and qualified or until a Director's prior death, resignation or removal.

Generally, any Director may be removed from office only for cause. Except as may otherwise be provided by law, cause for removal shall be construed to exist only if:

(i) the Director whose removal is proposed has been convicted of a felony by a court of competent jurisdiction and such conviction is no longer subject to direct appeal; or

(ii) such Director has been adjudicated by a court of competent jurisdiction to be liable for gross negligence, recklessness or misconduct in the performance of his or her duty to the Company in a manner of substantial importance to the Company and such adjudication is no longer subject to direct appeal; or

(iii) such Director has been adjudicated by a court of competent jurisdiction to be mentally incompetent, which mental incompetency directly affects his or her ability as a director of the Company, and such adjudication is no longer subject to direct appeal, with any action for removal having to be brought within three months of the date on which such conviction or adjudication is no longer subject to direct appeal.

Any Director may resign at any time upon written notice to the Company. Between successive annual meetings, the Directors shall have the power to appoint one or more additional Directors to fill any vacancies occurring for any reason. A Director so appointed shall hold office only until the next following annual meeting of the Company or until his successor is duly elected and qualified, but such Director shall be eligible for election at the next meeting of Shareholders for the purpose of electing Directors.

(c) *Quorum*

A whole number of Directors equal to at least a majority of Directors then in office shall constitute a quorum for the transaction of business. The act of the majority of directors present at a meeting at which a quorum is present shall be the act of the Board.

(d) *Committees*

The Board may, by resolution adopted by a majority of Directors then in office, designate one or more committees to exercise, subject to applicable law, the powers of the Board in the management of the business and affairs of the Company.

(e) *Compensation*

The Board has the authority to fix the compensation of Directors. The Directors may be paid their expenses, if any, of attendance at each meeting of the Board and may be paid a fixed sum for attendance at each meeting of the Board or a stated salary as Director. No such payment shall preclude any Director from serving the corporation in any other capacity and receiving compensation therefor. Members of special or standing committees may be allowed like compensation for attending committee meetings.

9.9 ***Forum for adjudication of disputes***

Pursuant to the Bylaws, to the fullest extent permitted by law and unless the Company consents in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for:

(i) any derivative action or proceeding brought in the name or right of the Company or on its behalf; or

(ii) any action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee, Shareholder or other agent of the Company to the Company or its Shareholders; or

(iii) any action arising or asserting a claim arising pursuant to any provision of the DGCL, the Certificate of Incorporation or the Bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware; or

(iv) any action asserting a claim governed by the internal affairs doctrine, including, without limitation, any action to interpret, apply, enforce or determine the validity of the Certificate of Incorporation or the Bylaws.

Any person or entity purchasing or otherwise acquiring any interest in Common Shares shall be deemed to have notice of and consented to these provisions of the Bylaws.

9.10 ***Major transactions***

In addition to any affirmative vote required by law or the Certificate of Incorporation, unless approved by a majority of the Continuing Directors (as defined below), the affirmative vote of the holders of at least 80 percent of the Voting Shares (as defined below), voting together as a single class, shall be required for the approval or authorisation of:

(i) any merger or consolidation of the Company with or into another company;

(ii) any share exchange with the Company;

(iii) the adoption of any plan or proposal for the liquidation, dissolution or reorganisation of the Company; and

(iv) any sale, lease or other disposition of all or substantially all the assets of the corporation (on a consolidated basis).

Such affirmative vote shall be required notwithstanding the fact that no vote may be required, or that a lesser percentage may be specified, by law or in any agreement with any national securities exchange or otherwise.

"**Continuing Directors**" means:

(i) any member of the Board as of 31 December 1992;

(ii) any new director who is proposed to be a Director by a majority of the Continuing Directors then on the Board; and

(iii) any successor of a Continuing Director who is recommended to succeed a Continuing Director by majority of the Continuing Directors then on the Board.

Notwithstanding any other provision of the Certificate of Incorporation or the Bylaws (and notwithstanding the fact that a lesser percentage may be specified by law, the Certificate of Incorporation or the Bylaws), the affirmative vote of the holders of 80 percent or more of the outstanding Voting Shares, voting together as a single class, shall be required to amend or repeal, or adopt any provisions inconsistent with these provisions.

"**Voting Shares**" means the affirmative vote of the holders of at least 66⅔ percent of the voting power of the then outstanding Shares entitled to vote generally in the election of directors.

10. Information on the Directors and Executive Officers

10.1 The Directors and Executive Officers, their functions within the Group and brief biographies are set out in Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus.

10.2 Details of the names of companies and partnerships (excluding directorships in the Group) of which the Directors and Executive Officers are or have been members of the administrative, management or supervisory bodies or partners at any time in the five years preceding the date of this document are set out below:

Name	***Current Partnerships/ Directorships***	***Past Partnerships/ Directorships***
Directors		
Cary M. Bounds	–	–
Andrew L. Fawthrop	Geordie, LLC Carinya Holdings, LLC	Chevron (Bermuda) Deepwater 6 Limited Chevron (Bermuda) Deepwater 7 Limited Chevron (Bermuda) Deepwater 8 Limited Chevron (Bermuda) Deepwater 9 Limited Chevron Manning Services (Nigeria) Limited Chevron N-Gas Limited Chevron Nigeria Deepwater B Limited Chevron Nigeria Deepwater D Limited Chevron Nigeria Deepwater E Limited

Name	***Current Partnerships/ Directorships***	***Past Partnerships/ Directorships***
Directors		
Andrew L. Fawthrop cont		Chevron Nigeria Deepwater F Limited Chevron Nigeria Deepwater G Limited Chevron Nigeria Closed PFA Limited Chevron Nigeria Gas Company Chevron Nigeria Limited Chevron Nigeria Savings Plan Limited Chevron OKLNG Holdings Limited Chevron Petroleum Holdings Limited Chevron Petroleum Nigeria Limited Chevron West African Gas Holding Company Ltd. Chevron West African Gas Pipeline Company Ltd. Nigeria Chevron Cooperatief U.A. Sasol Chevron Holdings Limited Star Deep Water Petroleum Limited Star Ultra Deep Petroleum Limited Texaco Nigeria Outer Shelf Limited Unocal Asia-Pacific Ventures, Ltd
A. John Knapp, Jr.	Andover Group, Inc. CCM Opportunistic Partners	ATRM Holdings, Inc. On Track Innovations Ltd
Steven J. Pully	Aspire Holdings, LLC Harvest Oil & Gas Corp. Heritage Power Permian Holdco 1, Inc. PGi PRIMEXX Energy Partners Ltd Titan Energy, LLC Tribune Resources, LLC Speyside Partners, LLC	Bellatrix Exploration Ltd Carlson Capital, L.P. Energy XXI Ltd Goodrich Petroleum Corp
William R. Thomas	Granite Peak Petroleum, LLC Lorna Glen Holdings, LLC Texas Oceanic Capital, LLC Texas Oceanic Petroleum Co. LLC	–
Executive Officers		
Elizabeth D. Prochnow	–	Total Safety U.S., Inc.
David A. DesAutels	–	Noble Energy, Inc. Seregon Energy, LLC Synertia Energy, LLC
Michael G. Silver	–	–
Jason J. Doornik	–	–

10.3 Steven J. Pully was a director of MaxWorldwide, Inc. ("**MaxWorldwide**") on 22 July 2003, when the company's shareholders adopted a plan of liquidation and dissolution, pursuant to which the company would liquidate and dissolve. The proposal became effective on 31 July 2003 and was contemporaneous with the sale by MaxWorldwide of its principal operating asset, MaxOnline division, effective 31 July 2003, leaving the company's remaining assets, excluding the company's cash, name and certain other intellectual property rights, being sold to Focus Interactive, Inc.

10.4 Steven J. Pully was a director of Energy Partners Ltd ("**Energy Partners**") that, on 1 May 2009, announced that it had filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code (Title 11 of the United States Code) in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. Energy Partners was an upstream oil and gas business that had operations in the U.S. and Gulf of Mexico. The filing for bankruptcy protection followed the collapse of the credit markets, lower oil prices and environmental disruption in the form of hurricanes affecting Energy Partner's operations in 2008. In October 2009, noteholders converted $455 million of notes issued by the company into equity, which, after conversion, represented 95 percent of the company's issued share capital. Four and a half years following the bankruptcy protection, while Mr. Pully was lead director of the company, Energy Partners was acquired by Energy XXI Ltd for $2.3 billion, approximately five times the value of the company at the time of entering into the bankruptcy protection.

10.5 Jason J. Doornik was corporate controller of BPZ Energy Inc. ("**BPZ Energy**") when, on 9 March 2015, it voluntarily filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code (Title 11 of the United States Code) in the United States Bankruptcy Court for the Southern District of Texas, Victoria Division. BPZ Energy was an upstream oil and gas company that had a 51 percent stake in Peru's offshore oil block Z-1 and 100 percent control of three onshore oil blocks in Peru. The filing for bankruptcy protection followed an approximate 50 percent decline in oil prices from June 2014 to March 2015, and the company's inability to find a suitable financing solution to its debt maturity and interest payments. On 31 December 2015, all of BPZ Energy's assets were transferred to a liquidating trust for the benefit of the company's creditors, of which approximately $9 million was distributed to creditors. Mr. Doornik left BPZ Energy on 15 October 2015.

10.6 Jason J. Doornik was chief accounting officer and controller of Fairway Energy LP ("**Fairway Energy**"), a midstream oil-storage business based in Houston, Texas, until 31 July 2018. On 26 November 2018, Fairway Energy voluntarily filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code (Title 11 of the Unites Stated Code) in the United States Bankruptcy Court for the District of Delaware. At the time of seeking protection, Fairway Energy owed more than $100 million in debt, nearly all of it owed to Riverstone Credit Partners Direct LP ("**Riverstone**"). On 10 April 2019, following an auction process for the assets of Fairway Energy, Riverstone emerged as the successful bidder and in June 2019 Converge Midstream LLC, an oil-storage and transportation company associated with Riverstone, acquired the assets of Fairway Energy.

10.7 Save as set out above, none of the Directors or Executive Officers:

- have any convictions in relation to fraudulent offences for at least the previous five years; or
- have been associated with any bankruptcy, receivership or liquidation while acting in the capacity of a member of the administrative, management or supervisory body or of a senior manager of any company for at least the previous five years; or
- have been subject to any official public incriminations and/or sanctions by any statutory or regulatory authority (including designated professional bodies) for at least the previous five years; or
- have ever been disqualified by a court from acting as a director of a company, or from acting as a member of the administrative, management or supervisor bodies of a company, or from acting the management or conduct of the affairs of any company for at least the previous five years.

10.8 There are no family relationships between any of the Directors or Executive Officers.

10.9 There are no potential or actual conflicts of interest between any duties owed by the Directors or the Executive Officers to the Company and their private interests and/or other duties, save for their interest as holders of securities of the Company.

11. Directors' and Executive Officers' interests

11.1 As at the Last Practicable Date, the Common Shares held by the Directors and Executive Officers (all of which are held beneficially unless otherwise stated) are as follows:

Name	***Number of Common Shares***	***Percentage of Issued and Outstanding Share Capital***	***Percentage of Issued Share capital***
Directors			
Cary M. Bounds[(1)]	1,174,714	2.0%	1.7%
Andrew L. Fawthrop[(2)]	413,622	0.7%	0.6%
A. John Knapp, Jr.[(3)]	692,463	1.2%	1.0%
Steven J. Pully[(4)]	416,850	0.7%	0.6%
William R. Thomas[(5)]	152,279	0.3%	0.2%
Executive Officers			
Elizabeth D. Prochnow[(6)]	163,240	0.3%	0.2%
David A. DesAutels	116,984	0.2%	0.2%
Michael G. Silver	22,926	0.0%	0.0%
Jason J. Doornik	–	–	–

Notes

(1) Includes 470,095 Common Shares directly held by Mr. Bounds and 704,619 Common Shares that may be acquired subject to Options exercisable within 60 days at a weighted-average exercise price of $1.25.

(2) Includes 197,577 Common Shares directly held by Mr. Fawthrop and 216,045 Common Shares that may be acquired subject to Options exercisable within 60 days at an exercise price of $1.28.

(3) Includes 456,418 Common Shares directly held by Mr. Knapp and 20,000 Common Shares owned by Andover Real Estate Services, Inc., an entity that Mr. Knapp controls and 216,045 Common Shares that may be acquired subject to Options exercisable within 60 days at an exercise price of $1.28.

(4) Includes 200,805 Common Shares directly held by Mr. Pully and 216,045 Common Shares that may be acquired subject to Options exercisable within 60 days at an exercise price of $1.28.

(5) Includes 87,972 Common Shares directly held by Mr. Thomas and 64,307 Common Shares that may be acquired subject to Options exercisable within 60 days at an exercise price of $1.43.

(6) Includes 19,330 Common Shares directly held by Ms. Prochnow and 143,910 Common Shares that may be acquired subject to Options exercisable within 60 days at a weighted-average exercise price of $1.09.

11.2 Details of outstanding Incentive Awards granted to the Directors and Executive Officers are set out in paragraph 16.4 of this Part 17 (*Additional Information*).

12. Major Shareholders

12.1 Save as set out below, as at the Last Practicable Date, the Company is not aware of any person who, directly or indirectly, is interested in five percent or more of the Company's capital or voting rights:

Name	***Number of Common Shares***	***Percentage of Issued and Outstanding Share Capital***	***Percentage of Issued Share capital***
Bradley L. Radoff*	4,494,905	7.7%	6.7%
Tieton Capital Management, LLC	3,008,598	5.1%	4.5%
Renaissance Technologies LLC	3,006,117	5.1%	4.5%

Note

* Based on a Schedule 13D/A filed with the SEC on 5 March 2019 by BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff, Mr. Radoff has sole voting power and sole dispositive power over all of 4,494,905 Common Shares. Mr. Radoff directly owns 1,938,905 Common Shares. As the sole shareholder and sole director of each of BLRGP Inc. and Fondren Management, LP and as director of The Radoff Family Foundation, Mr. Radoff may be deemed the beneficial owner of (i) 2,471,000 Common Shares owned by BLR Partners LP; and (ii) 85,000 Common Shares owned by The Radoff Family Foundation.

12.2 None of the Shareholders named in paragraph 12.1 of this Part 17 (*Additional Information*) has different voting rights from other Shareholders.

12.3 The Company is not aware of any person who, directly or indirectly, owns or controls the Company. The Company is not aware of any arrangements the operation of which may at a subsequent date result in a change of control of the Company.

13. Directors' and Executive Officers' service agreements

13.1 *Overview*

The Company has not entered into a service agreement with any of Andrew L. Fawthrop, Steven J. Pully, A. John Knapp, Jr. or William R. Thomas, each of whom are Directors or with each of Elizabeth D. Prochnow, Jason J. Doornik, David A. DesAutels or Michael G. Silver, each of whom are Executive Officers.

The Directors are appointed at each annual meeting of the Shareholders and may also be appointed at a special meeting of Shareholders. Once appointed, Directors hold office until the close of the next annual meeting of the Shareholders following their appointment, or until a successor is duly elected or appointed or his or her office is earlier vacated in accordance with the Certificate of Incorporation and Bylaws. Further details on the appointment and terms of office of the Directors is described at paragraph 9.8 of this Part 17 (*Additional Information*).

Directors who are not officers or employees of the Company or any of its Subsidiaries are compensated for their services as Directors through annual retainer fees and Incentive Awards, issuable from time to time under the 2014 LTIP and 2016 SAR Plan, based on recommendations of the Compensation Committee.

The Directors and Executive Officers on Admission and their functions are set out in Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus.

13.2 *Cary M. Bounds, Chief Executive Officer*

The Company entered into an amended and restated executive employment agreement with Cary M. Bounds, effective 29 December 2016, in connection with his appointment as CEO ("**Employment Agreement**"). The initial term of the Employment Agreement commenced on 29 December 2016 and is extended for successive one-year terms if neither party gives the other party notice of their intention to terminate the Employment Agreement 60 days prior to the end of the term. The Employment Agreement amends and replaces a prior employment agreement in effect between Mr. Bounds and the Company entered into in July 2015.

The Employment Agreement provides that Mr. Bounds will receive a minimum base salary of $400,000 per annum and that this base salary will be reviewed annually by the Compensation Committee. The base salary may be increased but not decreased. The Compensation Committee determined to keep his base salary flat for 2018 over 2017. Pursuant to the Employment Agreement, Mr. Bounds is eligible for Options or other Incentive Awards as determined by the Compensation Committee up to 200 percent of his base salary.

The Employment Agreement also provides Mr. Bounds with certain severance benefits if his employment is terminated due:

(i) to his death or disability; or

(ii) by the Company without cause (cause being primarily the act of (i) material fraud; (ii) conviction of a felony crime; or (iii) the wilful or continued failure of the CEO to carry out his material duties); or

(iii) by Mr. Bounds for good reason (good reason being primarily the assignment of duties to the CEO materially inconsistent with the CEO's position), including in connection with a change of control (generally meaning the occurrence of any one or more of the following events (i) the acquisition by any individual, entity or group of beneficial ownership of 50 percent or more of the Common Shares or combined voting power; or (ii) individuals who constitute the as of the effective date of the plan, or successors to such members approved by the Board, cease for any reason to constitute at least a majority of the Board; or (iii) the consolidation, merger or the sale or other disposition of at least 50 percent of the assets of the Company or the adoption of any plan or proposal for the liquidation of the Company).

Specifically, the Employment Agreement provides that upon termination of Mr. Bounds' employment by the Company without cause, by Mr. Bounds for good reason, or due to Mr. Bounds' death or disability, Mr. Bounds (or his beneficiaries) will receive, among other benefits, a cash severance payment at least equal to 50 percent of his annual base salary then in effect plus 50 percent of the greater of:

(i) his average annual bonus paid or payable for the preceding two calendar years; and

(ii) the annual bonus for the calendar year in which the termination occurs (prorated for the portion of the year actually worked).

If Mr. Bounds' employment is terminated by the Company without cause, by Mr. Bounds for good reason, or due to Mr. Bounds' death or disability, in each case within one year following a change in control, the Company will provide Mr. Bounds (or his beneficiaries) with a cash severance payment at least equal to 150 percent of his annual base salary then in effect plus 150 percent of the greater of:

(i) his average annual bonus paid or payable for the preceding two calendar years; and

(ii) the annual bonus for the calendar year in which the termination occurs (prorated for the portion of the year actually worked).

The Company would also be required to pay for continuing health insurance premiums for Mr. Bounds and his eligible spouse and dependents for a period of one year following the termination and accrued and unpaid base salary, unused vacation days, and reimbursement for previously incurred business expenses.

13.3 *Change of Control Agreements*

The Company has entered into the Change of Control Agreements with the Executive Officers and certain other associates of the Company to provide severance benefits in connection with a change in control of the Company. Under the terms of the respective Change of Control Agreements, upon a termination of a participant's employment by the Company without cause or a resignation by the participant for good reason three months prior to a change in control or six months following a change in control, the participant will be entitled to receive a cash amount equal to (i) one-hundred percent of the participant's base salary; (ii) reimbursement of costs incurred by the employee in the course of their employment; and (iii) the participant will also be entitled to receive a cash amount equal to the Company's group health plans for the participant and his or her eligible spouse and other dependents for six months.

For those Change of Control Agreements entered into between the Company and each of (1) Elizabeth D. Prochnow; (2) David A. DesAutels; and (3) Michael G. Silver, each respective Executive Officer will receive seventy-five percent of their target bonus. Any payments under a Change of Control Agreement are subject to the participant's execution and non-revocation of a general waiver and release of claims against the Company.

14. Directors' and Executive Officers' remuneration and benefits

14.1 A summary of the amount of remuneration paid by the Group to the Directors (including any contingent or deferred compensation) and benefits in kind for financial year ended 31 December 2018 for their services, in all capabilities, to the Group is set out below:

Name	***Fees ($)***	***Common Share Awards***	***Options and SARs Awards ($)***	***Non-Equity Incentive Plan Compensation ($)***	***All Other Compensation ($)***	***Total ($)***
Cary M. Bounds	400,000	132,000	392,187	460,000	16,500	1,400,687
Andrew L. Fawthrop	125,645	40,000	40,000	–	–	205,645
A. John Knapp, Jr.	93,376	40,000	40,000	–	–	173,376
Steven J. Pully	91,126	40,000	40,000	–	–	171,126
William R. Thomas	–	–	–	–	–	–

14.2 A summary of the amount of remuneration paid by the Group to the Executive Officers (including any contingent or deferred compensation) and benefits in kind for financial year ended 31 December 2018 for their services, in all capabilities, to the Group is set out below:

Name	***Salary ($)***	***Common Share Awards***	***Options and SARs Awards ($)***	***Non-Equity Incentive Plan Compensation ($)***	***All Other Compensation ($)***	***Total ($)***
Elizabeth D. Prochnow	200,016	–	79,230	109,190	15,494	403,930
David A. DesAutels	309,500	–	154,750	154,750	16,500	635,500
Michael G. Silver	10,000*	–	–	–	–	–
Jason J. Doornik	–	–	–	–	–	–

Note

* Michael G. Silver was a consultant for one month in financial year ended 31 December 2018, pursuant to which he was paid $10,000.

14.3 Directors are not entitled to any benefits upon termination of their services, other than those described at paragraphs 13.2 and 13.3 of this Part 17 (*Additional Information*).

14.4 Non-executive Directors are not entitled to any benefits upon termination of their services.

14.5 The Company maintains directors' and officers' insurance and agrees to indemnify its Directors and Executive Officers to the full extent allowed under the DGCL.

15. Pension arrangements

The Company does not have a pension plan or a deferred compensation plan.

16. Incentive Plans

16.1 *Overview*

The Company believes that long term performance and increases in Shareholder value are achieved through an ownership culture that encourages performance by all Employees, including Executive Officers, through the use of at-risk long term incentives. Accordingly, the Company provides Share-based compensation to its Directors, Executive Officers and Employees pursuant to (i) the 2014 LTIP; and (ii) the 2016 SAR Plan, with incentives to help align those employees' interests with the performance of the Company as reflected in the market price of its Common Shares. The 2014 LTIP and 2016 SAR Plan are the only Incentive Plans as at the date of this Prospectus.

The 2014 LTIP was adopted by the Compensation Committee on 4 March 2014, with an effective date of 16 April 2014. It was approved by the Shareholders on 4 June 2014. The 2014 LTIP permits the grant of Shares, Options, Restricted Shares, Restricted Share Units, Phantom Shares, Share

Appreciation Rights and other awards, any of which may be designated as performance awards or be made subject to other conditions.

The 2016 SAR Plan was adopted by the Compensation Committee, with immediate effect, on 10 March 2016. It permits the grant of cash settled SARS.

The Compensation Committee:

(i) reviews and makes recommendations to the Board for its ultimate approval with respect to the goals and objectives relevant to the compensation of the CEO and Executive Officers;

(ii) evaluates the CEO's and Executive Officers' performance in light of those goals and objectives;

(iii) determines and approves the CEO's and Executive Officers' compensation based on this evaluation, including the CEO's and Executive Officers' participation in the Company's incentive compensation plans;

(iv) exercises oversight with respect to the Company's compensation philosophy and incentive compensation plans covering Executive Officers and senior management;

(v) prepares an annual report on executive compensation for inclusion in the Company's proxy statement for the annual meeting of Shareholders; and

(vi) reviews the Company's Compensation Discussion & Analysis required by the SEC Rules to be included in the Company's proxy statement and annual report on Form 10-K.

To accomplish the Company's objectives, its compensation programme is comprised of the following four elements (i) base salary; (ii) cash bonus; (iii) long-term equity-based compensation; and (iv) benefits:

Element	*Note*
Base salary	● Recognise unique value and historical contributions to the Company's success. ● Competitive in light of salary norms in the industry and the general marketplace. ● Match competitors for executive talent. ● Provide executives with predictable, regularly-paid income. ● Reflect an executive's position and level of responsibility.
Cash bonus	● Motivate management to achieve key corporate objectives. ● Competitive remuneration package aligned with peers. ● Compensation Committee maintains complete discretion on the pay-out of bonuses to the executive team.
Long-term equity-based	● Aligns executives' interests with the interests of Shareholders. ● Rewards long-term performance. ● Is required in order for the Company to be competitive from a total remuneration standpoint. ● Encourages executive retention. ● Gives executives the opportunity to share in the Company's long-term performance. ● Utilise Restricted Shares, Option awards and SARs.
Benefits	● 401(k) plan and match. ● Payment of insurance premiums.

16.2 ***2014 LTIP***

The 2014 LTIP provides for the issuance of a total of 4,600,000 Common Shares. As at the Last Practicable Date, 47,973 Common Shares remained available for future grants under this plan. For each Option granted, the number of authorised Shares under the 2014 LTIP is reduced on a one-for-one basis. For each Restricted Share granted, the number of Shares authorised under the 2014 LTIP is reduced by twice the number of Restricted Shares.

(a) *Types of awards and full value awards*

Options, SARs, Restricted Shares, Restricted Share Units, and other Share based awards are available for Incentive Awards granted under the 2014 LTIP. To date, the Company has awarded Options, Restricted Shares and SARs under the plan.

(b) *Administration*

The 2014 LTIP is administered by the Compensation Committee which has the power to select the persons eligible to receive Incentive Awards, the type and amount of Incentive Awards to be awarded, and the terms and conditions of such awards.

(c) *Eligibility*

Any Employee or independent Director is eligible to participate in the 2014 LTIP. Non-Employee Directors are also eligible to participate, however, Options may be granted only to Employees.

(d) *Award agreements and term*

Awards under the plan are evidenced by an award agreement.

(e) *Options*

The exercise price must be at least equal to the fair market value of the Common Shares on the date of grant. Options must have a term of not more than five years from the date of grant. To date, the Company has awarded Options with vesting periods of three or five years. In addition, vesting may be subject to performance criteria as specified in the award agreement.

(f) *SAR*

The grant of a SAR provides the holder with the right to receive a "*spread*" equal to the excess of the fair market value of a specified number of Common Shares on the date the SAR is exercised over a SAR price specified in the applicable award agreement. The SAR price specified in an award agreement must be equal to the fair market value of the Common Shares on the grant date of the SAR. The term of each SAR is determined by the Compensation Committee subject to a limit of five years from the date of grant, as set forth in the award agreement. Following the adoption of the 2016 SAR Plan there have been no issuance of SARs under the 2014 LTIP, nor are any SARs issued under the 2014 LTIP outstanding.

(g) *Restricted Shares*

The award agreement for Restricted Share will specify the time or times within which such award may be subject to forfeiture and any performance goals which must be met in order to remove any restrictions on the award. To date, the Company has issued Restricted Shares to Employees that generally vests over a three-year period, vesting in three equal parts on the first three anniversaries following the date of grant. The Compensation Committee has granted Restricted Shares to Directors that vests immediately and are not restricted. Except for the limitations on transfer or other limitations as set forth in the award agreement, holders of Restricted Shares have all of the rights of a Shareholder, including, if provided in the award agreement, the right to vote the Common Shares and to receive any dividends thereon.

(h) *Restricted Share Units*

Restricted Share Units may be granted to participants in such number, and upon such terms as determined by the Compensation Committee and specified in the award agreement. A grant of Restricted Share Units will not represent the grant of Common Shares but will represent a promise to deliver a corresponding number of Shares based upon the completion of service, performance conditions, or such other terms and conditions as specified in the award agreement. A participant will have no voting rights with respect to any Restricted Share Units or to the Shares corresponding to such Restricted Share Units before vesting. There are no Restricted Share Units in issue as at the Last Practicable Date.

(i) *Other Share-based awards*

The Compensation Committee may grant other Share-based awards, such as Phantom Shares, in amounts and subject to such terms and conditions as the Compensation Committee determines. Such awards may involve the transfer of actual Shares to participants, or payment in cash or otherwise of amounts based on the value of Shares. Payment, if any, with respect to cash-based awards and other Share-based award will be made in accordance with the terms of the award agreement, in cash, in Shares, or a combination of both, as determined by the Compensation Committee and set out in the award agreement. The Compensation Committee may also specify any performance criteria for vesting and payment.

(j) *Termination of employment, death, disability and retirement*

Unless otherwise provided in an award agreement, or otherwise agreed to, upon the termination of a participant's employment, the non-vested portions of all outstanding awards will terminate immediately.

Subject to different provisions in an award agreement, the period during which a vested Option or other vested Incentive Award may be exercised following termination of the participant's employment depend upon the circumstances of the termination of employment:

(i) if a participant's employment is terminated for any reason other than as a result of death, disability, retirement or for cause, the vested portion of such award is exercisable until the earlier of (1) the expiration date set forth in the applicable award agreement; or (2) 120 days after the date of termination (three months in the case of Options); or

(ii) in the event of the termination of participant's employment for cause, all awards immediately expire; or

(iii) upon a participant's retirement, any vested award will expire on the earlier of (1) the expiration date set forth in the award agreement for such award; or (2) six months after the date of retirement (three months in the case of Options); or

(iv) upon the death or disability of a participant, any vested award will expire on the earlier of (1) the expiration date set forth in the award agreement; or (2) the one year anniversary date of the participant's termination of employment due to death or disability.

(k) *Change in control*

Unless provided otherwise in the applicable award agreement, in the event of a change in control of the Company:

(i) all Options and SARs will become 100 percent vested and all restrictions and conditions of any Restricted Share Awards, Restricted Share Units and any other Share-based awards shall be deemed satisfied and the restricted period shall be deemed to have expired; and

(ii) all performance-based awards shall become fully vested. Awards shall be payable as of the day immediately preceding the date of the change in control event.

A "**change in control**" of the Company generally means the occurrence of any one or more of the following events:

(i) the acquisition by any individual, entity or group of beneficial ownership of 50 percent or more of the Common Shares or combined voting power; or

(ii) individuals who constitute the Board as of the effective date of the plan, or successors to such members approved by the Board, cease for any reason to constitute at least a majority of the Board; or

(iii) the consolidation, merger or the sale or other disposition of at least 50 percent of the assets of the Company or the adoption of any plan or proposal for the liquidation of the Company.

16.3 ***2016 SAR Plan***

The 2016 SAR Plan is administered by the Compensation Committee, except that awards granted to non-executive Directors must be approved by the Board. Employees and Directors are eligible to participate in the 2016 SAR Plan. The terms and conditions of each SAR will be evidenced by an incentive agreement. The SAR price per Share must not be less than 100 percent of the fair market value of a Common Share on the date of grant of the SAR. The term of the SAR may not be greater than ten years from the date of grant.

(a) *Exercise*

SARs are exercisable subject to such terms and conditions as the Compensation Committee may specify in the incentive agreement for the SAR Award. A SAR Award may be exercised by the delivery of a signed written notice of exercise to the Company, which must be received and accepted by the Company as of a date set by the Company in advance of the effective date of the proposed exercise.

The notice must set forth the number of SARs with respect to which the SAR Award is to be exercised. No SAR granted to an Executive Officer, Director or 10 percent beneficial owner of any class of Shares may be exercised prior to six months from the date of grant, except in the event of the death or disability of such grantee which occurs prior to the expiration of such six month period if so permitted under the incentive agreement.

(b) *Settlement*

Upon exercise of a SAR, the grantee will receive an amount equal to the spread. The spread, less applicable withholdings, will be payable only in cash, within 10 calendar days from the exercise date. In no event may any SAR be settled in any manner other than by delivery of a cash payment from the Company.

(c) *Form of incentive agreement*

Each grantee to whom an Incentive Award is granted will be required to enter into an incentive agreement with the Company, in such a form as is provided by the Compensation Committee.

(d) *Termination of employment*

Unless otherwise expressly provided in the grantee's incentive agreement, if the grantee's employment is terminated for any reason other than due to his death, disability, retirement or for cause, any non-vested portion of any outstanding SAR Award at the time of such termination will automatically expire and terminate and no further vesting will occur after the termination date. In such event, except as otherwise expressly provided in his incentive agreement, the grantee will be entitled to exercise his rights only with respect to the portion of the incentive award that was vested as of his termination of employment date for a period that will end on the earlier of (i) the expiration date set forth in the incentive agreement; or (ii) ninety days after the date of his termination of employment.

Unless otherwise expressly provided in the grantee's incentive agreement, in the event of the termination of a grantee's employment for cause, all vested and non-vested SAR Awards granted to such grantee will immediately expire, and will not be exercisable to any extent, as of 12:01 a.m. (CST) on the date of such termination of employment.

Unless otherwise expressly provided in the grantee's incentive agreement, upon the termination of employment due to the grantee's retirement: any non-vested portion of any outstanding SAR Award will immediately terminate and no further vesting will occur and any vested SAR Award will expire on the earlier of (i) the expiration date set forth in the incentive agreement; or (ii) the expiration of six months after the date of termination.

Unless otherwise expressly provided in the grantee's incentive agreement, upon termination of employment as a result of the grantee's disability or death any non-vested portion of any outstanding SAR Award will immediately terminate upon termination of employment and no further vesting will occur and any vested incentive award will expire on the earlier of either (i) the expiration date set forth in the incentive agreement; or (ii) the one year anniversary date of the termination of employment date.

(e) *Change in control*

SARs will become exercisable upon a change in control (as defined in paragraph 16.2(k) of this Part 17 (*Additional Information*)), unless provided otherwise by the Compensation Committee.

16.4 ***Outstanding Incentive Awards***

As at the Last Practicable Date, 47,973 Common Shares remained available for the Compensation Committee to issue and the following securities were outstanding:

(a) *Options*

As at the Last Practicable Date, the following Options were outstanding:

Total Number of Options	***Number of Vested Options***	***Number of Unvested Options***	***Option Exercise Price ($)***	***Option Expiration Date***	***Aggregate Exercise Price of Options ($)***
402,507	128,065	274,442	$ 0.86	28 February 2023	$346,156
52,292	–	52,292	$ 0.93	2 November 2022	$48,632
279,570	279,570	–	$ 0.99	1 June 2022	$276,774
325,048	194,916	130,132	$ 1.00	11 April 2022	$325,048
258,735	258,735	–	$ 1.04	18 March 2021	$269,084
375,039	375,039	–	$ 1.08	29 December 2021	$405,042
257,228	257,228	–	$ 1.43	6 June 2024	$367,836
175,644	175,644	–	$ 1.60	9 May 2023	$281,030
150,000	150,000	–	$ 1.94	5 July 2020	$291,000
13,000	13,000	–	$ 2.20	12 April 2020	$28,600
44,163	–	44,163	$ 2.29	31 March 2024	$101,133
520,562	–	520,562	$ 2.33	28 February 2024	$1,212,909
119,700	119,700	–	$ 4.98	3 March 2020	$596,106
2,973,488	1,951,897	1,021,591			$4,549,350

As at the Last Practicable Date, the number of Options held by the Directors and Executive Officers was as follows:

Name	***Total Number of Options***	***Number of Vested Options***	***Number of Unvested Options***	***Option Exercise Price ($)***	***Option Expiration Date***	***Aggregate Exercise Price of Options ($)***
Directors						
Cary M. Bounds	179,580	179,580	–	$ 1.04	18 March 2021	$ 186,763
	375,039	375,039	–	$ 1.08	29 December 2021	$405,042
	150,000	150,000	–	$ 1.94	5 July 2020	$291,000
	162,145	–	162,145	$ 2.33	28 February 2024	$377,798
	866,764	704,619	162,145			$1,260,603
Andrew L. Fawthrop	93,190	93,190	–	$ 0.99	1 June 2022	$92,258
	64,307	64,307	–	$ 1.43	6 June 2024	$91,959
	58,548	58,548	–	$ 1.60	9 May 2023	$93,677
	216,045	216,045	–			$277,894

Name	Total Number of Options	Number of Vested Options	Number of Unvested Options	Option Exercise Price ($)	Option Expiration Date	Aggregate Exercise Price of Options ($)
Directors						
A. John Knapp, Jr.	93,190	93,190	–	$ 0.99	1 June 2022	$92,258
	64,307	64,307	–	$ 1.43	6 June 2024	$91,959
	58,548	58,548	–	$ 1.60	9 May 2023	$93,677
	216,045	216,045	–			$277,894
Steven J. Pully	93,190	93,190	–	$ 0.99	1 June 2022	$92,258
	64,307	64,307	–	$ 1.43	6 June 2024	$91,959
	58,548	58,548	–	$ 1.60	9 May 2023	$93,677
	216,045	216,045	–			$ 277,894
William R. Thomas	64,307	64,307	–	$ 1.43	6 June 2024	$ 91,959
	64,307	64,307	–			$91,959
Executive Officers						
Elizabeth D. Prochnow	90,034	30,011	60,023	$ 0.86	28 February 2023	$77,429
	68,930	45,954	22,976	$ 1.00	11 April 2022	$68,930
	54,945	54,945	–	$ 1.04	18 March 2021	$57,143
	13,000	13,000	–	$ 2.20	12 April 2020	$28,600
	20,268	–	20,268	$ 2.33	28 February 2024	$47,224
	247,177	143,910	103,267			$279,326
Jason J. Doornik	–	–	–			–
David A. DesAutels	52,292	–	52,292	$ 0.93	2 November 2022	$48,632
	31,365	–	31,365	$ 2.33	28 February 2024	$73,080
	83,657	–	83,657			$121,712
Michael G. Silver	44,163	–	44,163	$ 2.29	31 March 2024	$101,133
	44,163	–	44,163			$101,133

(b) *Restricted Shares*

As at the Last Practicable Date, the following unvested Restricted Shares were outstanding:

Total Number of Unvested Restricted Shares	Restricted Shares Grant Price ($)	Restricted Shares Award Date
163,372	$ 0.86	28 February 2018
26,882	$ 0.93	2 November 2017
12,500	$ 1.00	11 April 2017
61,729	$ 1.08	29 December 2016
22,926	$ 2.29	1 April 2019
130,875	$ 2.33	28 February 2019
418,284		

As at the Last Practicable Date, the following unvested Restricted Shares held by the Directors and Executive Officers was as follows:

Name	Total Number of Unvested Restricted Shares	Restricted Shares Grant Price ($)	Restricted Shares Award Date
Directors			
Cary M. Bounds	102,325	$ 0.86	28 February 2018
	61,729	$ 1.08	29 December 2016
	85,837	$ 2.33	28 February 2019
	249,891		
Andrew L. Fawthrop	–		
A. John Knapp, Jr.	–		
Steven J. Pully	–		
William R. Thomas	–		
Executive Officers			
Elizabeth D. Prochnow	10,730	$ 2.33	28 February 2019
	10,730		
Jason J. Doornik	–		
David A. DesAutels	29,070	$ 0.86	28 February 2018
	26,882	$ 0.93	2 November 2017
	16,604	$ 2.33	28 February 2019
	72,556		
Michael G. Silver	22,926	$ 2.29	1 April 2019
	22,926		

(c) *SARs*

As at the Last Practicable Date, the following SARs were outstanding:

Total Number of SARs	Number of Vested SARs	Number of Unvested SARs	SAR Exercise Price ($)	SAR Expiration Date	Aggregate Exercise Price of SARs ($)
1,732,944	509,769	1,223,175	$ 0.86	28 February 2023	$1,490,332
179,580	179,580	–	$ 1.04	18 March 2021	$ 186,763
849,057	550,315	298,742	$ 1.20	21 April 2022	$1,018,868
196,892	–	196,892	$ 1.72	9 May 2024	$ 338,654
767,783	–	767,783	$ 2.33	28 February 2024	$1,788,934
3,726,256	1,239,664	2,486,592			$4,823,551

As at the Last Practicable Date, the SARs held by the Directors and Executive Officers was as follows:

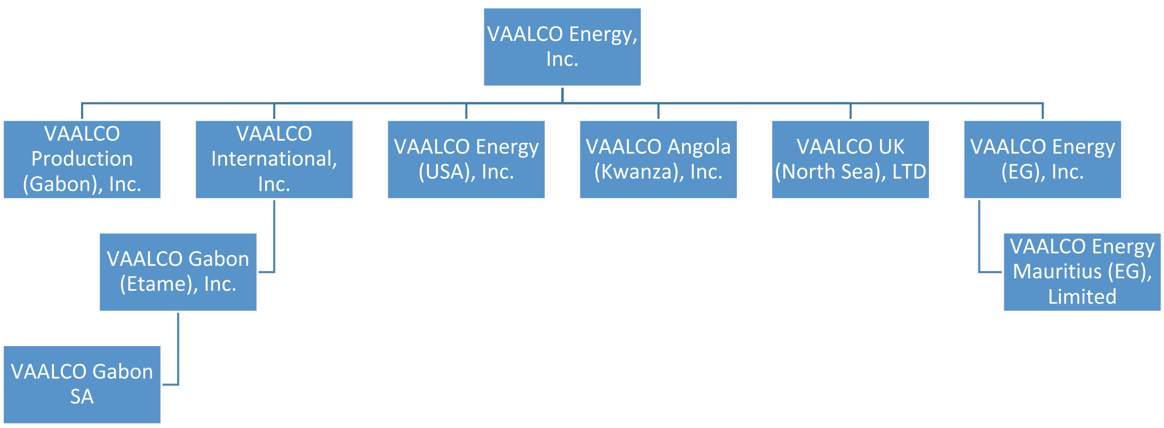
Name	***Total Number of SARs***	***Number of Vested SARs***	***Number of Unvested SARs***	***SAR Exercise Price ($)***	***SAR Expiration Date***	***Aggregate Exercise Price of SARs ($)***
Directors						
Cary M. Bounds	891,334	297,111	594,223	$ 0.86	28 February 2023	$ 766,547
	179,580	179,580	–	$ 1.04	18 March 2021	$ 186,763
	754,717	503,145	251,572	$ 1.20	21 April 2022	$ 905,660
	324,290	–	324,290	$ 2.33	28 February 2024	$ 755,596
	2,149,921	979,836	1,170,085			$ 2,614,566
Andrew L. Fawthrop	–	–	–			–
A. John Knapp, Jr.	–	–	–			–
Steven J. Pully	–	–	–			–
William R. Thomas	–	–	–			–
Executive Officers						
Elizabeth D. Prochnow	90,034	30,011	60,023	$ 0.86	28 February 2023	$ 77,429
	40,536	–	40,536	$ 2.33	28 February 2024	$ 94,449
	130,570	30,011	100,559			$ 171,878
Jason J. Doornik	–	–	–			–
David A. DesAutels	168,814	–	168,814	$ 0.86	28 February 2023	$ 145,180
	62,730	–	62,730	$ 2.33	28 February 2024	$ 146,161
	231,544	–	231,544			$ 291,341
Michael G. Silver	–	–	–			–

16.5 ***401(k)***

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

17. Subsidiaries

17.1 The Group structure is as follows:



17.2 The Company has the following Subsidiaries:

Name	***Place of Incorporation***	***Date of Incorporation***	***Proportion of Ownership Interest***	***Nature of Ownership Interest***	***Principal Activity***
VAALCO Energy (USA), Inc.	Delaware, USA	16 October 1996	100%	Direct	Dormant
VAALCO International, Inc.	Delaware, USA	31 July 2002	100%	Direct	Holding company
VAALCO Gabon (Etame), Inc.	Delaware, USA	14 June 1995	100%	Indirect (through VAALCO International, Inc.)	Holding company
VAALCO Production (Gabon), Inc.	Delaware, USA	14 June 1995	100%	Direct	Dormant
VAALCO Angola (Kwanza), Inc.	Delaware, USA	15 May 2006	100%	Direct	Dormant
VAALCO UK (North Sea), Limited	England & Wales	22 May 2006	100%	Direct	Dormant
VAALCO Energy (EG), Inc.	Delaware, USA	3 July 2012	100%	Direct	Holding company
VAALCO Energy Mauritius (EG), Limited	Mauritius	23 November 2012*	100%	Indirect (through VAALCO Energy (EG) Limited)	Oil and gas exploration operation company
VAALCO Gabon S.A.	Gabon	4 June 2014	100%	Indirect (through VAALCO Gabon (Etame), Inc.)	Oil and gas exploration operation company

Note

* Date of certificate of incorporation on change of name.

17.3 VAALCO Mauritius, which holds the Company's working interest in Block P, registered a branch with the Mercantile Registry of Bata, in Equatorial Guinea, on 18 July 2013. However, the duration of the branch has expired and is therefore currently considered not in good standing by the State of Equatorial Guinea. The Company is taking steps to restore the branch to good standing, which it expects to be completed by Q4 2019. The Group may be subject to fines, penalties and related administrative expenses, whether the branch is restored to good standing by Q4 2019 or after that date, which the Company understands are likely not to exceed €25,000.

18. Material contracts

The following is a summary of contracts (not being entered into in the ordinary course of business) which have been entered into by the Group: (i) within the two years immediately preceding the date of this Prospectus and are, or may be material; or (ii) which contain any provision under which the Group has any obligation or entitlement which is material to VAALCO as at the date of this Prospectus.

Shareholder agreements

18.1 ***Kornitzer Stockholder Agreement***

On 22 December 2015, (1) VAALCO; (2) Kornitzer Capital; and (3) John C. Kornitzer (together with Kornitzer Capital, the "**Kornitzer Group**") entered into the Kornitzer Stockholder Agreement, pursuant to which the Company agreed to give the Kornitzer Group the right to nominate an appointee Director at each Shareholder meeting until the Kornitzer Group beneficially owned less than 5 percent of the issued and outstanding Common Shares. A. John Knapp Jr. was appointed to the Board and to the Audit Committee as the Kornitzer Group's nominee Director.

The Kornitzer Group agreed to vote (i) in favour of the election of each Director nominated by the Board or any removal of Directors; and (ii) in accordance with the Board's recommendations with respect to any other proposal to be submitted at a meeting of Shareholders, unless ISS recommends otherwise, in which case the Kornitzer Group may vote in accordance with ISS' recommendations.

The Kornitzer Group also agreed to customary standstill restrictions, except that the Kornitzer Group is permitted to increase its beneficial ownership up to a total of 15 percent of the issued and outstanding Common Shares.

Each party can terminate the Kornitzer Stockholder Agreement at any time by giving written notice to the counterparties.

On 31 May 2019, A. John Knapp, Jr. resigned from the Board and each of the Company Committees with immediate effect, following notification by the Kornitzer Group on 23 May 2019 that it beneficially held less than 5 percent of the issued and outstanding Common Shares.

On 6 June 2019, the Board, acting on the recommendation of the Nominating and Corporate Governance Committee, determined to reappoint Mr. Knapp as a Director and member of each of the Compensation Committee, Nominating and Corporate Governance Committee and Strategic Committee, and chair of the Audit Committee, as an independent Director.

18.2 ***Group 42-BLR Settlement Agreement***

On 22 December 2015, (1) VAALCO; and (2) the Group 42-BLR Group entered into the Group 42-BLR Settlement Agreement, pursuant to which the Company agreed to give the Group 42-BLR Group the right to nominate an appointee Director at each Shareholder meeting until such a time as the Group 42-BLR Group beneficially owned less than 5 percent of the issued and outstanding Common Shares. William R. Thomas is the currently appointed nominee Director of the Group 42-BLR Group.

The Group 42-BLR Group agreed, among other things, to vote (i) in favour of the election of each Director nominated by the Board or any removal of Directors; and (ii) in accordance with the Board's recommendations with respect to any other proposal to be submitted at a meeting of Shareholders, unless ISS recommends otherwise, in which case the Group 42-BLR Group may vote in accordance with ISS' recommendations.

The Group-42 BLR Group also agreed to customary standstill restrictions, except that Group 42 is allowed to increase its Common Share ownership up to a total of 6.5 percent of the issued and outstanding Common Shares and BLR Group is allowed to increase its Common Share ownership up to a total of 8.5 percent of the issued and outstanding Common Shares.

Each party can terminate the Group 42-BLR Settlement Agreement at any time by giving written notice to the counterparties.

Etame Marin Block agreements

18.3 ***Etame PSC***

Overview

On 7 July 1995, (1) VAALCO Etame; (2) VAALCO Energy (Gabon) Inc.; and (3) the State of Gabon entered into the Etame PSC, which was approved by a Presidential Decree of 12 December 1995.

The Etame PSC has been amended and restated six times since the parties entered into the original agreement, on (1) 7 July 2001; (2) 13 April 2006; (3) 26 November 2009; (4) 5 January 2012; (5) 25 April 2016; and (6) 17 September 2018. The Etame PSC Extension was approved by Presidential Decree of 24 September 2018.

VAALCO Etame transferred its interests in the Etame PSC to VAALCO Gabon on 29 December 2016. VAALCO Gabon has a 31.1 percent interest in the Etame PSC.

Etame PSC Extension

The Etame PSC Extension extended the Etame PSC until September 2028, with an option to extend the Etame PSC for two additional five-year periods.

Under the Etame PSC Extension, the Etame Consortium agreed to a signing bonus of $65.0 million ($21.8 million, net to the Group) payable to the State of Gabon. The Etame Consortium paid $35.0 million ($11.8 million, net to the Group) on 26 September 2018 and paid $25.0 million ($8.4 million, net to the Group) through an agreed upon reduction of the VAT receivable owed by the State of Gabon to the Etame Consortium as of the effective date of the Etame PSC Extension. An additional $5.0 million is payable to the State of Gabon following completion of the Base Case Work. Pursuant to the Etame Audit Agreement, VAALCO Gabon will pay the full $5.0 million on behalf of the Etame Consortium.

Under the terms of the Etame PSC, the Etame Consortium is required to complete the Base Case Work by 16 September 2020. The Company estimates that the Base Case Work will cost approximately $61.2 million ($20.5 million, net to the Group). The Etame Consortium is also required to complete two technical studies by 16 September 2020 at an estimated cost of $1.3 million gross ($0.4 million, net to the Group). If the Base Case Work is not undertaken, the Etame Consortium must pay the costs of the work that has not been carried out as set out in the budget approved by the State of Gabon.

Exclusive exploration authorisations and exclusive exploration permits

Pursuant to the Etame PSC, VAALCO Etame was issued an exclusive exploration permit over 3,073 km^2 in the Etame Marin Block on 12 December 1995 ("**EEP Permit**") (Licence No. Etame G4-160).

Following the issuance of the EEP, which entitled VAALCO Etame to undertake exploration activities in the delimited area, VAALCO Etame was issued three EEAs pursuant to the Etame PSC ("**Etame EEAs**"). The Etame EEAs, which provide the Etame Consortium with the right to produce hydrocarbons in the delimited areas, were issued on (1) 17 July 2001 (Licence No. Etame Marin G5-88); (2) 25 March 2005 (Licence No. Avouma G5-95); and (3) 20 June 2006 (Ebouri G5-98).

The EEP Permit expired in 2014. Pursuant to the Etame PSC Extension, the Etame EEAs expire on 12 September 2028.

Development and production period

Under the Etame EEAs and the Etame PSC, the Etame Consortium is entitled to develop and exploit the reservoirs inside each EEA area until 12 September 2028. If, following this period, the commercial exploitation of one or more of the Etame EEAs is still possible, the relevant Etame EEA may be renewed at the request of the Etame Consortium, by order of the Minister in charge of hydrocarbons, for a maximum period of five years, provided that the obligations and commitments provided under the Etame PSC have been fulfilled. A second renewal of a renewed Etame EEA for a maximum duration of five years can be granted under the same conditions.

Prior to the Etame PSC Extension, the Etame PSC provided for the State of Gabon to take a 7.5 percent gross working interest carried by the Etame Consortium following the commencement of production. This working interest could be freely assignable by the State of Gabon, and is currently held by Tullow.

Pursuant to the Etame PSC Extension, the State of Gabon will acquire from the Etame Consortium an additional 2.5 percent gross working interest carried by the Etame Consortium effective 20 June 2026, to be transferred by each of the Etame Consortium *pro rata* to their respective participating interests in the Etame PSC. VAALCO Gabon's share of this interest to be transferred to the State of Gabon is 0.8 percent. If the State of Gabon wishes to acquire an additional participation in the Etame PSC or acquire shares in VAALCO Gabon, as operator, the terms of the acquisition will have to be market terms.

The agreement is governed by the laws of Gabon.

18.4 *Etame JOA*

General

On 4 April 1997, (1) VAALCO Etame; (2) VAALCO Energy (Gabon), Inc.; (3) Western Atlas Afrique, Ltd.; (4) Petrofields Exploration & Development Co., Inc.; and (5) Alcorn Petroleum and Minerals Corporation entered into the Etame JOA to govern the joint venture relationship between the parties in the exploration, development and operation of the Etame Marin Block. Under the terms of the original Etame JOA, VAALCO Etame was designated as operator of the fields.

The Etame JOA has been amended and/or novated seven times since the parties entered into the original agreement, on (1) 4 April 1997; (2) 5 September 2002; (3) 31 December 2004; (4) 12 October 2007; (5) 10 December 2014; (6) 22 November 2016; and (7) 29 December 2016 ("**Seventh Amendment**") (together, "**Amendments**"). In addition to the Amendments, the Etame JOA has been subject to a number of novation and assignments of working party's interest in, and obligations in respect of, the Etame JOA.

Following the Seventh Amendment, entered into between (1) VAALCO Etame; (2) Addax Etame; (3) Sasol; (4) PetroEnergy; and (5) VAALCO Gabon, pursuant to which VAALCO Etame agreed to transfer all of its rights and obligations under the Etame JOA to VAALCO Gabon, the parties to the Etame JOA are the Etame Consortium, with VAALCO Gabon appointed as the operator of the Etame Marin Block.

Operator responsibilities

As operator, VAALCO Gabon may enter into agreements with third parties relating to (i) the provision of the facilities used within the context of the Etame Marin Block; and (ii) the supply of goods or services, within certain monetary limits and subject to any limitations on such authority decided by the operating committee.

The operator is also responsible for:

- exclusively representing the Etame Consortium in dealings with the State of Gabon with respect to matters arising under the Etame PSC or Etame JOA;
- preparing the timetable for the work schedules and required budgets;
- hiring and assigning employees;
- preparing financial statements, reports and records as required under the Etame JOA;
- discharging all liability and expenses incurred in connection with operations taken pertaining to the Etame JOA;
- managing payments to the State of Gabon for all periodic payments, taxes, fees and other payment pertaining to the Etame JOA;
- performing the duties for the operating committee; and
- obtaining all permits, consents, approval, surface or other rights that may be required in connection with the conduct of the Etame JOA.

Operating committee

The powers of the operating committee include the management, control and supervision of all matters pertaining to joint operations. In particular, the operating committee has the power:

- to authorise and supervise the joint operations to properly explore the Etame Marin Block;
- to approve, revise or reject programmes and budgets;
- to study and approve the recommendations from subcommittees relating to programmes and budgets;
- to ensure that the operator applies the decisions of the operating committee; and
- more generally, to make any decisions on joint operations that do not fall within the operator's remit and exclusive control.

Each member of the Etame Consortium is entitled to one representative and one alternative representative on the operating committee. For the operating committee's decisions to be adopted, they must be approved by the vote of at least two representatives on behalf of the Etame Consortium then having collectively at least a majority of the participating interests in the Etame Marin Block. As operator, VAALCO Gabon has the right to appoint the chairman of the operating committee and all subcommittees.

Financing joint operations

Each member of the Etame Consortium contributes to the financing of joint operations in proportion to its participating interest in the Etame Marin Block. All costs, expenses and liabilities in respect of programmes and budgets and all income from the operations are determined, placed into a joint bank account and authorised according to specific procedures set out in the Etame JOA. Each party is also responsible for its *pro rata* share of the State of Gabon's participating interest of its costs, expenses and liabilities.

If a party fails to make payment further to a call for funds, it will be given notice by the operator and, if necessary, an emergency meeting of the operating committee will be convened. As long as a payment default persists, the defaulting party's portion of the joint account may be used to reimburse the party that has advanced the funds. The non-defaulting party may take recourse against the defaulting party after sixty days by any legal means, or may suspend joint operations related to the interest held by the defaulting party and require that they completely withdraw from the Etame JOA and Etame PSC.

Exclusive operations

Each member of the Etame Consortium may decide to undertake performance of an exclusive, sole-risk operation after the operating committee and each other member of the Etame Consortium, having received notice of entitlement to participate, have decided not to pursue or to abandon a given joint operation. Such party will then assume the risks and costs of that operation. If one or more members of the Etame Consortium wish to participate in an exclusive operation, the operator must perform the operation even if it is not a participant. However, the risks, costs, investments and supervision of the exclusive operations are the responsibility of the participating members of the Etame Consortium. An exclusive operation cannot be carried out if it may have a significant negative impact on joint operations or if it is contrary to the existing work programmes.

A non-participating member of the Etame Consortium may subsequently choose to participate in the sole risk operation by paying the participating parties a premium for its delayed participation in the operation, in an amount equal to the expenses and costs committed to the sole-risk operation on the date on which the former decided to contribute, in proportion to its participating interest plus 300 percent.

The implementation and execution of joint operations take priority over sole risk operations. In addition, any property acquired as part of a sole-risk operation is the exclusive property of the party or parties participating in the sole-risk operation. Facilities for a sole risk operation as well as the resulting oil production are the property of the participating parties until such time as any non-participating parties decide to participate.

The agreement is governed by the laws of the State of Texas, USA, excluding conflict of law rules.

18.5 ***Etame offshore drilling contract***

On 1 March 2019, (1) VAALCO Gabon; and (2) P2021 Rig Co. ("**P2021 Rig**"), a subsidiary of Vantage Drilling International, entered into an offshore drilling agreement for conducting drilling operations at Etame.

P2021 Rig provides drilling rig services in support of drilling, workover, testing, suspension, completion and/or abandonment operations in Etame. The primary work expected of P2021 Rig involves the drilling of pilot appraisal and horizontal development wells from production platforms. P2021 Rig must also provide the personnel, materials (if required) and onshore technical support necessary for the duration of the contract and for the services above.

The minimum duration of the agreement is the period of time required to drill, complete, abandon or workover two firm development wells (approximately 4 months) with VAALCO Gabon having the option to lengthen the term by electing 4 x 1 single option drill, complete, abandon or workover wells (to be completed in direct succession to each other, with the spud date of the first well expected by October 2019 as part of the Base Case Work following commencement of the Work Programme on 13 September 2019).

The agreement, except for where any matter is necessarily subject to and exclusively governed by Gabonese law, is governed by the general maritime law of the United States and, to the extent that such general maritime law and Gabonese law is not applicable, by the laws, excluding conflict of law rules, of the State of Texas, USA.

18.6 ***Etame Lifting Agreement***

On 1 November 2017, (1) the Etame Consortium; (2) Tullow; and (3) SNHG entered into a lifting agreement in respect of the Etame Marin Block. The agreement is supplementary to the Etame JOA and provides the procedures for scheduling the parties' respective entitlements, rights and obligations for the lifting of their share of the liquid hydrocarbons. In accordance with the Etame PSC and Etame JOA, VAALCO Gabon lifts the State of Gabon's share of the oil that it is entitled to, on its behalf.

As operator, VAALCO Gabon is responsible for, among other things, administering the agreement, determining the allocation of the liquid hydrocarbons, scheduling and coordinating the lifting, notifying the parties of any changes to FPSO Regulations and responding to emergency situations. The costs are borne by the parties in proportion to their respective interests in the Etame PSC.

On or before the tenth day of the month which is two months prior to the month of lifting, each party is required to nominate to VAALCO Gabon the quantities of oil it proposes to lift. The final lifting schedule is then confirmed on or before the 16th day of the same month.

All parties to the Etame Lifting Agreement bear the risk of loss for the crude oil when it passes the delivery point. In respect of matters covered by the agreement, there are no liabilities between parties or their subsequent affiliates or successors and their respective relevant parties for any consequential losses. Each party is responsible for all taxes, duties and other fees and charges in relation to the oil.

No party may transfer any interest in this agreement without transferring an identical interest under the Etame JOA and the Contract, as applicable.

The agreement shall continue until the termination of the Etame PSC, unless terminated earlier upon the unanimous agreement of the parties.

The agreement is governed by the laws of England and Wales.

18.7 ***FPSO Agreement***

On 20 August 2001, (1) VAALCO Etame; and (2) Tinworth Limited ("**Tinworth**") entered into the FPSO Agreement, pursuant to which VAALCO Etame leased the FPSO Petroleo Nautipa from Tinworth. The FPSO Agreement has been amended and restated from time to time. In March 2016, Tinworth novated its right and obligations under the agreement to each of (1) Tinworth Pte. Limited (as contractor); and (2) Tinworth Gabon S.A. (as operator) and, in June 2017, VAALCO Etame novated its right and obligations under the agreement to VAALCO Gabon ("**2017 Amendment**").

The duration of the FPSO Agreement was, following the 2017 Amendment, until 20 September 2020, after which VAALCO Gabon had the right to extend the FPSO Agreement for a further two additional terms of one year each. On 14 August 2019, VAALCO Gabon elected to extend the term to 20 September 2021. In the event VAALCO Gabon elects to extend the term to 20 September 2022 and after such date, VAALCO Gabon has the option to purchase the FPSO Petroleo Nautipa.

The agreement is governed by the laws of England and Wales.

18.8 ***Mercuria COSPA***

On 18 January 2019, (1) VAALCO Gabon; (2) PetroEnergy; (3) Sasol (together "**Sellers**"); and (4) Mercuria entered into the Mercuria COSPA. The Mercuria COSPA was amended and acceded on 1 February 2019, pursuant to which Addax was made a party to the Mercuria COSPA.

Pursuant to the agreement, Mercuria has agreed to purchase all oil lifted from Etame by and for the benefit of the Sellers, for the period from 1 February 2019 until termination of the Mercuria COSPA on 31 January 2020. Delivery of the oil from the Sellers to Mercuria takes place FOB at the FPSO Petroleo Nautipa ("**Load Port**").

The contract price for the oil is determined separately for each lifting of oil according to the Dated Brent plus/minus the differential from Dated Brent to Rabi Blend as published by the Ministry of Petroleum of the Republic of Gabon for the month of each loading.

Title and the risk of loss or damage to the oil supplied passes from the Sellers to Mercuria when the oil reaches the flange connecting Mercuria's nominated vessel's permanent hose connections to the Sellers' loading facilities at the Load Port and neither Mercuria nor the Sellers are liable for indirect, special or consequential damages.

The Mercuria COSPA contains customary termination provisions, including the Sellers' right to terminate the agreement where Mercuria (i) is made or becomes insolvent; or (ii) fails to make timely payments due under the agreement; or (iii) is in breach of any representation, warranty or undertaking provided to the Sellers under or in connection with the Mercuria COSPA and fails to rectify the breach within 14 days of receiving notice from the Sellers; or (iv) commits any other breach of the agreements and fails to rectify the breach within 14 days of receiving notice from the Sellers. Additionally, where Mercuria fails to pay to the Sellers any sums due under the Mercuria COSPA and fails to make payment within 30 days of being put on notice by the Sellers, the Sellers may terminate the agreement.

Each party to the Mercuria COSPA has agreed to indemnify and hold harmless each other party from and against any and all liabilities claims, damages, losses, penalties, costs and expense arising from or related to events in respect of violation of anti-bribery laws. This provision survives the expiration of the agreement.

The agreement is governed by the laws of England and Wales.

18.9 ***Crude oil sale and purchase agreement with Glencore Energy UK Limited***

On 20 December 2017, (1) the Etame Consortium; (2) Tullow (together "**Sellers**"); and (3) Glencore Energy UK Limited ("**Glencore**") entered into a crude oil sale and purchase agreement on 20 December 2017 ("**Glencore COSPA**") that ended on 31 January 2019.

Pursuant to the Glencore COSPA, Glencore agreed to purchase all oil lifted from Etame by and for the benefit of the Sellers, for the period from 1 February 2018 until termination of the Glencore COSPA on 31 January 2019. Under the terms of the Glencore COSPA, delivery of the oil from the Sellers to Glencore took place FOB at the FPSO Petroleo Nautipa ("**Load Port**").

The contract price for the oil was determined separately for each lifting of oil according to the Dated Brent plus/minus the differential from Dated Brent to Rabi Blend as published by the Ministry of Petroleum of the Republic of Gabon for the month of loading.

Title and the risk of loss or damage to the oil supplied passed from the Sellers to Glencore when the oil reached the flange connecting Glencore's nominated vessel's permanent hose connections to the Sellers' loading facilities at the Load Port and neither Glencore nor the Sellers were liable for indirect, special or consequential damages.

Each party to the Glencore COSPA agreed to indemnify and hold harmless each other party from and against any and all liabilities claims, damages, losses, penalties, costs and expense arising from or related to events in respect of violation of anti-bribery laws. This provision survived the expiration of the agreement.

The agreement is governed by the laws of England and Wales.

18.10 ***Etame agency agreement***

On 18 January 2019, (1) VAALCO Gabon; (2) PetroEnergy; and (3) Sasol entered into an agency agreement ("**Agency Agreement**") in respect of the Etame JOA, Mercuria COSPA and Etame Lifting Agreement. The Agency Agreement was amended and acceded on 1 February 2019, pursuant to which Addax was made a party to the Agency Agreement.

Pursuant to the Agency Agreement, VAALCO Gabon was appointed as agent on behalf of the parties in respect of their administrative duties under the Mercuria COSPA. Such duties include responsibility for the performance of the invoicing procedures under the Mercuria COSPA and documentation of instructions nominating vessels pursuant to the Etame Lifting Agreement.

It was agreed that VAALCO Gabon would not take any decisions in respect of the material obligations of the parties without first receiving written approval from the majority of the other parties to the agreement, with each party's vote being equal to its equity entitlement and "majority" being two or more party's having an aggregate of equity entitlement greater than sixty percent of the available equity entitlement.

Under the terms of the Agency Agreement, each of the parties agreed that each were severally liable (to the extent of their respective equity entitlement) for all obligations arising under the Mercuria COSPA.

The agreement is governed by the laws of England and Wales.

18.11 ***Etame Audit Agreement***

Effective 9 September 2019, the Etame Consortium entered into the Etame Audit Agreement in September 2019 to resolve a legacy issue related to outstanding audit exception findings by members of the Etame Consortium for audits undertaken under the Etame JOA for the periods from 2007 through 2016.

Pursuant to the Etame Audit Agreement, VAALCO Gabon will (1) pay approximately $1.1 million to the other members of the Etame Consortium in cash; and (2) pay the other members of the Etame Consortium's proportionate share of the $5.0 million payment due to the State of Gabon under the Etame PSC Extension (being $3.3 million), following completion of the Base Case Work.

The Etame Audit Agreement provides the manner in which such settlement payment and certain other overhead costs will be distributed among the Etame Consortium and releases VAALCO Gabon from any claims and liabilities for any audit exceptions through 2016.

Block P agreements

18.12 ***Block P PSC***

Overview

On 3 April 2003, (1) GEPetrol (on behalf of the State of Equatorial Guinea); (2) Petronas Carigali Equatorial Guinea Ltd. ("**PCEG**") (now known as VAALCO Mauritius); (3) Ocean; (4) DNO; and (5) Atlas entered into the Block P PSC, which was ratified by the State of Equatorial Guinea and became effective on 17 April 2003.

The Block P PSC has been amended on (1) 7 July 2011 ("**First Amendment**"); and (2) 14 May 2013 ("**Second Amendment**") (together "**Amendments**"). In addition to the Amendments, the Block P PSC has been subject to a number of novation and assignments of working party's interest in, and obligations in respect of, the Block P PSC. VAALCO acquired its 31.0 percent interest in the Block P PSC on 4 July 2012, through the acquisition of PCEG from Petronas Carigali Overseas SDN RHD.

The Block P PSC originally granted exclusive exploration rights to the Block P Consortium for a period of four years from 17 April 2003. This was extended until 31 December 2011 by the First Amendment. After the Second Amendment, the Block P PSC was suspended in June 2013. Pursuant to the Second Amendment, VAALCO Mauritius was recognised as owning a 31.0 percent participating interest in the PDA pursuant to the Block P PSC from 14 May 2013, which expires on 13 May 2038.

The Block P PSC was suspended in June 2013. The EG MMH lifted this suspension on 28 September 2018 and granted a two-year extension conditional on: (i), the introduction to the EG MMH of a new investor or joint venture owner in Block P within a term of no more than six months; and (ii) the drilling of an exploration well within one year of the EG MMH approving the new investor or joint venture owner. GEPetrol has completed the first condition and the Block P Consortium are waiting for the EG MMH to approve the new joint owner. Once the joint owner is approved, the Block P Consortium will be required to drill an exploration well within one year. In addition, VAALCO is awaiting the EG MMH to approve the appointment of VAALCO Mauritius as technical operator for Block P. If the Block

P Consortium fail to drill an exploration well within one year of the EG MMH approving the new joint owner, the Block P Consortium will lose or relinquish their interest in Block P.

Development and production period

The Block P PSC contemplates that upon the discovery of oil or gas, an exclusive appraisal period of 20 months may be granted by the EG MMH following approval of a work programme and budget for the appraisal. However, the Block P Consortium are required to report and declare a commercial discovery 30 days prior to the expiry of the exploration period and any extension. If upon the expiry of the initial exploration period or an extension, an appraisal work programme is in progress, a six-month extension of the exploration period to complete the appraisal work can be granted. If the discovery is deemed to be commercial, an exclusive exploitation period of 25 years, which may be renewed for a further five years, may be granted.

As from the date of approval of a development and production plan in respect of a discovery that is deemed to be commercial, the Block P Consortium would be permitted to exploit a targeted field for a 25-year period, which could be extended for an additional five-year period.

The royalty payable on volumes produced will range from 10 percent to 16 percent, depending on the daily production volume. Bonus payments of $1 million at first production and $1 million, $2 million, $4 million and $10 million are payable when production reaches 10,000, 30,000, 60,000 and 100,000 barrels (respectively) in a continuous 30- day period. The State of Equatorial Guinea also receives annual surface rentals of $1.00 per hectare of Block P during the initial exploration period and $1.50 during the development and production period.

The State of Equatorial Guinea also has the right to request that the Block P Consortium sell to the State of Equatorial Guinea a portion of its profit oil for internal consumption, at the market price determined in accordance with the Block P PSC.

Other terms

The Block P PSC provides for an abandonment plan and budget to be agreed when Block P reaches 50 percent of its productive capacity or six years prior to the estimated recoverable hydrocarbons from the field development and production area have been produced. The Block P PSC sets out the health and safety standards to be applied, the training, personnel obligations of the parties, dispute resolution mechanics and other standard terms in production sharing contracts.

The agreement is governed by the laws of Equatorial Guinea.

18.13 *Block P JOA*

General

On 9 August 2004, (1) GEPetrol; (2) Ocean; (3) Petronas Carigali Equatorial Guinea Ltd. (now known as VAALCO Mauritius); (4) DNO; and (5) Atlas entered into the Block P JOA to govern the joint venture relationship between the parties in the exploration, development and operation of Block P. Under the terms of the original Block P JOA, Ocean was designated as operator of the fields.

The Block P JOA has been amended on (1) 7 July 2011 ("**First Amendment**"); and (2) 14 May 2013 ("**Second Amendment**") (together "**Amendments**"). In addition to the Amendments, the Block P JOA has been subject to a number of novation and assignments of working party's interest in, and obligations in respect of, the Block P JOA. Under the First Amendment, GEPetrol replaced Ocean as the operator under the Block P JOA.

Operator responsibilities

As operator, GEPetrol may enter into agreements with third parties relating to (i) the provision of the facilities used within the context of the Block P; and (ii) the supply of goods or services, within certain monetary limits and subject to any limitations on such authority decided by the operating committee.

The operator is also responsible for:

- exclusively representing the Block P Consortium in dealings with the State of Equatorial Guinea with respect to matters arising under the Block P PSC or Block P JOA;

- preparing the timetable for the work schedules and required budgets;
- hiring and assigning employees;
- preparing financial statements, reports and records as required under the Block P JOA;
- discharging all liability and expenses incurred in connection with operations taken pertaining to the Block P JOA;
- managing payments to the State of Equatorial Guinea for all periodic payments, taxes, fees and other payment pertaining to the Block P JOA;
- performing the duties for the operating committee; and
- obtaining all permits, consents, approval, surface or other rights that may be required in connection with the conduct of the Block P JOA.

Operating committee

The powers of the operating committee include the management, control and supervision of all matters pertaining to joint operations. In particular, the operating committee has the power:

- to authorise and supervise the joint operations to properly explore and exploit Block P;
- to approve, revise or reject programmes and budgets;
- to study and approve the recommendations from subcommittees relating to programmes and budgets;
- to ensure that the operator applies the decisions of the operating committee; and
- more generally, to make any decisions on joint operations that do not fall within the operator's remit and exclusive control.

Each member of the Block P Consortium is entitled to one representative and one alternative representative on the operating committee. For the committee's decisions to be adopted, they must be approved by a majority and at least two member representatives on behalf of the Block P Consortium. As operator, GEPetrol has the right to appoint the chairman of the operating committee and all subcommittees.

Financing joint operations

Each of the Block P Consortium contributes to the financing of joint operations in proportion to its participating interest in Block P. All costs, expenses and liabilities in respect of programmes and budgets and all income from the operations are determined, placed into a joint bank account and authorised according to specific procedures set out in the Block P JOA. Each party is also responsible for its *pro rata* share of the State of Equatorial Guinea participating interest of its costs, expenses and liabilities.

If a party fails to make payment further to a call for funds, it will be given notice by the operator and, if necessary, an emergency meeting of the operating committee will be convened. As long as a payment default persists, the defaulting party's portion of the joint account may be used to reimburse the party that has advanced the funds. The non-defaulting party may take recourse against the defaulting party after sixty days by any legal means, or may suspend joint operations related to the interest held by the defaulting party and require that they completely withdraw from the Block P JOA and Block P PSC.

Exclusive operations

Each member of the Block P Consortium may decide to undertake performance of an exclusive, sole-risk operation after the operating committee and each other member of the Block P Consortium, having received notice of entitlement to participate, have decided not to pursue or to abandon a given joint operation. Such party will then assume the risks and costs. If one or more members of the Block P Consortium wish to participate in an exclusive operation, the operator must perform the operation even if it is not a participant. However, the risks, costs, investments and supervision of the exclusive operations are the responsibility of the participating members of the Block P Consortium. An exclusive operation cannot be carried out if it may have a significant negative impact on joint operations or if it is contrary to the existing work programmes.

A non-participating member of the Block P Consortium may subsequently choose to participate in the sole risk operation by paying the participating parties a penalty for its late participation in the operation, in an amount equal to the expenses and costs committed to the sole risk operation on the date on which the former decided to contribute, in proportion to its participating interest plus 500 percent.

The implementation and execution of joint operations take priority over sole risk operations. In addition, any property acquired as part of a sole-risk operation is the exclusive property of the party or parties participating in the sole-risk operation. Facilities for a sole risk operation as well as the resulting oil production are the property of the participating parties until such time as any non-participating parties decide to participate.

The agreement is governed by the laws of England and Wales.

Block 5 agreement

18.14 ***Block 5 Settlement Agreement***

Effective 1 December 2006, following a decree by the State of Angola on 1 November 2006, (1) VAALCO Angola; (2) Sonangol E.P.; (3) Sonangol P&P; and (4) InterOil (together "**Block 5 Consortium**") entered into the Block 5 PSA with respect to a 1.4 million-acre oil exploration concession off the coast of Angola. The Block 5 Consortium also entered into a joint operating agreement under the Block 5 PSA with effective date 1 December 2006 ("**Block 5 JOA**"), pursuant to which VAALCO Angola was appointed operator. VAALCO Angola's working interest was 40 percent, and it carried Sonangol P&P, for 10 percent of the work program. InterOil, which at the time of execution of the Block 5 PSA and Block 5 JOA had a 40 percent working interest, was excluded from the Block 5 PSA and left the Block 5 Consortium in 2010.

On 30 September 2016, VAALCO Angola notified Sonangol P&P that it was withdrawing from the Block 5 JOA with effect from 31 October 2016. On 30 November 2016, VAALCO Angola notified the national concessionaire, Sonangol E.P., that it was withdrawing from the Block 5 PSA. Further to VAALCO's decision to withdraw from Angola, it closed its local offices with no intention of conducting future activities in Angola.

Under the Block 5 PSA, VAALCO Angola and 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 Block 5 PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in Q1 2015. The Block 5 PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the Block 5 PSA, of which VAALCO's participating interest share would be $5.0 million per well.

On 26 February 2019, (1) VAALCO Angola; (2) Sonangol E.P.; and (3) Sonangol P&P entered into the Block 5 Settlement Agreement which was approved by an executive decree by the State of Angola on 28 June 2019. In consideration for the payment of $4.5 million by VAALCO Angola to the Angola National Agency of Petroleum, Gas, and Biofuels ("**ANAPGB**"), as national concessionaire, and the elimination of the $3.3 million outstanding receivable from Sonangol P&P, VAALCO Angola was released in full and final settlement from its outstanding obligations and liabilities arising under the Block 5 PSA. On 16 July 2019, VAALCO Angola made the final settlement payment to ANAPGB.

Derivative agreement

18.15 ***International Swaps and Derivatives Association, Inc. ("ISDA") 2002 Master Agreement***

On 31 May 2018, (1) BP Energy Company; and (2) VAALCO entered into an ISDA 2002 Master Agreement, schedule ("**Schedule**"), and credit support annex. The Master Agreement is a standardised framework agreement to facilitate individual OTC derivatives transactions to be carried out between the two parties. It contains certain fundamental non-commercial standard terms and conditions (including representations, undertakings, events of defaults, termination events, change of law provisions and transaction netting provisions).

The Schedule incorporates tailored terms for the requirements and circumstances of the parties and the purposes of the transactions, including for the individualised swap arrangements.

BP Energy Company and VAALCO agreed to a derivative transaction with an effective date of 1 June 2018 for a term ending on 30 June 2019 for crude oil, of approximately 400,000 BBL. On 6 May 2019, the parties agreed to a new current derivative transaction with an effective date of 1 July 2019, for a term ending on 30 June 2020 for crude oil of a notional quantity of 500,000 BBL. This swap is set at $66.70 per BBL / monthly and a varying floating amount price per barrel equal to the arithmetic average of the daily mean quote for Brent as published in Platts Calendar Month Average (Swaps).

The agreement is governed by the laws of England and Wales.

19. Exploration licences and production leases

The Group holds the following leases and licences:

Company	*Licence No.*	*Licence Type*	*Resources Covered*	*Area*	*Date of Grant*	*Date of Expiry*
VAALCO Gabon	Etame Marin G5-88	EEA	Liquid and gaseous hydrocarbons	94.44 km^2	17 July 2001	12 September 2028
	Avouma G5-95	EEA	Liquid and gaseous hydrocarbons	77.81 km^2	25 March 2005	12 September 2028
	Ebouri G5-98	EEA	Liquid and gaseous hydrocarbons	14.86 km^2	20 June 2006	12 September 2028
VAALCO Mauritius	N/A	Block P PSC (exploration, appraisal and development with a view to production of a field in the PDA)	Gaseous and/or liquid hydrocarbons	PDA	14 May 2013(1)	13 May 2038(2)

Notes

(1) Date of grant of PDA issued pursuant to the second amendment of the Block P PSC, subject to the conditional two-year extension conditions issued by the EG MMH on 28 September 2018.

(2) If the conditional two-year extension conditions of the EG MMH dated 28 September 2018 are not met by the Block P Consortium by 28 September 2020, the Block P Consortium will relinquish or lose its interests in the Block P PSC.

20. Statutory auditors

20.1 The auditors of the Group for financial years ended 31 December 2018, 31 December 2017, and 31 December 2016 have been BDO USA, whose address is 2929 Allen Parkway, 20th Floor, Houston, Texas 77019, United States. The auditors for the Group prior to the financial year ended 31 December 2016 were Deloitte & Touche LLP ("**Deloitte**"). Under the SEC Rules, companies are required to include the auditors' opinion for any comparable years presented in annual consolidated financial statements, which under the SEC Rules is the prior two financial years. Deloitte's opinion for financial year ended 31 December 2015 was therefore included for filing with the audited consolidated financial statements of the Group for financial years ended 31 December 2017 and 31 December 2016.

20.2 BDO USA has audited the annual consolidated financial statements for the Group for the financial years covered by the Historical Financial Information Period, which have been prepared in accordance U.S. GAAP.

20.3 The unaudited condensed consolidated interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018 have not been audited by BDO USA.

21. Working capital

In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements and the Working Capital Period.

22. No significant change

There has been no significant change in the financial performance or financial position of the Group since 30 June 2019, being the end of the last financial period of the Group for which financial information has been published, to the date of this Prospectus. Such financial information, being the Historical Financial Information, is included in Part 12 (*Historical Financial Information*) of this Prospectus.

23. Competent Person's Reports

The Company confirms that no material changes have occurred since the effective date of the Competent Person's Reports, being 31 March 2019, the omission of which would make the Competent Person's Reports misleading.

24. Legal and arbitration proceedings

The Company confirms that, other than the Etame Audit Agreement described at paragraph 18.11 of this Part 17 (*Additional Information*), there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the issuer is aware), during a period covering at least the previous 12 months which may have, or have had in the recent past significant effects on the Company and/or the Group's financial position or profitability.

25. Related party transactions

The Company confirms that, other than the Kornitzer Stockholder Agreement and Group 42-BLR Settlement Agreement described at paragraphs 18.1 and 18.2, respectively, of this Part 17 (*Additional Information*), there are no related party transactions in the period covered by the Historical Financial Information and up to the Last Practicable Date.

26. Consents

26.1 NSAI (in its capacity as an independent competent person) has given and not withdrawn its written consent to the inclusion of the Competent Person's Reports in Part 20 (*Etame Marin Block Competent Person's Report*) and Part 21 (*Block P Competent Person's Report*) of this Prospectus and references to the Competent Person's Reports in this Prospectus and for the purposes of Rule 5.3.2R(2)(f) of the Prospectus Regulation Rules has authorised the contents of such parts of this Prospectus that comprise the Competent Person's Reports.

26.2 GMP FirstEnergy has given and not withdrawn its written consent to the inclusion of references to its name in this Prospectus.

27. Miscellaneous

27.1 The total costs (including fees and commissions, but exclusive of VAT) payable by the Company in connection with Admission are estimated to be £720,000.

27.2 The Company confirms that all third party information contained in this Prospectus has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by such third parties, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this Prospectus, the source of such information has also been identified.

28. Documents available for inspection

Copies of the following documents will be available for inspection during normal business hours on any Business Day at the offices of Memery Crystal LLP for the period of 12 months following Admission:

28.1 this Prospectus;

28.2 the Certificate of Incorporation and Bylaws;

28.3 the audited annual consolidated financial statements of the Group for the financial years ended 31 December 2018, 31 December 2017, and 31 December 2016, together with the related audit reports from the independent auditor;

28.4 the unaudited condensed interim financial statements of the Group for the six months ended 30 June 2019 and 30 June 2018;

28.5 the Competent Person's Reports contained in Part 20 (*Etame Marin Block Competent Person's Report*) and Part 21 (*Block P Competent Person's Reports*) of this Prospectus; and

28.6 the letters confirming the consents referred to in paragraph 26 of this Part 17 (*Additional Information*).

Dated 23 September 2019

PART 18 – DEFINTIONS

2014 LTIP or **2014 Long-Term Incentive Plan**	the long-term incentive plan of the Company, adopted by the Compensation Committee on 4 March 2014 and approved by Shareholders on 4 June 2014, details of which are set out at paragraph 16.2 of Part 17 (*Additional Information*) of this Prospectus
2016 SAR Plan or **2016 Share Appreciation Rights Plan**	the share appreciation rights plan of the Company, adopted by the Compensation Committee on 10 March 2016, details of which are set out at paragraph 16.3 of Part 17 (*Additional Information*) of this Prospectus
401(k) Plan	the 401(k) plan sponsored by the Company for Employees
Addax	Addax Petroleum Oil & Gas Gabon, société anonyme registered to the Registre du Commerce et du Crédit Mobilier under the number 2003B442 with its registered office at Port-Gentil, BP 452
Addax Etame	Addax Petroleum Etame Inc., a private company incorporated in the British Virgin Islands with company number 561089 and having its registered office at Nemours Chambers, Road Town, Tortola, British Virgin Islands
Admission	the admission of all of the Common Shares to the standard segment of the Official List and to trading on the Main Market for listed securities
Amended Term Loan Agreement	the amended loan agreement entered into (1) the Company; and (2) the IFC, dated 30 January 2014 and terminated on 22 May 2018
Atlas	Atlas Petroleum (International) Ltd., a corporation organised and existing under the laws of Gibraltar, having its headquarter at 4, Akin Olugbade Street Victoria Island, Nigeria
Audit Committee	the Company's audit committee, details of which are set out at paragraph 3.2 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
Avouma/South Tchibala Field	the field operated by the Etame Consortium known as the Avouma/South Tchibala Field, part of the Etame Marin Block
Base Case Work	the drilling work required to be undertaken by the Etame Consortium at the Etame Marin Block, pursuant to the terms of the Etame PSC, details of which are set out at paragraph 5 of Part 8 (*Information on VAALCO Energy, Inc.*) of this Prospectus
BDO UK	BDO LLP, a limited liability partnership incorporated in England and Wales with company registration number of OC305127 and having its registered office at 55 Baker Street, London, W1U 7EU, the reporting accountants to the Company
BDO USA	BDO USA LLP, a limited liability partnership incorporated in the State of Delaware, USA whose address is 2929 Allen Parkway, 20th Floor, Houston, Texas 77019, United States, the independent auditors to the Company
Block 5	the 1.4 million-acre oil exploration concession off the coast of Angola

Block 5 PSA	the production sharing agreement entered into between (1) Sonangol E.P.; (2) VAALCO Angola; (3) Sonangol P&P; and (4) InterOil, dated 1 November 2006
Block 5 Settlement Agreement	the settlement agreement entered into between (1) VAALCO Angola; (2) Sonangol E.P.; and (3) Sonangol P&P on 26 February 2019, details of which are set out at paragraph 18.14 of Part 17 (*Additional Information*) of this Prospectus
Block P	a block offshore Equatorial Guinea known as Block P
Block P Consortium	the joint venture owners party to the Block P PSC from time to time, being (1) VAALCO Mauritius; (2) GEPetrol; (3) Atlas; and (4) Crown, as at the Last Practicable Date
Block P CPR or **Block P Competent Person's Report**	the Competent Person's Report on Block P set out at Part 21 (*Block P Competent Person's Report)* of this Prospectus
Block P PSC	the production sharing contract entered into between (1) the State of Equatorial Guinea; and (2) the Block P Consortium, dated 3 April 2003 in respect of an undeveloped portion of Block P, as amended, details of which are set out at paragraph 18.12 of Part 17 (*Additional Information*) of this Prospectus
BLR Group	each of (1) BLR Partners LP; (2) BLRPart, LP; (3) BLRGP Inc.; (4) Fondren Management, LP; (5) FMLP Inc.; (6) The Radoff Family Foundation; and (7) Bradley L. Radoff
Board	the Directors
Business Day	a day other than a Saturday, Sunday or public holiday in England when banks in London are open for business
Bylaws	the bylaws of the Company, as amended and restated from time to time
CEMAC	the Central African Economic and Monetary Community
CEO	the chief executive officer of the Company, who, as at today's date, is Cary M. Bounds
Certificate of Incorporation	the certificate of incorporation of the Company, as amended and restated from time to time
Change of Control Agreements	the change of control agreements entered into by the Company severally with the Executive Officers and certain other Employees, details of which are set out at paragraph 13.3 of Part 17 (*Additional Information*) of this Prospectus
Code	the Internal Revenue Code of 1986, as amended
Code of Business Conduct and Ethics	the Company's code of business conduct and ethics policy
Common Share	a common share of $0.10 par value in the capital of the Company
Company Committees	the (1) Audit Committee; (2) Compensation Committee; (3) Nominating and Corporate Governance Committee; and (4) Strategic Committee

Company or **VAALCO**	VAALCO Energy Inc., a public company incorporated in the State of Delaware, USA with registration file number 2188793 and having its registered office at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042, United States
Compensation Committee	the Company's compensation committee, details of which are set out at paragraph 3.2 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
Competent Person or **NSAI**	Netherland, Sewell & Associates, Inc. of 1301 McKinney Street #3200, Houston, Texas 77010, United States
Corporate Governance Policies	the Company's corporate governance policies, details of which are set out at paragraph 3.3 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
Corporate Governance Principles	the Company's corporate governance principles, details of which are set out at paragraph 3.3 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
CPRs or **Competent Person's Reports**	the Etame Marin Block CPR and the Block P CPR
CREST	the relevant system in respect of which Euroclear UK & Ireland is the operator (as defined in the CREST Regulations)
CREST Regulations	the Uncertificated Securities Regulations 2001 (SI 2001 No. 3755)
Crown	Crown Energy Ventures Corporation, a corporation organised and existing under the laws of British Virgin Islands
Custodian	Computershare Trust Company, N.A. or a subsidiary or third party appointed by the Depositary to provide the custody services
Deed Poll	the deed poll executed by the Depositary in favour of the holders of the Depositary Interests from time to time
Dentale Formation	the hydrocarbon formation known as the Dentale Formation, parts of which are included in the Etame Marin Block
Depositary	Computershare Investor Services plc, a private company incorporated in England and Wales with company number 3498808 and whose registered office is at The Pavilions, Bridgwater Road, Bristol BS13 8AE, United Kingdom
Depositary Agreement	the agreement entered into between the Company and the Depositary appointing the Depositary
Depositary Interests	the dematerialised depositary interests issued by the Depositary in respect of the underlying Common Shares
DGCL	the General Corporation Law of the State of Delaware, USA as amended from time to time
Directors	the directors of the Company from time to time, whose names, as at the date of this Prospectus, are set out on page 54 of this Prospectus
DNO	DNO ASA, a corporation organised and existing under the laws of Gibraltar

DTC	the Depositary Trust Company
DTR	the disclosure guidance and transparency rules made by the FCA under section 73A of FSMA
Ebouri Field	the field operated by the Etame Consortium known as the Ebouri Field, part of the Etame Marin Block
EDGAR	the Electronic Data Gathering, Analysis and Retrieval online public database of the SEC
EG MMH	the Equatorial Guinea Ministry of Mines and Hydrocarbons
Elf	Elf Aquitaine S.A.S, the original licence holder to the Etame PSC
Employees	the employees of the Company from time to time
ESMA	European Securities and Markets Authority
Etame Audit Agreement	the agreement between the Etame Consortium details of which are set out at paragraph 18.11 of Part 17 (*Additional Information*) of this Prospectus
Etame Consortium	the joint venture owners party to the Etame PSC from time to time, being (1) VAALCO Gabon (as field operator); (2) Addax; (3) Sasol; and (4) PetroEnergy, as at the Last Practicable Date
Etame Field	the field operated by the Etame Consortium known as the Etame Field, part of the Etame Marin Block
Etame Fields	the (1) Avouma/South Tchibala Field; (2) Ebouri Field; (3) Etame Field; (4) North Tchibala Field; and (5) Southeast Etame Field
Etame JOA	the joint operating agreement entered into between the Etame Consortium on 4 April 1997, as amended, details of which are set out at paragraph 18.4 of Part 17 (*Additional Information*) of this Prospectus
Etame Lifting Agreement	the agreement entered into between (1) the Etame Consortium; (2) Tullow; and (3) SNHG on 1 November 2017, details of which are set out at paragraph 18.6 of Part 17 (*Additional Information*) of this Prospectus
Etame Marin Block CPR or **Etame Marin Block Competent Person's Report**	the Competent Person's Report on the Etame Marin Block set out at Part 20 (*Etame Marin Block Competent Person's Report*) of this Prospectus
Etame Marin Block or **Etame**	an area of approximately 46,200 gross acres in the Congo Basin located 20 miles offshore Gabon in depths of approximately 250 feet that contains the Etame Fields
Etame PSC	the production sharing contract entered into between (1) the State of Gabon; and (2) the Etame Consortium, dated 7 July 1995 in respect of the Etame Marin Block, as amended, details of which are set out at paragraph 18.3 of Part 17 (*Additional Information*) of this Prospectus
Etame PSC Extension	amendment no.6 of the Etame PSC entered into between (1) the State of Gabon; and (2) the Etame Consortium, dated 17 September 2018, extending the term for each of the three EEAs

	in the Etame Marin Block for a period of ten years with effect from 17 September 2018, with the option for the Etame Consortium to extend for two additional five-year periods
Exchange Act	the U.S. Securities Exchange Act of 1934
Executive Officers	the executive officers of the Company from time to time, whose names, as at the date of this Prospectus, are set out on page 56 of this Prospectus
Expansive Work	any drilling work to be undertaken by the Etame Consortium at the Etame Marin Block in H1 2020 beyond the Base Case Work, details of which are set out at paragraph 5 of Part 8 (*Information on VAALCO Energy, Inc.*) of this Prospectus
FCA	the Financial Conduct Authority
FCPA	the U.S. Foreign Corrupt Practices Act 1977
FPSO Agreement	the agreement entered into between (1) VAALCO Gabon; and (2) Tinworth Limited pursuant to which the Group has leased FPSO Petroleo Nautipa, details of which are set out at paragraph 18.7 of Part 17 (*Additional Information*) of this Prospectus
FPSO Petroleo Nautipa	the FPSO leased by VAALCO Gabon pursuant to the FPSO Agreement
FSMA	the Financial Services and Markets Act 2000
Gamba Formation	the hydrocarbon formation known as the Gamba Formation, parts of which are included in the Etame Marin Block
GEPetrol	Compania Nacional de Petroleos de Guinea Equatorial, a company organised and existing under the laws of Equatorial Guinea, owned by the State of Equatorial Guinea
Gladstone Resources	Gladstone Resources Limited, a private company incorporated in the State of Delaware, USA under the DGCL, restated as the Company on 15 September 1997
GMP FirstEnergy	FirstEnergy Capital LLP (trading as GMP FirstEnergy), a limited liability partnership incorporated in England and Wales with company registration number OC346410 and having its registered office address at 85 London Wall, London, E2M 7AD, United Kingdom, the financial adviser to the Company
Group	the Company and its Subsidiaries
Group 42	each of (1) Group 42, Inc., a corporation incorporated in the State of Delaware, USA with registration file number 2971456 whose address is 312 Pearl Pkwy., Suite 2403, San Antonio, Texas 78215, USA; (2) Paul A. Bell; and (3) Michael Keane
Group 42-BLR Group	each of (1) Group 42; and (2) the BLR Group
Group 42-BLR Group Settlement Agreement	the settlement agreement entered into between (1) the Company; and (2) the Group 42-BLR Group dated 22 December 2015, details of which are set out at paragraph 18.2 of Part 17 (*Additional Information*) of this Prospectus

Historical Financial Information	the consolidated financial statements of the Group and its consolidated financial statements and the accompanying notes contained in the Appendix to this Prospectus, as referred to in Part 12 (*Historical Financial Information*) of this Prospectus
Historical Financial Information Period	the period covered by the Historical Financial Information
HMRC	Her Majesty's Revenue and Customs
ICE	the Intercontinental Exchange
IFC	International Finance Corporation
Incentive Award	a grant for Options, Restricted Shares, Restricted Share Units, Phantom Shares, SARs or otherwise awarded pursuant to the Incentive Plans
Incentive Plans	the 2014 LTIP and 2016 SAR Plan
InterOil	InterOil Exploration and Production ASA, a public company incorporated an organised under the laws of Norway with company registration access number 988 247 006 and having its main office at c/o Advokatfirmaet Schjødt AS, Ruseløkkveien 14, NO-0251 Oslo, Norway
IRS	the U. S. International Revenue Service
ISIN	International Securities Identification Number
ISS	the Institutional Shareholder Services
Kornitzer Capital	Kornitzer Capital Management, Inc., a for profit corporation incorporated in the State of Kansas, USA with business entity ID number 1684455 and having its registered officer at 5420 West 61st Place, Shawnee Mission, Kansas 66205, United States
Kornitzer Stockholder Agreement	the stockholder agreement entered into between (1) the Company; (2) Kornitzer Capital; and (3) John Kornitzer dated 22 December 2015, details of which are set out at paragraph 18.1 of Part 17 (*Additional Information*) of this Prospectus
Last Practicable Date	20 September 2019
LEI	Legal Entity Identifier
Listing Rules	the listing rules made by the FCA under section 73A of FSMA
London Stock Exchange or **LSE**	London Stock Exchange plc, a public limited company incorporated in England & Wales with company number 02075721 and having its registered office at 10 Paternoster Square, London EC4M 7LS
Main Market	the Main Market for listed securities of the London Stock Exchange
MAR	the European Union Market Abuse Regulation (596/2014)
Member State	one of the member states of the European Union
Mercuria	Mercuria Energy Trading SA, a company incorporated under the laws of Switzerland and having its registered office at 50 Rue du Rhone, 1204, Geneva, Switzerland
Mercuria COSPA	the crude oil sale and purchase agreement entered into between (1) VAALCO Gabon; and (2) Mercuria dated 18 January 2019,

	details of which are set out at paragraph 18.8 of Part 17 (*Additional Information*) of this Prospectus
Nominating and Corporate Governance Committee	the Company's nominating and corporate governance committee, details of which are set out at paragraph 3.2 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
North Tchibala Field	the field operated by the Etame Consortium known as the North Tchibala Field, part of the Etame Marin Block
NYSE	the New York Stock Exchange
Ocean	Ocean Equatorial Guinea Corporation a wholly-owned subsidiary of Devon Energy Corporation and a corporation organised and existing under the laws of the State of Delaware, USA and having its registered office at 1001 Fannin Suite 1600, Houston, Texas 77002, United States
Official List	the Official List of the FCA
OPEC	The Organization of the Petroleum Exporting Countries
Option	an option to acquire a Common Share
PDMR	person discharging managerial responsibilities, as defined in Article 3(1)(25) of MAR
PetroEnergy	PetroEnergy Resources Corporation, a public company incorporated in the Republic of the Philippines with having its registered office at 7th Floor, JMT Building, ADB Avenue, Ortigas Center, Pasig City, Metro Manila 1600, Philippines
Phantom Share	a phantom share in the capital of the Company granted to Employees and Directors that will vest over a period determined by the Compensation Committee
Preferred Share	a preferred share of $25.00 par value in the capital of the Company
Premium Listing	a listing on the premium segment of the Official List
PRMS	2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers
Projects	the Company's projects at the Etame Marin Block and Block P
Prospectus	this document
Prospectus Regulation	Regulation (EU) 2017/1129 of the European Parliament and Council of 14 June 2017
Prospectus Regulation Rules	the prospectus regulation rules made by the FCA under section 73A of FSMA
Restricted Share	a restricted share in the capital of the Company granted to Employees and Directors that will vest over a period determined by the Compensation Committee
Restricted Share Unit	a promise to deliver a corresponding number of Shares based upon the completion of service, performance conditions, or such other terms and conditions as specified in the award agreement

SAR	a share appreciation right, being the right to receive a "*spread*" equal to the excess of the fair market value of a specified number of Common Shares on the date the SAR is exercised over a SAR price specified in the applicable award agreement paid in cash as provided in the award agreement
SAR Award	an award for SARs granted pursuant to the 2016 SAR Plan
Sasol	Sasol Gabon S.A., a société anonyme registered to the Registre du Commerce et du Crédit Mobilier de Libreville with company number 2015 B 16969 and having its registered office at 705 Boulevard du Bord de Mer, Immeuble Dumez 6ème Etage, BP 2326 Libreville, Gabon
SEC	the U.S. Securities and Exchange Commission, an independent agency of the U.S. federal government
SEC Rules	the rules and regulations of the SEC
Securities Act	the U.S. Securities Act of 1933, as amended
SEENT	the Southeast Etame and North Tchibala Fields
Share	a share in the capital of the Company
Share Repurchase Programme	the Share repurchase programme approved by the Board on 20 June 2019, details of which are set out at paragraph 4.8 of Part 17 (*Additional Information*) of this Prospectus
Shareholders	the holders of Shares from time to time
SNHG	Societe Nationale Des Hydrocarbures Du Gabon (Gabon Oil Company)
Sojitz	Sojitz Etame Limited, a private company incorporated in England and Wales with company number 04516702 and having its registered office at 7th Floor, 8 Finsbury Circus, London EC2M 7EA
Sonangol E.P.	Sociedade Nacional de Combustíveis de Angola – Empresa Pública, a company incorporated in Angola in accordance with Decree No. 52/76, of 9 June 1976, having its headquarters in Rua Rainha Ginga 29-31, Luanda, Republic of Angola
Sonangol P&P	Sonangol Pesquisa e Produção, SA , a company incorporated in Angola in accordance with Decree No. 52/76, of 9 June 1976, having its with offices in Edificio Torres Atlântico, Av. 4 de Fevereiro No. 197, 12th Floor, Luanda, Angola
Southeast Etame Field	the field operated by the Etame Consortium known as the Southeast Etame Field, part of the Etame Marin Block
Standard Listing	a listing on the standard segment of the Official List
Strategic Committee	the Company's strategic committee, details of which are set out at paragraph 3.2 of Part 9 (*Directors, Executive Officers and Corporate Governance*) of this Prospectus
Subsidiaries	the subsidiaries (both direct and indirect) of the Company from time to time, details of which are set out at paragraph 17 of Part 17 (*Additional Information*) of this Prospectus

Takeover Panel	the Panel on Takeovers and Mergers
Treasury	the U. S. Department of the Treasury
Tullow	Tullow Oil Gabon SA, a private company incorporated under the laws of and having its registered office at Rue Louise Charron-Fortin, Batterie 4, BP 9773, Libreville, Gabon, a former participant of the Etame PSC
U.S. GAAP	accounting principles generally accepted in the U. S.
UK Bribery Act	the Bribery Act 2010
UK Takeover Code	The City Code on Takeovers and Mergers issued by the Takeover Panel
UKLA	the UK Listing Authority
United Kingdom or **UK**	the United Kingdom of Great Britain and Northern Ireland
United States or **U.S.** or **USA**	the United States of America, its territories and possessions, any state of the United States and the District of Columbia
VAALCO Angola	VAALCO Angola (Kwanza), Inc., a private company incorporated in the State of Delaware, USA with registration file number 4158022 and having its registered office at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042, United States
VAALCO Etame	VAALCO Gabon (Etame), Inc., a private company incorporated in the State of Delaware, USA with registration file number 2515801 and having its registered office at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042, United States
VAALCO Gabon	VAALCO Gabon S.A., a société anonyme registered to the Registre du Commerce et du Crédit Mobilier de Port-Gentil with company number 2014 B 1487 and having its registered office at Port-Gentil, Zone Industrielle OPRAG – Nouveau Port, Port-Gentil, B.P. 1335 Gabon
VAALCO Mauritius	VAALCO Energy (EG) Mauritius Limited., a private company incorporated in Mauritius with company registration number C44133 and having its registered office at 10 Frere Felix de Valois St., Port Louis, Mauritius
Work Programme	the Base Case Work and the Expansive Work
Working Capital Period	the 12 month period from the date of this Prospectus

PART 19 – GLOSSARY OF TECHNICAL TERMS AND CONVERSIONS

Glossary

The following provides an explanation of certain technical terms and abbreviations used in this Prospectus. The terms and their assigned meanings may not correspond to standard industry meanings or usage of these terms.

1C	low estimate scenario of contingent resources
1P	proved
1U	low estimate scenario of prospective resources
2C	best estimate scenario of contingent resources
2P	proved plus probable
2U	best estimate scenario of prospective resources
3C	high estimate scenario of contingent resources
3P	proved plus probable plus possible
3U	high estimate scenario of prospective resources
AVO	amplitude versus offset
BBBL	billion barrels
BBL	barrel, equivalent to 42 U.S. gallons
BCF	billion cubic feet
BOE	barrel of oil equivalent
BOPD	barrels of oil per day
Brent	Brent crude oil
contingent resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies
Dated Brent	a cargo of North Sea Brent that has been assigned a date when it will be loaded onto a tanker as published by the Platts Crude Oil Marketwire
E&P	exploration and production
EEA	exclusive exploitation authorisation
EIS	environmental impact study
ESP	electric submersible pumps
FB	fault block
FPSO	floating, production, storage and offloading vessel

H_2S	hydrogen sulphide
LNG	liquefied natural gas
MBBL	thousand barrels
MBOPD	thousands of barrels of oil per day
MCF	thousand cubic feet
MMBBL	million barrels
MMCF	million cubic feet
OTC	over-the-counter
P_g	probability of geological success
PDA	provisional development area
possible reserves	those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than probable reserves
probable reserves	those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves
Prospect	a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target
prospective resources	those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations
proved reserves	those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations
PSC	production sharing contract
Rabi Blend	Rabi Blend crude oil
reserves	those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions
resources	petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced, total resources is equivalent to total petroleum initially-in-place

Conversions

The following provides certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To convert to	From	Multiply by
1,000 cubic metres of gas	MCF	35.494
barrel	cubic metres of oil	0.158
cubic metres of oil	barrel	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

PART 20 – ETAME MARIN BLOCK COMPETENT PERSON'S REPORT

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES

to the

VAALCO GABON S.A. INTEREST

in

CERTAIN OIL PROPERTIES

located in the

ETAME MARIN PERMIT, OFFSHORE GABON

as of

MARCH 31, 2019

COMPETENT PERSON'S REPORT

BASED ON PRICE AND COST PARAMETERS

specified by

VAALCO GABON S.A.

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

September 20, 2019

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

Ladies and Gentlemen:

In accordance with the request of VAALCO Gabon S.A. (VAALCO), we have estimated the proved, probable, and possible reserves and future revenue, as of March 31, 2019, to the VAALCO interest in certain oil properties located in the Etame Marin Permit, offshore Gabon. Also as requested, we have estimated the unrisked contingent and prospective resources, as of March 31, 2019, to the VAALCO working interest in these properties. We completed our evaluation on or about the date of this letter. For the reserves, this Competent Person's Report (report) has been prepared using price and cost parameters specified by VAALCO, referred to as the Base Price Case, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$). Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties.

The estimates in this report have been prepared in accordance with the recommendations of the European Securities and Markets Authority (ESMA) and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification for the evaluators who contributed to this report and a list of abbreviations used in this report. This report has been prepared for use by VAALCO in filing with the United Kingdom Listing Authority (UKLA) and the London Stock Exchange (LSE); in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. 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 commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross oil reserves, the VAALCO working interest oil reserves, and the future net revenue to the VAALCO interest in these properties, as of March 31, 2019, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Working Interest[1]	Total	Present Worth at 10%
Proved Developed Producing	8,461.3	2,627.8	30,545.0	29,944.0
Proved Developed Non-Producing	1,837.5	570.7	8,222.8	7,069.2
Proved Undeveloped	7,654.2	2,377.1	19,805.0	14,399.8
Total Proved (1P)	17,953.0	5,575.6	58,572.8	51,413.0

Category	Oil Reserves (MBBL) Gross (100%)	Oil Reserves (MBBL) Working Interest[1]	Future Net Revenue (M$) Total	Future Net Revenue (M$) Present Worth at 10%
Probable	14,479.1	4,485.7	62,989.6	47,774.4
Proved + Probable (2P)	32,432.1	10,061.4	121,562.4	99,187.4
Possible	11,643.2	3,573.9	52,175.7	36,138.3
Proved + Probable + Possible (3P)	44,075.3	13,635.3	173,738.1	135,325.7

Totals may not add because of rounding.

[1] Working interest reserves are prior to deductions for government royalties and 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.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

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

As requested, this report has been prepared using Base Price Case oil price parameters specified by VAALCO. Oil prices are based on March 29, 2019, Brent Crude futures prices and are adjusted for quality, transportation fees, and market differentials. Sensitivities using Low and High Price Cases are further detailed in the Technical Discussion section of this report. Base Case oil prices, before adjustments, are shown in the following table:

Period Ending	Oil Price ($/Barrel)
12-31-2019	66.98
12-31-2020	65.01
12-31-2021	62.95
12-31-2022	60.85
12-31-2023	60.51
Thereafter	60.45

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

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure, actual costs from recent activity, and internal planning budgets. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. It is our understanding that VAALCO has established escrow accounts for abandonment liability and expects these accounts to be fully funded by December 31, 2028. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by December 31 of the year after the economic limit date. As requested, capital costs and abandonment costs are not escalated for inflation.

We have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon approval of a development plan with sufficient development wells to economically produce the volumes prior to termination of the PSC and commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. As requested, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined. The project maturity subclass for these contingent resources is development unclarified.

We estimate the unrisked gross contingent oil resources and the VAALCO unrisked working interest contingent oil resources for these properties, as of March 31, 2019, to be:

	Unrisked Contingent Oil Resources (MMBBL)	
Category	Gross (100%)	Working Interest
Low Estimate (1C)	15.6	4.8
Best Estimate (2C)	25.5	7.9
High Estimate (3C)	38.3	11.9

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL). Produced gas is expected to be flared or consumed in operations.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross prospective oil resources and the VAALCO unrisked working interest prospective oil resources for these prospects, along with the probability of geologic success (P_g), as of March 31, 2019, to be:

	Unrisked Prospective Oil Resources (MMBBL)						
	Gross (100%)			Working Interest			
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	P_g (%)
East Ebouri	1.6	3.6	8.6	0.5	1.1	2.7	73
Northeast Avouma	1.5	4.4	15.1	0.5	1.4	4.7	73
South Etame	1.9	4.6	12.3	0.6	1.4	3.8	64
Southwest Avouma	2.2	5.1	13.0	0.7	1.6	4.0	73
Southwest Etame	2.1	5.2	14.3	0.7	1.6	4.4	64
West Etame	0.4	1.0	2.4	0.1	0.3	0.8	56

The oil volumes shown include crude oil only. As requested, the scope of this project does not include prospective gas resources.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate.

Unrisked prospective resources are estimated ranges of recoverable oil volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes summary projections of reserves and revenue by reserves category, a technical discussion, and pertinent figures.

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. 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.

The reserves, contingent resources, and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates 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 volumes, and that our projections of future production will prove consistent with actual performance. If these volumes 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, and costs incurred 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, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (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 classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. The contingent and prospective resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. 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. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. 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.

The effective date of this report is March 31, 2019 ("Effective Date"). The publication of this report is assumed to be consistent with the publication date of the prospectus to be published by VAALCO. VAALCO has confirmed to us that there have been no material changes since the Effective Date, the omission of which would make this report misleading.

Sincerely,

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

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

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

Date Signed: September 20, 2019

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

Date Signed: September 20, 2019

JRC:RS

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

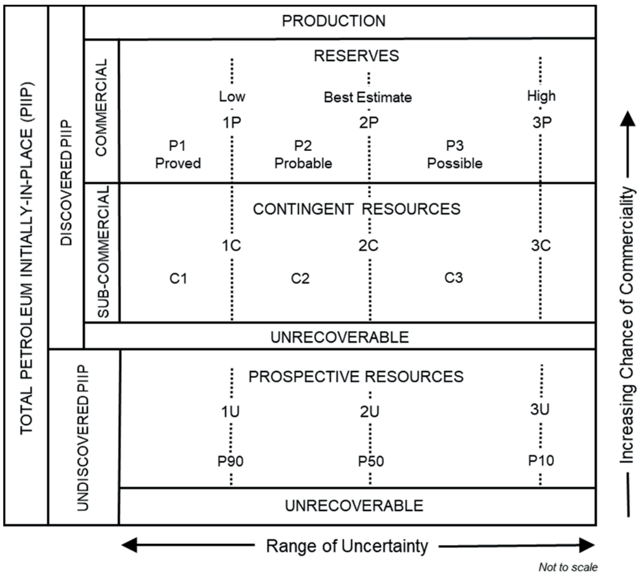


Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

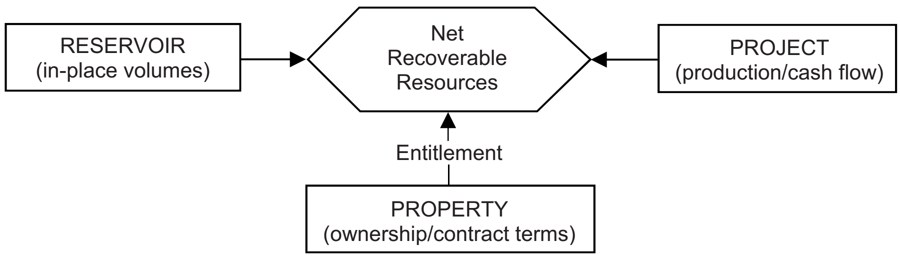


Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or 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 minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CERTIFICATE OF QUALIFICATION

I, John R. Cliver, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for VAALCO Gabon S.A. The effective date of this evaluation is March 31, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of VAALCO Gabon S.A. or its affiliated companies.

I 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; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 15 years of experience in petroleum engineering studies and evaluations.

/s/ John R. Cliver

By: ______________________________

John R. Cliver, P.E.
Vice President
Texas License No. 107216

September 20, 2019
Houston, Texas

CERTIFICATE OF QUALIFICATION

I, Zachary R. Long, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for VAALCO Gabon S.A. The effective date of this evaluation is March 31, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of VAALCO Gabon S.A. or its affiliated companies.

I 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; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 14 years of experience in geological and geophysical studies and evaluations.

/s/ Zachary R. Long
By: ______________________________
Zachary R. Long, P.G.
Vice President
Texas License No. 11792

September 20, 2019
Houston, Texas

ABBREVIATIONS

$	United States dollars
%	percent
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
1U	low estimate scenario of prospective resources
2U	best estimate scenario of prospective resources
3U	high estimate scenario of prospective resources
BBL	barrels
BBL/D	barrels per day
BOPD	barrels of oil per day
EEA	exclusive exploitation authorization
ESMA	European Securities and Markets Authority
ESP	electronic submersible pump
FB	fault block
FPSO	floating production, storage, and offloading vessel
H_2S	hydrogen sulfide
km^2	square kilometers
LKO	lowest known oil
LSE	London Stock Exchange
m	meters
M$	thousands of United States dollars
Max	maximum
MBBL	thousands of barrels
MBOPD	thousands of barrels of oil per day
Min	minimum
ML	most likely
MMBBL	millions of barrels
MTR	meters
NSAI	Netherland, Sewell & Associates, Inc.
OOIP	original oil-in-place
OWC	oil-water contact
P10	10 percent confidence level

ABBREVIATIONS

P90	90 percent confidence level
P_g	probability of geologic success
PID	Provision pour Investissements Diversifiées
PIH	Provision pour Investissements en Hydrocarbures
ppm	parts per million
PRMS	Petroleum Resources Management System
PSC	Production Sharing Contract
psi	pounds per square inch
RB/STB	reservoir barrels per stock tank barrel
SEENT	Southeast Etame and North Tchibala
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
the State	Gabonese national government
UKLA	United Kingdom Listing Authority
VAALCO	VAALCO Gabon S.A.

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SUMMARY PROJECTIONS OF RESERVES AND REVENUE

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

TOTAL PROVED (1P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,576.4	1,110.7	144.4	98.9	773.1	94.4	867.5	65.90	57,165.7
12-31-2020	5,044.5	1,566.7	203.7	140.0	1,090.4	132.6	1,223.0	63.93	78,184.1
12-31-2021	3,866.5	1,200.8	156.1	105.2	835.8	103.8	939.5	61.87	58,129.3
12-31-2022	3,054.8	948.7	123.3	82.5	660.3	82.5	742.9	59.77	44,400.3
12-31-2023	2,410.8	748.7	97.3	65.1	521.1	65.1	586.2	59.43	34,840.6
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	17,953.0	5,575.6	724.8	491.7	3,880.6	478.4	4,359.1	62.56	272,720.0
Cum Prod	109,440.4								
Ultimate	127,393.4								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	846.1	33,052.0	1,442.3	642.8	3,339.7	3,485.7
12-31-2020	0.0	846.1	41,645.1	3,524.6	2,588.8	34,757.1	34,519.3
12-31-2021	0.0	846.1	40,541.0	1,500.1	1,221.5	16,463.7	47,931.1
12-31-2022	0.0	846.1	37,604.9	1,177.3	390.3	5,162.4	51,744.3
12-31-2023	0.0	846.1	30,248.0	951.3	284.8	3,080.1	53,868.2
12-31-2024	0.0	4,230.3	0.0	0.0	0.0	(4,230.3)	51,413.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	51,413.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	51,413.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	51,413.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	51,413.0
Total	19,128.5	8,460.5	183,091.0	8,595.5	5,128.3	58,572.8	51,413.0

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,216.6	999.0	129.9	88.2	695.3	85.6	780.9	65.90	51,463.5
12-31-2020	3,409.3	1,058.8	137.6	92.2	736.9	92.0	828.9	63.93	52,994.0
12-31-2021	1,835.4	570.0	74.1	49.6	396.7	49.6	446.3	61.87	27,614.7
12-31-2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	8,461.3	2,627.8	341.6	230.0	1,829.0	227.2	2,056.2	64.23	132,072.2
Cum Prod	109,440.4								
Ultimate	117,901.8								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	763.3	29,064.5	1,307.8	1,635.5	21,963.4	21,271.3
12-31-2020	0.0	763.3	37,814.9	2,929.8	946.0	12,432.1	32,416.9
12-31-2021	0.0	763.3	24,785.1	736.9	162.9	1,492.4	33,696.2
12-31-2022	0.0	5,342.9	0.0	0.0	0.0	(5,342.9)	29,944.0
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	29,944.0
Total	0.0	7,632.7	91,664.5	4,974.4	2,744.4	30,545.0	29,944.0

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	90.5	28.1	3.7	2.7	19.6	2.2	21.8	65.90	1,434.3
12-31-2020	354.7	110.1	14.3	9.9	76.7	9.2	85.9	63.93	5,490.5
12-31-2021	1,170.1	363.4	47.2	31.6	252.9	31.6	284.5	61.87	17,604.3
12-31-2022	222.2	69.0	9.0	6.0	48.0	6.0	54.0	59.77	3,230.2
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	1,837.5	570.7	74.2	50.3	397.2	49.0	446.2	62.21	27,759.2
Cum Prod	0.0								
Ultimate	1,837.5								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	3,450.6	33.8	(79.3)	(2,129.5)	(2,028.3)
12-31-2020	0.0	0.0	317.2	129.6	379.8	5,423.5	2,785.2
12-31-2021	0.0	0.0	12,618.3	458.1	346.0	4,873.8	6,734.7
12-31-2022	0.0	(4,579.6)	3,091.7	87.0	3.4	4,634.5	9,992.9
12-31-2023	0.0	4,579.6	0.0	0.0	0.0	(4,579.6)	7,069.2
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	7,069.2
Total	0.0	0.0	19,477.8	708.5	650.0	8,222.8	7,069.2

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table III

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED UNDEVELOPED RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	269.3	83.6	10.9	8.0	58.2	6.5	64.8	65.90	4,268.0
12-31-2020	1,280.6	397.7	51.7	37.9	276.8	31.3	308.1	63.93	19,699.6
12-31-2021	860.9	267.4	34.8	24.0	186.1	22.6	208.7	61.87	12,910.3
12-31-2022	2,832.6	879.7	114.4	76.5	612.3	76.5	688.8	59.77	41,170.1
12-31-2023	2,410.8	748.7	97.3	65.1	521.1	65.1	586.2	59.43	34,840.6
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	7,654.2	2,377.1	309.0	211.5	1,654.5	202.1	1,856.6	60.80	112,888.6
Cum Prod	0.0								
Ultimate	7,654.2								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	82.8	536.8	100.7	(913.4)	(16,494.2)	(15,757.2)
12-31-2020	0.0	82.8	3,513.0	465.2	1,262.9	16,901.6	(682.8)
12-31-2021	0.0	82.8	3,137.6	305.1	712.6	10,097.5	7,500.2
12-31-2022	0.0	82.8	34,513.2	1,090.3	387.0	5,870.8	11,807.3
12-31-2023	0.0	(3,733.6)	30,248.0	951.3	284.8	7,659.7	16,855.0
12-31-2024	0.0	4,230.3	0.0	0.0	0.0	(4,230.3)	14,399.8
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	14,399.8
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	14,399.8
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	14,399.8
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	14,399.8
Total	19,128.5	827.8	71,948.7	2,912.6	1,734.0	19,805.0	14,399.8

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table IV

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE (2P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,805.6	1,181.9	153.6	105.7	822.6	100.0	922.6	65.90	60,798.1
12-31-2020	6,705.9	2,082.6	270.7	189.4	1,449.5	173.0	1,622.5	63.93	103,725.5
12-31-2021	5,355.4	1,663.2	216.2	178.3	1,101.1	167.6	1,268.7	61.87	78,494.9
12-31-2022	4,398.5	1,366.0	177.6	226.6	743.1	218.7	961.9	59.77	57,490.9
12-31-2023	3,722.3	1,156.0	150.3	140.5	725.7	139.5	865.2	59.43	51,418.2
12-31-2024	3,183.8	988.8	128.5	86.0	688.2	86.0	774.2	59.37	45,964.9
12-31-2025	2,734.4	849.2	110.4	75.5	587.8	75.5	663.3	59.37	39,379.4
12-31-2026	2,345.6	719.0	93.5	62.6	500.4	62.6	563.0	59.37	33,423.3
12-31-2027	180.6	54.6	7.1	4.7	38.0	4.7	42.7	59.37	2,537.1
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	32,432.1	10,061.4	1,308.0	1,069.4	6,656.4	1,027.7	7,684.0	61.59	473,232.3
Cum Prod	109,440.4								
Ultimate	141,872.5								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,257.0	1,528.0	575.9	6,573.1	6,576.5
12-31-2020	8,330.6	887.4	44,268.7	4,127.8	2,728.4	48,839.2	49,743.6
12-31-2021	0.0	887.4	43,106.9	1,986.6	1,895.6	34,409.5	77,721.6
12-31-2022	0.0	887.4	42,200.7	1,504.5	742.7	13,640.9	87,783.4
12-31-2023	0.0	887.4	41,595.8	1,350.1	452.0	8,036.8	93,195.8
12-31-2024	0.0	887.4	41,114.2	1,214.6	202.4	2,951.1	95,041.5
12-31-2025	0.0	887.4	30,889.6	1,059.0	405.4	6,948.8	98,921.8
12-31-2026	0.0	863.5	29,931.3	916.1	156.8	1,869.3	99,896.4
12-31-2027	0.0	863.5	2,447.1	70.3	1.0	(842.8)	99,529.7
12-31-2028	0.0	863.5	0.0	0.0	0.0	(863.5)	99,187.4
Total	27,459.1	8,802.5	308,811.3	13,757.2	7,160.1	121,562.4	99,187.4

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

[1] Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
[2] VAALCO's share of the state carry costs is shown as capital costs.
[3] Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table V

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROBABLE RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	229.2	71.2	9.3	6.8	49.5	5.6	55.1	65.90	3,632.5
12-31-2020	1,661.4	516.0	67.1	49.4	359.1	40.4	399.5	63.93	25,541.4
12-31-2021	1,488.9	462.4	60.1	73.1	265.3	63.9	329.2	61.87	20,365.6
12-31-2022	1,343.7	417.3	54.3	144.0	82.8	136.2	219.0	59.77	13,090.6
12-31-2023	1,311.5	407.3	52.9	75.4	204.6	74.4	278.9	59.43	16,577.6
12-31-2024	3,183.8	988.8	128.5	86.0	688.2	86.0	774.2	59.37	45,964.9
12-31-2025	2,734.4	849.2	110.4	75.5	587.8	75.5	663.3	59.37	39,379.4
12-31-2026	2,345.6	719.0	93.5	62.6	500.4	62.6	563.0	59.37	33,423.3
12-31-2027	180.6	54.6	7.1	4.7	38.0	4.7	42.7	59.37	2,537.1
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	14,479.1	4,485.7	583.1	577.6	2,775.7	549.2	3,325.0	60.31	200,512.3
Cum Prod	0.0								
Ultimate	14,479.1								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	41.4	205.0	85.7	(67.0)	3,233.4	3,090.8
12-31-2020	8,330.6	41.4	2,623.7	603.3	139.6	14,082.1	15,224.2
12-31-2021	0.0	41.4	2,565.9	486.6	674.1	17,945.8	29,790.5
12-31-2022	0.0	41.4	4,595.8	327.3	352.3	8,478.6	36,039.1
12-31-2023	0.0	41.4	11,347.8	398.8	167.1	4,956.7	39,327.6
12-31-2024	0.0	(3,342.8)	41,114.2	1,214.6	202.4	7,181.3	43,628.4
12-31-2025	0.0	887.4	30,889.6	1,059.0	405.4	6,948.8	47,508.8
12-31-2026	0.0	863.5	29,931.3	916.1	156.8	1,869.3	48,483.4
12-31-2027	0.0	863.5	2,447.1	70.3	1.0	(842.8)	48,116.7
12-31-2028	0.0	863.5	0.0	0.0	0.0	(863.5)	47,774.4
Total	8,330.6	342.0	125,720.3	5,161.6	2,031.8	62,989.6	47,774.4

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,992.4	1,239.9	161.2	111.2	863.0	104.5	967.5	65.90	63,757.8
12-31-2020	7,547.0	2,343.9	304.7	214.4	1,631.3	193.4	1,824.7	63.93	116,655.9
12-31-2021	6,538.1	2,030.5	264.0	444.6	914.5	407.5	1,321.9	61.87	81,787.7
12-31-2022	5,482.8	1,702.8	221.4	369.5	766.6	345.4	1,112.0	59.77	66,461.8
12-31-2023	4,744.3	1,473.4	191.5	269.0	756.2	256.7	1,012.9	59.43	60,195.7
12-31-2024	4,143.9	1,287.0	167.3	192.2	739.8	187.6	927.5	59.37	55,063.1
12-31-2025	3,640.7	1,130.7	147.0	128.4	727.5	127.8	855.3	59.37	50,781.0
12-31-2026	3,215.9	985.7	128.1	85.8	686.0	85.8	771.8	59.37	45,820.1
12-31-2027	2,849.0	860.9	111.9	74.9	599.2	74.9	674.1	59.37	40,020.6
12-31-2028	1,921.0	580.5	75.5	50.5	404.0	50.5	454.5	59.37	26,985.1
Total	44,075.3	13,635.3	1,772.6	1,940.5	8,088.1	1,834.1	9,922.2	61.23	607,528.8
Cum Prod	109,440.4								
Ultimate	153,515.7								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,424.0	1,597.8	649.7	9,369.8	9,255.9
12-31-2020	8,330.6	887.4	45,021.0	4,433.2	3,305.8	61,289.3	63,438.5
12-31-2021	0.0	887.4	44,265.5	2,103.5	1,932.7	36,463.9	93,103.0
12-31-2022	0.0	887.4	43,170.6	1,735.3	1,151.2	21,819.7	109,166.4
12-31-2023	0.0	887.4	42,510.0	1,574.2	110.1	15,334.2	119,437.5
12-31-2024	0.0	887.4	41,973.0	1,443.0	0.0	10,759.7	125,998.1
12-31-2025	0.0	887.4	41,522.9	1,333.5	0.0	7,037.2	129,916.3
12-31-2026	0.0	863.5	40,588.1	1,209.5	0.0	3,159.1	131,539.4
12-31-2027	0.0	863.5	32,543.8	1,070.5	0.0	5,542.8	134,058.8
12-31-2028	0.0	863.5	22,428.1	731.2	0.0	2,962.4	135,325.7
Total	27,459.1	8,802.5	387,447.0	17,231.6	7,149.5	173,738.1	135,325.7

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

SUMMARY PROJECTION OF RESERVES AND REVENUE - BASE PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

POSSIBLE RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[(1)] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	186.8	58.0	7.5	5.6	40.4	4.5	44.9	65.90	2,959.7
12-31-2020	841.1	261.2	34.0	25.0	181.8	20.5	202.3	63.93	12,930.4
12-31-2021	1,182.7	367.3	47.7	266.3	(186.6)	239.8	53.2	61.87	3,292.8
12-31-2022	1,084.3	336.8	43.8	142.9	23.4	126.7	150.1	59.77	8,970.9
12-31-2023	1,022.1	317.4	41.3	128.5	30.5	117.2	147.7	59.43	8,777.6
12-31-2024	960.2	298.2	38.8	106.2	51.6	101.6	153.2	59.37	9,098.2
12-31-2025	906.3	281.5	36.6	52.8	139.7	52.3	192.0	59.37	11,401.6
12-31-2026	870.2	266.7	34.7	23.2	185.6	23.2	208.8	59.37	12,396.8
12-31-2027	2,668.4	806.3	104.8	70.2	561.2	70.2	631.4	59.37	37,483.5
12-31-2028	1,921.0	580.5	75.5	50.5	404.0	50.5	454.5	59.37	26,985.1
Total	11,643.2	3,573.9	464.6	871.1	1,431.7	806.4	2,238.1	60.00	134,296.5
Cum Prod	0.0								
Ultimate	11,643.2								

Period Ending	Net Capital Cost[(2)] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[(3)] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	167.0	69.8	73.8	2,796.7	2,679.3
12-31-2020	0.0	0.0	752.3	305.4	577.4	12,450.1	13,695.0
12-31-2021	0.0	0.0	1,158.6	116.8	37.1	2,054.4	15,381.4
12-31-2022	0.0	0.0	969.9	230.8	408.5	8,178.7	21,382.9
12-31-2023	0.0	0.0	914.2	224.1	(341.8)	7,297.4	26,241.7
12-31-2024	0.0	0.0	858.8	228.3	(202.4)	7,808.6	30,956.6
12-31-2025	0.0	0.0	10,633.3	274.4	(405.4)	88.4	30,994.5
12-31-2026	0.0	0.0	10,656.8	293.4	(156.8)	1,289.8	31,643.0
12-31-2027	0.0	0.0	30,096.7	1,000.2	(1.0)	6,385.7	34,529.1
12-31-2028	0.0	0.0	22,428.1	731.2	0.0	3,825.9	36,138.3
Total	0.0	0.0	78,635.7	3,474.4	(10.6)	52,175.7	36,138.3

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table VIII

TECHNICAL DISCUSSION

TECHNICAL DISCUSSION
ETAME MARIN PERMIT, OFFSHORE GABON

1.0 GENERAL OVERVIEW

Netherland, Sewell & Associates, Inc. (NSAI) has estimated the proved, probable, and possible reserves and future revenue, as of March 31, 2019, to the VAALCO Gabon S.A. (VAALCO) working interest in certain oil properties located in the Etame Marin Permit, offshore Gabon. We have also estimated the unrisked contingent and prospective resources, as of March 31, 2019, to the VAALCO working interest in these properties. A location map for the Etame Marin Permit is shown on Figure 1. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties.

This Competent Person's Report (report) has been prepared in accordance with the recommendations of the European Securities and Markets Authority (ESMA) and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.

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 information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. 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 classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. 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.

2.0 GEOLOGY

The coastal sedimentary basin of Gabon started forming during the Upper Jurassic period with the onset of rifting and breakup of the Gondwana supercontinent. Rifting started with the formation of a series of tilted horst and graben blocks and fluviodeltaic deposition that ended with deposition of the Dentale Formation. The rift phase was terminated by major uplift of the western margin of Africa that caused an erosional event that planed off topographic highs and deposited the sediments in the lows, creating a surface with little or no topographic relief.

The rift phase was followed by an Aptian transition phase initiated by transgression of marine waters into the basin with deposition of the transgressive Gamba Sandstone and Vembo Shale. Later deposition of the Ezanga Salt occurred in the restricted seaway that formed and then was cut off from the main body of the ocean.

The transition phase was succeeded by the drift phase in which Albian oceanic crust started to form and the Madiela carbonates were deposited. These carbonates and the clastics of the Cenomanian Cap Lopez were deformed by basinward block faulting caused by a slight westward tilt of the basin and the mobility of the underlying salt.

From the Cenomanian onward, a large prograding wedge of marine and marginal marine clastics has been deposited along the west coast of Gabon. This sediment wedge has been broken up into large fault blocks (FBs) formed by listric faulting that soles out into the Ezanga Salt.

A generalized stratigraphic and lithologic column of south Gabon is shown on Figure 2. The Dentale Formation, Gamba Formation, Vembo Shale, and Ezanga Salt are of principal importance. These formations represent the source rock, reservoir, and seal for the fields evaluated in this report. A type log of the Dentale and Gamba Formations is shown on Figure 3.

The Dentale Formation contains a thick sequence of fluviodeltaic and fluviolacustrine sandstones and shales of Barremian age. The source rock for much of the offshore area is found in this formation. It is also one of the more prolific oil-producing zones in Gabon. The Dentale Formation is productive in offshore Etame, North Tchibala, and Tortue Fields, as well as onshore Obangue and Tsiengui Fields.

The Gamba Formation unconformably overlies the Dentale Formation and was deposited during the transgressive event after erosion of the Dentale Formation. The Gamba Formation is composed of a basal sandstone and an upper carbonate. The reservoir is usually contained in the sandstone since the carbonate is typically very tight unless a dolomite zone is developed. The Gamba Sandstone exhibits excellent reservoir properties, with porosity generally between 20 to 30 percent and permeability often greater than 1 darcy.

Capping the Gamba Formation are the Vembo Shale and the Ezanga Salt. The Vembo is a dark-colored, restricted marine shale. The Ezanga Salt varies in thickness from 500 to over 1,500 meters (m). The drastic change in thickness is caused by the mobility of the salt that has resulted in much of the structuring observed in the post-salt sequence. The Vembo Shale and Ezanga Salt make an excellent seal for the underlying Gamba and Dentale Formations.

3.0 OVERVIEW OF ETAME MARIN PERMIT AREA AND DEVELOPMENT

The Etame Marin Permit covers an area of approximately 3,074 square kilometers (km^2) in the coastal basin offshore southern Gabon. Currently, VAALCO holds the license to produce and drill within three Exclusive Exploitation Authorizations (EEAs) in the permit area, which comprise 187 km^2 located around the producing field areas. The Ebouri EEA includes Ebouri Field and comprises 14.86 km^2, the Avouma EEA includes Avouma/South Tchibala and North Tchibala Fields and comprises 77.81 km^2, and the Etame EEA includes Etame and Southeast Etame Fields and comprises 94.44 km^2. The location map on Figure 1 shows these areas. Water depths range from 75 to 85 m over the fields. The permit is located approximately 23 kilometers northwest of the Gabon-Congo international boundary. The table below describes the Etame Marine Permit and the fields it comprises.

License/Field	Operator	VAALCO Working Interest (%)	Status	License Expiration Date	License Area (km^2)
Etame Marin Permit	VAALCO Gabon S.A.	31.057	-	9/16/2028	187
Avouma/South Tchibala Field			Production		
Ebouri Field			Production		
Etame Field			Production		
North Tchibala Field			Production		
Southeast Etame			Production		

Elf Gabon, the original license holder, drilled several wells during the 1970s and 1980s when South Tchibala and North Tchibala Fields were discovered. VAALCO is the current operator, with a 31.057 percent working interest that was acquired in July 1995 and November 2016. VAALCO conducted a 385 km^2 3-D seismic survey in 1997 and drilled the discovery well for Etame Field in 1998.

The fields in the Etame Marin Permit produce to the Petroleo Nautipa floating production, storage, and offloading vessel (FPSO), which has a processing capacity of 30,000 barrels of total fluid per day. Dry tree wells are used to develop the fields from four manned production platforms. The Avouma, Ebouri, Etame, and Southeast Etame and North Tchibala (SEENT) Platforms are tied back through carbon steel subsea pipelines and unbonded flexible risers to the spread-moored FPSO. Some of the original wells in Etame Field have subsea trees, which are tied directly back to the FPSO. A summary of the key production facilities and their various production capacities is shown on Figure 4.

Development history and status for each of the fields is included below, and a table showing the various wells, their historical production, and their current status is shown on Figure 5. Representative depth structure maps for each field are shown on Figures 6 through 10.

3.1 AVOUMA/SOUTH TCHIBALA FIELD

The discovery well for South Tchibala Field was drilled in 1978, followed by the drilling of four more appraisal wells. The Avouma-1 exploration well was drilled in July 2004 to the southwest of the existing South Tchibala Field wells and confirmed a structure in a FB adjacent to South Tchibala Field. This field is now referred to as Avouma/South Tchibala Field. The Avouma-1 well drillstem tested at a rate of 6.6 thousand barrels of oil per day (MBOPD), so the decision was made to commercially develop this field. Two horizontal development wells were drilled in the second half of 2006. The ETBSM-1 well was drilled to the South Tchibala structure and the EAVOM-2H well was drilled to the Avouma structure. An unmanned production facility was installed and tied in by a subsea pipeline to Etame Field during 2006. Electronic submersible pumps (ESPs) installed in the two production wells provided the artificial lift mechanism for production. Production started from the two horizontal wells in January 2007. The field production rate in February 2007 was approximately 4.6 MBOPD; however, this rate was artificially restricted because of overall license processing limitations. The field production rate gradually increased throughout the year as the rate from Etame Field decreased. The field production rate reached a peak of 11.4 MBOPD in April 2008. The ETBSM-2H well, which targeted a central portion of the South Tchibala area, was drilled in October 2010 and put online in December 2010. The EAVOM-3H well was drilled in the southern portion of the Avouma structure and put online in April 2013. In 2014, the ETBSM-1 well was sidetracked to the ETBSM-1HB location to mitigate a mechanical issue in the original well. All of the Avouma/South Tchibala wells are produced using ESPs, and pump replacement workovers are a significant component of the ongoing operations in the field. NSAI's estimates for this field include the ETBSM-3H well, which will target a structural high to the north and west of the existing producing wells.

3.2 EBOURI FIELD

Ebouri Field is located along the boundary of the Etame Marin Permit, as shown on Figure 1. The field was discovered in December 2003 with the drilling of the EBO-1 well. The EBO-1 well was drilled to 2,026 m measured depth (1,901 m true vertical depth subsea) and encountered approximately 14 m of oil pay in the Gamba Formation near the center of the structure. The oil discovery was confirmed by the drilling of two sidetracks, the EBO-1 ST1 well on the east side of the structure and the EBO-1 ST2 well to the west of the discovery well. Ebouri development was then approved and the Ebouri Platform was installed. At the end of 2008, renewed appraisal and development began with the drilling of the EEBOM-2HP1 well. The EEBOM-2HP1 well came in high to prognosis and pushed the oil-water contact further west. A second pilot hole, EEBOM-2HP2, was then drilled from the platform to the north end of the structure and also came in high to prognosis. A horizontal drainhole, the EEBOM-2H, was drilled from this pilot hole in the north part of the field. A third well, the EEBONM-1, was drilled to the northeast in late 2008 to test a possible separate closure. This well came in slightly low to prognosis with the same contact as seen in Ebouri Field. The EEBONM-1 well was then sidetracked to the southwest of the original hole and encountered good-quality reservoir sands oil-filled to base. A second producing well, the EEBOM-3H, was drilled in early 2009 to produce the northeast area of the field.

The EEBOM-2H well began producing in January 2009 and the EEBOM-3H came online in April 2009. Initial field rates were 7.0 MBOPD. In early 2010, the EEBOM-4 pilot was drilled in the southwest portion of the Ebouri structure. This well helped define the extent of the structure in this area before being sidetracked to the EEBOM-4H producing location in the eastern part of the field. In May 2010, the well was brought online with initial rates of over 3.5 MBOPD. Peak production rates of over 9.0 MBOPD from the three producing wells occurred in June 2010.

In July 2012, it was found that hydrogen sulfide (H_2S) was being produced from the EEBOM-3H and EEBOM-4H wells. All production prior to this event was sweet crude; because the facilities and wellbores were not designed to handle sour production, the wells were shut in. Although these wells have been shut-in since that time, the EEBOM-2H well has continued to produce at low levels of H_2S, which are able to be treated by chemical injection. NSAI's forecasts include a workover on this well to repair a tubing leak and replace the ESPs. Discussions about a crude sweetening project are ongoing and, at some point, facilities modifications could be made in order to restore the sour crude production from the EEBOM-3H and EEBOM-4H wells.

3.3 ETAME FIELD

Etame Field was discovered in 1998 with the drilling of the ETAME-1V well, which discovered oil in the Gamba Formation. After the ETAME-2V well was drilled in 1999, the 3-D seismic data were reprocessed. The ETAME-3V well was drilled in February 2001 and the ETAME-4V well was drilled in May 2001. From April to July 2002, the ETAME-3V and ETAME-4V wells were reentered and drilled as the ETAME-3H and ETAME-4H horizontal production wells. Production from the field commenced in September 2002 from the ETAME-1V, ETAME-3H, and ETAME-4H wells. It became apparent that the field is divided into two regions separated by a northeast-to-southwest-trending sealing fault. Fluid properties, particularly gas-oil ratio, differ across this fault. The regions are known as the 1V FB and the Main FB, as shown on Figure 8.

Additional reprocessing of the 3-D seismic data was performed in 2003. The ETAME-5H-Pilot and ETAME-5H wells were drilled into the Main FB in June and July 2004, and the ETAME-5H well was placed on production. The ETAME-6H and ETAME-6HST wells were drilled into the Main FB in mid-2005, and the ETAME-6H ST was placed on production. Production from the ETAME-3H well ceased in September 2005 because of water production and subsequent loss of flowing tubing pressure. The ETAME-7H well was drilled into the 1V FB during August and September 2010 and commenced production in December 2010. Subsequent to the ETAME-7H coming online, the production rate from the ETAME-1V well went on a significantly steeper decline, and the well stopped producing in April 2012. The ETAME-5H, ETAME-6HST, and ETAME-7H wells are fitted with gas-lift valves.

Production from Etame Field had always been sweet crude with no H_2S. However, after the discovery of H_2S in two of the three Ebouri wells in July 2012, additional monitoring of all wells in the Etame Marin Permit was implemented. In early 2014, H_2S was discovered on the ETAME-5H well and it was subsequently shut in.

Installation of a four-pile platform was completed in the third quarter of 2014. The platform has the capability to serve as a first-stage processing facility for up to eight dry tree ESP-lifted wells. Three wells have been drilled from this platform to Etame Field: the ETAME-8H into the Main FB and the ETAME-10H and ETAME-12H into the 1V FB. The ETAME-8H was drilled in 2014 but encountered H_2S and, as a result, the well has remained shut-in. The ETAME-10H was drilled near the end of 2014, completed in January 2015, and started production in February 2015. The ETAME-12H was drilled in the first quarter of 2015 and was completed and started production in April 2015.

NSAI's estimates for Etame Field include a workover of the ETAME-6HST well and the drilling of at least one additional horizontal production well in the Main FB. The ETAME-6HST workover plan is to use a light intervention vessel to replace and relocate the existing gas-lift valves in an attempt to improve gas lift efficiency. The new production wells will be the ETAME-9H and potentially the ETAME-11H; both infill horizontal wells in the Gamba Formation. It is our understanding that VAALCO has also decided to proceed with additional appraisal drilling into the Dentale Formation in Etame Field as part of the work program described in Section 3.6, but the expenditures and potential volumes associated with this drilling have not been included in our estimates of reserves and future net revenue.

3.4 NORTH TCHIBALA FIELD

A complex of stacked Dentale sands known as North Tchibala Field is located southeast of Southeast Etame Field and northwest of Avouma/South Tchibala Field. The North Tchibala structure is a presalt anticlinal feature in which several sandstones within the Dentale Formation were found to be hydrocarbon-bearing. Gulf Oil of Gabon drilled a discovery well and two appraisal wells during the 1970s. Elf Gabon drilled an additional appraisal well in 1980 that further defined the field.

In the third quarter of 2014, VAALCO completed the installation of a four-pile fixed-leg platform to develop Southeast Etame and North Tchibala Fields. Two wells have been drilled from this platform into North Tchibala Field. The ETBNM-1H was drilled in 2015 and was completed and started production in September 2015. It is a horizontal well completed in the commingled D-9 and D-10 intervals in the Dentale Formation. ETBNM-2H was drilled in 2015, completed in November 2015, and started production in December 2015. It is a horizontal well completed in the commingled D-18 and D-19 intervals in the Dentale Formation. The ETBNM-1H and ETBNM-2H wells are both fitted with upper and lower ESPs which are operational if needed, but both wells currently flow naturally.

3.5 SOUTHEAST ETAME

Southeast Etame Field was identified as a southern extension to Etame Field on a separate anticlinal structure. During 2010, the ETSEM-1 exploration well was drilled and encountered oil pay in the Gamba Formation. The deposit was further defined by two appraisal sidetracks, the ETSEM-1 ST1 and the ETSEM-1 ST2. The discovery well encountered a reservoir in the Gamba that was 5 m thick; this reservoir was oil-bearing and filled-to-base.

Following the installation of the SEENT Platform, the ETSEM-2H development well was drilled in 2015. The well was completed and started production in July 2015 and is fitted with upper and lower ESPs that are operational and in use. It is our understanding that VAALCO has considered drilling an appraisal well in the Southeast Etame area; this well would target volumes in the Gamba Formation that are not currently included in the NSAI reserves estimates. If successful, VAALCO may drill a development well to produce these potential volumes. However, the expenditures and volumes associated with these activities are not included in our estimates of reserves and future net revenue.

3.6 WORK PROGRAM - ADDITIONAL INFORMATION

This report has been prepared for use by VAALCO in filing with the United Kingdom Listing Authority (UKLA) and the London Stock Exchange (LSE) and will be included in a prospectus that will be published by VAALCO on or about the date of this report. The development plans included in this report reflect the workover and drilling plans as of March 31, 2019 ("Effective Date"). We are aware of certain development plan options that VAALCO has described in more detail in their prospectus. We understand that these development plan options include two appraisal wells and two development wells in accordance with the requirements of the Etame production sharing contract (PSC). For the appraisal wells, neither future expenditures nor volumes associated with this drilling have been included in our estimates of reserves and future net revenue. Depending on the results of the appraisal drilling, we expect VAALCO to optimize development drilling for at least two development wells. Expenditures and volumes for these wells have been included in our estimates of reserves and future net revenue for the most likely development scenario as of the Effective Date, although the results of the appraisal drilling may have an impact on which development scenario VAALCO actually pursues. VAALCO has confirmed to us that there have been no material changes since the Effective Date, the omission of which would make this report misleading.

4.0 DATA AND METHODOLOGY

NSAI has evaluated the reserves and resources potential for the fields located in the Etame Marin Permit since their initial development. During annual updates each year, we have received from VAALCO various seismic data, well logs, core and fluid samples, and daily production and pressure gauge data. Early in the lives of the fields, we relied heavily on independent geologic mapping, volumetrics, and reservoir simulation to estimate recoveries and expected production profiles. Recently, we have relied more heavily on performance analysis (decline curve analysis) for reserves forecasts which are then checked against NSAI's and VAALCO's internal simulation models and volumetrics. In general, our reserves projections are based on decline curve analysis for the wells with production history, and future drillwell location volumes are based on a combination of reservoir simulation and volumetrics and analogy. A table including our base case volumetric inputs and original oil-in-place (OOIP) estimates is shown on Figure 11. Our projections of future oil rates, prior to economic and license term limits, have been summarized at the permit level and by field and category on the oil rate-versus-time graphs shown on Figures 12 through 17.

5.0 RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. 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 commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

For the purposes of this report, projections are prior to the application of the economic lives and the terms of the PSC. We model the economics of the Etame Marin Permit in a spreadsheet which incorporates all of the terms of the PSC. The primary terms of the PSC are summarized in the following section.

5.1 PRODUCTION SHARING CONTRACT

Estimates of reserves and future net revenue in this report are based on projections to the license life or to the economic limit with respect to the oil sales and operating costs under the terms of the PSC; these projections include total proved (1P), proved plus probable (2P), and proved plus probable plus possible (3P) reserves. The PSC governing the Etame Marin Permit became effective on July 7, 1995, and has since been amended six times. The current PSC terms were set out in the most recent amendment, signed September 13, 2018. This PSC expires on September 16, 2028, with provisions allowing for up to two five-year extensions provided certain conditions are met. No reserves or revenue are included after the PSC expiration date in 2028. Revenue interest factors are used to determine the net oil reserves to the VAALCO interest and are calculated based on including deductions under the PSC for profit oil and royalty oil payments to the Republic of Gabon. The total amount of oil attributable to VAALCO is defined to allow the recovery of costs (cost oil) and the sharing of after-tax profits (profit oil). Profit oil is the balance of available oil after deducting royalty oil and cost oil.

5.1.1 Royalties

Royalty payments are paid in kind to the Republic of Gabon as a percentage of the gross production. The royalty rate is defined in the PSC and calculated on an annual basis. The royalty rate for the Etame Marin Permit is 13 percent.

5.1.2 Recovery of Petroleum Costs (Cost Oil)

Certain operating and capital costs are classified as cost-recoverable in the PSC. These costs are accumulated in a cost-recovery account which will be recovered by lifting a portion of oil production. The oil used to recover these costs is called cost oil. This cost oil is limited to the amount of recoverable costs and is capped at 80 percent of the gross production after royalties. In the event that the PSC is extended beyond its current expiration date of September 16, 2028, the cap on the recoverable costs during the extension period would be reduced to 70 percent of the gross production after royalties.

5.1.3 Production Sharing (Profit Oil)

Profit oil is the remaining portion of the gross oil production after deductions for royalty oil and cost oil and is shared between the State and the contractors according to a sliding scale based on production rates in barrels of oil per day (BOPD). The percentages for the State share of profit oil are shown in the following table:

Production Rate (BOPD)	State Share Profit Oil (%)
< 10,000	50
10,000 – 25,000	55
> 25,000	60

5.2 ECONOMIC PARAMETERS

We have forecasted production for each reserves category using the development plan provided by VAALCO. These gross production forecasts were input into economic models that capture the contractual terms of the PSC. Key economic assumptions are described below. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$). Our economic modeling is calibrated to recent operating history. A table showing historical production, revenue, and expenses for the Etame Marin Permit is shown on Figure 18.

5.2.1 Base Case Oil Prices

This report has been prepared using oil price parameters specified by VAALCO. Oil prices are based on March 29, 2019, Brent Crude futures prices and are adjusted for quality, transportation fees, and market differentials. Base Case oil prices, before adjustments, are shown in the following table:

Period Ending	Oil Price ($/Barrel)
12-31-2019	66.98
12-31-2020	65.01
12-31-2021	62.95
12-31-2022	60.85
12-31-2023	60.51
Thereafter	60.45

5.2.2 Operating Costs

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

5.2.3 Capital and Abandonment Costs

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure, actual costs from recent activity, and internal planning budgets. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. It is our understanding that VAALCO has established escrow accounts for abandonment liability and expects these accounts to be fully funded by December 31, 2028. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by December 31 of the year after the economic limit date. Capital costs and abandonment costs are not escalated for inflation.

5.2.4 Net Reserves and Future Revenue

Gross reserves were input into an economic model that captures the contractual terms of the PSC; this model was used to calculate the estimated net reserves, future net revenue, and discounted future net revenue for the Etame Marin Permit. Net reserves are defined as the sum of VAALCO's share of the cost and profit oil. Gross revenue is VAALCO's net reserves multiplied by the realized price. Future net revenue is after deductions for VAALCO's share of operating expenses, capital costs and state carry, abandonment costs, and credits for VAALCO's share of reimbursement of state carry but before adjustments for any United States income taxes.

It should be noted that net reserves reported by VAALCO to the U.S. Securities and Exchange Commission include the net reserves as shown in the tables in this report plus income tax barrels.

5.3 SENSITIVITY ANALYSIS

In accordance with ESMA recommendations, Low and High Case price sensitivities were prepared. Summary projections of reserves and revenue by reserves category for the Low and High Price Cases are shown on Figures 19 through 34. Oil prices for the Low and High Cases are 15 percent lower and higher than the Base Case prices, respectively. Oil prices for the Low and High Cases, before adjustments, are shown in the following table:

Period Ending	Low Case Oil Price ($/Barrel)	High Case Oil Price ($/Barrel)
12-31-2019	56.93	77.03
12-31-2020	55.26	74.76
12-31-2021	53.51	72.39
12-31-2022	51.72	69.98
12-31-2023	51.43	69.59
Thereafter	51.38	69.52

6.0 CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon approval of a development plan with sufficient development wells to economically produce the volumes prior to termination of the PSC and commitment to develop the resources. As requested, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. The project maturity subclass for these contingent resources is development unclarified.

A table showing our estimates of the unrisked gross contingent oil resources for the Etame Marin Permit is shown on Figure 35.

6.1 ADDITIONAL VOLUMES BEYOND ECONOMIC LIMIT OF RESERVES OR PSC EXPIRATION

All wells included in our reserves forecast have technical projections which may continue beyond the economic end of field life and/or the end of the PSC license term. The first component of our contingent resources is for the volumes that are only recoverable beyond the economic and PSC term limits on existing wells or undeveloped wells included in our reserves projections. Should economic conditions improve or the PSC term be extended beyond September 16, 2028, some portion of these volumes could be reclassified as reserves.

6.2 CRUDE SWEETENING PROJECT

The original wells and facilities in the Etame Marin Permit were designed to handle sweet crude production. In 2012, VAALCO observed H_2S production from the Ebouri EEBOM-3H and EEBOM-4H wells. Since the wells and facilities were not designed to handle sour production, these wells have been shut-in since that time. The Ebouri EEBOM-2H well has continued to produce and H_2S production on it has been monitored. H_2S concentration from this well has risen slowly from approximately 10 parts per million (ppm) at the beginning of 2016 to approximately 40 ppm at the end of 2018. While it is expected that these levels of H_2S can continue to be treated chemically, restoring all wells back to full production at Ebouri could require additional investment. It is our understanding that VAALCO is currently investigating various options. We have included contingent resources for the two shut-in Ebouri wells assuming that those wells are brought back online and produced to depletion. If VAALCO can design an economic project to produce this sour production and commit to executing it, some portion of these contingent resources could be reclassified as reserves.

6.3 DENTALE FORMATION – PRESSURE MAINTENANCE

The ETBNM-1H well produces from the Dentale Formation in the D-9 and D-10 intervals. Since this well was brought online in 2015, the bottomhole pressure has declined steadily from approximately 3,800 psi to approximately 2,000 psi at the end of 2018. NSAI mapping on these reservoirs indicates a range of OOIP from 11.9 to 16.4 million barrels and expected recovery factors between 18 and 20 percent. It is our understanding that VAALCO is considering various options for pressure maintenance, such as water injection, that would help curb the pressure decline and increase the recovery factor from these reservoirs. Should VAALCO define and commit to developing an economic project to achieve pressure maintenance, some portion of these contingent resources could be reclassified as reserves.

6.4 DENTALE FORMATION – ADDITIONAL DRILLING

The ETBNM-2H well produces from the Dentale Formation in the D-18 and D-19 intervals. Since this well was brought online, its production rate has been approximately 500 BOPD and the drawdown has been high, which VAALCO believes is due to high skin on the completion. Based on current decline trends, we expect that this well will recover only approximately 6 percent of the OOIP in these reservoirs. It is our understanding that VAALCO has considered drilling two additional wells targeting these reservoirs to more effectively deplete the OOIP. Should these wells be economic and get the commitment and approval by all parties, some portion of the estimated contingent resources could be reclassified as reserves.

7.0 PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

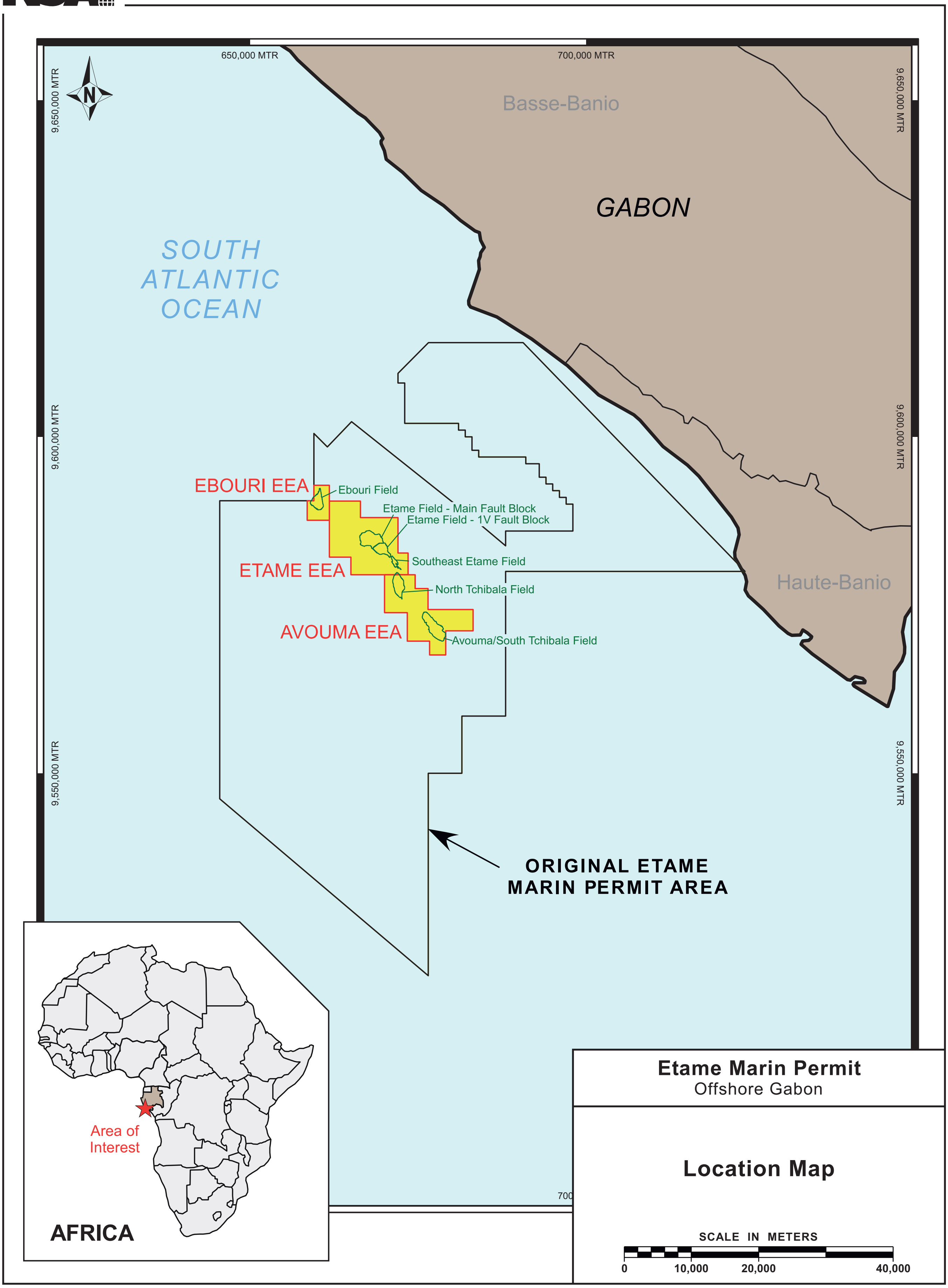
The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate.

Each prospect is based on structural mapping derived from seismic interpretation. A map showing the prospect locations is shown on Figure 36. For each prospect, a range of gross rock volumes was determined using various assumptions for percentage of structural fill on the interpreted structures. Net-to-gross ratio, porosity, water saturation, oil formation volume factor, and recovery ranges were based on analogy to the producing fields in the Etame Marin Permit. The gross rock volume is based on an assumed gross thickness of the mapped interval. To account for uncertainty in the net thickness, a broader range of net-to-gross ratios was used than the one seen in the producing fields. A summary of the inputs for our probabilistic analysis is shown on Figure 37, and the output ranges for the unrisked gross original hydrocarbons-in-place and the unrisked gross and working interest prospective resources are shown on Figure 38.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. A summary of the geologic risking for each prospect is shown on Figure 39.

FIGURES

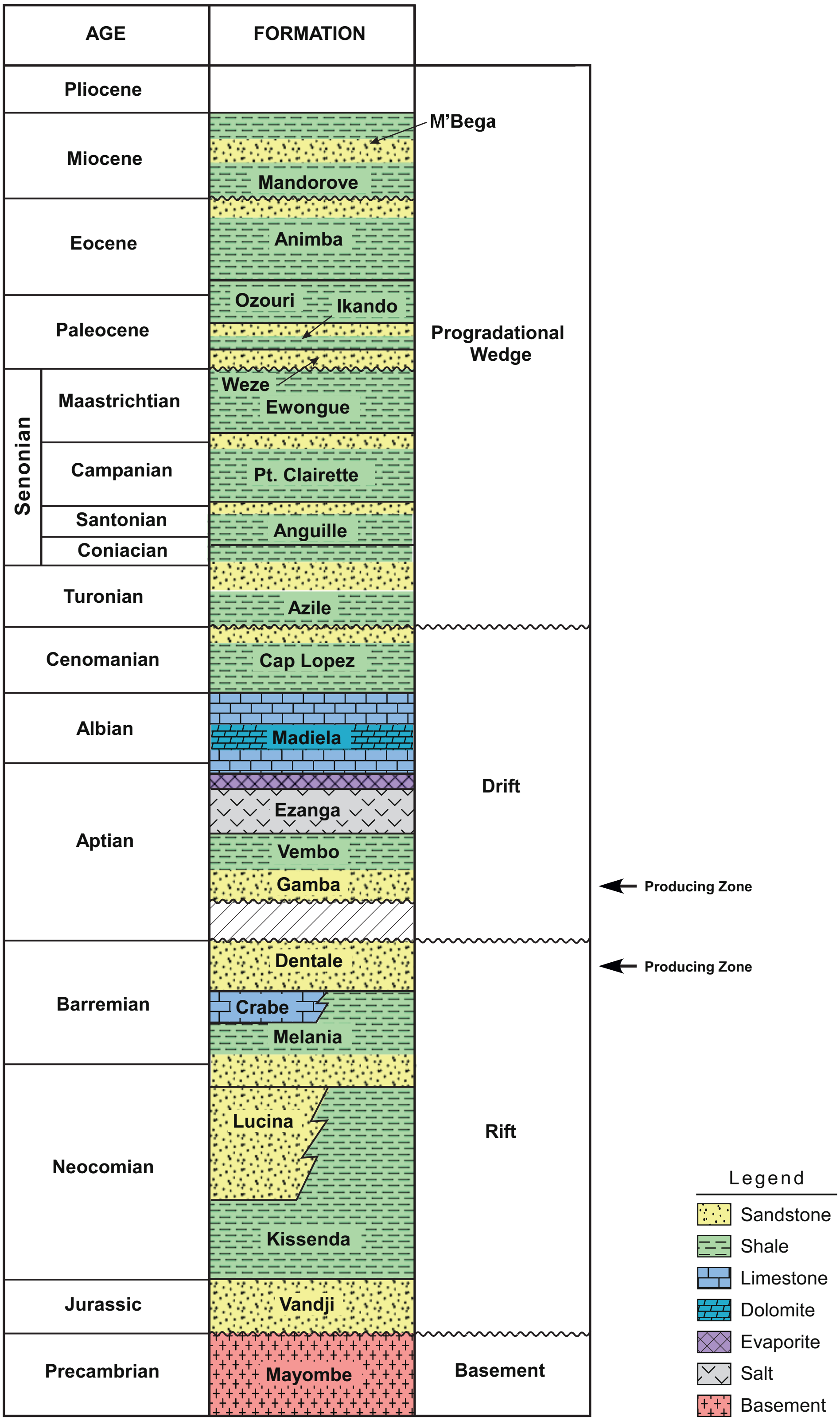
NETHERLAND, SEWELL
& ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 1

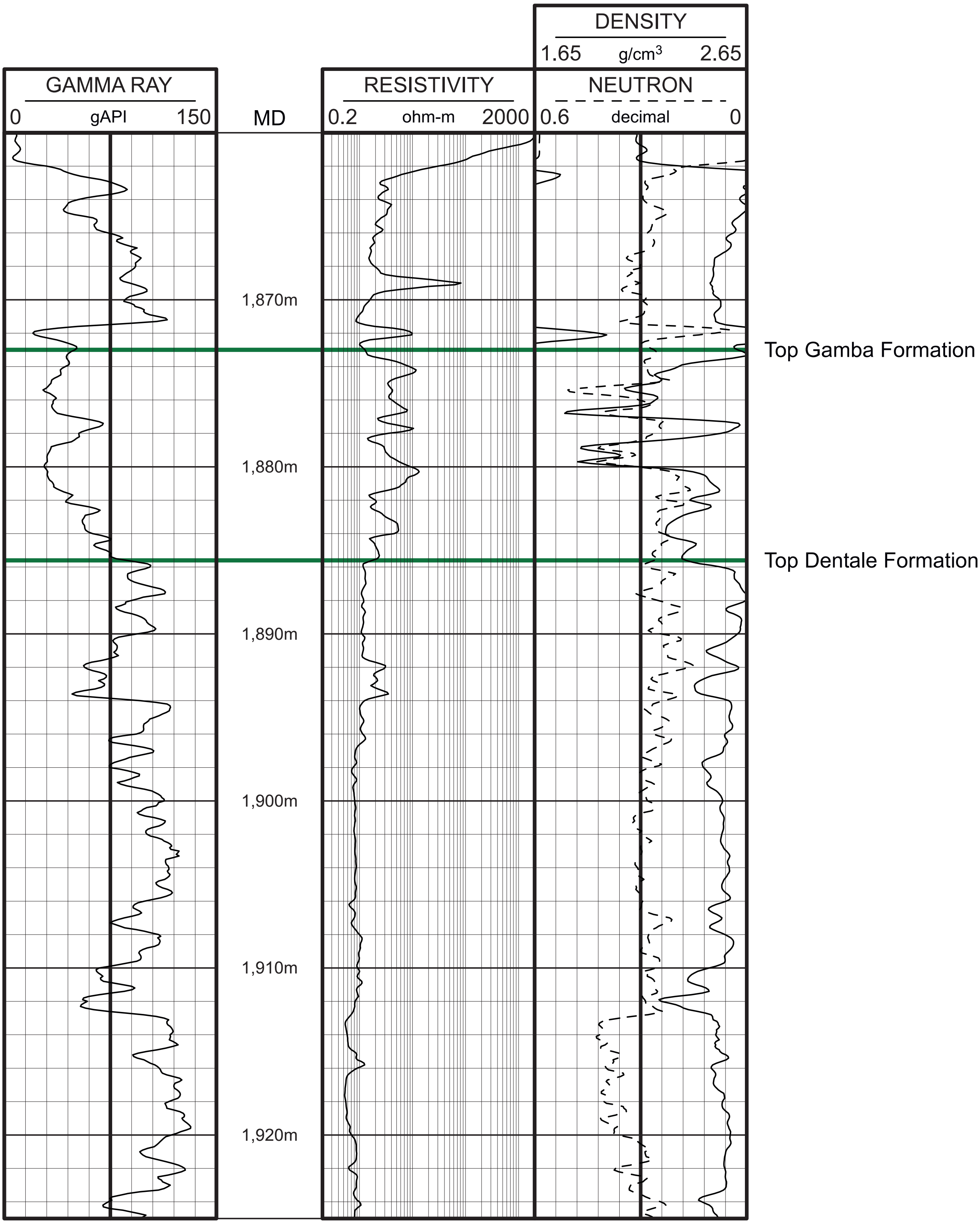
Stratigraphic and Lithologic Column
South Gabon



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

Type Log Section
Gamba and Dentale Formations
Etame-1V Well
Etame Marin Permit, Offshore Gabon



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

KEY PRODUCTION FACILITIES
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

		Capacity (barrels per day)		
Facility Name	Producing Field	Total Liquid	Oil	Water
Nautipa FPSO	All	30,000	25,000	20,000
Avouma Platform	Avouma/South Tchibala	16,000	16,000	15,000
Ebouri Platform	Ebouri	17,500	15,000	14,000
Etame Platform	Etame	26,000	25,000	22,500
SEENT Platform	North Tchibala/Southeast Etame	26,000	25,000	22,500

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

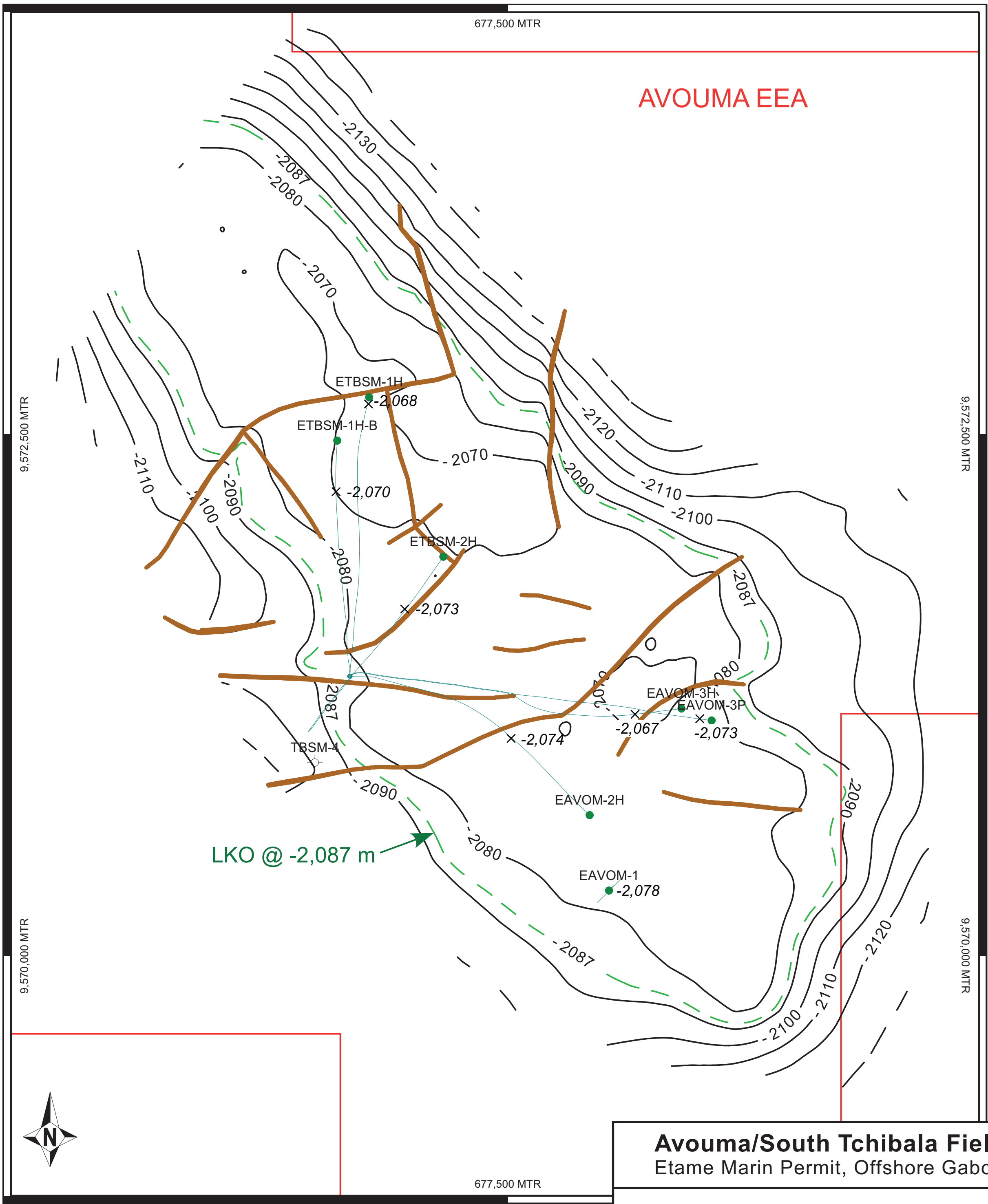
Figure 4

SUMMARY OF PRODUCTION WELLS
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

Well Name	Field	Well Type	Artificial Lift Type	First Production Date	Current Status	Cumulative Oil (MBBL)
EAVOM-2H	Avouma	Platform	ESP	01-2007	Active	14,701.4
EAVOM-3H	Avouma	Platform	ESP	04-2013	Shut-In	757.1
ETBSM-1H	Avouma	Platform	ESP	01-2007	Abandoned	4,474.5
ETBSM-1HB	Avouma	Platform	ESP	05-2014	Active	1,060.0
ETBSM-2H	Avouma	Platform	ESP	01-2011	Active	4,185.0
EEBOM-2H	Ebouri	Platform	ESP	01-2009	Active	10,191.9
EEBOM-3H	Ebouri	Platform	ESP	04-2009	Shut-In	1,586.3
EEBOM-4H	Ebouri	Platform	ESP	05-2010	Shut-In	1,124.6
ETAME-1VA	Etame	Subsea	Gas Lift	09-2002	Shut-In	6,274.0
ETAME-3H	Etame	Subsea	Gas Lift	09-2002	Shut-In	5,728.4
ETAME-4H	Etame	Subsea	Gas Lift	09-2002	Active	17,080.3
ETAME-5H	Etame	Subsea	Gas Lift	08-2004	Shut-In	5,305.5
ETAME-6HST1	Etame	Subsea	Gas Lift	07-2005	Active	18,485.6
ETAME-7H	Etame	Subsea	Gas Lift	12-2010	Active	7,551.5
ETAME-8H	Etame	Platform	ESP	N/A	Shut-In	0.0
ETAME-10H	Etame	Platform	ESP	02-2015	Active	1,683.3
ETAME-12H	Etame	Platform	ESP	04-2015	Active	3,531.1
ETBNM-1H	North Tchibala	Platform	Natural Flow	09-2015	Active	1,491.3
ETBNM-2H	North Tchibala	Platform	Natural Flow	12-2015	Active	534.9
ETSEM-2H	Southeast Etame	Platform	ESP	07-2015	Active	3,693.7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5



Avouma/South Tchibala Field
Etame Marin Permit, Offshore Gabon

Depth Structure
Top Gamba Sandstone

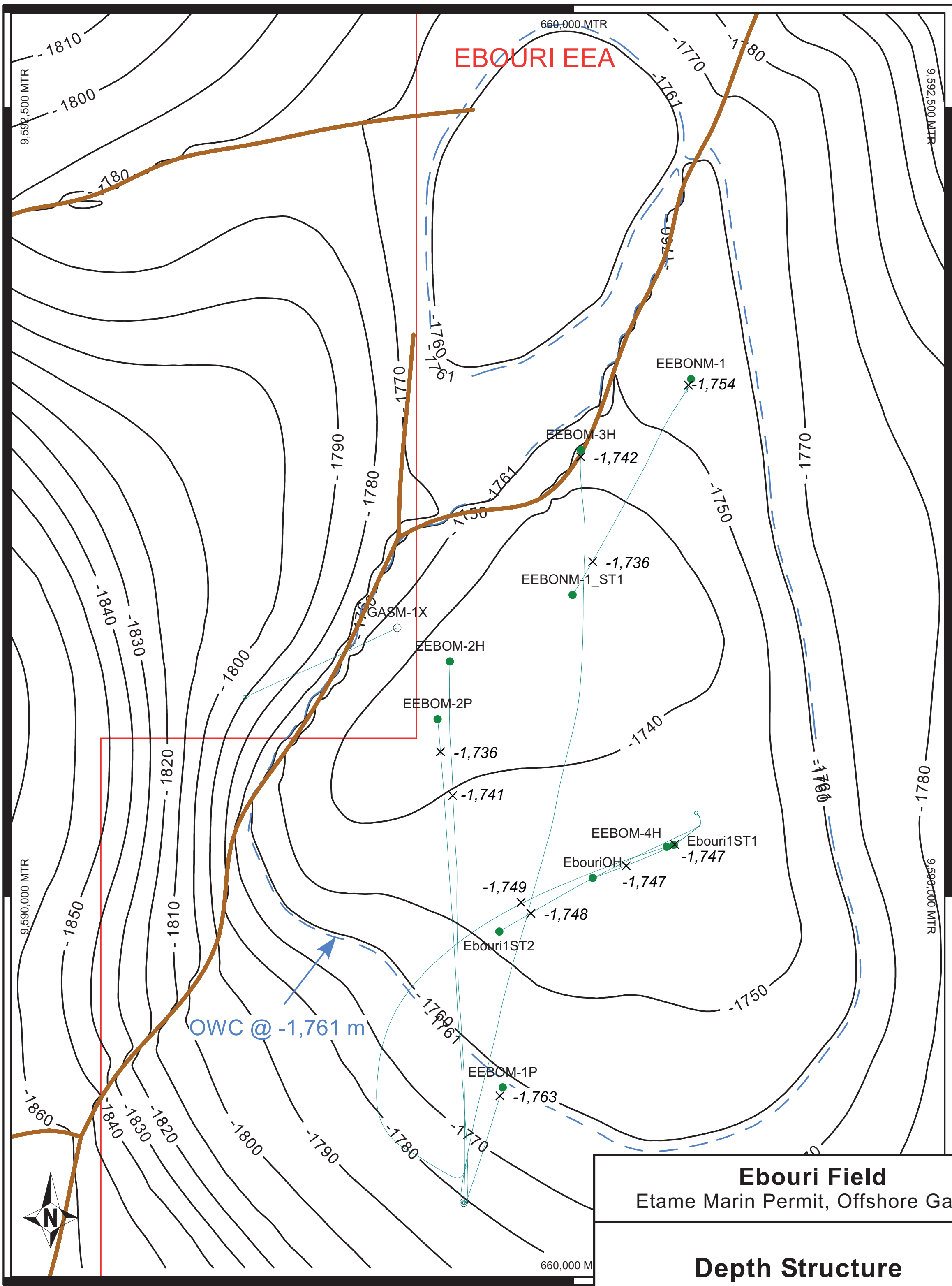
Contour Interval: 10 m

SCALE IN METERS

0 375 750 1,500

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6



Ebouri Field

Etame Marin Permit, Offshore Gabon

Depth Structure
Top Gamba Sandstone

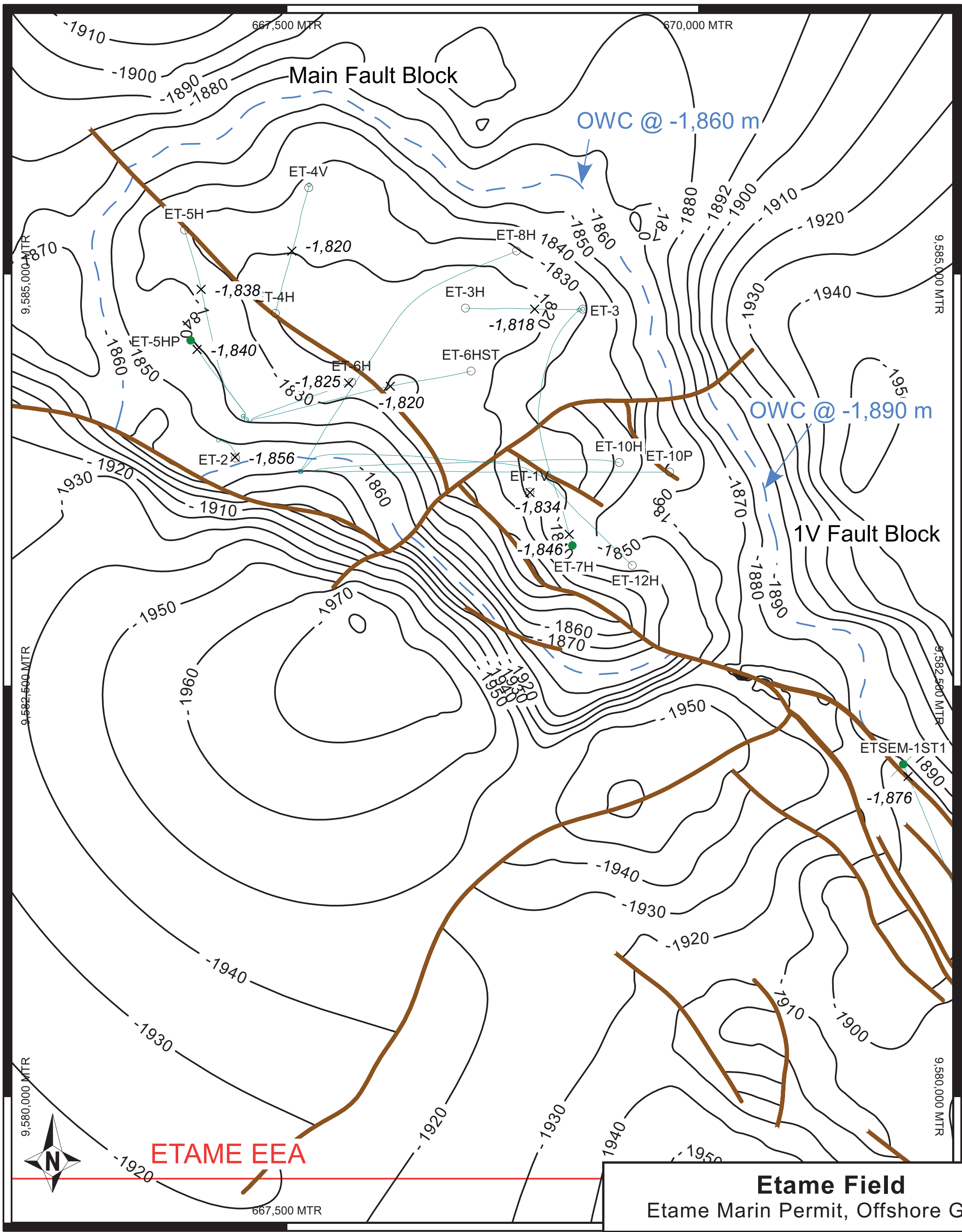
Contour Interval: 10 m

SCALE IN METERS

0 250 500 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7



Etame Field
Etame Marin Permit, Offshore Gabon

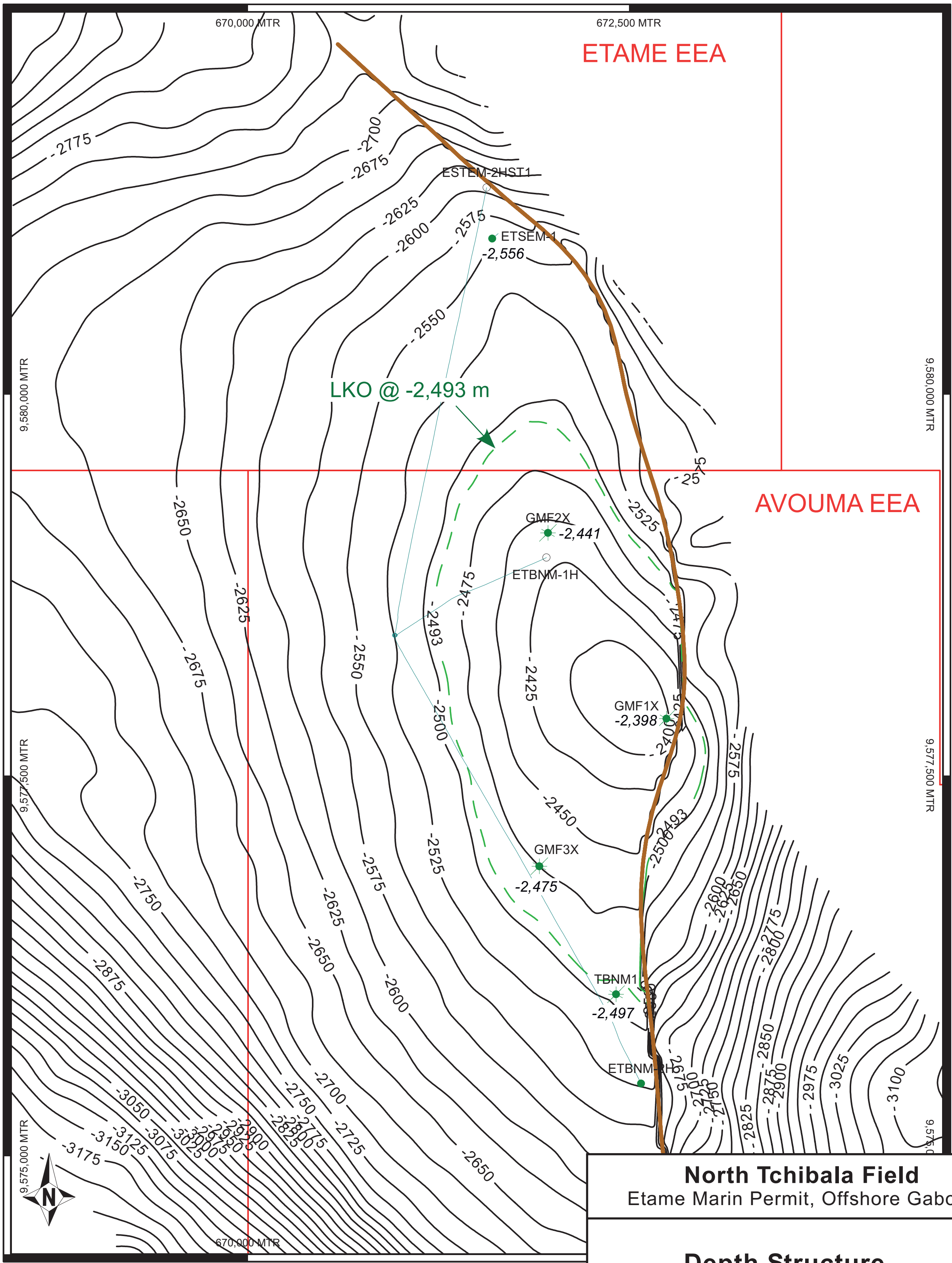
Depth Structure
Top Gamba Sandstone

Contour Interval: 10 m

SCALE IN METERS
0 500 1,000 2,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 8



North Tchibala Field
Etame Marin Permit, Offshore Gabon

Depth Structure
Top Dentale Sandstone

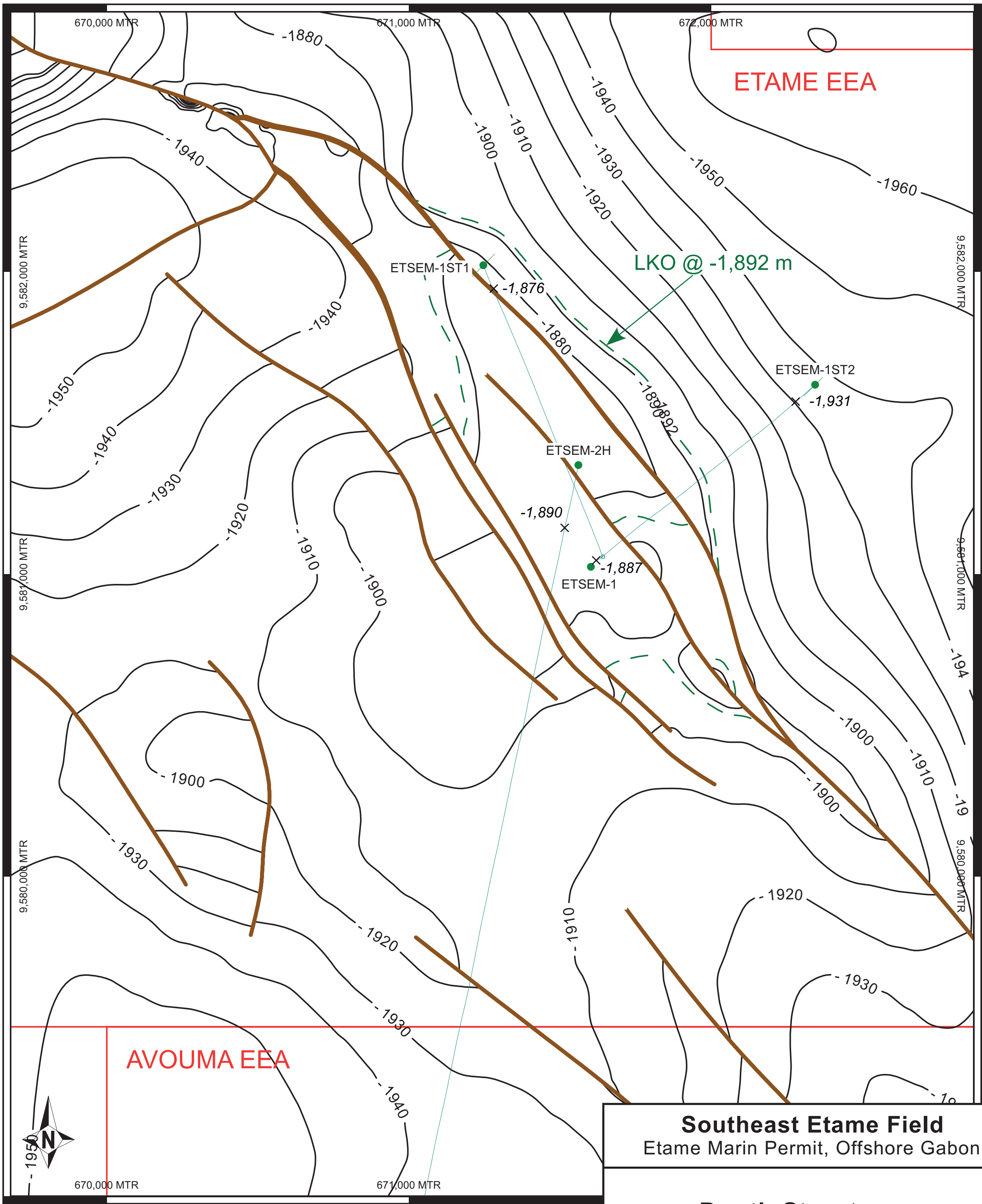
Contour Interval: 25 m

SCALE IN METERS

0 500 1,000 2,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 9



Southeast Etame Field
Etame Marin Permit, Offshore Gabon

Depth Structure
Top Gamba Sandstone

Contour Interval: 10 m

SCALE IN METERS

0 250 500 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 10

SUMMARY OF BASE CASE VOLUMETRIC PARAMETERS
PRODUCING FIELDS
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

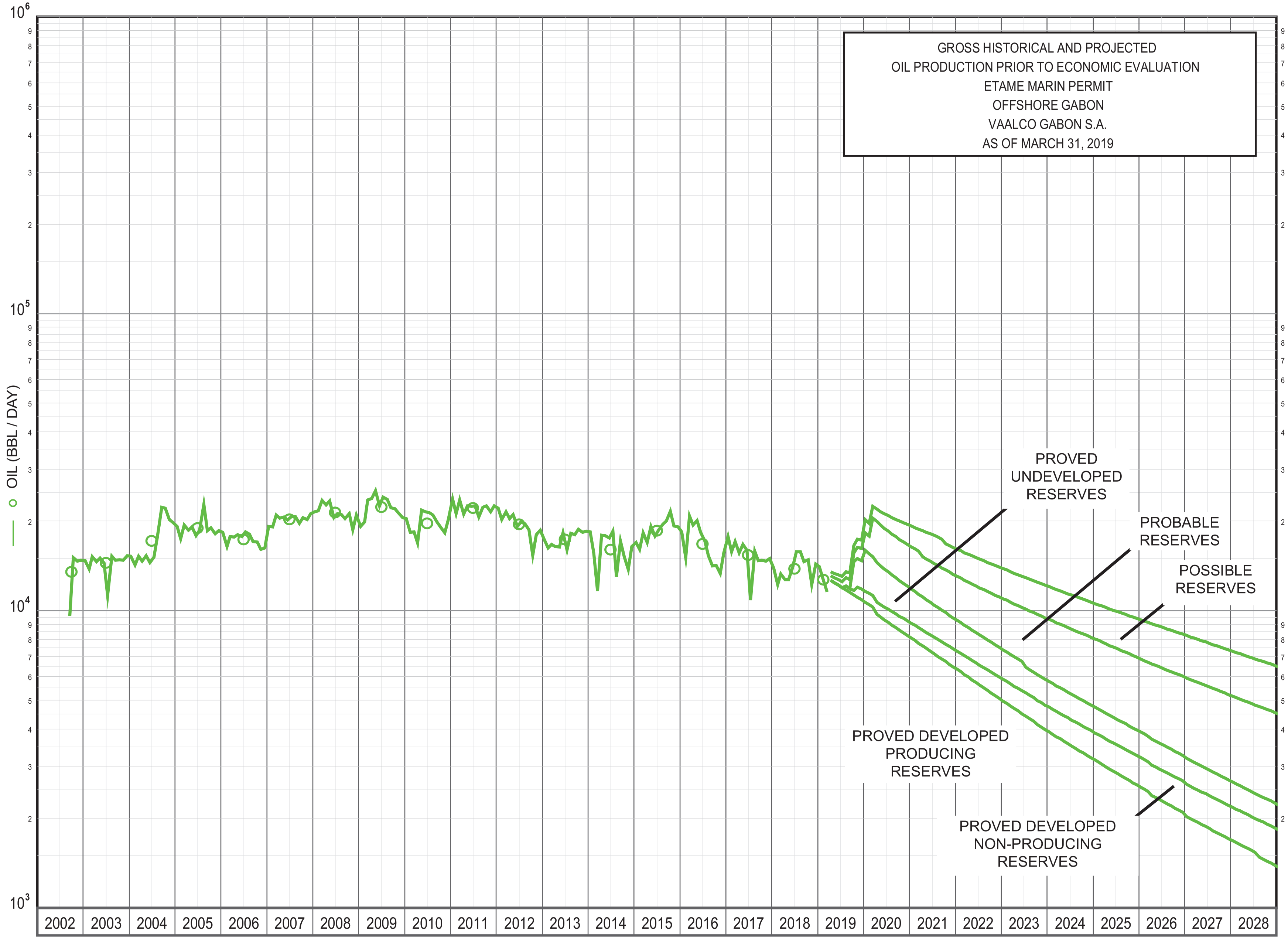
Field/Fault Block	Formation	Gross Rock Volume (acre-feet)	Net-to-Gross Ratio (%)	Net Rock Volume (acre-feet)	Porosity (%)	Water Saturation (%)	Formation Volume Factor (RB/STB)	Original Oil-in-place (MMBBL)
Avouma	Gamba	49,686	97.0	48,196	27.6	33.5	1.14	60.3
Ebouri	Gamba	23,630	100.0	23,625	28.4	15.1	1.04	42.4
	Dentale	1,558	27.6	429	23.2	30.0	1.04	0.5
Etame								
Main	Gamba	61,933	95.3	59,022	26.7	14.9	1.07	96.8
	Dentale	15,787	38.9	6,137	15.9	53.0	1.07	7.5
1V	Gamba	32,686	91.2	29,813	26.0	15.5	1.10	46.3
North Tchibala	Dentale[1]	69,419	41.2	28,626	12.3	35.4	1.53	14.1
	Dentale[2]	105,563	30.6	32,252	13.6	43.0	1.38	14.1
Southeast Etame	Gamba	10,362	90.0	9,326	26.0	15.5	1.10	14.5

(1) D-9 and D-10 intervals.
(2) D-18 and D-19 intervals.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

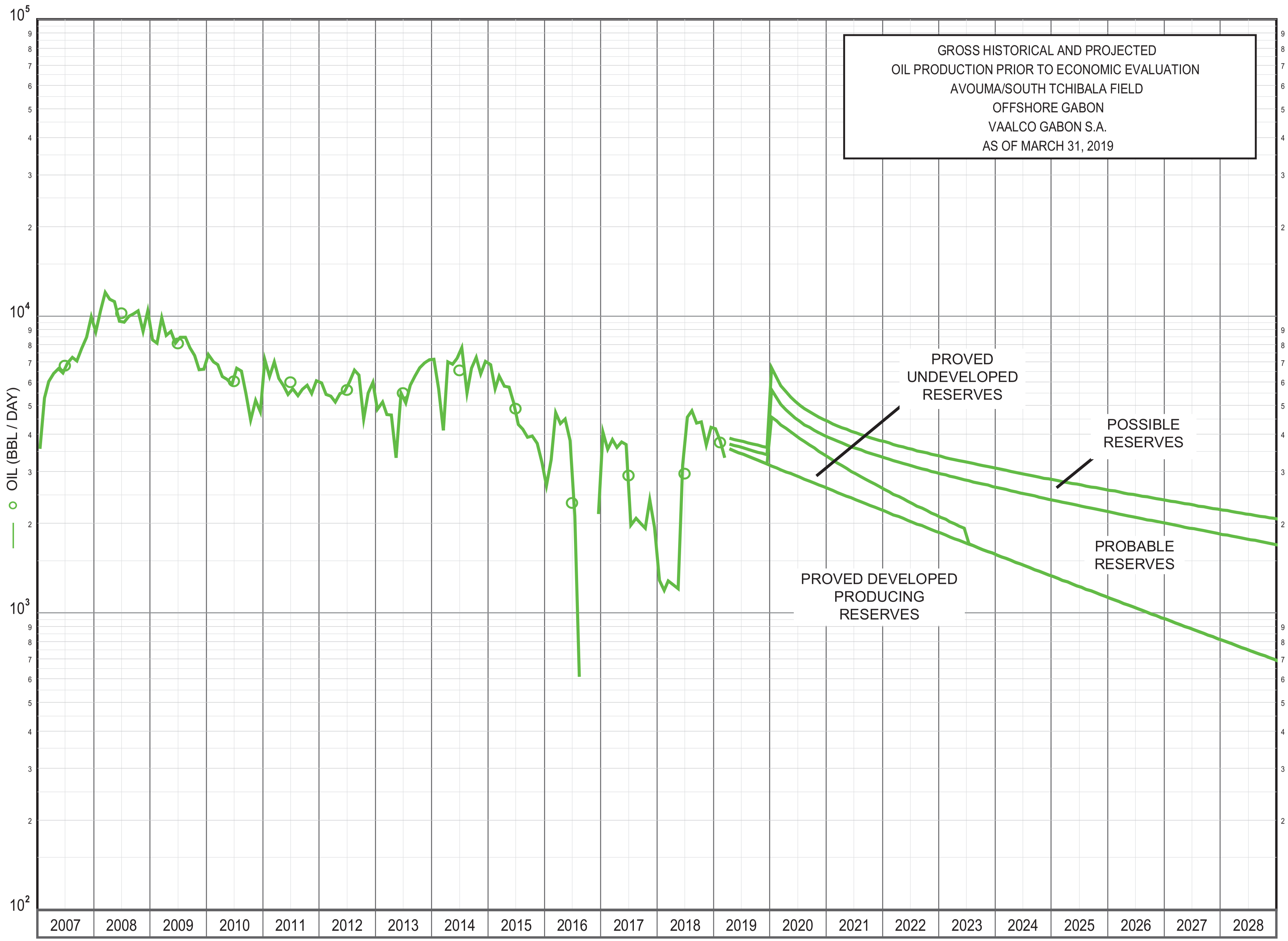
Figure 11

NETHERLAND, SEWELL & ASSOCIATES, INC.



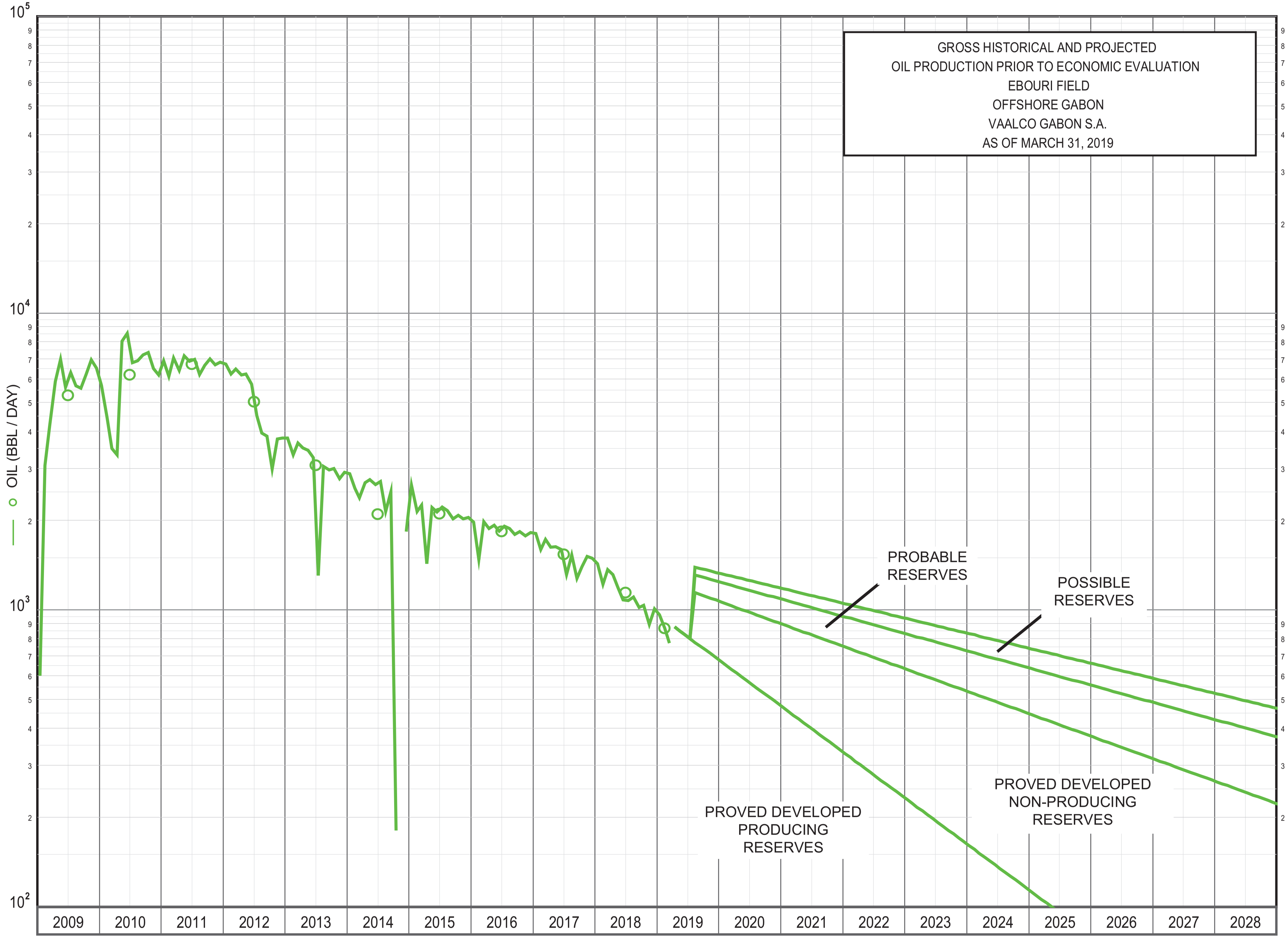
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 12



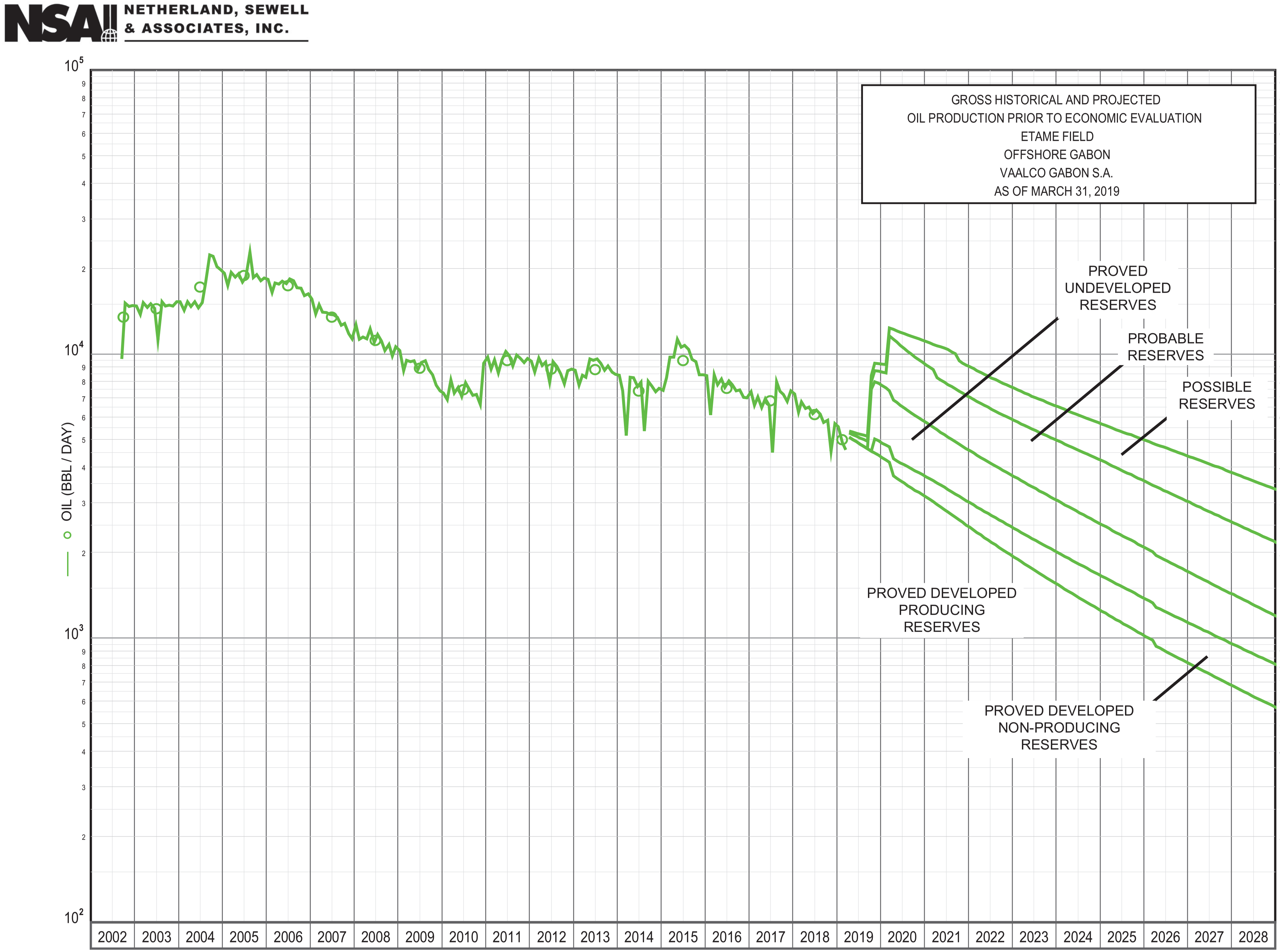
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 13



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

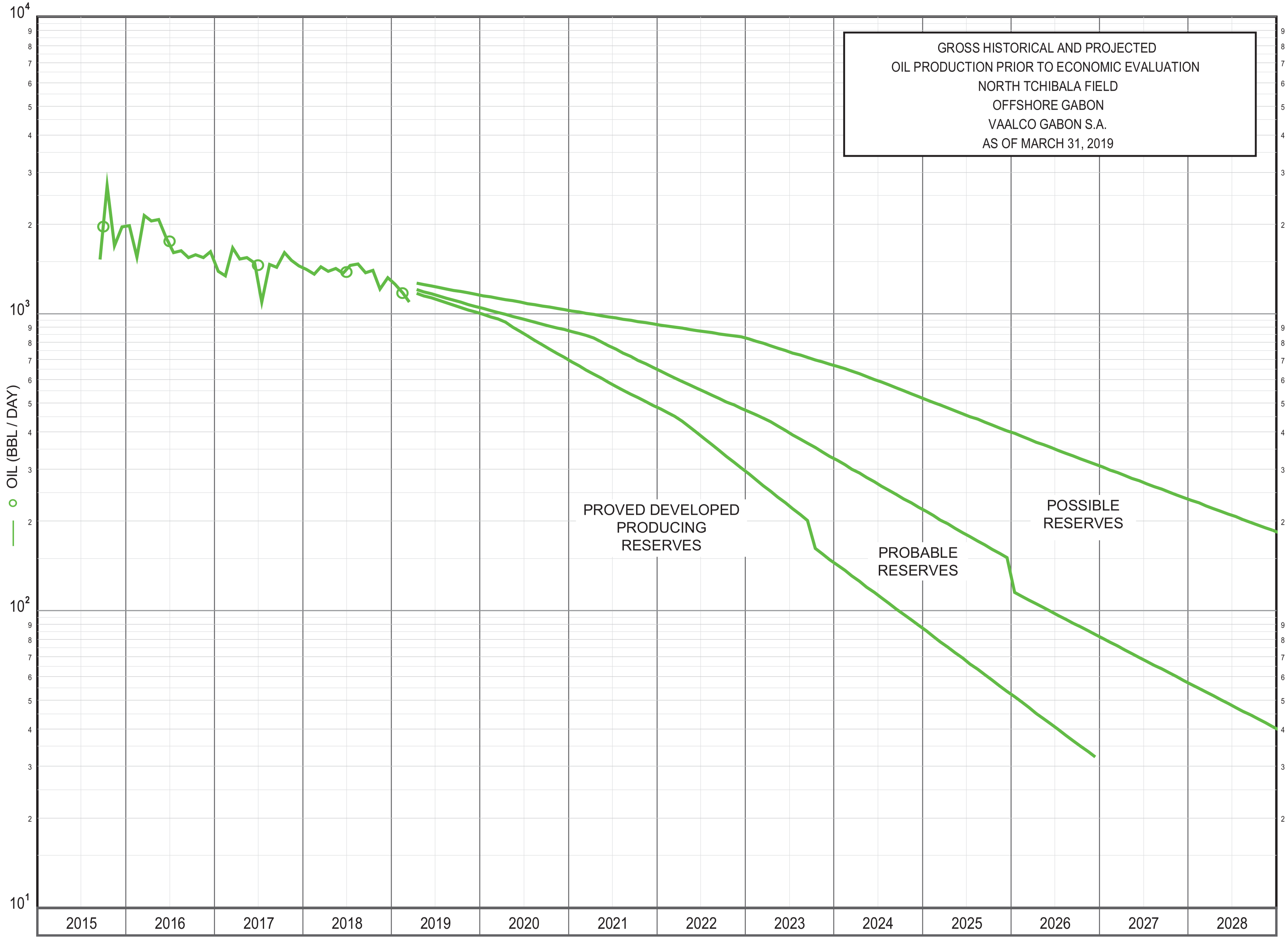
Figure 14



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 15

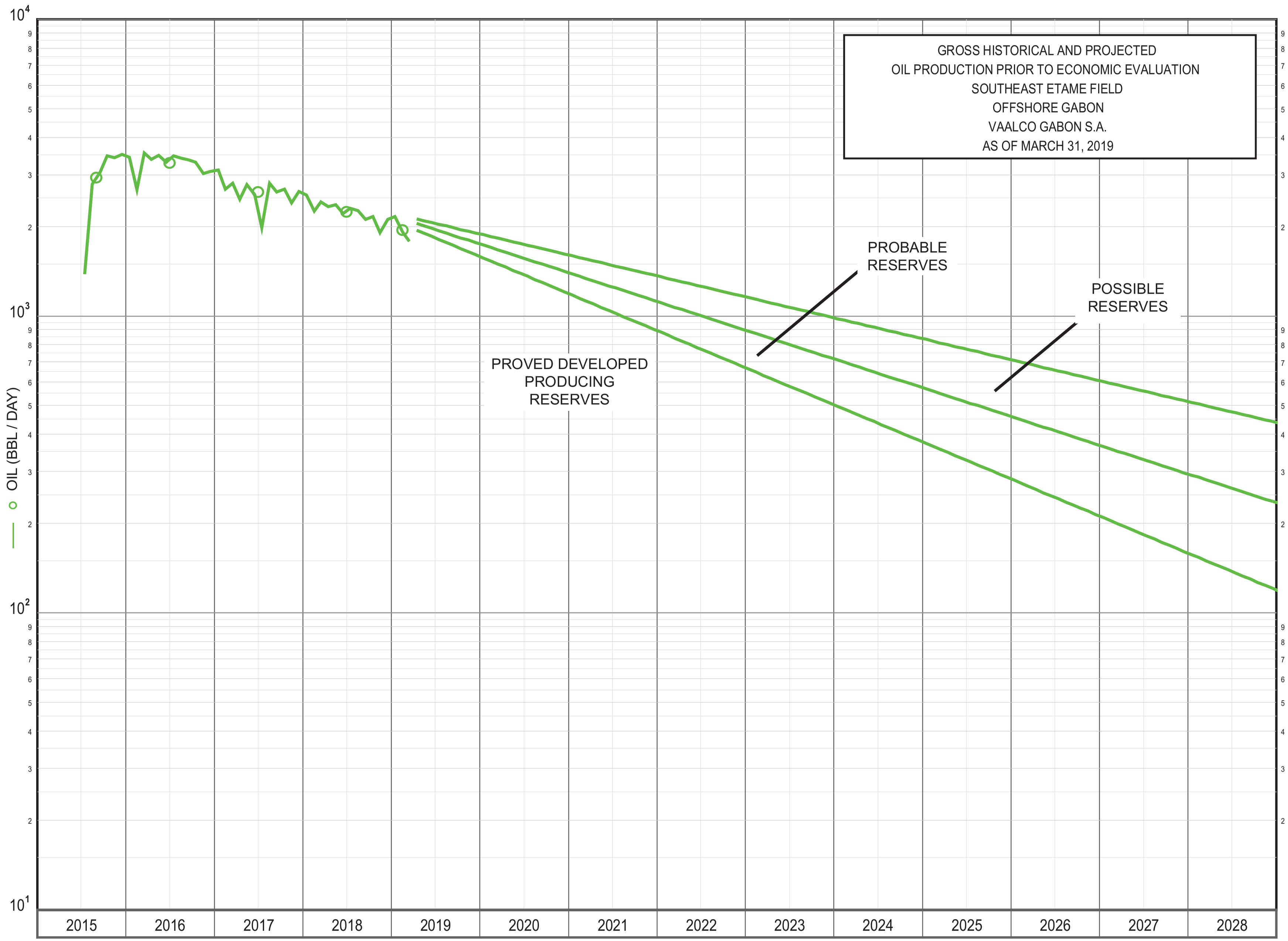
NETHERLAND, SEWELL & ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 16

NETHERLAND, SEWELL & ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 17

HISTORICAL PRODUCTION AND EXPENSE DATA
VAALCO GABON S.A.
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

Year	Gross Oil Production (MBBL)	Crude Oil and Natural Gas Sales[1] (M$)	Production Costs and Other Expenses[1][2] (M$)	Income Tax[1] (M$)
2018	5,062.3	104,938	37,865	37,591
2017	6,941.6	76,978	41,558	11,638
2016	7,692.0	59,460	38,160	9,248

(1) As reported in VAALCO's 2018 Form 10-K filed with the U.S. Securities and Exchange Commission.
(2) Local general and administrative expenses are included, but corporate general and administrative expenses and allocated corporate overhead are excluded.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 18

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

TOTAL PROVED (1P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,576.4	1,110.7	144.4	98.9	773.1	94.4	867.5	55.85	48,450.3
12-31-2020	5,044.5	1,566.7	203.7	140.0	1,090.4	132.6	1,223.0	54.18	66,258.4
12-31-2021	3,866.5	1,200.8	156.1	105.2	835.8	103.8	939.5	52.43	49,257.7
12-31-2022	3,054.8	948.7	123.3	82.5	660.3	82.5	742.9	50.64	37,619.9
12-31-2023	661.9	205.6	26.7	17.9	143.1	17.9	161.0	50.35	8,105.2
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	16,204.2	5,032.5	654.2	444.5	3,502.6	431.2	3,933.8	53.31	209,691.5
Cum Prod	109,440.4								
Ultimate	125,644.6								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	846.1	33,052.0	1,245.4	395.7	(5,425.8)	(4,966.9)
12-31-2020	0.0	846.1	41,645.1	3,255.1	1,646.6	22,158.7	14,852.3
12-31-2021	0.0	846.1	40,541.0	1,299.7	572.1	7,143.1	20,723.4
12-31-2022	0.0	846.1	30,974.6	1,024.1	432.4	5,207.5	24,621.1
12-31-2023	0.0	846.1	7,652.6	225.1	16.5	(602.1)	24,250.1
12-31-2024	0.0	4,230.3	0.0	0.0	0.0	(4,230.3)	21,794.9
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	21,794.9
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	21,794.9
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	21,794.9
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	21,794.9
Total	19,128.5	8,460.5	153,865.3	7,049.3	3,063.3	24,251.2	21,794.9

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 19

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,216.6	999.0	129.9	88.2	695.3	85.6	780.9	55.85	43,617.4
12-31-2020	3,409.3	1,058.8	137.6	92.2	736.9	92.0	828.9	54.18	44,910.6
12-31-2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	6,625.9	2,057.8	267.5	180.4	1,432.2	177.6	1,609.9	54.99	88,528.1
Cum Prod	109,440.4								
Ultimate	116,066.3								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	763.3	29,064.5	1,130.5	1,015.6	13,674.8	13,264.0
12-31-2020	0.0	763.3	37,814.9	2,747.2	409.8	3,995.0	16,899.5
12-31-2021	0.0	6,106.2	0.0	0.0	0.0	(6,106.2)	12,182.5
12-31-2022	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	12,182.5
Total	0.0	7,632.7	66,879.4	3,877.7	1,425.4	11,563.7	12,182.5

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	90.5	28.1	3.7	2.7	19.6	2.2	21.8	55.85	1,215.6
12-31-2020	354.7	110.1	14.3	9.9	76.7	9.2	85.9	54.18	4,653.0
12-31-2021	1,584.8	492.2	64.0	42.8	342.6	42.8	385.4	52.43	20,204.2
12-31-2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	2,029.9	630.4	82.0	55.5	438.8	54.2	493.0	52.88	26,072.8
Cum Prod	0.0								
Ultimate	2,029.9								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	3,450.6	28.9	(28.1)	(2,292.0)	(2,181.7)
12-31-2020	0.0	0.0	317.2	110.7	284.3	4,509.4	1,821.2
12-31-2021	0.0	(5342.9)	18,775.0	544.4	66.8	6,294.4	6,741.8
12-31-2022	0.0	5342.9	0.0	0.0	0.0	(5,342.9)	2,989.7
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	2,989.7
Total	0.0	0.0	22,542.9	684.0	323.0	3,168.9	2,989.7

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

[1] Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
[2] VAALCO's share of the state carry costs is shown as capital costs.
[3] Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 21

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED UNDEVELOPED RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	269.3	83.6	10.9	8.0	58.2	6.5	64.8	55.85	3,617.3
12-31-2020	1,280.6	397.7	51.7	37.9	276.8	31.3	308.1	54.18	16,694.8
12-31-2021	2,281.7	708.6	92.1	62.3	493.2	61.0	554.2	52.43	29,053.5
12-31-2022	3,054.8	948.7	123.3	82.5	660.3	82.5	742.9	50.64	37,619.9
12-31-2023	661.9	205.6	26.7	17.9	143.1	17.9	161.0	50.35	8,105.2
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	7,548.3	2,344.3	304.8	208.6	1,631.6	199.3	1,830.9	51.94	95,090.7
Cum Prod	0.0								
Ultimate	7,548.3								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	82.8	536.8	86.0	(591.8)	(16,808.6)	(16,049.1)
12-31-2020	0.0	82.8	3,513.0	397.3	952.6	13,654.3	(3,868.4)
12-31-2021	0.0	82.8	21,766.0	755.2	505.3	6,954.8	1,799.0
12-31-2022	0.0	(4,496.8)	30,974.6	1,024.1	432.4	10,550.4	9,448.8
12-31-2023	0.0	846.1	7,652.6	225.1	16.5	(602.1)	9,077.9
12-31-2024	0.0	4,230.3	0.0	0.0	0.0	(4,230.3)	6,622.7
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	6,622.7
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	6,622.7
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	6,622.7
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	6,622.7
Total	19,128.5	827.8	64,443.0	2,487.7	1,315.0	9,518.6	6,622.7

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 22

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE (2P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,805.6	1,181.9	153.6	105.7	822.6	100.0	922.6	55.85	51,529.0
12-31-2020	6,705.9	2,082.6	270.7	189.4	1,449.5	173.0	1,622.5	54.18	87,903.8
12-31-2021	5,355.4	1,663.2	216.2	149.3	1,157.6	140.1	1,297.7	52.43	68,034.9
12-31-2022	4,398.5	1,366.0	177.6	120.9	950.8	116.8	1,067.6	50.64	54,065.2
12-31-2023	3,722.3	1,156.0	150.3	100.9	804.6	100.2	904.8	50.35	45,560.9
12-31-2024	3,183.8	988.8	128.5	86.0	688.2	86.0	774.2	50.30	38,944.7
12-31-2025	2,304.8	715.8	93.1	62.3	498.2	62.3	560.5	50.30	28,193.3
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	29,476.3	9,154.4	1,190.1	814.5	6,371.5	778.4	7,149.9	52.34	374,231.8
Cum Prod	109,440.4								
Ultimate	138,916.7								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,257.0	1,318.5	439.6	(2,622.9)	(2,282.2)
12-31-2020	8,330.6	887.4	44,268.7	3,770.3	2,587.5	33,234.2	27,010.1
12-31-2021	0.0	887.4	43,106.9	1,747.3	1,790.6	24,083.8	46,583.2
12-31-2022	0.0	887.4	42,200.7	1,416.6	789.3	10,349.7	54,261.3
12-31-2023	0.0	887.4	40,777.3	1,213.9	213.9	2,896.2	56,232.8
12-31-2024	0.0	887.4	31,291.5	1,056.0	497.7	6,207.5	60,049.4
12-31-2025	0.0	887.4	25,731.1	778.4	129.6	926.0	60,601.5
12-31-2026	0.0	2,590.4	0.0	0.0	0.0	(2,590.4)	59,359.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	59,359.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	59,359.0
Total	27,459.1	8,802.5	260,633.2	11,301.0	6,448.1	72,484.1	59,359.0

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 23

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROBABLE RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	229.2	71.2	9.3	6.8	49.5	5.6	55.1	55.85	3,078.7
12-31-2020	1,661.4	516.0	67.1	49.4	359.1	40.4	399.5	54.18	21,645.4
12-31-2021	1,488.9	462.4	60.1	44.1	321.8	36.3	358.2	52.43	18,777.2
12-31-2022	1,343.7	417.3	54.3	38.3	290.4	34.3	324.7	50.64	16,445.3
12-31-2023	3,060.3	950.4	123.6	83.0	661.5	82.3	743.9	50.35	37,455.7
12-31-2024	3,183.8	988.8	128.5	86.0	688.2	86.0	774.2	50.30	38,944.7
12-31-2025	2,304.8	715.8	93.1	62.3	498.2	62.3	560.5	50.30	28,193.3
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	13,272.1	4,121.9	535.8	370.0	2,868.9	347.2	3,216.1	51.16	164,540.3
Cum Prod	0.0								
Ultimate	13,272.1								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	41.4	205.0	73.2	43.8	2,802.9	2,684.7
12-31-2020	8,330.6	41.4	2,623.7	515.2	940.9	11,075.5	12,157.8
12-31-2021	0.0	41.4	2,565.9	447.6	1,218.5	16,940.7	25,859.8
12-31-2022	0.0	41.4	11,226.1	392.5	356.9	5,142.2	29,640.2
12-31-2023	0.0	41.4	33,124.6	988.8	197.4	3,498.3	31,982.6
12-31-2024	0.0	(3,342.8)	31,291.5	1,056.0	497.7	10,437.7	38,254.5
12-31-2025	0.0	887.4	25,731.1	778.4	129.6	926.0	38,806.6
12-31-2026	0.0	2,590.4	0.0	0.0	0.0	(2,590.4)	37,564.1
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	37,564.1
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	37,564.1
Total	8,330.6	342.0	106,767.9	4,251.7	3,384.8	48,232.9	37,564.1

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 24

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,992.4	1,239.9	161.2	111.2	863.0	104.5	967.5	55.85	54,037.4
12-31-2020	7,547.0	2,343.9	304.7	214.4	1,631.3	193.4	1,824.7	54.18	98,861.9
12-31-2021	6,538.1	2,030.5	264.0	184.5	1,413.2	168.9	1,582.1	52.43	82,945.5
12-31-2022	5,482.8	1,702.8	221.4	236.6	1,023.3	221.5	1,244.9	50.64	63,042.4
12-31-2023	4,744.3	1,473.4	191.5	206.2	878.9	196.7	1,075.7	50.35	54,164.3
12-31-2024	4,143.9	1,287.0	167.3	128.0	866.7	125.0	991.7	50.30	49,884.4
12-31-2025	3,640.7	1,130.7	147.0	98.6	787.0	98.2	885.1	50.30	44,525.0
12-31-2026	3,215.9	985.7	128.1	85.8	686.0	85.8	771.8	50.30	38,822.1
12-31-2027	2,849.0	860.9	111.9	74.9	599.2	74.9	674.1	50.30	33,908.3
12-31-2028	659.8	199.4	25.9	17.3	138.8	17.3	156.1	50.30	7,853.2
Total	42,814.0	13,254.2	1,723.0	1,357.4	8,887.5	1,286.2	10,173.7	51.90	528,044.5
Cum Prod	109,440.4								
Ultimate	152,254.5								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,424.0	1,378.1	343.1	(437.6)	(191.9)
12-31-2020	8,330.6	887.4	45,021.0	4,031.1	2,321.9	42,913.5	37,663.5
12-31-2021	0.0	887.4	44,265.5	2,102.8	2,011.0	37,700.7	68,220.3
12-31-2022	0.0	887.4	43,170.6	1,643.5	969.8	18,310.7	81,780.7
12-31-2023	0.0	887.4	42,510.0	1,430.6	517.9	9,854.2	88,398.0
12-31-2024	0.0	887.4	41,973.0	1,319.4	343.6	6,048.2	92,114.1
12-31-2025	0.0	887.4	39,885.8	1,189.2	144.4	2,707.0	93,614.6
12-31-2026	0.0	863.5	30,898.1	1,051.4	411.4	6,420.4	96,870.6
12-31-2027	0.0	863.5	30,154.5	932.4	153.8	2,111.7	97,864.8
12-31-2028	0.0	863.5	7,493.0	218.2	0.0	(721.5)	97,583.6
Total	27,459.1	8,802.5	358,795.5	15,296.8	7,217.0	124,907.5	97,583.6

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 25

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - LOW PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

POSSIBLE RESERVES
AS OF MARCH 31, 2019

	Gross (100%)	Working Interest	Government Share		Net Oil Reserves			Realized	Gross Revenue
Period Ending	Oil Reserves (MBBL)	Oil Reserves (MBBL)	Royalty (MBBL)	Income Tax[1] (MBBL)	Cost Recovery (MBBL)	Profit (MBBL)	Total (MBBL)	Oil Price ($/BBL)	to Net Interest (M$)
12-31-2019	186.8	58.0	7.5	5.6	40.4	4.5	44.9	55.85	2,508.4
12-31-2020	841.1	261.2	34.0	25.0	181.8	20.5	202.3	54.18	10,958.1
12-31-2021	1,182.7	367.3	47.7	35.2	255.6	28.8	284.4	52.43	14,910.6
12-31-2022	1,084.3	336.8	43.8	115.7	72.5	104.7	177.3	50.64	8,977.2
12-31-2023	1,022.1	317.4	41.3	105.3	74.3	96.5	170.9	50.35	8,603.4
12-31-2024	960.2	298.2	38.8	42.0	178.5	39.0	217.5	50.30	10,939.7
12-31-2025	1,335.9	414.9	53.9	36.3	288.8	35.9	324.7	50.30	16,331.7
12-31-2026	3,215.9	985.7	128.1	85.8	686.0	85.8	771.8	50.30	38,822.1
12-31-2027	2,849.0	860.9	111.9	74.9	599.2	74.9	674.1	50.30	33,908.3
12-31-2028	659.8	199.4	25.9	17.3	138.8	17.3	156.1	50.30	7,853.2
Total	13,337.8	4,099.8	533.0	543.0	2,516.0	507.8	3,023.8	50.87	153,812.6
Cum Prod	0.0								
Ultimate	13,337.8								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	167.0	59.6	(96.5)	2,185.3	2,090.3
12-31-2020	0.0	0.0	752.3	260.8	(265.7)	9,679.3	10,653.3
12-31-2021	0.0	0.0	1,158.6	355.5	220.5	13,617.0	21,637.1
12-31-2022	0.0	0.0	969.9	226.9	180.5	7,961.0	27,519.4
12-31-2023	0.0	0.0	1,732.7	216.7	304.1	6,958.0	32,165.3
12-31-2024	0.0	0.0	10,681.5	263.4	(154.0)	(159.3)	32,064.7
12-31-2025	0.0	0.0	14,154.7	410.8	14.8	1,781.0	33,013.0
12-31-2026	0.0	(1,726.9)	30,898.1	1,051.4	411.4	9,010.8	37,511.6
12-31-2027	0.0	863.5	30,154.5	932.4	153.8	2,111.7	38,505.8
12-31-2028	0.0	863.5	7,493.0	218.2	0.0	(721.5)	38,224.6
Total	0.0	0.0	98,162.3	3,995.8	768.9	52,423.4	38,224.6

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 26

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

TOTAL PROVED (1P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,576.4	1,110.7	144.4	98.9	773.1	94.4	867.5	75.95	65,881.1
12-31-2020	5,044.5	1,566.7	203.7	140.0	1,090.4	132.6	1,223.0	73.68	90,109.8
12-31-2021	3,866.5	1,200.8	156.1	105.2	835.8	103.8	939.5	71.31	67,001.0
12-31-2022	3,054.8	948.7	123.3	95.7	633.9	95.7	729.7	68.90	50,271.3
12-31-2023	2,413.3	749.5	97.4	65.2	521.7	65.2	586.9	68.51	40,204.1
12-31-2024	1,480.3	459.7	59.8	40.0	320.0	40.0	360.0	68.44	24,636.2
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	19,435.9	6,036.2	784.7	545.0	4,174.8	531.7	4,706.5	71.84	338,103.5
Cum Prod	109,440.4								
Ultimate	128,876.3								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	846.1	33,052.0	1,639.2	928.2	12,143.6	11,970.6
12-31-2020	0.0	846.1	41,645.1	3,794.1	2,983.6	46,808.2	53,730.3
12-31-2021	0.0	846.1	40,541.0	1,700.5	1,624.4	25,537.8	74,480.4
12-31-2022	0.0	846.1	39,815.0	1,311.4	585.9	8,884.8	81,099.3
12-31-2023	0.0	846.1	35,375.2	1,072.5	221.7	3,132.1	83,193.0
12-31-2024	0.0	846.1	22,203.5	674.6	115.3	1,027.4	83,864.8
12-31-2025	0.0	3,384.2	0.0	0.0	0.0	(3,384.2)	82,079.2
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	82,079.2
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	82,079.2
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	82,079.2
Total	19,128.5	8,460.5	212,631.8	10,192.3	6,459.3	94,149.7	82,079.2

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

[1] Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
[2] VAALCO's share of the state carry costs is shown as capital costs.
[3] Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,216.6	999.0	129.9	88.2	695.3	85.6	780.9	75.95	59,309.5
12-31-2020	3,409.3	1,058.8	137.6	92.2	736.9	92.0	828.9	73.68	61,077.4
12-31-2021	2,646.8	822.0	106.9	71.5	572.1	71.5	643.6	71.31	45,898.8
12-31-2022	381.9	118.6	15.4	10.3	82.6	10.3	92.9	68.90	6,398.6
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	9,654.6	2,998.4	389.8	262.2	2,086.9	259.5	2,346.4	73.60	172,684.2
Cum Prod	109,440.4								
Ultimate	119,095.0								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	763.3	29,064.5	1,485.0	2,255.3	30,252.0	29,278.6
12-31-2020	0.0	763.3	37,814.9	3,112.4	1,556.9	20,943.7	47,999.8
12-31-2021	0.0	763.3	37,082.5	1,204.8	586.3	7,434.5	54,100.3
12-31-2022	0.0	763.3	6,127.4	171.6	6.5	(657.3)	53,645.3
12-31-2023	0.0	4,579.6	0.0	0.0	0.0	(4,579.6)	50,721.6
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	50,721.6
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	50,721.6
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	50,721.6
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	50,721.6
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	50,721.6
Total	0.0	7,632.7	110,089.3	5,973.8	4,405.0	53,393.4	50,721.6

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 28

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	90.5	28.1	3.7	2.7	19.6	2.2	21.8	75.95	1,652.9
12-31-2020	354.7	110.1	14.3	9.9	76.7	9.2	85.9	73.68	6,327.9
12-31-2021	358.8	111.4	14.5	9.7	77.5	9.7	87.2	71.31	6,221.5
12-31-2022	1,668.7	518.3	67.4	45.1	360.7	45.1	405.8	68.90	27,958.4
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	2,472.7	767.9	99.8	67.4	534.5	66.2	600.7	70.19	42,160.7
Cum Prod	0.0								
Ultimate	2,472.7								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	3,450.6	38.8	(300.4)	(2,136.9)	(2,039.6)
12-31-2020	0.0	0.0	317.2	148.5	311.3	6,173.5	3,438.9
12-31-2021	0.0	0.0	320.9	146.1	345.8	6,100.3	8,365.2
12-31-2022	0.0	0.0	24,636.0	742.0	185.6	2,766.0	10,438.6
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	10,438.6
Total	0.0	0.0	28,724.7	1,075.4	542.3	12,902.8	10,438.6

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED UNDEVELOPED RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	269.3	83.6	10.9	8.0	58.2	6.5	64.8	75.95	4,918.6
12-31-2020	1,280.6	397.7	51.7	37.9	276.8	31.3	308.1	73.68	22,704.5
12-31-2021	860.9	267.4	34.8	24.0	186.1	22.6	208.7	71.31	14,880.7
12-31-2022	1,004.2	311.9	40.5	40.3	190.7	40.3	231.0	68.90	15,914.4
12-31-2023	2,413.3	749.5	97.4	65.2	521.7	65.2	586.9	68.51	40,204.1
12-31-2024	1,480.3	459.7	59.8	40.0	320.0	40.0	360.0	68.44	24,636.2
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Total	7,308.7	2,269.8	295.1	215.3	1,553.4	206.0	1,759.4	70.06	123,258.5
Cum Prod	0.0								
Ultimate	7,308.7								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	82.8	536.8	115.4	(1,026.7)	(15,971.6)	(15,268.3)
12-31-2020	0.0	82.8	3,513.0	533.2	1,115.4	19,691.0	2,291.6
12-31-2021	0.0	82.8	3,137.6	349.6	692.4	12,003.1	12,015.0
12-31-2022	0.0	82.8	9,051.6	397.7	393.8	6,776.1	17,015.3
12-31-2023	0.0	(3,733.6)	35,375.2	1,072.5	221.7	7,711.7	22,032.7
12-31-2024	0.0	846.1	22,203.5	674.6	115.3	1,027.4	22,704.6
12-31-2025	0.0	3,384.2	0.0	0.0	0.0	(3,384.2)	20,919.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	20,919.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	20,919.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	20,919.0
Total	19,128.5	827.8	73,817.7	3,143.1	1,512.0	27,853.5	20,919.0

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 30

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE (2P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,805.6	1,181.9	153.6	105.7	822.6	100.0	922.6	75.95	70,067.3
12-31-2020	6,705.9	2,082.6	270.7	189.4	1,449.5	173.0	1,622.5	73.68	119,547.1
12-31-2021	5,355.4	1,663.2	216.2	410.6	651.3	385.0	1,036.4	71.31	73,906.1
12-31-2022	4,398.5	1,366.0	177.6	274.3	649.2	264.9	914.1	68.90	62,981.3
12-31-2023	3,722.3	1,156.0	150.3	184.5	638.1	183.1	821.2	68.51	56,260.9
12-31-2024	3,183.8	988.8	128.5	118.3	623.7	118.3	741.9	68.44	50,776.9
12-31-2025	2,734.4	849.2	110.4	73.9	591.1	73.9	664.9	68.44	45,506.7
12-31-2026	2,348.3	719.8	93.6	65.0	496.3	65.0	561.3	68.44	38,413.6
12-31-2027	2,033.0	614.3	79.9	53.4	427.6	53.4	481.0	68.44	32,919.4
12-31-2028	312.0	94.3	12.3	8.2	65.6	8.2	73.8	68.44	5,052.5
Total	34,599.2	10,716.3	1,393.1	1,483.3	6,415.1	1,424.8	7,839.8	70.85	555,431.9
Cum Prod	109,440.4								
Ultimate	144,039.6								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,257.0	1,737.4	930.7	15,987.7	15,647.8
12-31-2020	8,330.6	887.4	44,268.7	4,485.4	3,509.2	65,084.1	73,256.8
12-31-2021	0.0	887.4	43,106.9	1,911.0	1,561.5	29,562.2	97,217.1
12-31-2022	0.0	887.4	42,200.7	1,635.7	1,016.9	19,274.5	111,416.3
12-31-2023	0.0	887.4	41,595.8	1,465.1	131.8	12,444.3	119,764.5
12-31-2024	0.0	887.4	41,114.2	1,327.0	0.0	7,448.3	124,326.1
12-31-2025	0.0	887.4	40,712.2	1,197.3	0.0	2,709.7	125,869.1
12-31-2026	0.0	863.5	29,984.1	1,029.1	0.0	6,536.9	129,188.4
12-31-2027	0.0	863.5	29,248.2	897.8	0.0	1,910.0	130,091.1
12-31-2028	0.0	863.5	4,851.4	139.4	0.0	(801.8)	129,775.4
Total	27,459.1	8,802.5	350,339.3	15,825.2	7,150.1	160,156.0	129,775.4

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROBABLE RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax(1) (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	229.2	71.2	9.3	6.8	49.5	5.6	55.1	75.95	4,186.3
12-31-2020	1,661.4	516.0	67.1	49.4	359.1	40.4	399.5	73.68	29,437.3
12-31-2021	1,488.9	462.4	60.1	305.5	(184.4)	281.3	96.8	71.31	6,905.2
12-31-2022	1,343.7	417.3	54.3	178.6	15.3	169.2	184.5	68.90	12,710.0
12-31-2023	1,308.9	406.5	52.8	119.3	116.5	117.9	234.4	68.51	16,056.8
12-31-2024	1,703.4	529.0	68.8	78.3	303.7	78.3	382.0	68.44	26,140.7
12-31-2025	2,734.4	849.2	110.4	73.9	591.1	73.9	664.9	68.44	45,506.7
12-31-2026	2,348.3	719.8	93.6	65.0	496.3	65.0	561.3	68.44	38,413.6
12-31-2027	2,033.0	614.3	79.9	53.4	427.6	53.4	481.0	68.44	32,919.4
12-31-2028	312.0	94.3	12.3	8.2	65.6	8.2	73.8	68.44	5,052.5
Total	15,163.3	4,680.1	608.4	938.3	2,240.3	893.1	3,133.4	69.36	217,328.4
Cum Prod	0.0								
Ultimate	15,163.3								

Period Ending	Net Capital Cost(2) (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes(3) (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	41.4	205.0	98.2	2.5	3,844.2	3,677.1
12-31-2020	8,330.6	41.4	2,623.7	691.3	525.6	18,275.9	19,526.5
12-31-2021	0.0	41.4	2,565.9	210.5	(62.9)	4,024.4	22,736.6
12-31-2022	0.0	41.4	2,385.7	324.3	431.0	10,389.7	30,317.1
12-31-2023	0.0	41.4	6,220.7	392.6	(90.0)	9,312.2	36,571.5
12-31-2024	0.0	41.4	18,910.7	652.3	(115.3)	6,421.0	40,461.2
12-31-2025	0.0	(2,496.8)	40,712.2	1,197.3	0.0	6,093.9	43,789.9
12-31-2026	0.0	863.5	29,984.1	1,029.1	0.0	6,536.9	47,109.1
12-31-2027	0.0	863.5	29,248.2	897.8	0.0	1,910.0	48,011.8
12-31-2028	0.0	863.5	4,851.4	139.4	0.0	(801.8)	47,696.2
Total	8,330.6	342.0	137,707.5	5,632.9	690.8	66,006.3	47,696.2

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 32

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share: Royalty (MBBL)	Government Share: Income Tax[1] (MBBL)	Net Oil Reserves: Cost Recovery (MBBL)	Net Oil Reserves: Profit (MBBL)	Net Oil Reserves: Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	3,992.4	1,239.9	161.2	111.2	863.0	104.5	967.5	75.95	73,478.2
12-31-2020	7,547.0	2,343.9	304.7	319.4	1,431.2	288.6	1,719.8	73.68	126,716.2
12-31-2021	6,538.1	2,030.5	264.0	574.2	667.0	525.4	1,192.4	71.31	85,032.7
12-31-2022	5,482.8	1,702.8	221.4	420.2	668.4	392.8	1,061.3	68.90	73,118.1
12-31-2023	4,744.3	1,473.4	191.5	318.7	659.0	304.2	963.2	68.51	65,982.8
12-31-2024	4,143.9	1,287.0	167.3	238.2	648.9	232.5	881.5	68.44	60,325.3
12-31-2025	3,640.7	1,130.7	147.0	173.8	636.9	173.0	809.9	68.44	55,429.6
12-31-2026	3,215.9	985.7	128.1	120.1	617.4	120.1	737.5	68.44	50,470.2
12-31-2027	2,849.0	860.9	111.9	75.1	598.8	75.1	673.9	68.44	46,120.0
12-31-2028	1,921.0	580.5	75.5	50.5	404.0	50.5	454.5	68.44	31,106.5
Total	44,075.3	13,635.3	1,772.6	2,401.3	7,194.6	2,266.7	9,461.4	70.58	667,779.6
Cum Prod	109,440.4								
Ultimate	153,515.7								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	19,128.5	887.4	33,424.0	1,817.4	1,102.7	19,323.6	18,843.8
12-31-2020	8,330.6	887.4	45,021.0	4,673.5	3,855.2	71,658.8	82,496.3
12-31-2021	0.0	887.4	44,265.5	2,196.3	2,101.7	39,785.1	114,695.5
12-31-2022	0.0	887.4	43,170.6	1,894.8	72.2	27,237.5	134,740.0
12-31-2023	0.0	887.4	42,510.0	1,712.7	0.0	20,872.6	148,706.9
12-31-2024	0.0	887.4	41,973.0	1,568.3	0.0	15,896.6	158,382.0
12-31-2025	0.0	887.4	41,522.9	1,444.1	0.0	11,575.1	164,794.6
12-31-2026	0.0	863.5	40,588.1	1,318.4	0.0	7,700.3	168,687.7
12-31-2027	0.0	863.5	39,711.7	1,208.3	0.0	4,336.5	170,699.2
12-31-2028	0.0	863.5	27,206.7	824.3	0.0	2,212.1	171,628.8
Total	27,459.1	8,802.5	399,393.5	18,658.2	7,131.9	220,598.2	171,628.8

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE - HIGH PRICE CASE
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST

POSSIBLE RESERVES
AS OF MARCH 31, 2019

Period Ending	Gross (100%) Oil Reserves (MBBL)	Working Interest Oil Reserves (MBBL)	Government Share Royalty (MBBL)	Government Share Income Tax[1] (MBBL)	Net Oil Reserves Cost Recovery (MBBL)	Net Oil Reserves Profit (MBBL)	Net Oil Reserves Total (MBBL)	Realized Oil Price ($/BBL)	Gross Revenue to Net Interest (M$)
12-31-2019	186.8	58.0	7.5	5.6	40.4	4.5	44.9	75.95	3,410.9
12-31-2020	841.1	261.2	34.0	130.0	(18.3)	115.6	97.3	73.68	7,169.1
12-31-2021	1,182.7	367.3	47.7	163.5	15.7	140.4	156.0	71.31	11,126.6
12-31-2022	1,084.3	336.8	43.8	145.9	19.2	127.9	147.1	68.90	10,136.8
12-31-2023	1,022.1	317.4	41.3	134.2	20.8	121.1	141.9	68.51	9,721.9
12-31-2024	960.2	298.2	38.8	119.9	25.3	114.3	139.5	68.44	9,548.3
12-31-2025	906.3	281.5	36.6	99.9	45.8	99.2	145.0	68.44	9,922.9
12-31-2026	867.6	265.8	34.6	55.1	121.1	55.1	176.2	68.44	12,056.6
12-31-2027	816.0	246.6	32.1	21.6	171.2	21.6	192.9	68.44	13,200.6
12-31-2028	1,609.0	486.2	63.2	42.3	338.4	42.3	380.7	68.44	26,054.1
Total	9,476.1	2,919.0	379.5	918.0	779.6	842.0	1,621.5	69.28	112,347.7
Cum Prod	0.0								
Ultimate	9,476.1								

Period Ending	Net Capital Cost[2] (M$)	Net Abandonment Cost (M$)	Net Operating Expense (M$)	Production Taxes[3] (M$)	Reimbursement From State (M$)	Future Net Revenue (M$)	Cum P.W. at 10% (M$)
12-31-2019	0.0	0.0	167.0	80.0	172.0	3,335.9	3,196.0
12-31-2020	0.0	0.0	752.3	188.1	346.0	6,574.7	9,239.5
12-31-2021	0.0	0.0	1,158.6	285.3	540.2	10,222.9	17,478.5
12-31-2022	0.0	0.0	969.9	259.2	(944.7)	7,963.0	23,323.6
12-31-2023	0.0	0.0	914.2	247.6	(131.8)	8,428.3	28,942.4
12-31-2024	0.0	0.0	858.8	241.3	0.0	8,448.2	34,055.9
12-31-2025	0.0	0.0	810.7	246.8	0.0	8,865.4	38,925.5
12-31-2026	0.0	0.0	10,604.0	289.3	0.0	1,163.4	39,499.3
12-31-2027	0.0	0.0	10,463.4	310.6	0.0	2,426.6	40,608.2
12-31-2028	0.0	0.0	22,355.3	684.9	0.0	3,013.9	41,853.4
Total	0.0	0.0	49,054.2	2,833.0	(18.2)	60,442.2	41,853.4

Notes: The oil volumes shown include crude oil only.
Totals may not add because of rounding.

(1) Income tax barrels are calculated as the Gabonese government's share of profit oil multiplied by VAALCO's working interest, net of government participation.
(2) VAALCO's share of the state carry costs is shown as capital costs.
(3) Production taxes include bonuses and state fees for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and PID/PIH.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 34

SUMMARY OF UNRISKED GROSS (100 PERCENT) CONTINGENT OIL RESOURCES
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A.
AS OF MARCH 31, 2019

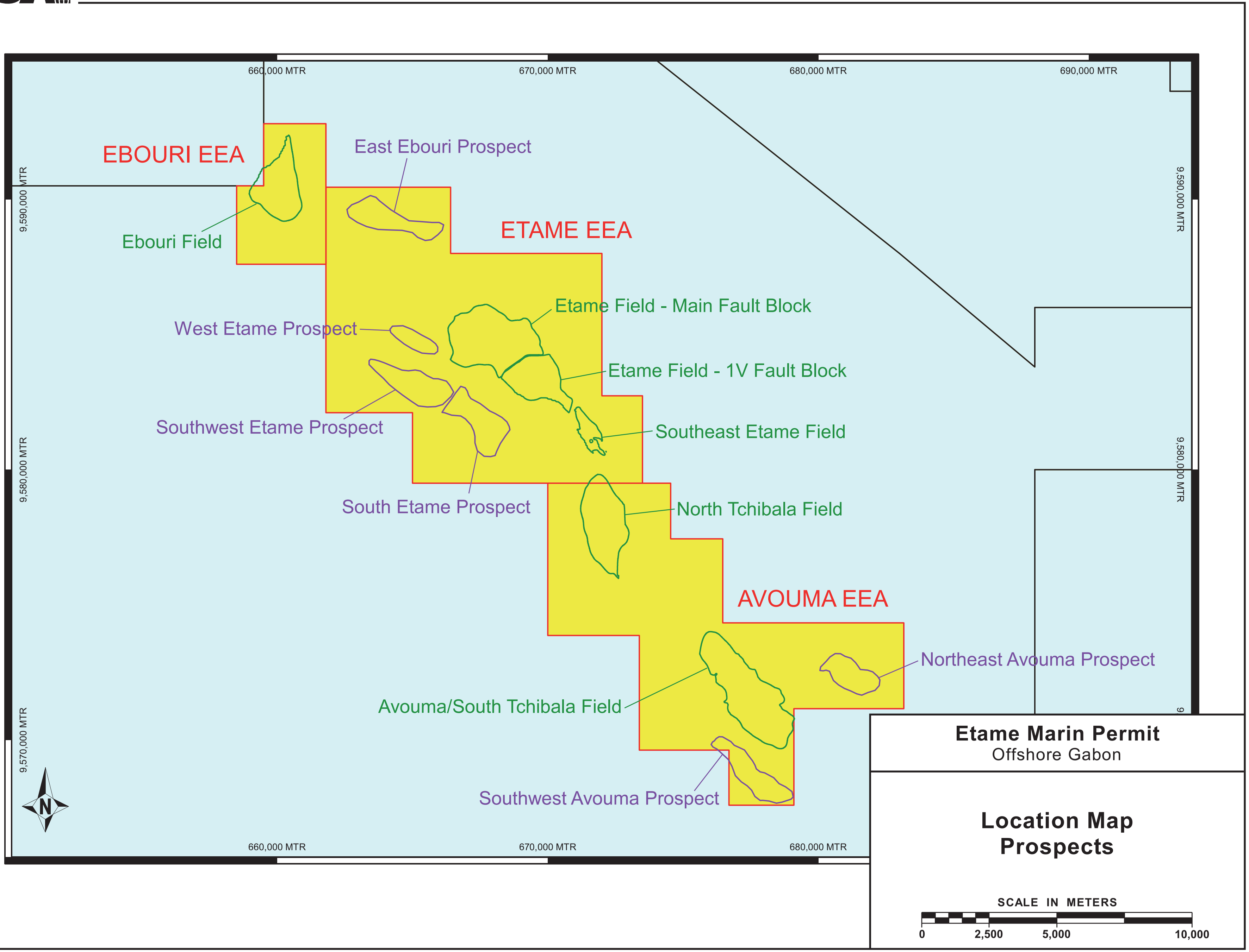
	Gross (100%) Contingent Oil Resources (MMBBL)		
Category/Field	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Additional Volumes[1]			
Avouma	3.4	7.5	9.3
Ebouri	1.0	1.2	1.4
Etame	5.9	6.5	9.3
North Tchibala	0.1	0.0	0.2
Southeast Etame	0.6	0.5	1.0
Crude Sweetening Project			
Ebouri	1.8	5.3	9.6
Dentale - Pressure Maintenance[2]			
North Tchibala	1.4	1.8	3.4
Dentale - Additional Drilling[3]			
North Tchibala	1.4	2.6	4.1
Total	15.6	25.5	38.3

Totals may not add because of rounding.

(1) These resources are the additional volumes estimated to be recovered beyond the economic limit of the reserves or expiration date of the PSC and are dependent on the price and cost parameters used in the reserves estimates.
(2) Resources associated with pressure maintenance on the D-9 and D-10 intervals.
(3) Resources associated with additional drilling targeting the D-18 and D-19 intervals.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 35



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 36

SUMMARY OF VOLUMETRIC PARAMETERS
PROSPECTIVE RESOURCES
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

Prospect	Gross Rock Volume (acre-feet) Lognormal Distribution		Net-to-Gross Ratio (decimal) Normal Distribution		Porosity (decimal) Normal Distribution		Hydrocarbon Saturation (decimal) Normal Distribution	
	P90	P10	P90	P10	P90	P10	P90	P10
East Ebouri	2,974	13,397	0.65	0.95	0.25	0.30	0.75	0.90
Northeast Avouma	2,687	24,818	0.65	0.95	0.25	0.30	0.75	0.90
South Etame	3,379	19,815	0.65	0.95	0.25	0.30	0.75	0.90
Southwest Avouma	3,986	20,488	0.65	0.95	0.25	0.30	0.75	0.90
Southwest Etame	3,830	22,715	0.65	0.95	0.25	0.30	0.75	0.90
West Etame	817	3,801	0.65	0.95	0.25	0.30	0.75	0.90

Prospect	Initial Oil Formation Volume Factor (RB/STB) Triangular Distribution			Oil Recovery Factor (decimal) Triangular Distribution		
	Min	ML	Max	Min	ML	Max
East Ebouri	1.05	1.10	1.15	0.35	0.55	0.65
Northeast Avouma	1.05	1.10	1.15	0.35	0.55	0.65
South Etame	1.05	1.10	1.15	0.35	0.55	0.65
Southwest Avouma	1.05	1.10	1.15	0.35	0.55	0.65
Southwest Etame	1.05	1.10	1.15	0.35	0.55	0.65
West Etame	1.05	1.10	1.15	0.35	0.55	0.65

Note: NSAI assumed a constant gross thickness of 20 meters in the Gamba Sand and used a wide net-to-gross ratio range to account for potential thickness variations.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 37

SUMMARY OF UNRISKED PROSPECTIVE OIL RESOURCES
ETAME MARIN PERMIT, OFFSHORE GABON
VAALCO GABON S.A. INTEREST
AS OF MARCH 31, 2019

	Undiscovered Original Oil-In-Place (MMBBL)			Unrisked Gross (100%) Prospective Oil Resources (MMBBL)		
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
East Ebouri	3.6	7.4	17.1	1.6	3.6	8.6
Northeast Avouma	3.2	9.2	30.8	1.5	4.4	15.1
South Etame	4.1	9.6	24.5	1.9	4.6	12.3
Southwest Avouma	4.8	10.6	26.0	2.2	5.1	13.0
Southwest Etame	4.7	10.9	28.8	2.1	5.2	14.3
West Etame	1.0	2.1	4.8	0.4	1.0	2.4

	Unrisked Working Interest Prospective Oil Resources (MMBBL)		
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
East Ebouri	0.5	1.1	2.7
Northeast Avouma	0.5	1.4	4.7
South Etame	0.6	1.4	3.8
Southwest Avouma	0.7	1.6	4.0
Southwest Etame	0.7	1.6	4.4
West Etame	0.1	0.3	0.8

Note: Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 38

SUMMARY OF GEOLOGIC RISKING
ETAME MARIN PERMIT, OFFSHORE GABON
AS OF MARCH 31, 2019

	Geologic Risk Element (decimal)				
Prospect	Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	Probability of Geologic Success (decimal)
East Ebouri	0.85	0.95	1.00	0.90	0.73
Northeast Avouma	0.85	0.95	1.00	0.90	0.73
South Etame	0.75	0.95	1.00	0.90	0.64
Southwest Avouma	0.85	0.95	1.00	0.90	0.73
Southwest Etame	0.75	0.95	1.00	0.90	0.64
West Etame	0.65	0.95	1.00	0.90	0.56

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 39

PART 21 – BLOCK P COMPETENT PERSON'S REPORT

ESTIMATES

of

UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES

to the

VAALCO ENERGY INC. WORKING INTEREST

in the

VENUS DISCOVERY AND PROSPECTS

located in

BLOCK P, OFFSHORE EQUATORIAL GUINEA

as of

MARCH 31, 2019

COMPETENT PERSON'S REPORT

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

September 20, 2019

VAALCO Energy Inc.
9800 Richmond Avenue, Suite 700
Houston, Texas 77042

Ladies and Gentlemen:

In accordance with the request of VAALCO Energy Inc. (VAALCO), we have estimated the unrisked contingent and prospective resources, as of March 31, 2019, to the VAALCO working interest in the Venus Discovery and prospects located in Block P, offshore Equatorial Guinea. We completed our evaluation on or about the date of this letter. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the discovery and prospects.

The estimates in this Competent Person's Report (report) have been prepared in accordance with the recommendations of the European Securities and Markets Authority (ESMA) and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are certificates of qualification for the evaluators who contributed to this report and a list of abbreviations used in this report. This report has been prepared for use by VAALCO in filing with the London Stock Exchange; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon finalization and approval of a development plan and commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate contingent resources in this report have a reasonable chance of being economically viable. The project maturity subclass for these contingent resources is development unclarified.

We estimate the unrisked gross contingent oil resources and the VAALCO unrisked working interest contingent oil resources for the Venus Discovery, as of March 31, 2019, to be:

	Unrisked Contingent Oil Resources (MMBBL)	
Category	Gross (100%)	Working Interest
Low Estimate (1C)	11.1	3.4
Best Estimate (2C)	16.5	5.1
High Estimate (3C)	26.5	8.2

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. As requested, the scope of this project does not include contingent gas resources.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross prospective oil resources and the VAALCO unrisked working interest prospective oil resources for these prospects, along with the probability of geologic success (P_g), as of March 31, 2019, to be:

	Unrisked Gross (100%) Prospective Oil Resources (MMBBL)			Unrisked Working Interest Prospective Oil Resources (MMBBL)			
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	P_g (%)
Marte	11.1	40.6	131.9	3.4	12.6	40.9	19
Marte North	23.8	66.9	136.8	7.4	20.7	42.4	17
Saturno	3.5	10.9	25.7	1.1	3.4	8.0	23
Southwest Grande M-3	9.1	28.1	69.5	2.8	8.7	21.5	19
Southwest Grande O-1	11.0	32.9	76.5	3.4	10.2	23.7	16
Southwest Grande Oligocene	7.1	29.0	114.2	2.2	9.0	35.4	13
Southwest Grande OM-1	15.4	43.0	85.9	4.8	13.3	26.6	19
Southwest Grande OM-2	11.8	31.4	64.7	3.7	9.7	20.1	23

The oil volumes shown include crude oil only. As requested, the scope of this project does not include prospective gas resources.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The prospects in this report have been sized at their full technical volume and their volumes have not been truncated by the Block P boundary, where applicable.

Unrisked prospective resources are estimated ranges of recoverable oil volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

GENERAL INFORMATION

As shown in the Table of Contents, this report includes a technical discussion and pertinent figures.

For the purposes of this report, we did not perform any field inspection of the discovery and prospects. We have not investigated possible environmental liability related to the discovery and prospects.

The contingent and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance.

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, and property ownership interests. The contingent and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. 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. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE

Standards. 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.

The effective date of this report is March 31, 2019 ("Effective Date"). The publication of this report is assumed to be consistent with the publication date of the prospectus to be published by VAALCO. VAALCO has confirmed to us that there have been no material changes since the Effective Date, the omission of which would make this report misleading.

Sincerely,

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

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

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

Date Signed: September 20, 2019

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

Date Signed: September 20, 2019

JRC:RS

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

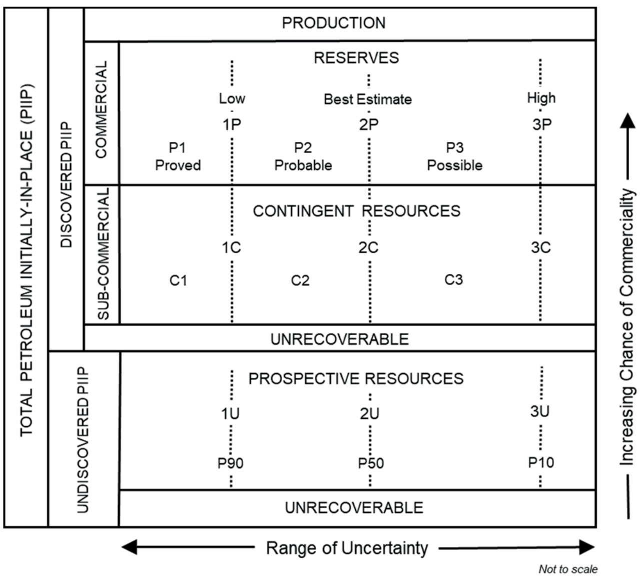


Figure 1.1—Resources classification framework

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

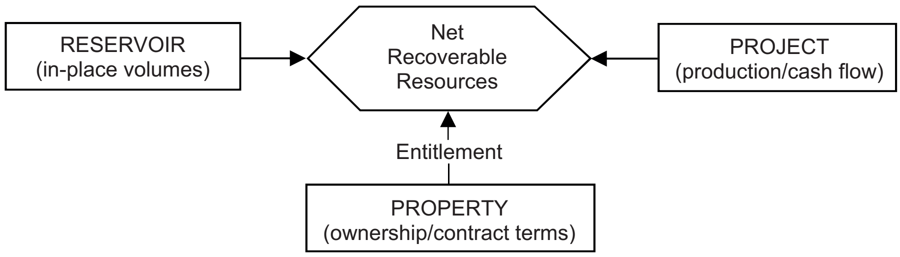

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or 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 minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CERTIFICATE OF QUALIFICATION

I, John R. Cliver, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for VAALCO Energy Inc. The effective date of this evaluation is March 31, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of VAALCO Energy Inc. or its affiliated companies.

I 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; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 15 years of experience in petroleum engineering studies and evaluations.

By: /s/ John R. Cliver
John R. Cliver, P.E.
Vice President
Texas License No. 107216

September 20, 2019
Houston, Texas

CERTIFICATE OF QUALIFICATION

I, Zachary R. Long, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a Competent Person's Report for VAALCO Energy Inc. The effective date of this evaluation is March 31, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of VAALCO Energy Inc. or its affiliated companies.

I 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; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 14 years of experience in geological and geophysical studies and evaluations.

/s/ Zachary R. Long
By: ____
Zachary R. Long, P.G.
Vice President
Texas License No. 11792

September 20, 2019
Houston, Texas

ABBREVIATIONS

%	percent
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1U	low estimate scenario of prospective resources
2U	best estimate scenario of prospective resources
3U	high estimate scenario of prospective resources
API	American Petroleum Institute
AVO	amplitude versus offset
Devon	Devon Energy Corporation
EG	Equatorial Guinea
ESMA	European Securities and Markets Authority
km^2	square kilometers
m	meters
MDT	modular formation dynamics tester
MMBBL	millions of barrels
NSAI	Netherland, Sewell & Associates, Inc.
OWC	oil-water contact
P10	10 percent confidence level
P90	90 percent confidence level
PDA	production and development area
P_g	probability of geologic success
PRMS	Petroleum Resources Management System
PSC	Production Sharing Contract
RB/STB	reservoir barrels per stock tank barrel
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
TVDSS	true vertical depth subsea
VAALCO	VAALCO Energy Inc.

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TECHNICAL DISCUSSION

TECHNICAL DISCUSSION
BLOCK P, OFFSHORE EQUATORIAL GUINEA

1.0 GENERAL OVERVIEW

Netherland, Sewell & Associates, Inc. (NSAI) has estimated the unrisked contingent and prospective resources, as of March 31, 2019, to the VAALCO Energy Inc. (VAALCO) working interest in the Venus Discovery and prospects located in Block P, offshore Equatorial Guinea (EG). A location map for Block P is shown on Figure 1. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the discovery and prospects.

The estimates in this Competent Person's Report (report) have been prepared in accordance with the recommendations of the European Securities and Markets Authority (ESMA) and the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.

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, and property ownership interests. The contingent and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. 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.

2.0 GEOLOGY

Block P is located in the Rio Muni Basin, offshore EG. The rift between South America and Africa began in the early Cretaceous (126 million years ago), with the formation of a series of basins that would resemble the lakes in East Africa today. As Brazil continued to pull away from West Africa, faulting and sliding associated with the rift formed the early Rio Muni Basin. The Rio Muni Basin contains a thick wedge of Cretaceous to Tertiary sediments deposited over an early Cretaceous rifted terrain. Deposition of this wedge was interrupted by low stands in sea level and tectonic uplift in the Aptian and Santonian stages. During the regional Santonian tectonic episode and associated uplift, valleys were incised into the underlying Lower Cretaceous synrift, transitional, and early drift deposits in the prospect area. Subsequently, stacked Upper Cretaceous channels and fans were deposited as valley fill on the Santonian unconformity. Continued opening of the Atlantic Ocean accommodated the deposition of Tertiary and younger shales and sands that buried the Santonian unconformity and related valley fill deposits to their current depths.

During the Barremian and Aptian rifting, deep, anoxic, lacustrine systems developed, resulting in the deposition of important synrift source rocks. These permanently stratified lakes did not experience seasonal overturn. During humid episodes, when the lake level was high, the lakes were highly productive and anoxia was widespread, resulting in the accumulation of thick sequences of organic-rich, laminated shale. During arid episodes, when evaporation rates were high and thus the lake level was low, organic shale and carbonate mudstone or marl was deposited in shallow, aerated water. These source rocks are a key part of the hydrocarbon system within the basin. A representative stratigraphic column is shown on Figure 2.

The Upper Cretaceous sequence of sedimentation is important as it relates to prospectivity within the basin. This was a period of sand-rich deposition, as incised valleys were filled and stacked channels systems and fans were formed. Some of these features are imaged on 3-D seismic data and are the subjects of potential future exploration.

During the early Tertiary, thick sections of sediment were deposited, but were subsequently eroded during the Oligocene, when sea level dropped. Valleys were cut into the existing sediments during the period of erosion that were later filled in by sediments of varying lithology. The sand members within the valley fill are potential exploration targets.

3.0 OVERVIEW OF BLOCK P AREA AND DEVELOPMENT

In April 2003, Devon Energy Corporation (Devon) executed a production sharing contract (PSC) on Block P. As shown on Figure 1, Block P covers a total area of 1,333 square kilometers (km^2); the southwest corner of this block is designated as the Venus Production and Development Area (PDA), which is the key area of focus for VAALCO. In November 2012, VAALCO completed its acquisition of the 31 percent working interest in the Venus PDA from Petronas Carigali Overseas Sdn. Bhd. Other interest owners in the block include GEPetrol, Atlas Petroleum International Ltd., and Crown Energy AB. The various interests owned by these companies in the Venus PDA are shown in the following table:

Company	Working Interest (%)	Exploration Interest (%)
VAALCO	31.00	38.75
GEPetrol	38.40	48.00
GEPetrol (Back-In)[(1)]	20.00	0.00
Atlas Petroleum International Ltd.	5.60	7.00
Crown Energy AB	5.00	6.25

(1) Development expenditures will be paid back from production.

For a number of years, the Block P interest under the Block P PSC was in suspension; however, in September 2018, the Equatorial Guinea Ministry of Mines and Hydrocarbons lifted the suspension. Under the terms of lifting of the suspension of the Block P PSC, GEPetrol was required to introduce a new investor or joint venture owner of Block P by March 28, 2019, and it has fulfilled this requirement. Once the joint owner is approved, VAALCO will be required to drill one exploration well within one year. Certain details of the Venus PDA are summarized in the following table:

License	Operator	VAALCO Working Interest (%)	Status	License Expiration Date	License Area (km^2)
Venus Production and Development Area	VAALCO(1)	31.00	Exploration and Development	TBD(2)	227

(1) Operatorship is pending approval from the EG Ministry of Mines and Hydrocarbons. VAALCO will act as the technical operator and GEPetrol will act as the administrative operator.
(2) The license expiration date is 25 years from the date of approval of a development and production plan.

The first well on Block P, the P-1, was drilled in 2004 and targeted Campanian and Santonian channel sands within the Jupiter Complex. This well demonstrated that a viable hydrocarbon system was present in the area, finding 17 feet of low-permeability pay and numerous hydrocarbon shows. In 2005, Devon made the Venus Discovery with the P-2 well, which targeted a stratigraphic trap in the Venus Channel complex. A log from the P-2 well over the Campanian Green Sand is shown on Figure 3. The P-2ST1 and P-3 wells were subsequently drilled in 2005 and 2006, further delineating this discovery in the Green Sand. The P-4 well, drilled in 2007 to test amplitude versus offset (AVO) anomalies in the Europa Discovery, made another discovery in the Europa Channel system. Since that time, the data have been studied and various development plans have been evaluated by VAALCO; however, no development activity has commenced to date. It is our understanding that VAALCO is currently considering additional exploration activity in order to optimize the commerciality of a development on the block.

4.0 DATA AND METHODOLOGY

VAALCO provided NSAI the seismic, well log, sidewall core, fluid sample, and formation pressure data, as well as the current draft of the Integrated Field Development Plan for Block P. For the contingent resources in the Venus Discovery, we integrated these data to build a 3-D geologic model in Schlumberger's Petrel software package. This model was input into a dynamic reservoir simulation model in Schlumberger's Eclipse software package. Various sensitivities were run to evaluate the uncertainty in oil and gas recovery under various geologic interpretations. These were then used to guide our deterministic estimates of contingent resources in this discovery.

Prospective resources were estimated probabilistically using volumetric calculations in a Monte Carlo simulation. We defined low- and high-case values and a distribution shape for each prospect's volumetric parameters; these were then sampled in the Monte Carlo simulation to estimate original oil-in-place and recoverable resources.

5.0 CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon finalization and approval of a development plan and commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate contingent resources in this report have a reasonable chance of being economically viable. The project maturity subclass for these contingent resources is development unclarified.

The Block P reservoirs that have been discovered, as of March 31, 2019, are located within two Upper Cretaceous slope channel systems identified as the Jupiter and Venus systems. The P-1 and P-4 wells targeted Jupiter Channel sands, and the P-2, P-2ST1, and P-3 wells were drilled into Venus Channel sands. The Venus Green Sand was discovered by the P-2 well and appraised by the P-2ST1 well. The P-3 well targeted stratigraphically younger targets relative to the Green Sand.

5.1 VENUS DISCOVERY

The Green Sand in the Venus Channel is situated between approximately 5,050 and 6,265 feet true vertical depth subsea (TVDSS), with an oil-water contact (OWC) at 5,623 feet TVDSS. This sand was penetrated by the P-2, P-2ST1, and P-3 wells. Gross reservoir thickness ranges between 175 and 200 feet, with an average net-to-gross ratio of 80 percent. Based on modular formation dynamics tester (MDT) transient analyses, average porosity is 27 percent above the OWC, oil saturation is 76 percent, and permeabilities range between 100 and 2,000 millidarcies. MDT oil samples show 30-degree API gravity oil. A depth structure map for the top of the Venus Green Sand is shown on Figure 4. Volumetric parameters for the Venus Green Sand are shown on Figure 5.

5.2 EUROPA DISCOVERY

The P-1 well encountered a vertical sequence of reservoir-quality, water-bearing sands in a location structurally downdip to the P-4 well. The P-4 well was drilled into the Europa Discovery and encountered five sands over a 650-foot interval. The shallowest of these sands is wet, two sands are gas-charged, and two sands are oil-bearing.

As requested by VAALCO, NSAI has not estimated any contingent resources that might be associated with the reservoirs discovered by the wells drilled in the Europa Discovery; any such resources that might exist have not been included in this report.

6.0 PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The prospects in this report have been sized at their full technical volume and their volumes have not been truncated by the Block P boundary, where applicable.

A map showing the location of the various prospects within the Venus PDA is shown on Figure 6. A summary of the inputs for our probabilistic analysis is shown on Figure 7, and the ranges for the undiscovered original oil-in-place and the unrisked gross and working interest prospective oil resources are shown on Figure 8.

Unrisked prospective resources are estimated ranges of recoverable oil volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. A summary of the geologic risking for each prospect is shown on Figure 9.

6.1 MARTE PROSPECT

The Marte Prospect is located along the north boundary of Block P. The target reservoir is a Cenomanian age turbidite sand that lies above the Aptian Unconformity. The trap is interpreted to be stratigraphic in nature because the sand pinches out along the limits of the depositional footprint. This prospect is supported by an amplitude response on the 3-D seismic data.

6.2 MARTE NORTH PROSPECT

The Marte North Prospect is positioned to the north of the Marte Prospect and is interpreted to be a separate lobe within the same depositional system. A structural high is interpreted to have been in place during deposition, which created separation between the turbidite lobes. The trap is interpreted to be stratigraphic and there is an amplitude response on the 3-D seismic data.

6.3 SATURNO PROSPECT

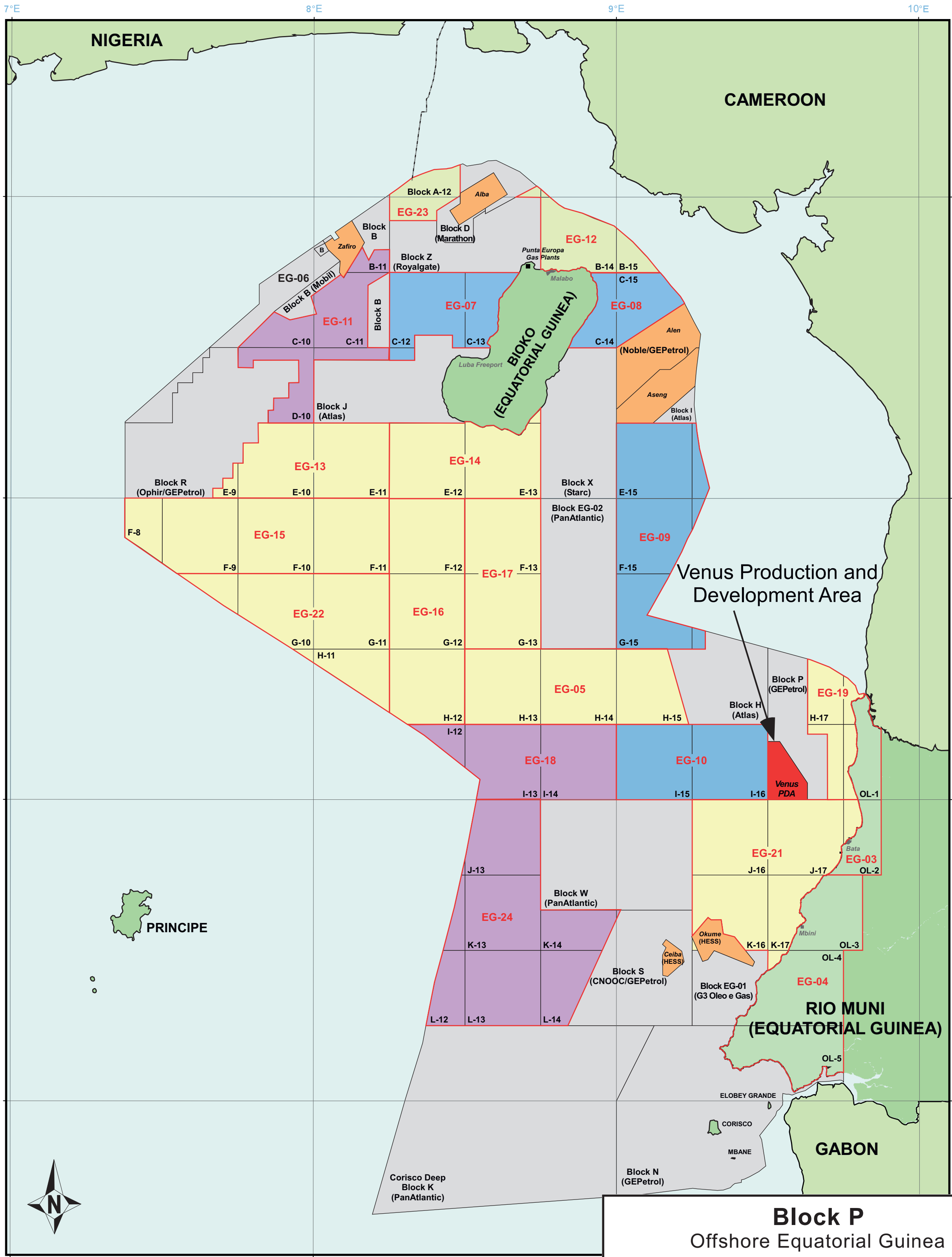
The Saturno Prospect is located near the Venus Discovery and targets potential sands of Aptian age. The structure is interpreted to be a four-way closure, the presence and potential size of which is strongly dependent on assumptions made when modeling seismic velocities. There are no seismic amplitude anomalies associated with this prospect.

6.4 SOUTHWEST GRANDE PROSPECT AREA

The Southwest Grande Prospect Area is located along the southeast boundary of Block P and comprises five prospective intervals that are a combination of stacked channels and turbidites. Each of the prospective intervals rely on stratigraphic trapping mechanisms for containment of potential hydrocarbon accumulations. The M-3, O-1, OM-1, and OM-2 Prospects are stacked channels of Miocene and Oligocene age. Each is individually mappable on the seismic data and exhibits discrete amplitude responses. The Oligocene Prospect is interpreted to be a turbidite similar to the Marte Prospect and, like the Marte Prospect, it relies on a stratigraphic trapping mechanism and has amplitude support from the 3-D seismic data.

FIGURES

NETHERLAND, SEWELL & ASSOCIATES, INC.



Block P

Offshore Equatorial Guinea

Open Offshore Blocks	Producing Areas
Open Onshore Blocks	Blocks in Direct Negotiation
Operated Blocks	Blocks Under Negotiation

Location Map

SCALE IN KILOMETERS

0 25 50 100

Adapted from a licensing map found at http://egronda2016.com.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 1

Stratigraphic and Lithologic Section
Offshore Equatorial Guinea

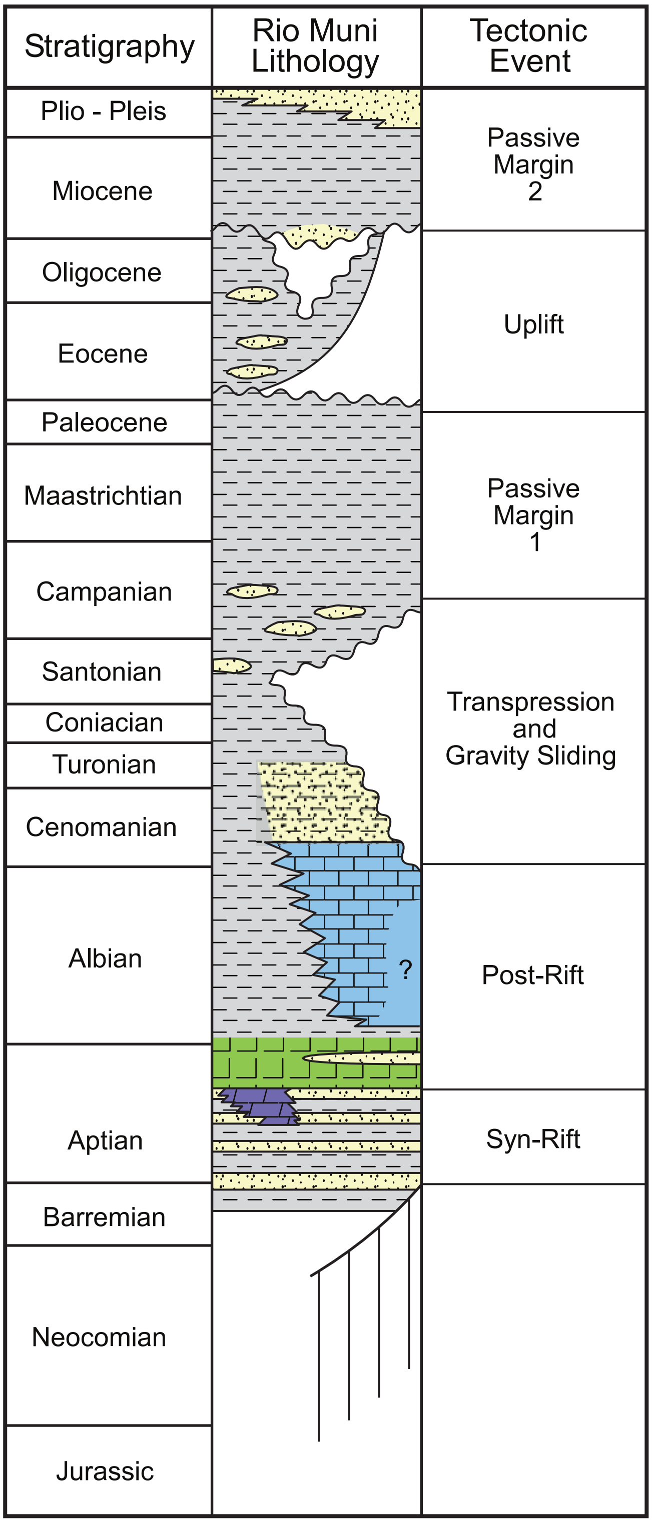
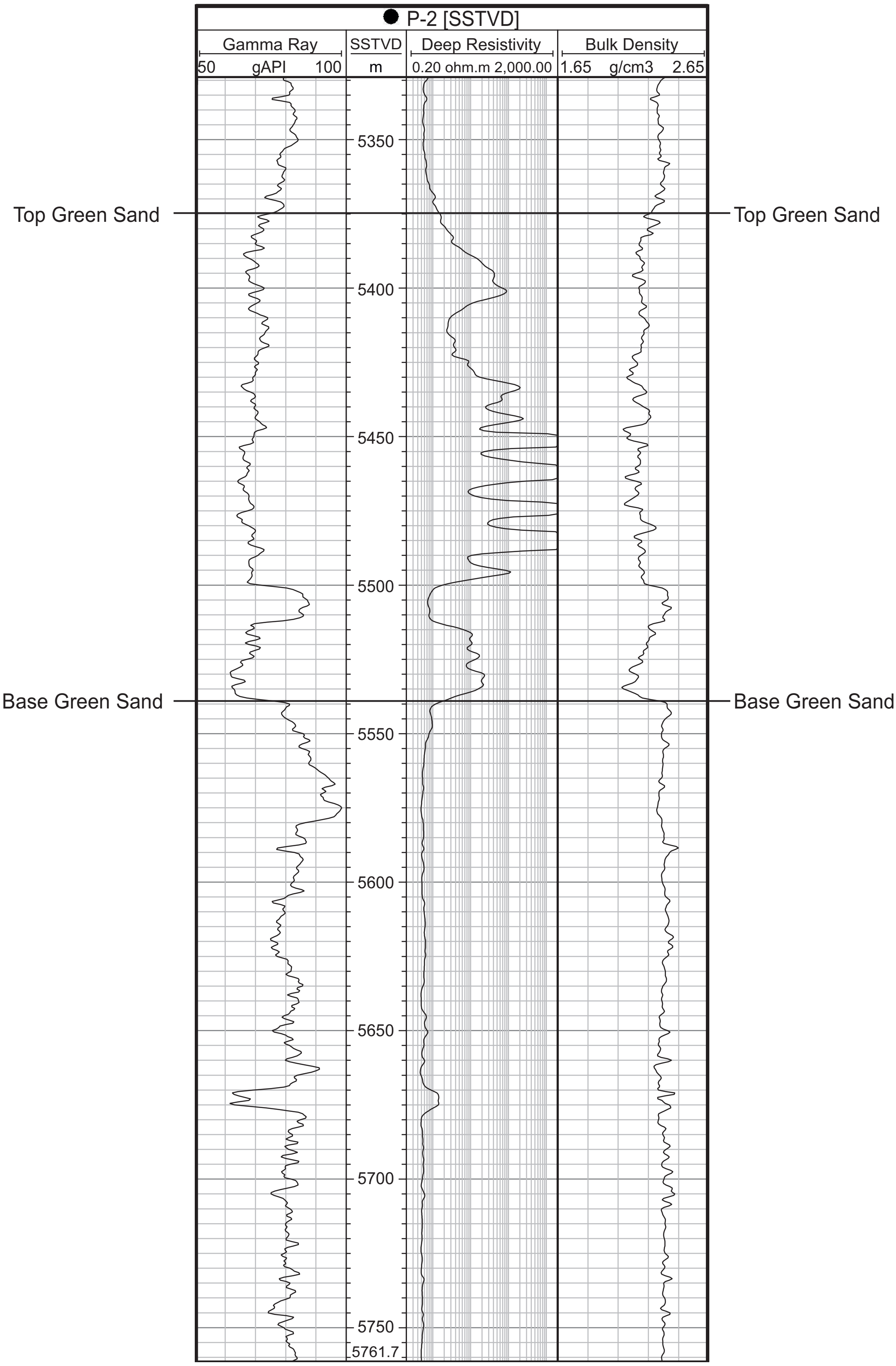


Figure 2

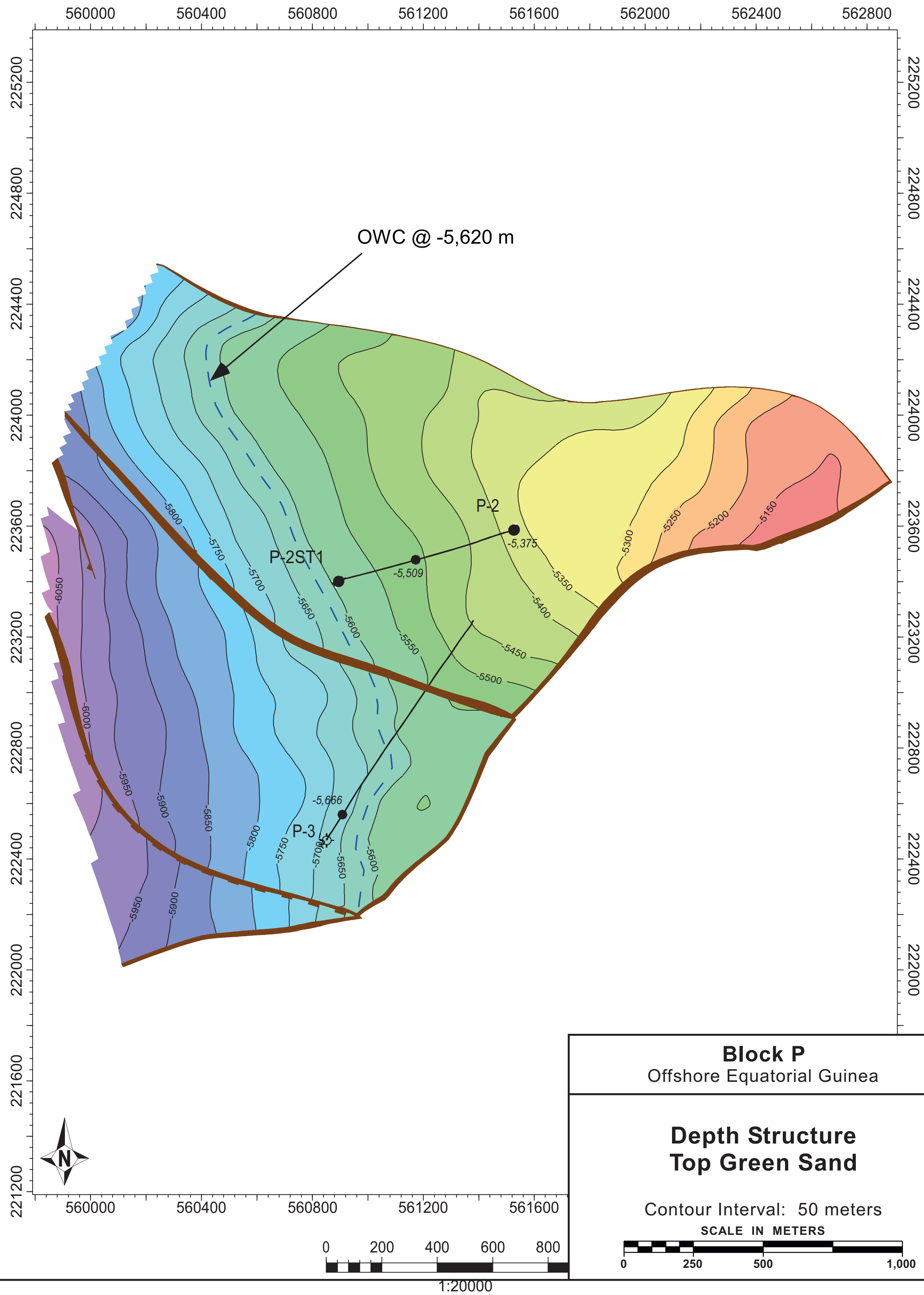
Type Log Section
Green Sand - P-2 Well
Venus Production and Development Area, Offshore Equatorial Guinea



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

NETHERLAND, SEWELL & ASSOCIATES, INC.



Block P

Offshore Equatorial Guinea

Depth Structure
Top Green Sand

Contour Interval: 50 meters

SCALE IN METERS

0 250 500 1,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4

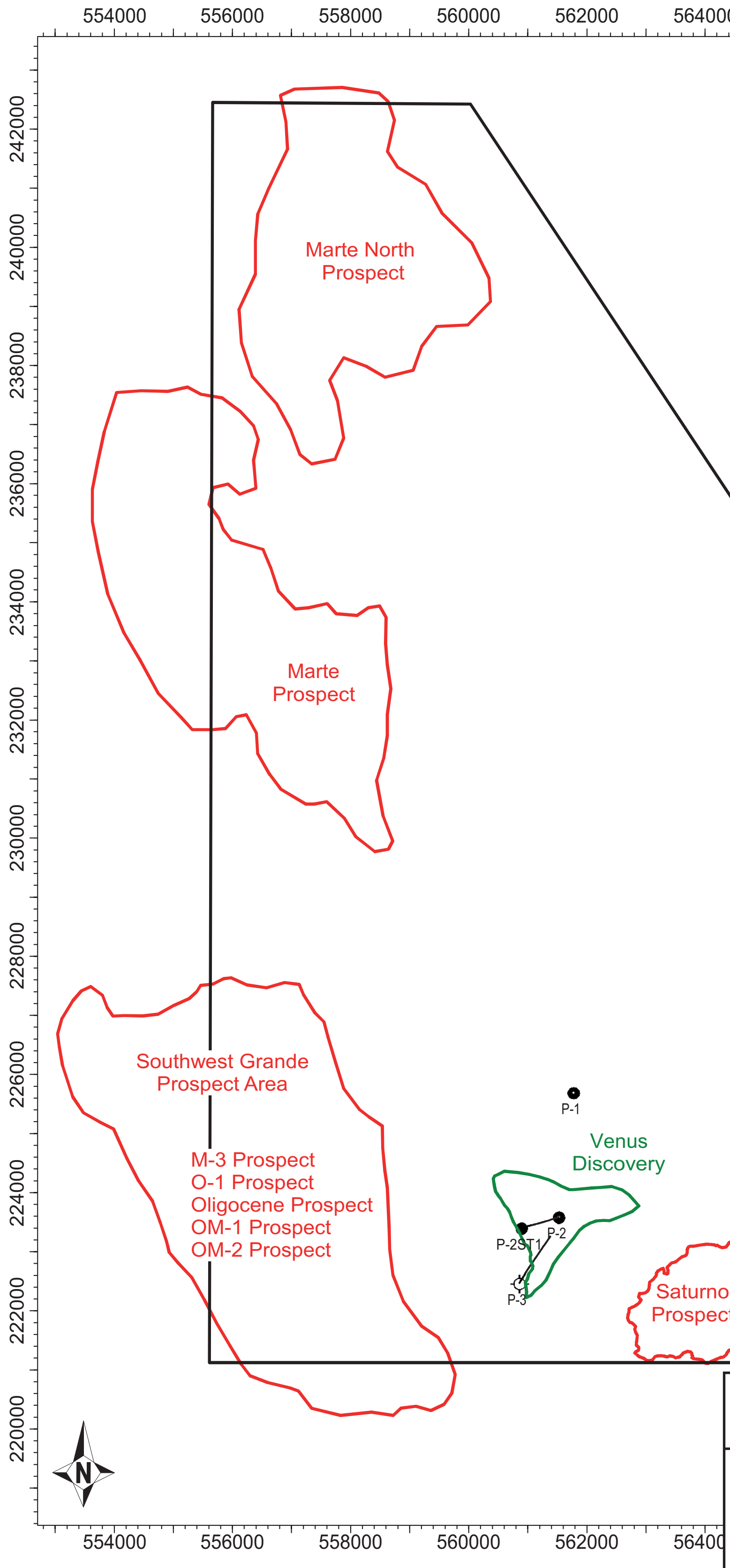
SUMMARY OF VOLUMETRIC PARAMETERS
CONTINGENT RESOURCES
GREEN SAND - VENUS DISCOVERY
BLOCK P, OFFSHORE EQUATORIAL GUINEA
AS OF MARCH 31, 2019

Scenario	Gross Rock Volume (acre-feet)	Net-to-Gross Ratio (%)	Net Rock Volume (acre-feet)	Porosity (%)	Water Saturation (%)	Formation Volume Factor (RB/STB)	Original Oil-in-place (MMBBL)	Recovery Factor (%)
Low Estimate (1C)	25,117	78.0	19,591	26.8	26.0	1.267	23.8	46.8
Best Estimate (2C)	36,200	79.5	28,779	26.7(1)	24.0	1.267	35.8	46.3(2)
High Estimate (3C)	44,887	81.0	36,358	26.9	22.0	1.268	46.7	56.8

(1) The gross rock volume in the best estimate (2C) scenario includes a portion of rock that is lower porosity than that included in the low estimate (1C) scenario.
(2) The best estimate (2C) recovery factor is slightly lower than the low estimate (1C) recovery factor, but when applied to a larger original oil-in-place, results in a higher ultimate recovery.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5



Block P
Offshore Equatorial Guinea

Location Map
Discoveries and Prospects

SCALE IN METERS
0 1,250 2,500 5,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6

SUMMARY OF VOLUMETRIC PARAMETERS
PROSPECTIVE RESOURCES
BLOCK P, OFFSHORE EQUATORIAL GUINEA
AS OF MARCH 31, 2019

Prospect	Reservoir Area (acres) Lognormal Distribution		Average Net Pay Thickness (feet) Normal Distribution		Porosity (%) Normal Distribution		Hydrocarbon Saturation (%) Normal Distribution	
	P90	P10	P90	P10	P90	P10	P90	P10
Marte	793	5,007	20	80	23	28	65	85
Marte North	2,252	3,813	20	80	23	28	65	85
Saturno	300	820	20	80	23	28	65	85
SW Grande M-3	703	2,357	20	80	23	28	65	85
SW Grande O-1	920	2,476	20	80	23	28	65	85
SW Grande Oligocene	464	4,758	20	80	23	28	65	85
SW Grande OM-1	1,528	2,354	20	80	23	28	65	85
SW Grande OM-2	1,078	1,789	20	80	23	28	65	85

Prospect	Initial Oil Formation Volume Factor (RB/STB) Normal Distribution		Oil Recovery Factor (%) Normal Distribution	
	P90	P10	P90	P10
Marte	1.10	1.45	25	60
Marte North	1.10	1.45	25	60
Saturno	1.10	1.45	25	60
SW Grande M-3	1.10	1.45	25	60
SW Grande O-1	1.10	1.45	25	60
SW Grande Oligocene	1.10	1.45	25	60
SW Grande OM-1	1.10	1.45	25	60
SW Grande OM-2	1.10	1.45	25	60

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7

SUMMARY OF UNRISKED PROSPECTIVE OIL RESOURCES
BLOCK P, OFFSHORE EQUATORIAL GUINEA
AS OF MARCH 31, 2019

	Undiscovered Original Oil-In-Place (MMBBL)			Unrisked Gross (100%) Prospective Oil Resources (MMBBL)		
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
Marte	31.4	101.9	311.9	11.1	40.6	131.9
Marte North	70.3	167.9	302.0	23.8	66.9	136.8
Saturno	10.4	27.0	57.1	3.5	10.9	25.7
SW Grande M-3	26.2	70.0	161.3	9.1	28.1	69.5
SW Grande O-1	31.5	83.5	173.6	11.0	32.9	76.5
SW Grande Oligocene	19.9	72.6	272.4	7.1	29.0	114.2
SW Grande OM-1	45.2	108.2	189.1	15.4	43.0	85.9
SW Grande OM-2	34.1	79.2	141.4	11.8	31.4	64.7

	Unrisked Working Interest Prospective Oil Resources (MMBBL)		
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
Marte	3.4	12.6	40.9
Marte North	7.4	20.7	42.4
Saturno	1.1	3.4	8.0
SW Grande M-3	2.8	8.7	21.5
SW Grande O-1	3.4	10.2	23.7
SW Grande Oligocene	2.2	9.0	35.4
SW Grande OM-1	4.8	13.3	26.6
SW Grande OM-2	3.7	9.7	20.1

Note: Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 8

SUMMARY OF GEOLOGIC RISKING
BLOCK P, OFFSHORE EQUATORIAL GUINEA
AS OF MARCH 31, 2019

Prospect	Geologic Risk Element (decimal) Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	Probability of Geologic Success (decimal)
Marte	0.30	0.80	0.90	0.90	0.19
Marte North	0.30	0.70	0.90	0.90	0.17
Saturno	0.40	0.70	0.90	0.90	0.23
Southwest Grande M-3	0.30	0.80	0.90	0.90	0.19
Southwest Grande O-1	0.25	0.80	0.90	0.90	0.16
Southwest Grande Oligocene	0.20	0.80	0.90	0.90	0.13
Southwest Grande OM-1	0.30	0.80	0.90	0.90	0.19
Southwest Grande OM-2	0.35	0.80	0.90	0.90	0.23

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 9

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Condensed financial statements for six months ended June 30, 2019

VAALCO ENERGY, INC. AND SUBSIDIARIES

Table of Contents

Unless the context otherwise indicates, references to "VAALCO," "the Company", "we," "our," or "us" in this Form 10-Q are references to VAALCO Energy, Inc., including its wholly-owned subsidiaries.

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(in thousands, except share and per share amounts)

	June 30, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 48,557**	$ 33,360
Restricted cash	**799**	804
Receivables:		
Trade	**13,828**	11,907
Accounts with joint venture owners, net of allowance of $0.5 million for both periods	**130**	949
Other	**1,239**	1,398
Crude oil inventory	**553**	785
Prepayments and other	**4,808**	6,301
Current assets - discontinued operations	**—**	3,290
Total current assets	**69,914**	58,794
Oil and natural gas properties and equipment - successful efforts method:		
Wells, platforms and other production facilities	**409,862**	409,487
Work-in-progress	**1,002**	519
Undeveloped acreage	**23,771**	23,771
Equipment and other	**10,903**	9,552
	445,538	443,329
Accumulated depreciation, depletion, amortization and impairment	**(393,669)**	(390,605)
Net oil and natural gas properties, equipment and other	**51,869**	52,724
Other noncurrent assets:		
Restricted cash	**922**	920
Value added tax and other receivables, net of allowance of $1.3 million and $2.0 million, respectively	**2,742**	2,226
Right of use operating lease assets	**34,124**	—
Deferred tax assets	**30,946**	40,077
Abandonment funding	**11,550**	11,571
Total assets	**$ 202,067**	$ 166,312
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 8,016**	$ 8,083
Accounts with joint venture owners	**3,781**	304
Accrued liabilities and other	**19,539**	14,138
Operating lease liabilities - current portion	**10,500**	—
Foreign taxes payable	**453**	3,274
Current liabilities - discontinued operations	**4,847**	15,245
Total current liabilities	**47,136**	41,044
Asset retirement obligations	**15,214**	14,816
Operating lease liabilities - net of current portion	**23,624**	—
Other long term liabilities	**421**	625
Total liabilities	**86,395**	56,485
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	**—**	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 67,452,385 and 67,167,994 shares issued, 59,756,235 and 59,595,742 shares outstanding, respectively	**6,745**	6,717
Additional paid-in capital	**73,059**	72,358
Less treasury stock, 7,696,150 and 7,572,251 shares, respectively, at cost	**(37,870)**	(37,827)
Retained earnings	**73,738**	68,579
Total shareholders' equity	**115,672**	109,827
Total liabilities and shareholders' equity	**$ 202,067**	$ 166,312

See notes to condensed consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Revenues:				
Oil and natural gas sales	**$ 25,230**	$ 24,426	**$ 44,995**	$ 52,071
Operating costs and expenses:				
Production expense	**9,819**	12,817	**18,038**	23,777
Exploration expense	**—**	12	**—**	12
Depreciation, depletion and amortization	**1,909**	1,035	**3,462**	2,159
General and administrative expense	**2,728**	5,008	**7,167**	7,611
Bad debt (recovery) expense	**5**	145	**(24)**	89
Total operating costs and expenses	**14,461**	19,017	**28,643**	33,648
Other operating income (expense), net	**(4,399)**	314	**(4,436)**	338
Operating income	**6,370**	5,723	**11,916**	18,761
Other income (expense):				
Derivative instruments gain (loss), net	**1,911**	(1,010)	**(1)**	(1,010)
Interest income (expense), net	**201**	(30)	**388**	(384)
Other, net	**(145)**	(214)	**(383)**	(145)
Total other income (expense), net	**1,967**	(1,254)	**4**	(1,539)
Income from continuing operations before income taxes	**8,337**	4,469	**11,920**	17,222
Income tax expense	**9,208**	3,582	**11,961**	7,624
Income (loss) from continuing operations	**(871)**	887	**(41)**	9,598
Income (loss) from discontinued operations, net of tax	**(162)**	(343)	**5,509**	(395)
Net income (loss)	**$ (1,033)**	$ 544	**$ 5,468**	$ 9,203
Basic net income (loss) per share:				
Income (loss) from continuing operations	**$ (0.01)**	**$** 0.02	**$ 0.00**	$ 0.16
Income (loss) from discontinued operations, net of tax	**0.00**	(0.01)	**0.09**	(0.01)
Net income (loss) per share	**$ (0.01)**	**$** 0.01	**$ 0.09**	$ 0.15
Basic weighted average shares outstanding	**59,801**	59,090	**59,716**	58,977
Diluted net income (loss) per share:				
Income (loss) from continuing operations	**$ (0.01)**	**$** 0.02	**$ 0.00**	$ 0.16
Income (loss) from discontinued operations, net of tax	**0.00**	(0.01)	**0.09**	(0.01)
Net income (loss) per share	**$ (0.01)**	**$** 0.01	**$ 0.09**	$ 0.15
Diluted weighted average shares outstanding	**59,801**	59,851	**59,716**	59,358

See notes to condensed consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Unaudited)
(in thousands)

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings	Total
Balance at January 1, 2019	**67,168**	**(7,572)**	**$ 6,717**	**$ 72,358**	**$ (37,827)**	**$ 68,579**	**$ 109,827**
Shares issued - stock-based compensation	**160**	**—**	**16**	**31**	**—**	**—**	**47**
Stock-based compensation	**—**	**—**	**—**	**28**	**—**	**—**	**28**
Treasury stock acquired	**—**	**(45)**	**—**	**—**	**(105)**	**—**	**(105)**
Net income	**—**	**—**	**—**	**—**	**—**	**6,501**	**6,501**
Balance at March 31, 2019	**67,328**	**(7,617)**	**6,733**	**72,417**	**(37,932)**	**75,080**	**116,298**
Shares issued - stock-based compensation	**124**	**—**	**12**	**48**	**—**	**—**	**60**
Stock-based compensation expense	**—**	**—**	**—**	**594**	**—**	**—**	**594**
Treasury stock acquired	**—**	**(79)**	**—**	**—**	**62**	**(309)**	**(247)**
Net loss	**—**	**—**	**—**	**—**	**—**	**(1,033)**	**(1,033)**
Balance at June 30, 2019	**67,452**	**(7,696)**	**$ 6,745**	**$ 73,059**	**$ (37,870)**	**$ 73,738**	**$ 115,672**

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance at January 1, 2018	66,444	(7,581)	$ 6,644	$ 71,251	$ (37,953)	$ (29,653)	$ 10,289
Stock-based compensation expense	—	—	—	149	—	—	149
Net income	—	—	—	—	—	8,659	8,659
Balance at March 31, 2018	66,444	(7,581)	$ 6,644	$ 71,400	$ (37,953)	$ (20,994)	$ 19,097
Shares issued - stock-based compensation	522	36	52	216	177	—	445
Stock-based compensation expense	—	—	—	397	—	—	397
Net income	—	—	—	—	—	544	544
Balance at June 30, 2018	66,966	(7,545)	$ 6,696	$ 72,013	$ (37,776)	$ (20,450)	$ 20,483

See notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	**$ 5,468**	$ 9,203
Adjustments to reconcile net income to net cash provided by operating activities:		
(Income) loss from discontinued operations	**(5,509)**	395
Depreciation, depletion and amortization	**3,462**	2,159
Other amortization	**121**	191
Deferred taxes	**7,667**	—
Unrealized foreign exchange loss	**21**	79
Stock-based compensation	**1,620**	2,756
Cash settlements paid on exercised stock appreciation rights	**(261)**	(82)
Derivatives instruments loss	**1**	1,010
Cash settlements received (paid) on matured derivative contracts, net	**1,563**	(11)
Bad debt (recovery) expense	**(24)**	89
Other operating (income) loss, net	**37**	(338)
Operational expenses associated with equipment and other	**(60)**	1,739
Change in operating assets and liabilities:		
Trade receivables	**(1,921)**	(6,051)
Accounts with joint venture owners	**4,291**	13,203
Other receivables	**158**	(23)
Crude oil inventory	**232**	1,965
Prepayments and other	**(1,175)**	(764)
Value added tax and other receivables	**718**	(249)
Accounts payable	**(730)**	(535)
Foreign taxes payable	**(2,865)**	5,431
Accrued liabilities and other	**3,858**	1,381
Net cash provided by continuing operating activities	**16,672**	31,548
Net cash used in discontinued operating activities	**(91)**	(892)
Net cash provided by operating activities	**16,581**	30,656
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property and equipment expenditures	**(1,163)**	(976)
Net cash used in continuing investing activities	**(1,163)**	(976)
Net cash used in discontinued investing activities	**—**	**—**
Net cash used in investing activities	**(1,163)**	(976)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from the issuances of common stock	**107**	445
Treasury shares	**(352)**	—
Debt repayment	—	(9,166)
Net cash used in continuing financing activities	**(245)**	(8,721)
Net cash used in discontinued financing activities	**—**	**—**
Net cash used in financing activities	**(245)**	(8,721)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**15,173**	20,959
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD	**46,655**	32,286
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD	**$ 61,828**	$ 53,245

See notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2019	**2018**
Supplemental disclosure of cash flow information:		
Interest paid	$ —	$ 257
Income taxes paid	$ —	$ 2,720
Income taxes paid in-kind with crude oil	**$ 7,347**	$ —
Supplemental disclosure of non-cash investing and financing activities:		
Property and equipment additions incurred but not paid at end of period	**$ 3,378**	$ 463
Initial recognition of right-of-use operating lease assets and lease liabilities	**$ 38,934**	$ —

See notes to condensed consolidated financial statements.

1. ORGANIZATION AND ACCOUNTING POLICIES

VAALCO Energy, Inc. (together with its consolidated subsidiaries "we", "us", "our", "VAALCO," or the "Company") is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, the Company has production operations and conduct exploration activities in Gabon, West Africa. The Company has opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 3 below, the Company has discontinued operations associated with the Company's activities in Angola, West Africa.

VAALCO's 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.

These condensed consolidated financial statements are unaudited, but in the opinion of management, reflect all adjustments necessary for a fair presentation of results for the interim periods presented. All adjustments are of a normal recurring nature unless disclosed otherwise. Interim period results are not necessarily indicative of results expected for the full year.

These condensed consolidated financial statements have been prepared in accordance with rules of the Securities and Exchange Commission ("SEC") and do not include all the information and disclosures required by accounting principles generally accepted in the United States ("GAAP") for complete financial statements. They should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2018, which includes a summary of the significant accounting policies.

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and time duration. Current amounts in restricted cash at June 30, 2019 and December 31, 2018, respectively, each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long term amounts at June 30, 2019 and December 31, 2018 include a charter payment escrow for the floating, production, storage and offloading vessel ("FPSO") offshore Gabon as discussed in Note 10. The Company invests restricted and excess cash in readily redeemable money market funds.

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

	June 30, 2019	December 31, 2018
	(in thousands)	
Cash and cash equivalents	**$ 48,557**	$ 33,360
Restricted cash - current	**799**	804
Restricted cash - non-current	**922**	920
Abandonment funding	**11,550**	11,571
Total cash, cash equivalents and restricted cash shown in the condensed consolidated statements of cash flows	**$ 61,828**	$ 46,655

The Company is required under the Exploration and Production Sharing Contract entitled "Etame Marin No. G4-160," dated as of July 7, 1995, as amended, (the "Etame PSC") for the Etame Marin block in Gabon to conduct abandonment studies to update the amounts needed to fund the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was completed in November 2018. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on the Company's condensed consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the Company's asset retirement obligation and the amount of future abandonment funding payments. See Note 10 for further discussion.

Accounts Receivable and Allowance for Doubtful Accounts – The Company's accounts receivable result from sales of crude oil production and joint interest billings to its joint interest owners for their share of expenses on joint venture projects for which the Company is the operator as well as from the government of Gabon for reimbursable Value-Added Tax ("VAT"). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company. Portions of the Company's costs in Gabon (including the Company's VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). The majority of these receivables have payment terms of 30 days or less. The Company monitors the creditworthiness of the counterparties, and it has obtained credit enhancements from some parties in the form of parental guarantees or letters of credit. Joint owner receivables are secured through cash calls and other mechanisms for collection under the terms of the joint operator agreements.

The Company routinely assesses the recoverability of all material receivables to determine their collectability. The Company accrues a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. When collectability is in doubt, the Company records an allowance against the accounts receivable and a corresponding income charge for bad debts, which appears in the "Bad debt (recovery) expense" line item of the condensed consolidated statements of operations.

As of June 30, 2019, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately $8.0 million ($2.7 million, net to VAALCO). As of June 30, 2019, the exchange rate was XAF 576.6 = $1.00. As of December 31, 2018, the exchange rate was XAF 573.0 = $1.00.

For the three and six months ended June 30, 2019, the Company recorded a net recovery (expense) of $(3) thousand and $29 thousand, respectively, related to the allowance for bad debt for VAT for which the government of Gabon has not reimbursed us. For the three and six months ended June 30, 2018, the Company recorded a net recovery of $0.1 million and $0.1 million, respectively. 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 condensed consolidated balance sheets. Because both the VAT receivable and the related allowances 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 condensed consolidated statements of operations.

The following table provides a roll forward of the aggregate allowance:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands)			
Allowance for bad debt				
Balance at beginning of year	$ **(1,854)**	$ (7,164)	$ **(2,535)**	$ (7,033)
Bad debt recovery (charge)	**(5)**	(145)	**24**	(89)
Adjustment associated with settlement of customs audit	**—**	—	**623**	—
Foreign currency gain (loss)	**(17)**	361	**12**	174
Balance at end of period	$ **(1,876)**	$ (6,948)	$ **(1,876)**	$ (6,948)

Derivative Instruments and Hedging Activities – The Company enters into crude oil hedging arrangements in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil production. While these instruments mitigate the cash flow risk of future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company records balances resulting from commodity risk management activities in the condensed consolidated balance sheets as either assets or liabilities measured at fair value. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the "Derivative instruments gain (loss), net" line item located within the "Other income (expense)" section of the condensed consolidated statements of operations. See Note 8 for further discussion.

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

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

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

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

Fair value of financial instruments – The Company's 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 above, 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 the Company's 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. There were no transfers between levels for the three and six months ended June 30, 2019 and 2018.

	Balance Sheet Line	As of June 30, 2019 Level 1	Level 2	Level 3	Total
			(in thousands)		
Assets					
Derivative asset commodity	Prepayments and other	$ —	$ 1,956	$ —	$ 1,956
		$ —	$ 1,956	$ —	$ 1,956
Liabilities					
SARs liability	Accrued liabilities	$ —	$ 1,777	$ —	$ 1,777
SARs liability	Other long-term	—	421	—	421
		$ —	$ 2,198	$ —	$ 2,198

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

Leases – In February 2016, the Financial Accounting Standards Board ("FASB") issued a new standard related to leases to increase transparency and comparability among organizations by requiring the recognition of operating lease right-of-use ("ROU") assets and lease liabilities on the balance sheet. Most prominent among the changes in the standard is the recognition of ROU assets and lease liabilities by lessees for those leases classified as operating leases. Under the standard, disclosures are required to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The Company is also required to recognize and measure new leases at the adoption date and recognize a cumulative-effect adjustment in the period of adoption using a modified retrospective approach, with certain practical expedients available.

The Company adopted Accounting Standards Codification ("ASC") 842 effective January 1, 2019 using the modified retrospective transition method through a cumulative-effect adjustment at the beginning of the first quarter of 2019. The Company has elected the package of practical expedients which allows the Company not to reassess (1) whether any expired or existing contracts as of the adoption date are or contain a lease, (2) lease classification for any expired or existing leases as of the adoption date and (3) initial direct costs for any existing leases as of the adoption date. The standard had an impact on the Company's condensed consolidated balance sheet but did not have an impact on the Company's condensed consolidated statements of operations or condensed consolidated statements of cash flows upon adoption and as a result, a cumulative-effect adjustment was not required. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases. See Notes 2 and 10 for further discussion.

The Company determines whether an arrangement is a lease at inception. At commencement, the Company records a ROU asset and lease liability for the operating leases on its consolidated balance sheet based on the present value of lease payments over the lease term. ROU assets represent our right to use an underlying asset for the lease term and lease liability obligations represent the Company's obligation to make lease payments arising from the lease. The Company has lease agreements that have both lease and non-lease components and has elected to separate these. Payments related to the lease component are included in the calculation of the lease liability; payments related to non-lease components are recorded consistent with other accounting guidance. The Company uses the implicit rate when readily determinable; however, as most of the Company's leases do not provide an implicit rate, the Company estimated its incremental borrowing rate in accordance with the standard based on the information available at the commencement date in determining the present value of lease payments. The ROU asset also includes any lease payments made prior to the commencement date, including initial direct costs and excluding lease incentives. The Company's lease terms include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Lease expense is recognized on a straight-line basis over the lease term.

Asset retirement obligations ("ARO") – The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and natural gas production operations. The Company's 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 the Company's oil and natural gas properties. The Company uses current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to 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. Accretion of interest increases the initial ARO liabilities over time until the liability matches the amount expected to settle the related retirement obligation. See Note 11 for further discussion.

Revenue recognition– Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements. There is a single performance obligation (delivering oil to the delivery point, i.e. the connection to the customer's crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. In addition to revenues from customer contracts, the Company has other revenues related to contractual provisions under the Etame PSC. The Etame PSC is not a customer contract. The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of "Profit Oil" determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. For both royalties and Profit Oil, the Etame PSC provides that the government of Gabon may settle these obligations in-kind, i.e. taking crude oil barrels, rather than with cash payments. See Note 6 for further discussion.

Foreign currency transactions – The U.S. dollar is the functional currency of the Company's foreign operating subsidiaries. Gains and losses on foreign currency transactions are included in income. Within the condensed consolidated statements of operations line item "Other income (expense) — Other, net," the Company recognized a loss on foreign currency transactions of \$0.0 million and \$0.2 million, respectively, during the three and six months ended June 30, 2019. During the three and six months ended June 30, 2018, the Company recognized losses on foreign currency transactions of \$0.2 million and \$0.1 million, respectively.

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

Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized, and when it is estimated to be more-likely-than-not that all or some portion of specific deferred tax assets, such as net operating loss carry forwards or foreign tax credit carryovers, will not be realized, a valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered are earnings generated in previous periods, forecasted earnings and the expiration period of net operating loss carry forwards or foreign tax credit carryovers.

In certain jurisdictions, the Company may deem the likelihood of realizing deferred tax assets as remote where the Company expects that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. For such jurisdictions, the Company has not recognized deferred tax assets. Should the Company's expectations change regarding the expected future tax consequences, the Company may be required to record additional deferred taxes that could have a material effect on the Company's consolidated financial position and results of operations. See Note 14 for further discussion.

2. NEW ACCOUNTING STANDARDS

Adopted

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"), which amends the accounting standards for leases. This accounting standard was further clarified by ASU 2018-10, Codification Improvements to Topic 842 and ASU 2018-11, Leases: Targeted Improvements, both of which were issued in July 2018 together ("Topic 842"). Topic 842 retains a distinction between finance leases and operating leases. The primary change is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Certain aspects of lease accounting have been simplified and additional qualitative and quantitative disclosures are required along with specific quantitative disclosures required by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. In transition, lessees and lessors may use either a prospective approach in which they recognize and measure leases at the date of adoption and recognize a cumulative effect adjustment to the opening balance of retained earnings or they may use a modified retrospective approach in which leases are recognized and measured at the beginning of the earliest period presented. The Company used the prospective approach with adoption of the new standard effective January 1, 2019. Leases with terms greater than 12 months, which were previously treated as operating leases, have been capitalized. The adoption of this standard resulted in the recording of a right of use asset related to certain of the Company's operating leases with a corresponding lease liability. This resulted in a significant increase in total assets and liabilities and a decrease in working capital. In connection with the Company's implementation plan, the Company reviewed its lease contracts and evaluated other contracts to identify embedded leases to determine the appropriate accounting treatment. The new leasing standard requires capitalization based on the expected term of this lease which may or may not extend beyond the minimum period. The most significant lease the Company currently has is related to the FPSO. As of January 1, 2019, for operating leases under which the Company is the lessee, the Company recorded a non-cash adjustment of $38.9 million in "Right of use operating lease assets" to recognize an aggregate right-of-use asset, and the Company recorded a corresponding $10.2 million and $28.7 million in "Operating lease liabilities" and "Long-term operating lease liabilities," respectively, for the aggregate operating lease liability. The Company has accounted for lease and non-lease components of its operating leases separately. The Company has not recognized ROU assets or lease liabilities for its short-term leases. The Company's adoption did not have and is not expected in the future to have a material effect on the Company's condensed consolidated statements of operations or cash flows. See Note 10 for further discussion.

Not yet adopted

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

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

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including the Company's trade and joint venture owners' receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date 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. The FASB subsequently issued ASU No. 2019-04 ("ASU 2019-04"): Codification Improvements to Topic 326,Financial Instruments-Credit Losses, Topic 815, Derivatives, and Topic 825, Financial Instruments and ASU No. 2019-05 ("ASU 2019-05"): Financial Instruments-Credit Losses (Topic 326) - Targeted Transition Relief. ASU 2019-04 and ASU 2019-05 provide certain codification improvements related to implementation of ASU 2016-13 and targeted transition relief consisting of an option to irrevocably elect the fair value option for eligible instruments. The Company is currently evaluating the provisions of ASU 2016-13 and is assessing its potential impact on the Company's financial position, results of operations, cash flows and related disclosures.

3. DISPOSITIONS

Discontinued Operations - Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola ("Block 5 PSA"). The Company's working interest was 40%, and the Company carried Sonangol P&P, for 10% of the work program. On September 30, 2016, the Company notified Sonangol P&P that it was withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, the Company notified the national concessionaire, Sonangol E.P., that it was withdrawing from the Block 5 PSA. Further to the decision to withdraw from Angola, the Company closed its office in Angola and reduced its activities in Angola. As a result of this strategic shift, the Company classified all the related assets and liabilities as those of discontinued operations in the condensed consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in the Company's condensed consolidated statements of operations. The Company segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in the Company's condensed consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment's assets and liabilities as of June 30, 2019 and December 31, 2018 and its results of operations for the three and six months ended June 30, 2019 and 2018.

Summarized Results of Discontinued Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Operating costs and expenses:				
Gain on settlement of drilling obligation	**$ —**	$ —	**$ (7,193)**	$ —
General and administrative expense	**206**	332	**220**	364
Total operating costs, expenses and (recovery)	**206**	332	**(6,973)**	364
Operating income (loss)	**(206)**	(332)	**6,973**	(364)
Other income (expense):				
Other, net	**—**	(11)	**—**	(31)
Total other income (expense)	**—**	(11)	**—**	(31)
Income (loss) from discontinued operations before income taxes	**(206)**	(343)	**6,973**	(395)
Income tax expense (benefit)	**(44)**	—	**1,464**	—
Income (loss) from discontinued operations	**$ (162)**	$ (343)	**$ 5,509**	$ (395)

Assets and Liabilities Attributable to Discontinued Operations

	June 30, 2019	December 31, 2018
	(in thousands)	
ASSETS		
Accounts with joint venture owners	$ —	$ 3,290
Total current assets	—	3,290
Total assets	$ —	$ 3,290
LIABILITIES		
Current liabilities:		
Accounts payable	**$ —**	$ 73
Accrued liabilities and other	**4,847**	15,172
Total current liabilities	**4,847**	15,245
Total liabilities	$ **4,847**	$ 15,245

Drilling Obligation

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

4. SEGMENT INFORMATION

The Company's operations are based in Gabon and the Company has an undeveloped block in Equatorial Guinea. Each of the

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

Segment activity of continuing operations for the three and six months ended June 30, 2019 and 2018 as well as long-lived assets and segment assets at June 30, 2019 and December 31, 2018 are as follows:

	Three Months Ended June 30, 2019			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	**$ 25,230**	**$ —**	**$ —**	**$ 25,230**
Depreciation, depletion and amortization	**1,835**	**—**	**74**	**1,909**
Other operating income (expense), net	**(4,399)**	**—**	**—**	**(4,399)**
Operating income (loss)	**8,963**	**(130)**	**(2,463)**	**6,370**
Derivatives instruments loss, net	**—**	**—**	**1,911**	**1,911**
Other, net	**(46)**	**1**	**(100)**	**(145)**
Interest income	**2**	**—**	**199**	**201**
Income tax expense	**7,869**	**2**	**1,337**	**9,208**
Additions to oil and natural gas properties and equipment - accrual	**1,593**	**—**	**29**	**1,622**

	Six Months Ended June 30, 2019			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	**$ 44,995**	**$ —**	**$ —**	**$ 44,995**
Depreciation, depletion and amortization	**3,314**	**—**	**148**	**3,462**
Other operating income (expense), net	**(4,436)**	**—**	**—**	**(4,436)**
Operating income (loss)	**18,493**	**(316)**	**(6,261)**	**11,916**
Derivatives instruments loss, net	**—**	**—**	**(1)**	**(1)**
Other, net	**(218)**	**(1)**	**(164)**	**(383)**
Interest income	**3**	**—**	**385**	**388**
Income tax expense	**10,360**	**12**	**1,589**	**11,961**
Additions to oil and natural gas properties and equipment - accrual	**2,274**	**(187)**	**220**	**2,307**

	Three Months Ended June 30, 2018			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-oil and natural gas sales	$ 24,425	$ —	$ 1	$ 24,426
Depreciation, depletion and amortization	971	—	64	1,035
Other operating income (expense), net	314	—	—	314
Operating income (loss)	10,147	(85)	(4,339)	5,723
Derivatives instruments loss, net	—	—	(1,010)	(1,010)
Other, net	(199)	(6)	(9)	(214)
Interest expense, net	(43)	—	13	(30)
Income tax expense	3,582	—	—	3,582
Additions to oil and natural gas properties and equipment - accrual	527	—	15	542

(in thousands)	Six Months Ended June 30, 2018 Gabon	Equatorial Guinea	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 52,068	$ —	$ 3	$ 52,071
Depreciation, depletion and amortization	2,030	—	129	2,159
Other operating income (expense), net	338	—	—	338
Operating income (loss)	25,844	(115)	(6,968)	18,761
Derivatives instruments loss, net	—	—	(1,010)	(1,010)
Other, net	(130)	(3)	(12)	(145)
Interest expense, net	(397)	—	13	(384)
Income tax expense	7,624	—	—	7,624
Additions to oil and natural gas properties and equipment - accrual	955	—	14	969

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Long-lived assets from continuing operations:				
As of June 30, 2019	**$ 41,455**	**$ 10,000**	**$ 414**	**$ 51,869**
As of December 31, 2018	$ 42,195	$ 10,187	$ 342	52,724

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Total assets from continuing operations:				
As of June 30, 2019	**$ 137,660**	**$ 10,083**	**$ 54,324**	**$ 202,067**
As of December 31, 2018	$ 103,401	$ 10,320	$ 49,301	163,022

Information about the Company's most significant customers

The Company sells crude oil production from Gabon under term contracts with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. From August 2015 through January 2019, the Company sold its crude oil to Glencore Energy UK Ltd. ("Glencore"). The Company signed a new contract with Mercuria Energy Trading SA ("Mercuria") which covers sales from February 2019 through January 2020 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Sales of oil to Glencore and Mercuria were approximately 100% of total revenues for the period during the terms of their contracts.

5. EARNINGS PER SHARE

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

A reconciliation from basic to diluted shares follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Net income (loss) (numerator):				
Income (loss) from continuing operations	**$ (871)**	$ 887	**$ (41)**	$ 9,598
(Income) from continuing operations attributable to unvested shares	**—**	(9)	**—**	(87)
Numerator for basic	**(871)**	878	**(41)**	9,511
(Income) loss from continuing operations attributable to unvested shares	**—**	—	**—**	1
Numerator for dilutive	**$ (871)**	$ 878	**$ (41)**	$ 9,512
Income (loss) from discontinued operations, net of tax	**$ (162)**	$ (343)	**$ 5,509**	$ (395)
Income (loss) from discontinued operations attributable to unvested shares	**—**	3	**(42)**	3
Numerator for basic	**(162)**	(340)	**5,467**	(392)
Income (loss) from discontinued operations attributable to unvested shares	**—**	—	**42**	—
Numerator for dilutive	**$ (162)**	**$ (340)**	**$ 5,509**	$ (392)
Net income (loss)	**$ (1,033)**	$ 544	**$ 5,468**	$ 9,203
Net (income) loss attributable to unvested shares	**—**	(6)	**(42)**	(84)
Numerator for basic	**(1,033)**	538	**5,426**	9,119
Net (income) loss attributable to unvested shares	**—**	—	**42**	1
Numerator for dilutive	**$ (1,033)**	$ 538	**$ 5,468**	$ 9,120
Weighted average shares (denominator):				
Basic weighted average shares outstanding	**59,801**	59,090	**59,716**	58,977
Effect of dilutive securities	**—**	761	**—**	381
Diluted weighted average shares outstanding	**59,801**	59,851	**59,716**	59,358
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**370**	172	**644**	1,713

6. REVENUE

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

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

Customer sales generally occur on a monthly basis when the customer's tanker arrives at the FPSO and the crude oil is delivered to the tanker through a connection. There is a single performance obligation (delivering oil to the delivery point, i.e. the connection to the customer's crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. This is referred to as a "lifting". Liftings can take one to two days to complete. The intervals between liftings are generally 30 days; however, changes in the timing of liftings will impact the number of liftings which occur during the period. Therefore, the performance obligation attributable to volumes to be sold in future liftings are wholly unsatisfied, and there is no transaction price allocated to remaining performance obligations. The Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

The Company accounts for production imbalances as a reduction in reserves. The volumes sold may be more or less than the volumes to which the Company is entitled based on the its ownership interest in the property, and the Company would recognize a liability if its existing proved reserves were not adequate to cover an imbalance.

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

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

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

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

With respect to the government's share of profit oil, the Etame PSC provides that the corporate income tax liability is satisfied through the payment of profit oil. In the condensed consolidated statements of operations, the government's share of revenues from profit oil is reported in revenues with a corresponding amount reflected as current income tax expense. Prior to February 1, 2018, the government did not take any of its share of profit oil in-kind. These revenues have been included in revenues to customers as the Company entered into the contract with the customer to sell the crude oil and was subject to the performance obligations associated with the contract. For the in-kind sales by the government beginning February 1, 2018, these are not considered revenues under a customer contract as the Company is not a party to the contracts with the buyers of this crude oil. However, consistent with the reporting of profit oil in prior periods, the amount associated with the profit oil under the terms of the Etame PSC is reflected as revenue with an offsetting amount reported as a current income tax expense. Payments of the income tax liability is reported in the period in which the government takes its profit oil in-kind, i.e. the period in which it lifts the crude oil. The only in-kind payment in the current year was $7.3 million and occurred with the April 2019 lifting. As of June 30, 2019 and December 31, 2018, the foreign taxes payable attributable to the government's share of profit oil was $0.5 million and $3.3 million, respectively.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Revenue from customer contracts:		*(in thousands)*		
Sales under the COSPA	**$ 20,949**	$ 27,193	**$ 42,760**	$ 55,656
Gabonese government share of Profit Oil	**—**	—	**—**	2,193
Other items reported in revenue not associated with customer				
Gabonese government share of Profit Oil taken in-kind	**7,347**	—	**7,347**	—
Carried interest recoupment	**733**	705	**1,440**	1,356
Royalties	**(3,799)**	(3,472)	**(6,552)**	(7,134)
Total revenue, net	**$ 25,230**	$ 24,426	**$ 44,995**	$ 52,071

7. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Extension of Term of Etame PSC

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

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

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

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

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

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

Depletion and Impairment

The Company reviews 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 the Company's impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers' report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results.

There was no triggering event in the second quarter of 2019 that would cause the Company to believe the value of oil and natural gas producing properties should be impaired. As a result of lower future strip prices for the second quarter of 2019 compared to the first quarter of 2019, VAALCO compared the undiscounted estimated future net cash flows to the carrying value of the crude oil and natural gas properties. Based on this analysis, no impairment was identified and there were no indicators that adjustments were needed to the year-end reserve report.

There was no triggering event in the second quarter of 2018 that would cause the Company to believe the value of oil and natural gas producing properties should be impaired. Factors considered included the fact that the Company incurred no significant capital expenditures in 2018 related to the fields in the Etame Marin block, the future strip prices for the second quarter of 2018 modestly increased from the first quarter of 2018, and there were no indicators that adjustments were needed to the year-end reserve report.

Undeveloped Leasehold Costs

The Company has a 31% working interest in an undeveloped portion of a block offshore Equatorial Guinea that the Company acquired in 2012 (the "Block P interest"). The Company is currently awaiting the Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH") to approve its appointment as operator for Block P. Compania Nacional de Petroleos de Guinea Equatorial ("GEPetrol") is the state-owned oil company and one of the joint venture owners in Block P. For a number of years, the Block P interest was in suspension; however, in September 2018, the EG MMH lifted the suspension subject to several conditions. GEPetrol was required to introduce a new investor or joint venture owner to the EG MMH by March 28, 2019, and it has fulfilled this requirement. Upon EG MMH approving the new joint owner, the Contractor group has one year to drill an exploration well. The Company intends to seek a joint venture owner on a promoted basis that will cover all or substantially all of the cost to drill an exploratory well. If the joint venture owners fail to drill an exploration well, the Company would lose its interest in the license, and the associated costs would become impaired. As of June 30, 2019, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. The Company and the joint venture owners are evaluating the timing and budgeting for development and exploration activities under a development and production area in the block, including the approval of a development and production plan. The production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

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

8. DERIVATIVES AND FAIR VALUE

The Company uses derivative financial instruments to achieve a more predictable cash flow from oil production by reducing the Company's exposure to price fluctuations. See Note 1 for further information.

Commodity swaps **-** In June 2018, the Company entered into commodity swaps at a Dated Brent weighted average of $74.00 per barrel for the period from and including June 2018 through June 2019 for a quantity of approximately 400,000 barrels. On May 6, 2019, the Company entered into commodity swaps at a Dated Brent weighted average of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. If a liability position for these swaps exceed $10.0 million, the Company would be required to provide a bank letter of credit or deposit cash into an escrow account for the amount by which the liability exceeds $10.0 million. At June 30, 2019, the Company's unexpired commodity swaps as shown in the table below had a fair value asset position of $2.0 million reflected in "Prepayments and other" line of the Company's condensed consolidated balance sheet. These swaps settle on a monthly basis.

				Swaps
Settlement Period	**Type of Contract**	**Index**	**Barrels**	Weighted Average Fixed Price
2019	Swaps	Dated Brent	225,130	$ 66.70
2020	Swaps	Dated Brent	274,870	66.70
			500,000	

While these commodity swaps are intended to be an economic hedge to mitigate the impact of a decline in oil prices, the Company has not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. The Company does not enter into derivative instruments for speculative or trading proposes.

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

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

The following table sets forth the gain (loss) on derivative instruments on the Company's condensed consolidated statements of operations:

Derivative Item	Statement of Operations Line	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
		(in thousands)			
Crude oil swaps	Realized gain (loss) - contract settlements	**$ 432**	$ (11)	**$ 1,563**	$ (11)
	Unrealized gain (loss)	**1,479**	(999)	**(1,564)**	(999)
	Derivative instruments gain (loss), net	**$ 1,911**	$ (1,010)	**$ (1)**	$ (1,010)

9. DEBT

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

Interest

The table below shows the components of the "Interest income (expense), net" line item of the Company's condensed consolidated statements of operations and the average effective interest rate, excluding commitment fees, on the Company's borrowings:

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(in thousands)			
Interest expense related to debt, including commitment fees	**$ —**	$ (84)	**$ —**	$ (257)
Deferred finance cost amortization	**—**	(131)	**—**	(191)
Interest income	**201**	22	**388**	31
Other interest expense not related to debt	**—**	163	**—**	33
Interest income (expense), net	**$ 201**	$ (30)	**$ 388**	$ (384)
Average effective interest rate, excluding commitment fees	**0.00%** (1)	8.21%	**0.00%** (1)	7.09%

(1) There were no outstanding borrowings during 2019

10. COMMITMENTS AND CONTINGENCIES

Leases

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

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

The Company has entered into several agreements for the lease of office, warehouse and storage yard space, the FPSO and a hydraulic workover rig ("HWU"). The duration for these agreements ranges from 21 to 45 months. The FPSO, HWU and office space contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset relate to the lease component and are included in the calculation of ROU assets and lease liabilities.

Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities. For leases on ROU assets used in joint operations, generally the operator reflects the full amount of the lease component, including the amount which will be funded by the non-operators. As operator for the Etame Marin block, the ROU asset recorded for the FPSO, HWU and warehouse and storage yard space used in the joint operations includes the gross amount of the lease components.

The FPSO lease includes an option to extend the term through September 2022. The Company considered this option reasonably certain of exercise and has included it in the calculation of ROU assets and lease liabilities.

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

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

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

For the three and six months ended June 30, 2019, the components of the lease costs and the supplemental information were as follows:

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Lease cost:	*($ in thousands)*	
Operating lease cost	$ **3,775**	$ **7,334**
Short-term lease cost	**101**	**404**
Variable lease cost	**1,408**	**2,738**
Total lease cost	$ **5,284**	$ **10,476**
Other information:		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from (to) operating leases		$ 8,913
Weighted-average remaining lease term		3.18 years
Weighted-average discount rate		6.25%

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

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(in thousands)	
Production expense	$ **1,626**	$ **3,223**
General and administrative expense	**49**	**98**
Lease costs billed to the joint venture owners	**3,609**	**7,155**
Total lease costs	$ **5,284**	$ **10,476**

The following table describes the future maturities of the Company's operating lease liabilities at June 30, 2019:

Year		Lease Obligation (in thousands)
2019	$	**6,164**
2020		**11,979**
2021		**11,224**
2022		**8,088**
2023		**—**
		37,455
Less: imputed interest		**3,331**
Total lease liabilities	$	**34,124**

Under the joint operating agreements, other joint owners are obligated to fund $25.8 million of the $37.5 million in future lease liabilities.

Abandonment funding

As part of securing the first of two five-year extensions to the Etame PSC to which the Company is entitled from the government of Gabon, the Company 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 as of 2011) providing for annual funding over a period of ten years in amounts equal to 12.14% of the total abandonment estimate for the first seven years and 5.0% per year for the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.8 million ($19.2 million net to VAALCO) on an undiscounted basis. Through June 30, 2019, $37.4 million ($11.6 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on the Company's condensed consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the Company's asset retirement obligation and the amount of future abandonment funding payments.

On March 5, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account transferred the funds to the Central Bank for "CEMAC" (the Central African Economic and Monetary Community), of which Gabon is one of the six member states. The U.S. dollars were converted to local currency with a credit back to the Gabonese branch. Amendment 5 to the Etame PSC provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Company will no longer be held liable for the resulting shortfall in funding the obligation to remediate the sites.

FPSO charter

In connection with the charter of the FPSO, the Company, as operator of the Etame Marin block, guaranteed all of the charter payments under the charter through its contract term, which expires in September 2022. At the Company's election, the charter may be extended for two one-year periods beyond September 2020. The Company obtained guarantees from each of the Company's joint venture owners for their respective shares of the payments. The Company's net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although the Company believes the need for performance under the charter guarantee is remote, the Company recorded a liability of $0.2 million as of June 30, 2019 and December 31, 2018 representing the guarantee's estimated fair value. The guarantee of the offshore Gabon FPSO charter has $53.9 million in remaining gross minimum obligations as of December 31, 2018.

Estimated future minimum obligations through the end of the FPSO charter which reflects the right of early termination are as follows as of December 31, 2018 (in thousands):

	Balance at December 31, 2018			
(in thousands)		Full Charter Payment		VAALCO, Net
Year				
2019	$	31,294	$	9,718
2020		22,634		7,029
2021		—		—
2022		—		—
2023		—		—
Total	$	53,928	$	16,747

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

Other lease obligations

In addition to the FPSO, the Company has other operating lease obligations as of December 31, 2018 (in thousands):

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

The Company incurred rent expense of $0.4 million and $0.9 million, respectively, during the three and six months ended June 30, 2018.

Regulatory and Joint Interest Audits

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

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

At December 31, 2018, the Company had accrued $1.3 million, net to VAALCO, in "Accrued liabilities and other" on the Company's condensed consolidated balance sheets for potential fees which may result from customs audits. This matter was fully resolved in January 2019 for $1.3 million, net to VAALCO.

In July 2019, the Company reached an agreement in principle to resolve a legacy issue related to findings from Etame joint venture owners' audits for the periods from 2007 through 2016 for $4.4 million net to VAALCO. The agreement in principle also provides for procedures to minimize the chances of future audit claims. Accordingly, the Company has accrued $4.4 million which is reflected in the "Accrued liabilities and other" line of the Company's condensed consolidated balance sheet and is recorded as a second quarter 2019 expense in the condensed consolidated statements of operations in the line item "Other operating income (expense), net". The agreement in principle is expected to become final upon signing of a binding settlement agreement by all of the joint venture owners.

Drilling Rig

The Company has contracted a drilling rig to be used to drill two wells, including two appraisal wellbores, for the Etame Marin joint operations beginning in the second half of 2019. The agreement includes options to drill four additional wells at the Etame Marin block. The drilling rig contract stipulates a day rate of approximately $75,000. The Company expects the term associated with the drilling rig commitment to be less than one year.

11. ASSET RETIREMENT OBLIGATIONS

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

(in thousands)	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Beginning balance	**$ 14,816**	$ 20,163
Accretion	**398**	1,180
Revisions	**—**	(6,527)
Ending balance	**$ 15,214**	$ 14,816

Accretion is recorded in the line item "Depreciation, depletion and amortization" on the Company's condensed consolidated statements of operations.

The Company is required under the Etame PSC to conduct regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. In 2018, the Company recorded a downward revision of $6.5 million to the ARO liability as a result of a change in the expected timing of the abandonment costs when the period of exploitation under the Etame PSC was extended to at least September 16, 2028 as discussed further in Note 10. The most recently completed abandonment study was in November 2018.

12. SHAREHOLDERS' EQUITY

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of June 30, 2019 or December 31, 2018.

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

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

As of June 30, 2019, the Company had purchased 141,686 shares of our common stock at an average price of $1.73 per share for an aggregate purchase price of $0.2 million under the plan. From July 1, 2019 through a settlement date of August 7, 2019, the Company has purchased 746,668 shares of its common stock at an average price of $1.73 per share for an aggregate purchase price of $1.3 million.

For the majority of restricted stock awards granted by the Company, the number of shares issued on the date the restricted stock awards vest is net of shares withheld to meet applicable tax withholding requirements. Although these withheld shares are not issued or considered common stock repurchases under the Company's stock repurchase program, they are treated as common stock repurchases in our financial statements as they reduce the number of shares that would have been issued upon vesting. See Note 13 for further discussion.

13. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

The Company's stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of the Company's Board of Directors to issue various types of incentive compensation. Currently, the Company has issued stock options and restricted shares under the 2014 Long-Term Incentive Plan ("2014 Plan") and stock appreciation rights under the 2016 Stock Appreciation Rights Plan. At June 30, 2019, 373 shares were authorized for future grants under the 2014 plan.

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

The Company records compensation expense related to stock-based compensation as general and administrative expense. For the three months ended June 30, 2019 and 2018, stock-based compensation was $(0.1) million and $2.4 million, respectively, related to the issuance of stock options, restricted stock and stock appreciation rights. For the six months ended June 30, 2019 and 2018, stock-based compensation was $1.6 million and $2.8 million, respectively, related to the issuance of stock options, restricted stock and stock appreciation rights. During the six months ended June 30, 2019 and 2018, the Company settled in cash $0.3 million and $0.1 million, respectively, for stock appreciation rights exercises. Because the Company does not pay significant United States federal income taxes, no amounts were recorded for future tax benefits.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Stock-based compensation - equity awards	**$ 595**	$ 397	**$ 622**	$ 547
Stock-based compensation - liability awards	**(698)**	2,044	**998**	2,209
Total stock-based compensation	**$ (103)**	$ 2,441	**$ 1,620**	$ 2,756

Stock options

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors, which in the past has been a five-year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. There were $0.1 million and $0.4 million, respectively, in cash proceeds from the exercise of stock options in the six months ended June 30, 2019 and 2018, respectively. On February 28, 2019, the Company granted stock options for 622,140 shares to employees; these options vest over a three-year period, vesting in three equal parts on the first, second and third anniversaries after the date of grant with an exercise price of $2.33 per share. On April 1, 2019, the Company granted stock options for 44,163 shares to an employee with an exercise price of $2.29 per share. On June 6, 2019, the Company granted stock options for 257,228 shares to directors with an exercise price of $1.43 per share; these options vested immediately.

During the six months ended June 30, 2019, 13,875 shares were added to treasury as a result of tax withholding on options exercised. During the six months ended June 30, 2019, 62,235 shares that had been granted from treasury were exercised and taken from treasury.

The Company uses the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the vesting period of the option. During the six months ended June 30, 2019 and 2018, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because the Company has not paid cash dividends and does not anticipate paying cash dividends on the common stock in the foreseeable future, no expected dividend yield was input to the Black-Scholes model.

	Six Months Ended June 30,	
	2019	2018
Weighted average exercise price - ($/share)	$ **2.08**	$ 1.05
Expected life in years	**3.2**	3.5
Average expected volatility	**72.53 %**	70.50 %
Risk-free interest rate	**2.33 %**	2.51 %
Weighted average grant date fair value - ($/share)	$ **1.06**	$ 0.68

Stock option activity for the six months ended June 30, 2019 is provided below:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2019	2,601	$ 1.54		
Granted	923	2.08		
Exercised	(114)	0.93		
Unvested shares forfeited	(286)	1.44		
Vested shares expired	(76)	6.98		
Outstanding at June 30, 2019	3,048	1.60	3.15	$ 1,249
Exercisable at June 30, 2019	2,026	1.55	2.67	$ 901

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 anniversaries following the date of the grant. Share grants to directors vest immediately and are not restricted. On February 28, 2019, the Company issued 174,464 shares of service based restricted stock to employees with a grant date fair value of $2.33 per share. The vesting of these shares is dependent upon the employee's continued service with the Company. The shares will vest in three equal parts over three years. On April 1, 2019, the Company issued 22,926 shares of service based restricted stock to an employee with a grant date fair value of $2.29 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. On June 6, 2019, the Company issued 111,888 shares of service based restricted stock to directors with a grant date fair value of $1.43 per share. These shares vested immediately.

The following is a summary of activity for the six months ended June 30, 2019:

	Restricted Stock	Weighted Average Grant Price
	(in thousands)	
Non-vested shares outstanding at January 1, 2019	507	$ 0.91
Awards granted	309	2.00
Awards vested	(232)	1.14
Awards forfeited	(166)	1.29
Non-vested shares outstanding at June 30, 2019	418	1.44

During the three and six months ended June 30, 2019, 30,573 shares were added to treasury as a result of tax withholding on the vesting of restricted shares. During the three and six months ended June 30, 2018, 35,265 shares were added to treasury as a result of tax withholding on the vesting of restricted shares.

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 the Company's common stock on the date of grant) and the fair market value per share on the date of exercise of the SAR. SARs granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of the Company's Board of Directors.

On February 28, 2019, 951,699 SARs were granted which vest over a three-year period with a life of 5 years and have a $2.33 SAR price per share specified in a SAR award on the date of grant. On May 10, 2019, 196,892 SARs were granted which vest over a three-year period with a life of 5 years and have a $1.72 SAR price per share specified in a SAR award on the date of grant.

SAR activity for the six months ended June 30, 2019 is provided below:

	Number of Shares Underlying SARs	Weighted Average Exercise Price Per Share	Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2019	3,369	$ 0.96		
Granted	1,148	2.23		
Exercised	(270)	0.86		
Unvested shares forfeited	(521)	1.38		
Vested shares expired	—	—		
Outstanding at June 30, 2019	3,726	1.29	3.65	$ 1,916
Exercisable at June 30, 2019	1,240	1.04	3.01	$ 785

Other Benefit Plans

On May 2, 2019, the Company adopted a form of change in control agreement for its named executive officers and certain other officers of the Company and amended its severance plan for its Houston-based non-executive employees in order to provide severance benefits in connection with a change in control. Upon a termination of a participant's employment by the Company without cause or a resignation by the participant for good reason three months prior to a change in control or six months following a change in control, executives and officers with change in control agreements and participants in the severance plan will be entitled to receive 100% and 50%, respectively, of their participant's base salary and continued participation in the Company's group health plans for the participant and his or her eligible spouse and other dependents for six months. In addition, certain named executive officers will receive 75% of their target bonus.

14. INCOME TAXES

For 2019, the Company will determine its tax expense by estimating an annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to the Company's ordinary income or loss to calculate its estimated tax expense or benefit. The tax effect of discrete items are recognized in the period in which they occur at the applicable statutory tax rate.

The income tax provision for VAALCO consists primarily of Gabonese and United States income taxes. The Company's operations in other foreign jurisdictions have a 0% effective tax rate because the Company has incurred losses in those countries and have full valuation allowances against the corresponding net deferred tax assets.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	**2019**	2018
U.S. Federal:		(in thousands)		
Current	**$ (128)**	$ —	**$ (165)**	$ —
Deferred	**1,467**	—	**1,766**	—
Foreign:				
Current	**3,411**	3,582	**4,459**	7,624
Deferred	**4,458**	—	**5,901**	—
Total	**$ 9,208**	$ 3,582	**$ 11,961**	$ 7,624

The Company's effective tax rate for the three and six months ended June 30, 2019 is 79%. For the three and six months ended June 30, 2018, the Company recorded tax expense using the actual tax rate. For the three and six months ended June 30, 2019, the Company's overall effective tax rate was impacted by non-deductible items associated with operations and deducting foreign taxes rather than crediting them for United States tax purposes. Additionally, the joint venture owners' audit settlement was treated as discrete to the quarter and for which only an income tax benefit at the U.S. tax rate of 21% was provided.

The Company files income tax returns in all jurisdictions where such requirements exist, with Gabon and the United States being its primary tax jurisdictions.

As of June 30, 2019, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to unrecognized tax benefits as a component of income tax expense.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

- volatility of, and declines and weaknesses in oil and natural gas prices;
- the discovery, acquisition, development and replacement of oil and natural gas reserves;
- future capital requirements;
- our ability to maintain sufficient liquidity in order to fully implement our business plan;
- our ability to generate cash flows that, along with our cash on hand, will be sufficient to support our operations and cash requirements;
- our ability to attract capital;
- our ability to pay the expenditures required in order to develop certain of our properties offshore Equatorial Guinea;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the impact of competition;
- weather conditions;
- the uncertainty of estimates of oil and natural gas reserves;
- currency exchange rates and regulations;
- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- timing and amount of future production of oil and natural gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- our ability to enter into new customer contracts;
- changes in customer demand and producers' supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our joint venture owners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit; and
- actions of operators of our oil and natural gas properties.

The information contained in this report and the information set forth under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2018 ("2018 Form 10-K") and under the heading "Item 1A. Risk Factors" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2019 ("2019 First Quarter 10-Q"), 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 and the 2018 Form 10-K, 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.

INTRODUCTION

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 3 to the condensed consolidated financial statements, we have discontinued operations associated with our activities in Angola, West Africa.

Our financial results are heavily dependent upon the margins between prices received for our offshore Gabon oil production and the costs to find and produce such oil. In light of the volatility of oil prices over the past several years, we have focused on maximizing our margins by reducing costs, paying off debt, divesting non-core assets, minimizing capital expenditures and maintaining our existing production at optimal levels. On September 25, 2018, the term of the Etame PSC with Gabon, related to the Etame Marin block located offshore, was extended through 2028 with options to extend up to an additional ten years. The PSC Extension provides us with the extended time horizon necessary to pursue developing the resources we have identified at Etame. See Note 7 for further discussion. As a result of these efforts, our financial position has improved, and we believe that we have working capital sufficient to sustain current operations and fund development projects on our Etame license in Gabon. In combination with improved oil pricing and positive production performance, the PSC Extension enabled us to increase proved reserves during 2018 by 76% to 5.4 MMBbls at December 31, 2018 which include reserves for wells we expect to drill in 2019.

CURRENT DEVELOPMENTS

On June 20, 2019, the Board of Directors authorized and approved a share repurchase program for up to $10.0 million of the currently outstanding shares of the Company's common stock over a period of 12 months. Under the stock repurchase program, the Company intends to repurchase shares through open market purchases, privately-negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the Securities Exchange Act of 1934. See Note 12 to the condensed consolidated financial statements for further discussion.

During the second quarter of 2019, the Etame 4H well produced an average of 350 barrels per day gross (95 barrels net to VAALCO); however, in July 2019, this well stopped producing. We are currently undertaking a technical analysis of remedial work with a view to reestablishing production. Separately in July, we performed an acid simulation job on the N. Tchibala 2H well. Subsequent to this work, the well would not flow naturally, and we were unable to restore production. We are planning to perform additional work on the well to restore production. During the second quarter of 2019, this well produced an average of 420 barrels per day gross (113 barrels net to VAALCO).

In the third quarter of 2019, the Company has scheduled a planned maintenance turnaround for the Etame Marin FPSO and platforms which includes a full field shut down for approximately 8 days which will impact third quarter production.

VAALCO and its joint owners have moved forward with executing a development drilling program for 2019. We have contracted a drilling rig to drill a minimum of two wells and two appraisal wellbores at our Etame Marin Block beginning in the second half of 2019. The contract includes options to drill four additional wells at the Etame Marin Block. We believe that there is significant reserve upside associated with the two appraisal wellbores. We anticipate drilling two wells and a possible third well in the second half of 2019 and the first half of 2020. We are forecasting that the 2019 drilling program will be funded by cash on hand and cash generated from operations.

ACTIVITIES BY ASSET

Gabon

Offshore – Etame Marin Block

<u>Development and Production</u>

We operate the Etame, Avouma/South Tchibala, Ebouri, Southeast Etame and the North Tchibala fields on behalf of a consortium of four companies. As of June 30, 2019, production operations in the Etame Marin block included 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 anchored to the seabed on the block. We currently have ten producing wells. The FPSO has production limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day. During the three months ended June 30, 2019 and 2018, production from the block was approximately 1,235 MBbls (333 MBbls net) and 1,198 MBbls (323 MBbls net), respectively. During the six months ended June 30, 2019 and 2018, production from the block was approximately 2,399 MBbls (648 MBbls` net) and 2,398 MBbls (648 MBbls net), respectively.

Equatorial Guinea

VAALCO has a 31% working interest in an undeveloped portion of a block offshore Equatorial Guinea that it acquired in 2012 (the "Block P interest"). We are currently awaiting the Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH") to approve our appointment as operator for Block P. Compania Nacional de Petroleos de Guinea Equatorial ("GEPetrol") is the state-owned oil company and one of the joint venture owners in Block P. For a number of years, the Block P interest was in suspension; however, in September 2018, the EG MMH lifted the suspension subject to several conditions. GEPetrol was required to introduce a new investor or joint venture owner to the EG MMH by March 28, 2019, and it has fulfilled this requirement. Upon EG MMH approving the new joint owner, the Contractor group has one year to drill an exploration well. VAALCO intends to seek a joint venture owner on a promoted basis that will cover all or substantially all of the cost to drill an exploratory well. If the joint venture owners fail to drill an exploration well, VAALCO would lose its interest in the license, and the associated costs would become impaired. As of June 30, 2019, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. VAALCO and its joint venture owners are evaluating the timing and budgeting for development and exploration activities under a development and production area in the block, including the approval of a development and production plan. The production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for the Block 5 PSA. Our working interest was 40%, and it carried Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the Block 5 PSA. Further to our decision to withdraw from Angola, we closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the condensed consolidated financial statements for all periods presented.

Drilling Obligation

Under the Block 5 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 Block 5 PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The Block 5 PSA provided for a stipulated payment of $10.0 million for each of the three exploration wells for which a drilling obligation remains under the terms of the Block 5 PSA, of which our participating interest share would be $5.0 million per well. We reflected an accrual of $15.0 million for a potential payment as of December 31, 2018. In the first quarter of 2019, we and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola.

Pursuant to the settlement agreement, we agreed to pay $4.5 million to Angola National Agency of Petroleum, Gas, and Biofuels, as National Concessionaire, and to eliminate the $3.3 million receivable from Sonangol P&P. The receivable was related to joint interest billings and was reflected as current assets from discontinued operations at year-end 2018. As a result, we adjusted a previously accrued liability and recognized a net of tax non-cash benefit from discontinued operations of $5.7 million in the first quarter of 2019. In July 2019, subsequent to the publication of an executive decree from the Ministry of Mineral Resources and Petroleum, the Company paid the $4.5 million due under the settlement agreement.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the six months ended June 30, 2019 and 2018 are as follows:

	Six Months Ended June 30, 2019	2018	Increase (Decrease)
		(in thousands)	
Net cash provided by operating activities before change in operating assets and liabilities	**$ 14,106**	$ 17,190	$ (3,084)
Net change in operating assets and liabilities	**2,566**	14,358	(11,792)
Net cash provided by continuing operating activities	**16,672**	31,548	(14,876)
Net cash used in discontinued operating activities	**(91)**	(892)	801
Net cash provided by operating activities	**16,581**	30,656	(14,075)
Net cash used in continuing investing activities	**(1,163)**	(976)	(187)
Net cash used in discontinued investing activities	**—**	—	—
Net cash used in investing activities	**(1,163)**	(976)	(187)
Net cash used in continuing financing activities	**(245)**	(8,721)	8,476
Net cash used in discontinued financing activities	**—**	—	—
Net cash used in financing activities	**(245)**	(8,721)	8,476
Net change in cash, cash equivalents and restricted cash	**$ 15,173**	$ 20,959	$ (5,786)

The decrease in net cash provided by our operating activities for the six months ended June 30, 2019 compared to the same period of 2018 includes a $3.1 million decrease in cash generated by continuing operations before change in operating assets and liabilities, which was mainly due to lower revenue, and a decrease in our operating assets and liabilities of $11.8 million. The net change in operating assets and liabilities of $2.6 million for the six months ended June 30, 2019 included a $3.2 million decrease in trade and other receivables, and an increase in “Accrued liabilities and other” of $3.9 million offset by a $2.8 million decrease in “Foreign taxes payable,” and a $0.7 decrease in “Accounts payable” and an increase of $1.2 million in “Prepayments and other”. The net change in operating assets and liabilities of $14.4 million for the six months ended June 30, 2018 included $13.2 million in payments made by joint venture owners partially offset by a pay down of “Accounts payable” and “Accrued liabilities and other” of $0.8 million.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. During the six months ended June 30, 2019, these expenditures on a cash basis were $1.2 million, primarily related to equipment purchases. This compares to $1.0 million in property and equipment expenditures included in capital expenditures for the six months ended June 30, 2018. See “Capital Expenditures” below for further discussion.

Net cash used in financing activities during the six months ended June 30, 2018 included $9.2 million in principal payments on debt which was extinguished in May 2018.

Capital Expenditures

During the six months ended June 30, 2019, we made accrual basis capital expenditures of $2.3 million. Pursuant to the PSC Extension as discussed in Note 7, we have commitments for capital expenditures related to the drilling of two wells and two appraisal wellbores at an estimated cost of approximately $61.2 million ($20.5 million, net to VAALCO), by September 16, 2020. We anticipate drilling these wells and a possible third well in the second half of 2019 and the first quarter of 2020. The third well is subject to approval by the joint venture owners and the government of Gabon.

Contractual Obligations

See Note 10 to the condensed consolidated financial statements as well as our 2018 Form 10-K for discussion of our contractual obligations.

During the six months ended June 30, 2019, we entered into a drilling rig contract. There were no other material changes in our contractual obligations during the six months ended June 30, 2019.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies in Gabon, including audits of our petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements. In July 2019, the Company reached an agreement in principle to resolve a legacy issue related to findings from Etame joint ventures owners’ audits for the periods from 2007 through 2016 for $4.4 million net to VAALCO. The agreement in principle also provides for procedures to minimize the chances of future audit claims.

Accordingly, the Company has accrued $4.4 million which is reflected in the "Accrued liabilities and other" line of the Company's condensed consolidated balance sheet and is recorded as a second quarter 2019 expense in the condensed consolidated results of operations in the line item "Other operating income (expense), net". The agreement in principle is expected to become final upon signing of a binding settlement agreement by all of the joint venture owners.

Capital Resources

Credit Facility

Historically, our primary sources of capital have been cash flows from operating activities, borrowings under the Amended Term Loan Agreement with the IFC and cash balances on hand. On May 22, 2018, we terminated the Amended Term Loan Agreement by prepaying the outstanding principal and accrued interest. We did not incur any termination or prepayment penalties as a result of the early termination of the Amended Term Loan Agreement.

Cash on Hand

At June 30, 2019, we had unrestricted cash of $48.6 million. The unrestricted cash balance includes $3.8 million of cash attributable to non-operating joint venture owner advances. As operator of the Etame Marin block in Gabon, we enter into project related activities on behalf of our working interest joint venture owners. We generally obtain advances from the joint venture owners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations for the foreseeable future.

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

Liquidity

As discussed above, our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices. After a period of low commodity prices, oil and natural gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and natural gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. As discussed above, we are committed to drill two wells and two appraisal wellbores in the Etame Marin block by September 16, 2020. In addition, the conditions for lifting the suspension for Block P require the drilling of one exploration well in Block P by September 2020, although there is no financial penalty for not meeting this requirement. We expect any capital expenditures made during 2019 and expenditures for share repurchases will be funded by cash on hand and cash flow from operations. We believe that at current prices, cash generated from continuing operations, together with cash on hand at June 30, 2019, will be adequate to support our operations and cash requirements during 2019 and through September 30, 2020.

At December 31, 2018, we had 5.4 MMBbls of estimated net proved reserves, all of which are related to the Etame Marin block offshore Gabon. The current term for exploitation of the reserves in the Etame Marin block ends in September 2028 with rights for two five-year extension periods. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. While both short-term and long-term liquidity are impacted by crude oil prices, our long-term liquidity also depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable.

OFF-BALANCE SHEET ARRANGEMENTS

None.

CRITICAL ACCOUNTING POLICIES

There have been no changes to our critical accounting policies subsequent to December 31, 2018 except for the adoption of a new leasing standard on January 1, 2019. See Note 1 to the condensed consolidated financial statements.

NEW ACCOUNTING STANDARDS

See Note 2 to the condensed consolidated financial statements.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2019 Compared to the Three Months Ended June 30, 2018

We reported net loss for the three months ended June 30, 2019 of $1.0 million compared to net income of $0.5 million for the same period of 2018. The net income for the three months ended June 30, 2019 is inclusive of the loss from discontinued operations for the same period of $0.2 million. The net income for the three months ended June 30, 2018 was inclusive of the loss from discontinued operations for the same period of $0.3 million. Substantially all of our operations are attributable to our Gabon segment. Further discussion of results by significant line item follows.

Oil and natural gas revenues increased $0.8 million, or approximately 3.3%, during the three months ended June 30, 2019 compared to the same period of 2018. The increase in revenue is primarily attributable to higher sales volumes.

The revenue changes in the three months ended June 30, 2019 compared to the three months ended June 30, 2018, identified as related to changes in price or volume, are shown in the table below:

(in thousands)		
Price	$	(2,049)
Volume		2,826
Other		27
	$	804

	Three Months Ended June 30,			
		2019		2018
Gabon net oil production (MBbls)		333		323
International net oil sales (MBbls)		357		319
Average realized oil price ($/Bbl)	$	68.62	$	74.36
Average Dated Brent spot* ($/Bbl)		69.04		74.53

*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 four liftings in the second quarter of 2019 and three liftings in the comparable period in 2018. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 21,526 and 52,900 barrels at June 30, 2019 and 2018, respectively. Production volumes for the three months ended June 30, 2019 were not materially different from the comparable 2018 period.

Production expenses decreased $3.0 million, or approximately 23.4%, in the three months ended June 30, 2019 compared to the same period of 2018. The decrease was primarily a result of lower workover costs. We recorded no workover costs in 2019 compared to $4.5 million in workovers during the comparable period. The lower workover costs were offset by higher transportation and personnel costs during 2019 compared to 2018.

Depreciation, depletion and amortization ("DD&A") costs increased due to higher depletable costs associated with the PSC Extension as discussed in Note 7 to the condensed consolidated financial statements.

General and administrative expenses decreased $2.3 million, or approximately 45.5% in the three months ended June 30, 2019 compared to the same period of 2018. The decrease in expense was related to a $2.7 million decrease in SARs expense. SARs liability awards are fair valued. The primary driver to changes in the fair value of these awards is changes in the Company's stock price. See Note 13 to our condensed consolidated financial statements for further discussion. The decrease in stock-based compensation expense from 2018 to 2019 was offset by higher professional fees and other costs ($0.4 million) during the three months ended June 30, 2019 compared to the same period in 2018.

Bad debt (recovery) expense was lower between the three months ended June 30, 2019 and 2018 due to higher bad debt recoveries.

Other operating income (expense), net for the three months ended June 30, 2019 is related to a $4.4 million agreement in principle to resolve a legacy issue related to findings from Etame joint ventures owners' audits for the periods from 2007 through 2016. During the three months ended June 30, 2018, we recorded a reduction in inventory obsolescence.

Interest income (expense), net for the three months ended June 30, 2019 relates to interest income on cash balances as comparable to June 30, 2018 which relates to our term loan with the IFC as discussed in Note 9 to the condensed consolidated financial statements and to interest on taxes other than income taxes.

Derivative instruments gain (loss), net for the three months ended June 30, 2019 and 2018 is attributable to our swaps as discussed in Notes 8 to the condensed consolidated financial statements and is a result of the decrease in the price of Dated Brent crude oil during the three months ended June 30, 2019 as compared to an increase in price during the comparable prior period.

Other, net for the three months ended June 30, 2019 and 2018 primarily consists of foreign currency losses as discussed in Note 1 to the condensed consolidated financial statements.

Income tax expense for the three months ended June 30, 2019 was $9.2 million. This is comprised of $5.9 million of deferred tax expense and a current tax provision of $3.3 million and was impacted by the above referenced $4.4 million related to the joint venture owners' audits. Income from continuing operations, excluding the $4.4 million, was $12.7 million. At an effective tax rate of 79% (which was impacted by items associated with operations and foreign taxes for which no U.S. tax benefit was recognized), income taxes would have been $10.0 million. The $10.0 million of income tax expense is reduced by the tax benefit of the $4.4 million expense (taxed at the U.S. income tax rate of 21%) or $0.9 million; thus, the expected tax is $9.2 million and consistent with the actual income tax expense recorded of $9.2 million. For the three months ended June 30, 2018, the Company had a current provision of

$3.6 million and no amounts related to the deferred provision. The decrease in the current provision is primarily attributable to Gabon income taxes which were impacted by an increase in the amount of costs which can be deducted as a result of the PSC Extension obtained in September 2018. With respect to deferred income tax, for periods prior to the three months ended September 30, 2018, the Company had full valuation allowances on its net deferred tax assets, and deferred income tax was zero. See Note 14 to the condensed consolidated financial statements for further discussion.

Loss from discontinued operations for the three months ended June 30, 2019 and 2018 is attributable to our Angola segment as discussed further in Note 3 to the condensed consolidated financial statements. The loss from discontinued operations for the three months ended June 30, 2019 and 2018 was related to Angola administration costs.

Six Months Ended June 30, 2019 Compared to the Six Months Ended June 30, 2018

We reported net income for the six months ended June 30, 2019 of $5.5 million compared to net income of $9.2 million for the same period of 2018. The net income for the six months ended June 30, 2019 is inclusive of the income from discontinued operations for the same period of $5.5 million. The net income for the six months ended June 30, 2018 was inclusive of the loss from discontinued operations for the same period of $0.4 million. Substantially all of our operations are attributable to our Gabon segment. Further discussion of results by significant line item follows.

Oil and natural gas revenues decreased $7.1 million, or approximately 13.6%, during the six months ended June 30, 2019 compared to the same period of 2018. The decrease in revenue is attributable to lower sales volumes and to a lesser extent lower prices.

The revenue changes in the six months ended June 30, 2019 compared to the six months ended June 30, 2018, identified as related to changes in price or volume, are shown in the table below:

(in thousands)		
Price	$	(3,029)
Volume		(4,131)
Other		84
	$	(7,076)

	Six Months Ended June 30,			
		2019		2018
Gabon net oil production (MBbls)		648		648
International net oil sales (MBbls)		654		712
Average realized oil price ($/Bbl)	$	66.60	$	71.23
Average Dated Brent spot* ($/Bbl)		66.07		70.67

*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 seven liftings during both six months ended June 30, 2019 and 2018. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 21,526 and 52,900 barrels at June 30, 2019 and 2018, respectively. Production volumes for the six months ended June 30, 2019 were consistent with the comparable 2018 period. Sales volumes were lower between the periods because sales volumes for the six months ended June 30, 2018 included 95,525 barrels associated with the last lifting in 2017 which was not completed until January 1, 2018. Net revenues of $6.5 million associated with these net volumes were reported as revenue in the six months ended June 30, 2018.

Production expenses decreased $5.7 million, or approximately 24.1%, in the six months ended June 30, 2019 compared to the same period of 2018. We recorded $0.1 million in workover costs in 2019 compared to $4.8 million in workovers during the comparable period. The lower workover costs were offset by higher transportation ($0.6 million), FPSO ($0.2 million), customs and other costs ($0.3 million) during 2019 compared to 2018.

Depreciation, depletion and amortization ("DD&A") costs increased due to higher depletable costs associated with the PSC Extension as discussed in Note 7 to the condensed consolidated financial statements.

General and administrative expenses decreased $0.4 million, or approximately 5.8% in the six months ended June 30, 2019 compared to the same period of 2018. The decrease in expense was related to a $1.2 million decrease in SARs expense. SARs liability awards are fair valued. The primary driver to changes in the fair value of these awards is changes in the Company's stock price. See Note 13 to our condensed consolidated financial statements for further discussion. The decrease in SARs expense was offset by higher professional fees ($0.3 million), accounting and audit fees ($0.2 million), personnel related costs ($0.2 million) and other costs ($0.1 million) during the six months ended June 30, 2019 compared to the same period in 2018.

Bad debt (recovery) expense was lower between the six months ended June 30, 2019 primarily related to bad debt recoveries in the 2019 period as compared to the bad debt expense in the comparable 2018 period.

Other operating income (expense), net for the six months ended June 30, 2019 is related to a $4.4 million agreement in principle to resolve a legacy issue related to findings from Etame joint ventures owners' audits for the periods from 2007 through 2016. During the six months ended June 30, 2018, we recorded a reduction in inventory obsolescence.

Interest income (expense), net for the six months ended June 30, 2019 relates to interest income on cash balances as comparable to June 30, 2018 which relates to our term loan with the IFC as discussed in Note 9 to the condensed consolidated financial statements and to interest on taxes other than income taxes.

Derivative instruments gain (loss), net for the six months ended June 30, 2019 is attributable to our swaps as discussed in Notes 8 to the condensed consolidated financial statements and is a result of an increase in the price of Dated Brent crude oil during each of the six months ended June 30, 2019 and June 30, 2018.

Other, net for the six months ended June 30, 2019 and 2018 primarily consists of foreign currency losses as discussed in Note 1 to the condensed consolidated financial statements.

Income tax expense for the six months ended June 30, 2019 was $12.0 million. This is comprised of $7.7 million of deferred tax expense and a current tax provision of $4.3 million and was impacted by the above referenced $4.4 million related to the joint venture owners' audits. Income from continuing operations, excluding the $4.4 million, was $16.3 million. At an effective tax rate of 79% (which was impacted by items associated with operations and foreign taxes for which no U.S. tax benefit was recognized), income taxes would have been $12.9 million. The $12.9 million of income tax expense is reduced by the tax benefit of the $4.4 million expense (taxed at the U.S. income tax rate of 21%) or $0.9 million; thus, the expected tax is $12.0 million and consistent with the actual income tax expense recorded of $12.0 million. For the six months ended June 30, 2018, we had a current provision of $7.6 million and no amounts related to the deferred provision. The decrease in the current provision is primarily attributable to Gabon income taxes which were impacted by the decline in revenues between periods as well as an increase in the Cost Recovery percentage from 70% to 80% under the PSC Extension. With respect to deferred income tax, for periods prior to the six months ended September 30, 2018, we had full valuation allowances on our net deferred tax assets, and deferred income tax was zero. See Note 14 to the condensed consolidated financial statements for further discussion.

Gain (loss) from discontinued operations for the six months ended June 30, 2019 and 2018 is attributable to our Angola segment as discussed further in Note 3 to the condensed consolidated financial statements. The gain from discontinued operations for the six months ended June 30, 2019 is primarily related to recording a $5.7 million after tax gain on the finalized Angola settlement as discussed in Note 3 to the condensed consolidated financial statements. The loss from discontinued operations for the six months ended June 30, 2018 was related to Angola administration costs.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 are denominated in the local currency (the Central African CFA Franc, or XAF), and our VAT receivable as well as certain liabilities in Gabon are also denominated in XAF. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing costs. For our VAT receivable in Gabon, a strengthening U.S. dollar will have the effect of decreasing the value of this receivable resulting in foreign exchange losses, and vice versa. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has historically fluctuated in response to international political conditions, general economic conditions and other factors beyond our control. As of June 30, 2019, we had net monetary assets of $3.2 million (XAF 1,853.2 million) (net to VAALCO) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $0.3 million reduction in the value of these net assets. For the three and six months ended June 30, 2019, we had expenditures of approximately $2.7 million and $5.1 million (net to VAALCO), respectively, denominated in XAF.

COUNTERPARTY RISK

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

COMMODITY PRICE RISK

Our major market risk exposure continues to be the prices received for our crude oil production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for oil and natural gas have been volatile and unpredictable in recent years, and this volatility may continue. Sustained low oil 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 quarterly sales volumes of 357 MBbls, a $5 per Bbl decrease in oil price would be expected to cause a $1.8 million decrease per quarter ($7.2 million annualized) in revenues and operating income and a $0.4 million decrease per quarter ($1.7 million annualized) in net income.

During the three and six months ended June 30, 2019, we had oil swaps outstanding. These instruments were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes.

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. The evaluation was performed with the participation of senior management, under the supervision of the principal executive officer and principal financial officer. Based on this evaluation, the principal executive officer and principal financial officer concluded that our disclosure controls and procedures were not effective due to the existence of a previously reported material weakness as of the end of the period covered by this Quarterly Report on Form 10-Q. The material weakness was identified and discussed in "Part II – Item 9A – Disclosure Controls and Procedures" of our Annual Report on Form 10-K for the year ended December 31, 2018.

Notwithstanding the identified material weakness, management, including our principal executive officer and principal financial officer, believes the consolidated financial statements included in this Quarterly Report on Form 10-Q fairly represent in all material respects our financial condition, results of operations and cash flows at and for the periods presented in accordance with GAAP.

DESCRIPTION OF MATERIAL WEAKNESS

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

MANAGEMENT'S PLAN FOR REMEDIATION OF THE MATERIAL WEAKNESS

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation of condensed consolidated financial statements for external purposes.

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

Management is committed to improving our internal control processes and believes that the additional resources described above should assist in remediating the material weakness identified and strengthen internal control over financial reporting. As we continue to evaluate and improve internal control over financial reporting, additional measures to remediate the material weakness or modification to the remediation procedures described above may be necessary. We expect to complete the required remedial actions during 2019. While senior management and our Audit Committee are closely monitoring the implementation of the remediation plans, we cannot provide any assurance that the remediation efforts will be successful or that internal control over financial reporting will be effective as a result of these efforts. Until the remediation steps set forth above are fully implemented and operating for a sufficient period of time, the material weakness that existed at December 31, 2018 will continue to exist.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Except for the activities taken related to the remediation of the material weakness described above, there were no changes in our internal control over financial reporting that occurred during three months ended June 30, 2019 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. 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 condensed consolidated financial position, cash flows or results of operations.

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed elsewhere in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

For a discussion of our potential risks and uncertainties, see the information in Item 1A "Risk Factors" in our 2018 Form 10-K and our 2019 First Quarter 10-Q. There have been no material changes in our risk factors from those described in our 2018 Form 10-K and our 2019 First Quarter 10-Q other than the following:

The entity holding our license in Equatorial Guinea is not in good standing.

VAALCO Mauritius, an indirect wholly owned subsidiary of VAALCO, which holds VAALCO's working interest in Block P, is not currently in good standing in Equatorial Guinea. Although VAALCO is taking steps to restore VAALCO Mauritius to good standing, should it fail to do so, it may be subject to fines, penalties and/or other administrative actions.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

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

The following table represents details of the various repurchases during the three and six months ended June 30, 2019:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program
June 20, 2019				$ 10,000,000
June 27, 2019 - June 30, 2019	141,686	$ 1.73	141,686	9,752,344

See Note 12 to the condensed consolidated financial statements for further discussion. Subsequent to June 30, 2019 and through a settlement date of August 7, 2019, the Company purchased 746,668 shares at an average price of $1.73 for $1.3 million.

ITEM 6. EXHIBITS

(a) **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 31, 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).
10.1	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 8, 2019, and incorporated herein by reference).
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.
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

SIGNATURE

In accordance with the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By: /s/ Elizabeth D. Prochnow
Elizabeth D. Prochnow
Chief Financial Officer
(duly authorized officer and principal financial officer)

Dated: August 7, 2019

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Accounts for year ended December 31, 2018

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and our report dated March 8, 2019 expressed an adverse opinion thereon.

Basis for Opinion

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

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

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

/s/BDO USA, LLP

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

Houston, TX

March 8, 2019

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

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

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Oil and natural gas sales	**$ 104,943**	$ 77,025	$ 59,784
Operating costs and expenses:			
Production expense	**40,415**	39,697	37,586
Exploration expense	**14**	7	5
Depreciation, depletion and amortization	**5,596**	6,457	6,926
Gain on revision of asset retirement obligations	**(3,325)**	—	—
General and administrative expense	**11,398**	10,377	9,561
Impairment of proved properties	—	—	88
Other operating expense	—	—	8,853
General and administrative related to shareholder matters	—	—	(332)
Bad debt (recovery) expense and other	**(77)**	452	1,222
Total operating costs and expenses	**54,021**	56,990	63,909
Other operating income (expense), net	**365**	(84)	(266)
Operating income (loss)	**51,287**	19,951	(4,391)
Other income (expense):			
Interest expense, net	**(145)**	(1,414)	(2,613)
Other, net	**4,332**	2,113	(2,015)
Total other income (expense)	**4,187**	699	(4,628)
Income (loss) from continuing operations before income taxes	**55,474**	20,650	(9,019)
Income tax expense (benefit)	**(43,254)**	10,378	9,248
Income (loss) from continuing operations	**98,728**	10,272	(18,267)
Loss from discontinued operations	**(496)**	(621)	(8,283)
Net income (loss)	**$ 98,232**	$ 9,651	$ (26,550)
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.65**	$ 0.17	$ (0.31)
Loss from discontinued operations	**(0.01)**	(0.01)	(0.14)
Net income (loss) per share	**$ 1.64**	$ 0.16	$ (0.45)
Basic weighted average shares outstanding	**59,248**	58,717	58,384
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.63**	$ 0.17	$ (0.31)
Loss from discontinued operations	**(0.01)**	(0.01)	(0.14)
Net income (loss) per share	**$ 1.62**	$ 0.16	$ (0.45)
Diluted weighted average shares outstanding	**59,997**	58,720	58,384

See notes to consolidated financial statements

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

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

See notes to consolidated financial statements.

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

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

See notes to consolidated financial statements.

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

See notes to consolidated financial statements.

1. ORGANIZATION

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

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

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

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

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

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and time duration. Current amounts in restricted cash at December 31, 2018 and 2017 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2018 and 2017 include a charter payment escrow for the floating, production, storage and offloading vessel (“FPSO”) offshore Gabon as discussed in Note 12. We invest restricted and excess cash in readily redeemable money market funds.

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

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

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

Bad debts – Quarterly, we evaluate our accounts receivable balances to confirm collectability. When collectability is in doubt, we record an allowance against the accounts receivable and a corresponding income charge for bad debts which appears in the "Bad debt expense and other" line item of the consolidated statements of operations. The majority of our accounts receivable balances are with our joint venture owners, purchasers of our production and the government of Gabon for reimbursable Value-Added Tax ("VAT"). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed us. Portions of our costs in Gabon (including our VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). As of December 31, 2018, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately XAF 6.9 billion (XAF 2.3 billion, net to VAALCO). The VAT receivable balance was reduced by XAF14.1 billion (XAF 4.7 billion, net to VAALCO or $4.2 million) associated with a signing bonus as part of the Sixth Amendment to the Etame PSC executed on September 17, 2018 ("PSC Extension"). As of December 31, 2018, the exchange rate was XAF 573.0 = $1.00.

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

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

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

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

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

Oil and natural gas properties, equipment and other – We use the successful efforts method of accounting for oil and natural gas producing activities. Our management believes that this method is preferable, as we have focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results.

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

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

Impairment – We review our oil and natural gas producing properties for 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. Capitalized equipment inventory is reviewed regularly for obsolescence. We identified equipment inventory in Gabon that required an adjustment of $0.4 million to the "Other operating income (expense), net" line item of the consolidated statement of operations for the year ended December 31, 2018. We identified equipment inventory in Gabon that we do not expect to use and charged $(0.3) million to the "Other operating income (expense), net" line item of the consolidated statement of operations in each of the years ended December 31, 2017 and 2016, respectively. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to undeveloped acreage in the Etame Marin block and in Equatorial Guinea.

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

We capitalized no interest costs during the years ended December 31, 2018, 2017 and 2016.

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

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

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to oil and natural gas properties. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. See Note 11 for disclosures regarding our asset retirement obligations. Where there is a downward revision to the ARO that exceeds the net book value of the related asset, the corresponding adjustment is limited to the amount of the net book value of the asset and the remaining amount is recognized as a gain. During the year ended December 31, 2018, we recorded a downward revision of $6.5 million to the

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

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

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

Stock based compensation – We measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. Grant date fair value for options is estimated using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. For restricted stock, grant date fair value is determined using the market value of our common stock on the date of grant. The fair value of stock appreciation rights ("SARs") is based on a Monte Carlo simulation at grant date and at each subsequent reporting date for the 2016 grants. The Monte Carlo simulation to value our SARs uses the following inputs: (i) the quoted market price of our common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term which is based on the contractual term, (iv) the expected volatility which is based on the historical volatility of the our stock for the length of time corresponding to the expected term of the SARs, (v) the expected dividend yield is based on our anticipated dividend payments, (vi) the risk-free interest rate which is based on the U.S. treasury yield curve in effect as of the reporting date for the length of time corresponding to the expected term of the SARs. We utilize the Black-Scholes option pricing model to measure the fair value of the 2017 and 2018 SARs.

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

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

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Gains and losses on foreign currency transactions are included in income. Within the consolidated statements of operations line item "Other income (expense)—Other, net," we recognized losses on foreign currency transactions of $0.1 million and $30 thousand in 2018 and 2016, respectively, while we recognized gains on foreign currency transactions of $0.5 million in 2017.

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

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

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

Derivative instruments and hedging activities – We use derivative financial instruments to achieve a more predictable cash flow from oil production by reducing our exposure to price fluctuations. Our derivative instruments at December 31, 2016 consisted of fixed price oil puts, which give us the option to sell a contracted volume of oil at a contracted price on a contracted date in the future.

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

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

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

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

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

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

Fair value of financial instruments – Our current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets and liabilities, accounts payable, liabilities for stock appreciation rights ("SARs") and guarantee. As discussed further in Note 10, derivative assets and liabilities are measured and reported at fair value each period with changes in fair value recognized in net income. The derivative asset commodity swaps referenced below are reported on the consolidated balance sheet on line item "Prepayments and other." SARs liabilities are measure and reported at fair value using level 2 inputs each period with changes in fair value recognized in net income. The current portion of the SARs liabilities is reported on the consolidated balance sheet on line item "Accrued liabilities and other" while the long-term portion is located on the line item "Other long term liabilities". With respect to our other financial instruments included in current assets and liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments.

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

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

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

3. NEW ACCOUNTING STANDARDS

Not Yet Adopted

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

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

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

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"), which amends the accounting standards for leases. This accounting standard was further clarified by ASU 2018-10, Codification Improvements to Topic 842 and ASU 2018-11, Leases:

Targeted Improvements, both of which were issued in July 2018 together ("Topic 842"). Topic 842 retains a distinction between finance leases and operating leases. The primary change is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Certain aspects of lease accounting have been simplified and additional qualitative and quantitative disclosures are required along with specific quantitative disclosures required by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. In transition, lessees and lessors may use either a prospective approach in which they recognize and measure leases at the date of adoption and recognize a cumulative effect adjustment to the opening balance of retained earnings or they may use a modified retrospective approach in which leases are recognized and measured at the beginning of the earliest period presented. We intend to use the prospective approach when we adopt the new standard effective January 1, 2019. Leases with terms greater than 12 months, which are currently treated as operating leases, will be capitalized. The adoption of this standard will result in the recording of a right of use asset related to certain of our operating leases with a corresponding lease liability. This will result in a significant increase in total assets and liabilities and a decrease in working capital. In connection with our implementation plan, we have reviewed our lease contracts and are evaluating other contracts to identify embedded leases to determine the appropriate accounting treatment. The most significant lease we currently have is related to the FPSO as further discussed in Note 12, and we are finalizing the evaluation of that lease. Lease payments reflected in the table in Note 12 represent the minimum amounts due. The new leasing standard requires capitalization based on the expected term of this lease which may or may not extend beyond the minimum period. While we may exercise our right to terminate the contract as early as September 2020, the minimum lease period, the FPSO charter ends in September 2022.

Adopted

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

In November 2016, the FASB issued ASU No. 2016-18, which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. We adopted ASU 2016-18 beginning January 1, 2018 with retroactive application to prior periods. Due to the nature of this accounting standards update, this had an impact on items reported in our consolidated statements of cash flows and related disclosures, but no impact on our financial position and results of operations.

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

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

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

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

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15") related to how certain cash receipts and payments are presented and classified in the statement of cash flows. These cash flow issues include debt prepayment or extinguishment costs, settlement of zero-coupon debt, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, beneficial interests in securitization transactions, and separately identifiable cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The adoption of ASU 2016-15 has not had a material impact on our financial position, results of operations, cash flows and related disclosures.

4. ACQUISITIONS AND DISPOSITIONS

Sojitz Acquisition

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

The actual impact of the Sojitz acquisition was an increase to "Total revenues" in the consolidated statement of operations of $0.2 million for the year ended December 31, 2016 and a minimal decrease to "Net loss" in the consolidated statement of operations for the year ended December 31, 2016.

Sale of Certain U.S. Properties

In December 2016, we completed the sale of our interests in two wells in the Hefley field in North Texas for $0.8 million resulting in a minimal 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"). Our working interest is 40%, and we carry Sonangol P&P for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to the decision to withdraw from Angola, we have taken actions to close our office in Angola and reduce future activities in Angola. As a result of this strategic shift, we classified all the related assets and liabilities as those of discontinued operations in the consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in our consolidated statements of operations. We segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in our consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment assets and liabilities as of December 31, 2018 and 2017 and its results of operations for the years ended December 31, 2018, 2017 and 2016.

Summarized Results of Discontinued Operations

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

Assets and Liabilities Attributable to Discontinued Operations

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

Drilling Obligation

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

Other Matters – Joint Owner Receivable

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

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

5. SEGMENT INFORMATION

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

Segment activity of continuing operations for the years ended December 31, 2018, 2017 and 2016 and long-lived assets and segment assets at December 31, 2018 and 2017 are as follows:

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

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

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

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

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

Information about our most significant customers

For the years ended December 31, 2018, 2017 and 2016, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchaser was Glencore Energy UK Ltd. ("Glencore") for these periods and through January 2019. Sales of oil to Glencore were approximately 100% of revenues sold to customers for 2018, 2017 and 2016. We have signed a new contract with Mercuria Energy Trading SA which covers sales from February 2019 through January 2020.

6. EARNINGS PER SHARE

Basic earnings per share ("EPS") is calculated using the average number of shares of common stock outstanding during each period. For the calculation of diluted shares, we assume that restricted stock is outstanding on the date of vesting, and we assume the issuance of shares from the exercise of stock options using the treasury stock method. A reconciliation of reported net income (loss) to net income (loss) used in calculating EPS as well as a reconciliation from basic to diluted shares follows:

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

7. REVENUE

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

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

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

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

Previously, we followed the sales method of accounting to account for crude oil production imbalances. In conjunction with our adoption of ASC Topic 606 on January 1, 2018, we will continue to account for production imbalances as a reduction in reserves. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property, and we would recognize a liability if our existing proved reserves were not adequate to cover an imbalance.

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

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

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

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

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

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

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

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

8. INCOME TAXES

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

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

- Beginning January 1, 2018, the U.S. corporate income tax rate is 21%. The Company recognized the impacts of this rate change on its deferred tax assets and liabilities in the period enacted, i.e. during the year ended December 31, 2017. As the Company has a full valuation allowance on its net deferred tax asset as of December 31, 2017, the deferred tax recognized due to the change in rate was offset with a change in the valuation allowance. Therefore, there was no overall impact to the Financial Statements in 2017 due to this change in rate.
- The Tax Reform Act also repealed the corporate AMT for tax years beginning on or after January 1, 2018 and provided for existing alternative minimum tax credit carryovers to be refunded beginning in 2018. The Company has approximately $1.4 million in refundable credits, and it expects that a substantial portion will be refunded between 2018 and 2021. As such, most of the valuation allowance in place at the end of 2017 related to these credits was released in 2017 and a deferred tax asset of $1.3 million was reflected as of December 31, 2017 related to the expected benefit in future years.
- The Transition Tax on unrepatriated foreign earnings is a tax on previously untaxed accumulated and current earnings and profits ("E&P") of the Company's foreign subsidiaries. To determine the amount of the Transition Tax, the Company must determine, among other factors, the amount of post-1986 E&P of its foreign subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. Based on the Company's reasonable estimate of the Transition Tax, there is no provisional Transition Tax expense.
- The Tax Reform Act created a new requirement that GILTI income earned by foreign subsidiaries must be included currently in the gross income of the U.S. shareholder. The Company did not have any amounts related to potential GILTI tax.

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

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

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

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

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

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

Taxes paid in Gabon with respect to earnings from the Etame Marin block are determined under the provisions of the Etame PSC. In accordance with the Etame PSC, the Consortium maintains a “Cost Account” which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. For each calendar year, the Consortium is entitled to receive a percentage of the production (“Cost Recovery Percentage”) remaining after deducting royalties so long as there are amounts remaining in the Cost Account. Prior to the PSC Extension, the Cost Recovery Percentage was 70%. As a result of the PSC Extension, the Cost Recovery Percentage has been increased to 80% for the period from September 17, 2018 through September 16, 2028. See Note 9 for further discussion of the PSC Extension. After September 16, 2028, the Cost Recovery Percentage returns to 70%. The difference between revenues, net of royalties, and the costs recovered for the period is “Profit Oil.” As payment of corporate income taxes, the Consortium pays the government an allocation of the remaining Profit Oil production from the contract area ranging from 50% to 60%. The percentage of Profit Oil paid to the government as tax is a function of production rates. When the Cost Account is less than the entitled recovery percentage (either 70% or 80%, depending on the period), Profit Oil as a percentage of revenues increases and Gabon taxes paid increase as a percentage of revenues. At December 31, 2017, there was $97.6 million remaining in the portion of the Cost Account associated with our interest.

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

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

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

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

Foreign tax credits will expire between the years 2019 and 2025. Foreign tax credits of $4.3 million expired during the year. The alternative minimum tax credits do not expire, and foreign net operating losses ("NOLs") are not subject to expiry dates. The NOL for our United Kingdom subsidiary can be carried forward indefinitely, while the NOLs for our Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues. We plan to liquidate the United Kingdom subsidiary and the Gabon branch which carries the NOL's, and therefore the realization of deferred tax assets for these entities is remote. Accordingly, the related deferred tax assets of $8.7 million and $15.9 million, respectively, were written off during the year with a corresponding offset to the valuation allowance. All of the Company's U.S. federal NOLs were incurred prior to 2018 and will expire between 2035 and 2037. U.S. federal NOLs incurred after 2017 do not expire. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. We do not anticipate utilization of the foreign tax credits prior to expiration and have recorded a full valuation allowance on these deferred tax assets.

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

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

The Company recognizes the financial statement benefit of a tax position only after determining that they are more likely than not to sustain the position following an audit. The Company believes that its income tax positions and deductions will be sustained on audit and therefore no reserves for uncertain tax positions have been established. Accordingly, no interest or penalties have been accrued as of December 31, 2018 and 2017. The Company's policy is to include interest and penalties related to unrecognized tax benefits as a component of income tax expense.

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

(in thousands)	Year Ended December 31, 2018	2017	2016
U.S.	**$ (5,672)**	$ (9,453)	$ (9,893)
Foreign	**61,146**	30,103	874
	$ 55,474	$ 20,650	$ (9,019)

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

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

For the years ended December 31, 2018, 2017 and 2016, we were subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

Jurisdiction	Years
U.S.	2009-2018
Gabon	2014-2018

9. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Extension of Term of Etame Marin Block PSC

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

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

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

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

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

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

Proved Properties

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

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

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

During 2016, our negative price differential to Brent narrowed and we incurred no significant capital spending. We considered these and other factors and determined that there were no events or circumstances triggering an impairment evaluation for most of our fields, with the exception of the Avouma field in the Etame Marine block offshore Gabon where reserves were impacted by temporary shut-ins on certain wells in the field. We evaluated the undiscounted future net cash flows for the Avouma field and determined that they were in excess of the field's carrying value at December 31, 2016. As a result, no impairment was required for the Avouma field, or any of our other fields in Gabon, for 2016.

Undeveloped Leasehold Costs

We have a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that we acquired in 2012 for which we have $10.0 million capitalized in undeveloped acreage. For a number of years, the Block P interest was in suspension; however, in September 2018, the Ministry of Mines and Hydrocarbons ("EG MMH") lifted the suspension. We are awaiting the EG MMH to approve our appointment as technical operator for Block P. Compania Nacional de Petroleos de Guinea Equatorial ("GEPetrol") will act as the administrative operator. Under the terms of lifting of the suspension, a new joint owner is expected to assume GEPetrol's working interest obligations and be presented to the EG MMH by March 28, 2019. Once the joint owner is approved, we are required to drill one exploration well within one year. While there is no monetary penalty for failing to meet the terms of the lifting of the suspension, we would lose our interest in the license, and the associated capitalized unproved leasehold costs of $10.0 million as of December 31, 2018 would become impaired. Our production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

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

Capitalized Equipment Inventory

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

10. DERIVATIVES AND FAIR VALUE

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

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

Put options - During 2016, we executed crude oil put contracts as market conditions allowed in order to economically hedge anticipated 2016 and 2017 cash flows from crude oil producing activities. At December 31, 2017, our crude oil put contracts expired.

While these commodity swaps and crude oil puts are intended to be an economic hedge to mitigate the impact of a decline in oil prices, we have not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. We do not enter into derivative instruments for speculative or trading proposes.

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

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

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

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

11. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

12. COMMITMENTS AND CONTINGENCIES

FPSO charter

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

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

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

The FPSO charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of oil per day. VAALCO's net share of payments was $10.8 million, $12.8 million and $11.2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Other lease obligations

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

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

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

Drilling and other commitments

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

Rig commitment

In 2014, we entered into a long-term contract for the Constellation II drilling rig that was under a long-term contract for the multi-well development drilling campaign offshore Gabon. The campaign included the drilling of development wells and workovers of existing wells in the Etame Marin block. We released the drilling rig in February 2016, prior to the original July 2016 contract termination date, and in June 2016, we reached an agreement with the drilling contractor for us to pay $5.1 million, net to VAALCO's interest for unused rig days under the contract. The expense related to the termination was reported in the "Other operating expense" line item in our consolidated statement of operations for the year ended December 31, 2016.

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC, effective in April 2016, the Consortium is required to provide to the local government refinery a volume of crude at a 15% discount to market price (the "Gabon DMO"). Prior to April 2016, the discount was 25%. The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of oil refined by the refinery per year. In 2018, we paid $1.1 million for our share of the 2017 obligation. In 2017, we paid $1.2 million for our share of the 2016 obligation. In 2016, we paid $1.7 million for our share of the 2015 obligation. We accrue an amount for the Gabon DMO based on management's best estimate of the volume of crude required, because the refinery does not publish throughput figures. The amount accrued at December 31, 2018, for our share of the 2018 obligation was $1.2 million. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.3 million. These costs are cost recoverable under the terms of the Etame PSC. Also, beginning in April 2016, the Consortium is required to pay an additional 1% of revenues for provisions for diversified investments ("PID") and for investments in hydrocarbons ("PIH"). The amount accrued at December 31, 2018, for our share of the 2018 obligation was $1.9 million. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.4 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

Abandonment funding

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

Regulatory and Joint Interest Audits

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

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

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

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

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

Employment agreements

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

13. DEBT

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

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

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

Interest

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

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

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

14. SHAREHOLDERS' EQUITY

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2018 or 2017.

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

15. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

Our stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of our Board of Directors to issue various types of incentive compensation. Currently, we have issued stock options, restricted shares and SARs from the 2014 Long-Term Incentive Plan ("2014 Plan"). At December 31, 2018, 1,112,527 shares were authorized for future grants under this plan.

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

We record non-cash compensation expense related to stock-based compensation as general and administrative expense. For the years ended December 31, 2018, 2017 and 2016, non-cash compensation expense was $2.3 million, $1.1 million and $0.2 million, respectively, related to the issuance of stock options, restricted stock and SARs. Because we do not pay significant U.S. federal income taxes, no amounts were recorded for tax benefits.

Stock options

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors, which in the past has been a five year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. There were $0.5 million and $39 thousand in cash proceeds received from the exercise of stock options in 2018 and 2017, respectively. For 2016, there were no cash proceeds received from the exercise of stock options. During 2018, options for 494,941 shares were granted to employees; these options vest over a three-year period, vesting in three equal parts on the first, second and third anniversaries after the date of grant and have an exercise price of $0.86 per share. Options for 175,644 shares also were granted in 2018 to our non-employee directors, which were fully vested upon their grant and have an exercise price of $1.60 per share.

We use the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the vesting period of the option. During 2018, 2017 and 2016, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because we have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future, no expected dividend yield was input to the Black-Scholes model.

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

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

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

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The intrinsic value of stock options exercised in 2018 and 2017 was $0.6 million and $0.0 million, respectively. There were no exercises of stock options in 2016.

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

As of December 31, 2018, unrecognized compensation cost related to outstanding stock options was $0.2 million, which is expected to be recognized over a weighted average period of 1.1 years.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee which is generally a three-year period, vesting in three equal parts on the first three anniversaries following the date of the grant. Share grants to directors vest immediately and are not restricted. The following is a summary of activity in unvested restricted stock in 2018.

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

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

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

As of December 31, 2018, unrecognized compensation cost related to restricted stock totaled $0.2 million and is expected to be recognized over a weighted average period of 1.2 years.

Stock appreciation rights ("SARs")

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

The 815,355 SARs granted in 2016 vest over a three-year period with a life of 5 years and have a maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. On February 28, 2018, 2,373,411 SARs were granted which vest over a three-year period with a life of 5 years and have a $0.86 SAR price per share specified in a SAR award on the date of grant. On February 28, 2019, 951,699 SARs were granted which vest over a three-year period with a life of 5 years and have a $2.33 SAR price per share specified in a SAR award on the date of grant.

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

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

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

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

Other benefit plans

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

16. SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Our unaudited quarterly results for years ended December 31, 2018 and 2017 were prepared in accordance with GAAP, and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature. Quarterly income per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands of dollars except per share information)			
2018:				
Total revenues	$ 27,645	$ 24,426	$ 25,266	$ 27,606
Total operating costs and expenses	14,631	19,017	7,940	12,433
Operating income	13,038	5,723	17,320	15,206
Income from continuing operations	8,711	887	78,626	10,504
Loss from discontinued operations	(52)	(343)	(21)	(80)
Net income	8,659	544	78,605	10,424
Basic net income per share	$ 0.15	$ 0.02	$ 1.31	$ 0.17
Diluted net income per share	$ 0.15	$ 0.02	$ 1.28	$ 0.17
Basic income from continuing operations per share	$ 0.15	$ 0.02	$ 1.31	$ 0.17

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

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

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

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

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

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

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

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
	2018	2017	2016
Costs incurred during the year:		*(in thousands)*	
International:			
Exploration costs - capitalized	$ —	$ —	$ —
Exploration costs - expensed	**14**	7	5
Acquisition of properties	**36,239**	—	5,754
Development costs	**—**	—	—
Total	**$ 36,253**	$ 7	$ 5,759

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

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

	December 31,	
	2018	2017
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 30,059**	$ 15,668
Properties being amortized [(1)]	**409,487**	389,935
Total capitalized costs	**$ 439,546**	$ 405,603
Less accumulated depletion, amortization and impairment	**(387,868)**	(384,014)
Net capitalized costs	**$ 51,678**	$ 21,589

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

Results of Operations for Oil and Natural Gas Producing Activities

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

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

Estimated Quantities of Proved Reserves

The estimation of net recoverable quantities of crude oil and natural gas is a highly technical process which is based upon several underlying assumptions that are subject to change. See "*Item 1A. Risk Factors*" and "*Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Policies and Estimates – Successful Efforts Method of Accounting for Oil and Natural Gas Activities."* For a discussion of our reserve estimation process, including internal controls, see "*Item 1. Business – Reserve Information*."

Proved reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2016	2,855	1,053
Production	(1,518)	(124)
Purchases of minerals in place	308	—
Sales of minerals in place	(12)	(929)
Revisions of previous estimates	1,009	—
Balance at December 31, 2016	2,642	—
Production	(1,518)	—
Revisions of previous estimates	1,925	—
Balance at December 31, 2017	3,049	—
Production	(1,369)	—
Additions associated with PSC Extension	2,235	—
Revisions of previous estimates	1,455	—
Balance at December 31, 2018	5,370	—

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

Our proved developed reserves are located offshore Gabon. In 2018, we replaced 270% of production by adding a total of 3.7 MMBbls of proved reserves including 2.2 MMBbls of proved reserves additions as a result of extending the Etame PSC in Gabon. We also added 1.1 MMBbls of proved reserves as a result of improved reservoir performance and another 0.4 MMBbls of proved reserves as a result of higher oil pricing. The upward revision of the previous estimates in 2017 was primarily a result of improved well performance and to a lesser degree the higher average crude oil prices. Reserves in 2018 also increased as a result of the PSC Extension. In 2016, reserves increased as a result of estimated proved reserve quantities related to our acquisition of the Sojitz working interest in Etame Marin block (308 MBbls) as well as upward revisions to our estimated proved reserve quantities as a result of cost cutting efforts that had the impact of driving down operating cost projections and extending economic limits, demonstration of the effectiveness of deploying lower cost hydraulic workover units to conduct workovers during 2016 and success in production optimization produced better-than-forecasted results from the prior year's development program (1,575 MBbls).

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

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

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

In accordance with the guidelines of the SEC, our estimates of future net cash flow from our properties and the present value thereof are made using oil and natural gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other Consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. However, all future costs related to future property abandonment when the wells become uneconomic to produce are included in future development costs for purposes of calculating the standardized measure of discounted net cash flows. There were no discounted future net cash flows attributable to U.S. properties as of December 31, 2018, 2017 and 2016.

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

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

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

Changes in Standardized Measure of Discounted Future Net Cash Flows

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

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

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

In accordance with the current guidelines of the SEC, estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2018, the average of such prices reflected a 32% increase during the year and were $70.83 per Bbl for crude oil from Gabon when compared to the average of such prices for 2017 of $53.49 per Bbl for crude oil from Gabon.

Under the Etame PSC in Gabon, the Gabonese government is the owner of all oil and natural gas mineral rights. The right to produce the oil and natural gas is stewarded by the Directorate Generale de Hydrocarbures and the Etame PSC was awarded by a decree from . Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the Etame PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, we were authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for Profit Oil (see discussion in Note 7 above).

The Consortium maintains a Cost Account, which entitles it to receive a portion of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). Prior to the PSC Extension, the Consortium was entitled to a 70% Cost Recovery Percentage. Under the PSC Extension, the Cost Recovery Percentage is increased to 80% for the ten-year period from September 17, 2018 through September 16, 2028. After September 16, 2028, the Cost Recovery Percentage returns to 70%. At December 31, 2018, there was $65.5 million in the Cost Account, net to our interest. As payment of corporate income taxes, the Consortium pays the government an allocation of the remaining Profit Oil production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of Profit Oil paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, we only recover ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also because of the nature of the Cost Account, decreases in oil prices result in a higher number of barrels required to recover costs.

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

The PSC for Block P in Equatorial Guinea entitles us to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The Consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 10% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2018, we have no proved reserves related to Block P in Equatorial Guinea.

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Accounts for year ended December 31, 2017

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. (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

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(in thousands)	
ASSETS		
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.

VAALCO 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

VAALCO 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	—	—	—	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	—	—	—	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	—	—	—	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 our activities in Angola, West Africa.

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

2. LIQUIDITY

Our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on 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 basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentation related to 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 classified as 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.

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

Impairment – We review our oil and natural gas producing properties for impairment on a field-by-field 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. We report interest related to income tax liabilities in 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	**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 includes 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	Level 2	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:

Derivative Item	Statement of Operations Line	Year Ended December 31, 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 a three-year period with a life of 5 years and have a maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. 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 be 21%. 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 of its 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:

	Year Ended December 31,		
(in thousands)	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 operations to income tax on income (loss) from continuing operations at the U.S. statutory rate is as follows:

	Year Ended December 31,		
(in thousands)	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, and we assume the issuance of shares from the exercise of stock options using the treasury stock method.

A reconciliation from basic to diluted shares follows:

	Year Ended December 31,		
	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 discovery indicating that the development well will be drilled within five years from the date of its initial booking. Additionally, the development plan is required to have the approval of our 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 produce are 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 the U.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 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 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.

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Accounts for year ended December 31, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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

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

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

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

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

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

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

/s/ BDO USA, LLP

Houston, Texas
March 13, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited, before the effects of the retrospective adjustments for the discontinued operations as discussed in Note 5 to the consolidated financial statements, the consolidated balance sheet of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2015, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the years ended December 31, 2015 and 2014 (the 2015 and 2014 consolidated financial statements before the effects of the retrospective adjustments discussed in Note 5 to the consolidated financial statements are not presented herein). Our audit also includes the financial statement schedule listed in the index at item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such 2015 and 2014 consolidated financial statements, before the effects of the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements, present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2015, and the results of their operations and their cash flows for the years ended December 31, 2015 and 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic 2015 and 2014 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

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

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 16, 2016

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

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

See notes to consolidated financial statements.

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

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

See notes to consolidated financial statements

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

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

See notes to consolidated financial statements.

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

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

See notes to consolidated financial statements.

1. ORGANIZATION

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

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

2. LIQUIDITY

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

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

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

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

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

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

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

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

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

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

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

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

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

The table provides a rollforward of the aggregate allowance:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> Level 1 – Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).
>
> Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).
>
> Level 3 – Inputs that are not observable from objective sources, such as internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in our internally developed present value of future cash flows model that underlies the fair-value measurement).

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

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

4. NEW ACCOUNTING STANDARDS

Not Yet Adopted

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

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15") related to how certain cash receipts and payments are presented and classified in the statement of cash flows. These cash flow issues include debt prepayment or extinguishment costs, settlement of zero-coupon debt, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, beneficial interests in securitization transactions, and separately identifiable cash flows. ASU 201(effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. We are currently evaluating the provisions of this guidance and are assessing its potential impact on our cash flows and related disclosures. Due to the nature of this accounting standards update, this may have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

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

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

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

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

Adopted

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

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

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

5. ACQUISITIONS AND DISPOSITIONS

Sojitz Acquisition

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

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

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

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

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

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

Sale of Certain U.S. Properties

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

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. The four year primary term, with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and our partner to drill two additional exploration wells. Our working interest is 40% and we carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P, our joint venture partner, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have taken actions to begin closing our office in Angola and do not intend to conduct futu activities in Angola. As a result of this strategic shift, we classified all the related assets and liabilities as those of discontinued operations in the consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in our consolidated statements of operations. We segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in our consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment's operations as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

Summarized Results of Discontinued Operations

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

Assets and Liabilities Attributable to Discontinued Operations

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

Drilling Obligation

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

Other Matters – Partner Receivable

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

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

6. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Proved Properties

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

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

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

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

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

Undeveloped Leasehold Costs

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

Capitalized Exploratory Well Costs

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

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

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

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

Capitalized Equipment Inventory

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

7. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

8. DEBT

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

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

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

Covenants

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

Interest

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

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

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

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

9. COMMITMENTS AND CONTINGENCIES

Litigation

Butcher settlement

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

McDonough litigation

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

FPSO charter

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

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

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

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

Other lease obligations

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

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

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

Rig commitment

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

Gabon domestic market obligation and other investment obligations

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

Abandonment funding

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

Audits

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

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

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

Employment agreements

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

10. DERIVATIVES AND FAIR VALUE

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

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

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

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

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

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

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

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

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

11. SHAREHOLDERS' EQUITY (DEFICIT)

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

12. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

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

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

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

Stock options

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

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

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

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

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

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

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

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee which is generally a three-year period, vesting in three equal parts on the first three anniversaries of the date of the grant. Share grants to directors vest immediately and are not restricted. The following is a summary of activity in unvested restricted stock in 2016.

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

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

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

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

Stock appreciation rights ("SARs")

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

The 815,355 SARs granted in the three months ended March 31, 2016 vest over a three-year period with a life of 5 years and hav maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. Compensation payable related to these awards through December 31, 2016 is not significant.

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

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

Other benefit plans

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

13. INCOME TAXES

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

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

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

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

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

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

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

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

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

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

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

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

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

Jurisdiction	**Years**
United States	2009-2016
Gabon	2007-2016

14. EARNINGS PER SHARE

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

A reconciliation from basic to diluted shares follows:

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

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

15. SEGMENT INFORMATION

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

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

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

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

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

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

Information about our most significant customers

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

SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

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

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

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

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

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

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

Costs Incurred for Acquisition, Exploration and Development Activities

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

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

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

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

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

Results of Operations for Oil and Natural Gas Producing Activities

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

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

Estimated Quantities of Proved Reserves

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

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

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

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

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

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

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

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

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

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

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

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

Changes in Standardized Measure of Discounted Future Net Cash Flows

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

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

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

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

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

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

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

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

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

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