SAVANNAH ENERGY


SAVANNAH ENERGY PLC

# ADMISSION DOCUMENT

DECEMBER 2021

STRAND HANSON

Nominated &
Financial Adviser
**Strand Hanson Limited**

Panmure Gordon AND COMPANY

Joint broker
**Panmure Gordon (UK) Limited**

finnCap

Joint broker
**finnCap Ltd**

**THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to what action you should take, you should seek your own personal advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who specialises in advising on the acquisition of shares and other securities and is authorised under the Financial Services and Markets Act 2000 (as amended) ("FSMA") if you are resident in the UK, or, if you are not resident in the UK, from another authorised independent adviser.**

**This document does not comprise a prospectus within the meaning of section 85 of FSMA and does not constitute an offer of transferable securities to the public in the United Kingdom, within the meaning of section 102B of FSMA, and has not been approved or examined by and will not be filed with the United Kingdom Financial Conduct Authority, the London Stock Exchange plc (the "London Stock Exchange") or the United Kingdom Listing Authority ("UKLA"), but comprises an admission document in relation to AIM, a market operated by the London Stock Exchange ("AIM"). This document has been drawn up in accordance with the AIM Rules for Companies (the "AIM Rules") and has been issued in connection with an application for admission to trading on AIM of the entire issued and to be issued share capital of Savannah Energy PLC (the "Company"). The Company and its directors (together, the "Directors"), whose names appear on page 12 of this document, accept responsibility, collectively and individually, for the information contained in this document and for compliance with the AIM Rules. To the best of the knowledge and belief of the Company and the Directors, who have taken all reasonable care to ensure that such is the case, the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. To the extent that information has been sourced from a third party, this information has been accurately reproduced and, as far as the Directors are aware, no facts have been omitted which may render the reproduced information inaccurate or misleading. In connection with this document, no person is authorised to give any information or make any representation other than as set out in this document.**

**The Company's entire existing issued share capital (the "Existing Ordinary Shares") are admitted to trading on AIM. Application will be made to the London Stock Exchange for the Existing Ordinary Shares, the new ordinary shares being placed and the new ordinary shares being subscribed for (together, the "Enlarged Share Capital") and the new ordinary shares being issued to the employee benefit trust (together, the "Further Enlarged Share Capital") to be readmitted to trading on AIM following the Company's proposed acquisition of one or both of ExxonMobil's and PETRONAS'S entire upstream and midstream asset portfolio in Chad ("Re-Admission"). It is expected that trading in the Existing Share Capital will recommence on 31 December 2021 and that Re-Admission will become effective during or around June 2022. The Further Enlarged Share Capital is not dealt in on any market other than, from Re-Admission, AIM and, apart from the application for Re-Admission, no application has been or is intended to be made for the Further Enlarged Share Capital to be admitted to trading on any such other market.**

**AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UKLA (the "Official List") and the AIM Rules are less demanding than those regulations applicable to companies on the Official List. It is emphasised that no application is being made for admission of the Further Enlarged Share Capital to trading on the Official List. A prospective investor should be aware of the risks of investing in AIM companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser.**

**Each AIM company is required pursuant to the AIM Rules to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Re-Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this document.**

**THE WHOLE OF THE TEXT OF THIS DOCUMENT SHOULD BE READ AND IN PARTICULAR YOUR ATTENTION IS DRAWN TO THE SECTION ENTITLED "RISK FACTORS" SET OUT IN PART 3 OF THIS DOCUMENT THAT DESCRIBES CERTAIN RISKS ASSOCIATED WITH AN INVESTMENT IN THE COMPANY.**

# SAVANNAH ENERGY PLC

*(incorporated in England and Wales under the Company's Act 2006 with registered number 09115262)*

## PROPOSED ACQUISITION OF EXXONMOBIL'S AND PETRONAS'S ENTIRE UPSTREAM AND MIDSTREAM ASSET PORTFOLIO IN CHAD AND CAMEROON

## PLACING AND SUBSCRIPTION OF 251,623,456 NEW ORDINARY SHARES AT 19.35 PENCE PER SHARE

## NOTICE OF GENERAL MEETING

## RE-ADMISSION OF THE FURTHER ENLARGED SHARE CAPITAL TO TRADING ON AIM FOLLOWING SATISFACTION OF CONDITIONS PRECEDENT

STRAND HANSON

finnCap

Panmure Gordon AND COMPANY

| ***Financial & Nominated Adviser*** | ***Joint Broker*** | ***Joint Broker*** |
|---|---|---|
| **Strand Hanson Limited** | **finnCap Ltd** | **Panmure Gordon (UK) Limited** |

Strand Hanson Limited ("Strand Hanson"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as financial and nominated adviser to the Company in connection with Re-Admission. Its responsibility as the Company's nominated adviser under the AIM Rules for Nominated Advisers is owed solely to the London Stock Exchange and is not owed to the Company or to any Director or to any other person in respect of their decision to acquire shares in the Company in reliance on any part of this document. Strand Hanson is acting exclusively for the Company and for no one else 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 the contents of this document or Re-Admission.

finnCap Ltd ("finnCap"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Joint Broker to the Company in connection with Re-Admission. finnCap is acting exclusively for the Company and for no one else 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 the contents of this document or Re-Admission.

Panmure Gordon (UK) Limited ("Panmure"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Joint Broker to the Company in connection with Re-Admission. Panmure is acting exclusively for the Company and for no one else 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 the contents of this document or Re-Admission.

None of Strand Hanson, finnCap or Panmure have authorised the contents of this document and no representation or warranty, express or implied, is made by any of Strand Hanson, finnCap or Panmure as to the accuracy or contents of this document or the opinions contained herein, without limiting the statutory rights of any person to whom this document is issued. The information contained in this document is not intended to inform or be relied upon by any subsequent purchasers of any ordinary shares in the capital of the Company ("Ordinary Shares") (whether on or off exchange) and accordingly no duty of care is accepted by Strand Hanson, finnCap or Panmure in relation to them. No person has been authorised to give any information or make any representations other than those contained in this document and, if given or made, such information or representations must not be relied upon as having been so authorised. The delivery of this document will not, under any circumstances, be deemed to create any implication that there has been no change in the affairs of the Company since the date of this document or that the information in this document is correct at any time subsequent to its date.

No legal, business, tax or other advice is provided in this document. Prospective investors should consult their professional advisers as needed on the potential consequences of subscribing for, purchasing, holding or selling Ordinary Shares under the laws of their country and/or state of citizenship, domicile or residence.

This document does not constitute an offer to sell, or a solicitation to buy, Ordinary Shares in any jurisdiction in which such offer or solicitation is unlawful. The distribution of this document in certain jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe such restrictions. Any such distribution could result in a violation of the laws of such jurisdictions. In particular, subject to certain exceptions, this document is not for distribution into Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan, or any other jurisdiction where to do so would be in breach of any applicable laws and/or regulations. The Ordinary Shares have not been, nor will they be, registered under the securities legislation of any province or territory of Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan. Accordingly, the Ordinary Shares may not, subject to certain exemptions, be offered, sold, re-sold, renounced, taken up or delivered, directly or indirectly, into Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan, or to any national, citizen or resident of Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan. No action has been taken by the Company, the holders of Ordinary Shares, or by Strand Hanson, finnCap or Panmure that would permit a public offer of Ordinary Shares or possession or distribution of this document where action for that purpose is required.

Investors should only rely on the information in this document and any additional supplementary Admission Document produced to supplement the information contained in this document. No person has been authorised to give any information or to make any representations other than as contained in this document in connection with Re-Admission and, if given or made, such information and representations must not be relied upon as having been authorised by or on behalf of the Company. The contents of the websites of the Group (and/or any of its affiliates) or any website directly or indirectly linked to such websites do not form part of this document and investors should not rely on them.

Copies of this document and any supplementary Admission Document will be available free of charge during normal business hours on weekdays (excluding Saturdays, Sundays and public holidays) from the date hereof until one month after Re-Admission from the offices of Computershare Investor Services plc at the Pavilions, Bridgwater Road, Bristol, BS13 8AE and from the Company's website: www.savannah-energy.com.

Your attention is also drawn to the letter from the Chair on pages 34 to 63 (inclusive) of this document and which recommends you vote in favour of the Resolutions to be proposed at the General Meeting. All statements regarding the business of the Enlarged Group, its financial position and prospects should be reviewed in light of the risk factors set out in the section headed "Risk Factors" in Part 3 of this document.

**Forward-looking statements**

This document contains forward looking statements relating to the Company's future prospects, developments and strategies, which have been made after due and careful enquiry and are based on the Directors' current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in such statements. Forward-looking statements are or may be, without limitation, identified by the use of terms and phrases such as "believe", "could", "envisage", "estimate", "intend", "may", "plan", "will" or the negative of those, variations or comparable expressions, including references to assumptions. These forward-looking statements are subject to, *inter alia*, the risk factors described in Part 3 of this document. The Directors believe that the expectations reflected in these statements are reasonable, but may be affected by a number of variables which could cause actual results or trends to differ materially. Each forward-looking statement speaks only as of the date of the particular statement.

## IMPORTANT INFORMATION

### General

This document should be read in its entirety before making any decision to subscribe for Ordinary Shares. Prospective investors should rely only on the information contained in this document. No person has been authorised to give any information or make any representations other than as contained in this document and, if given or made, such information or representations must not be relied on as having been authorised by the Company, the Nominated Adviser or the Brokers or any of their respective affiliates, officers, directors, partners, employees or agents. Without prejudice to the Company's obligations under applicable laws and the AIM Rules for Companies, neither the delivery of this document nor any subscription or purchase made under this document shall, under any circumstances, create any implication that there has been no change in the affairs of the Company or the Existing Group since the date of this document or that the information contained herein is correct as at any time subsequent to its date.

Prospective investors in the Company must not treat the contents of this document or any subsequent communications from the Company, the Nominated Adviser or the Brokers or any of their respective affiliates, officers, directors, partners, employees or agents as advice relating to legal, taxation, accounting, regulatory, investment or any other matters.

If you are in any doubt about the contents of this document or the action you should take, you should immediately seek your own personal financial advice from your stockbroker, bank manager, solicitor, accountant or other independent adviser who is authorised under the FSMA if you are in the UK, or, if you are outside the UK, from another appropriately authorised independent adviser.

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 or any other person regarding the Proposals or the Enlarged Group. The Company makes no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication.

As required by the AIM Rules for Companies, the Company will update the information provided in this document by means of a supplement to it if a significant new factor that may affect the evaluation of the Placing by prospective investors occurs prior to Admission or if it is noted that this document contains any mistake or substantial inaccuracy. This document and any supplement thereto will be made public in accordance with the AIM Rules for Companies.

This document is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation, by the Company, the Nominated Adviser or the Brokers or any of their respective representatives, that any recipient of this document should subscribe for or purchase any of the Ordinary Shares. Prior to making any decision as to whether to subscribe for or purchase any Ordinary Shares, prospective investors should read the entirety of this document and, in particular, the section headed "Risk Factors" in Part 3 of this document.

Investors should ensure that they read the whole of this document 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 (or an examination by the prospective investor's FSMA-authorised or other appropriate advisers) of the Company and the terms of this document, including the risks involved. Any decision to purchase Ordinary Shares should be based solely on this document and the prospective investor's own (or such prospective investor's FSMA-authorised or other appropriate advisers') examination of the Company.

Investors who subscribe for Placing Shares in the Placing will be deemed to have acknowledged that: (i) they have not relied on the Nominated Adviser or the Brokers or any person affiliated with them in connection with any investigation of the accuracy of any information contained in this document for their investment decision; (ii) they have relied only on the information contained in this document; and (iii) no person has been authorised to give any information or to make any representation concerning the Company or the Ordinary Shares (other than as contained in this document) and, if given or made, any such other information or representation has not been relied upon as having been authorised by or on behalf of the Company, the Directors, the Nominated Adviser or the Brokers.

None of the Company, the Directors, the Nominated Adviser or the Brokers or any of their respective representatives makes any representation to any subscriber or purchaser of Ordinary Shares regarding the legality of an investment by such subscriber or purchaser.

In connection with the Placing, the Brokers and any of their affiliates, acting as investors for their own accounts, may acquire Ordinary Shares, and in that capacity may retain, purchase, sell, offer to sell or otherwise deal for their own accounts in such Ordinary Shares and other securities of the Company or related investments in connection with the Placing or otherwise. Accordingly, references in this document to the Ordinary Shares being offered, subscribed, purchased, acquired, placed or otherwise dealt with v should be read as including any offer to, or subscription, purchase, acquisition, dealing or placing by the Brokers or any of their affiliates acting as investors for their own accounts. The Brokers do not intend to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligation to do so.

The Brokers and the Nominated Adviser and any of their affiliates may have engaged in transactions with, and provided various investment banking, financial advisory or other services to, the Company, for which they would have received customary fees. The Brokers and the Nominated Adviser and any of their affiliates may provide such services to the Company and any of its affiliates in the future.

**Notice to prospective investors in the UK**

This document is being distributed in the UK where it is directed only at persons who are "qualified investors" within the meaning of Article 2(e) of the UK Prospectus Regulation, and who are: (i) persons having professional experience in matters relating to investments, i.e., investment professionals within the meaning of Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "FPO"); or (ii) high net-worth companies, unincorporated associations and other bodies within the meaning of Article 49 of the FPO; and (iii) at persons to whom it is otherwise lawful to distribute it without any obligation to issue a prospectus approved by competent regulators. The investment or investment activity to which this document relates is available only to such persons. It is not intended that this document be distributed or passed on, directly or indirectly, to any other class of person and in any event, and under no circumstances, should persons of any other description rely on or act upon the contents of this document.

None of the Company, the Nominated Adviser or the Brokers has authorised, nor does any of them authorise, the making of any offer of Ordinary Shares in circumstances in which an obligation arises for the Company, the Nominated Adviser or the Joint Brokers to publish a prospectus or a supplemental prospectus in the United Kingdom in respect of such offer.

This document has not been approved by any person for the purposes of section 21 of FSMA.

**Notice to prospective investors in the European Economic Area**

In relation to each Member State of the European Economic Area ("EEA") (each a "Member State"), no Ordinary Shares have been offered or will be offered pursuant to the Placing to the public in that Member State prior to the publication of a prospectus which has been approved by the competent authority in that Member State, or otherwise in accordance with the Prospectus Regulation, except that offers of Ordinary Shares to the public may be made at any time under the following exemptions under the Prospectus Regulation:

(1) to any legal entity which is a "qualified investor" as defined in the Prospectus Regulation;

(2) to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Regulation) in such Member State; or

(3) in any other circumstances falling within Article 1(4) of the Prospectus Regulation,

provided that no such offer of Ordinary Shares shall require the Company or any other person to publish a prospectus pursuant to Article 21 of the Prospectus Regulation or supplementary prospectus pursuant to 4 Article 23 of the Prospectus Regulation and each person who initially acquires any Ordinary Shares (other than any Retail Offeree) or to whom any offer is made under the Placing will be deemed to have represented, acknowledged and agreed that it is a qualified investor within the meaning of the Prospectus Regulation.

Neither the Company, the Nominated Adviser nor the Brokers have authorised, nor does any of them authorise, the making of any offer of Ordinary Shares in circumstances in which an obligation arises for the Company to publish a prospectus or a supplemental prospectus in respect of such offer. In the case of any Ordinary Shares being offered to a financial intermediary as that term is used in Article 5(1) of the Prospectus Regulation, each such financial intermediary will be deemed to have represented, acknowledged and agreed to and with the Company, the Directors and the Brokers that the Ordinary Shares acquired by it have not been acquired on a non-discretionary basis on behalf of, nor have they been acquired with a view to their offer or resale to, persons in circumstances which may give rise to an offer to the public other than their offer or resale in a Relevant State to qualified investors, in circumstances in which the prior consent of the Brokers has been obtained to each such proposed offer or resale.

The Company, the Directors, the Nominated Adviser and the Brokers will rely upon the truth and accuracy of the foregoing representations, acknowledgements and agreements. For the purposes of this provision, the expression “an offer to the public” in relation to any offer of Ordinary Shares in any Member State means a communication in any form and by any means presenting sufficient information on the terms of the offer and any Ordinary Shares to be offered so as to enable an investor to decide to purchase or subscribe for the Ordinary Shares, and the expression “Prospectus Regulation” means Regulation 2017/1129/EU.

**Notice to prospective investors in the United States**

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this document is truthful or complete. Any representation to the contrary is a criminal offence.

The securities have not been and will not be registered under the U.S. Securities Act of 1933, as amended. The securities are subject to restrictions on transferability and resale and may not be transferred or resold, except as permitted under the Securities Act pursuant to registration or an exemption therefrom.

**Available information**

For so long as any the Company’s securities are “restricted securities” within the meaning of Rule 144(a)(3) under the U.S. Securities Act of 1933, as amended, the Company will, during any period in which it is not subject to Section 13 or 15(d) under the U.S. Securities Exchange Act of 1934, as amended, nor exempt from reporting under the Exchange Act pursuant to Rule 12g3-2(b) thereunder, make available to any holder or beneficial owner of such restricted securities, or to any prospective purchaser of such restricted securities designated by such holder or beneficial owner, upon request the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

**Enforceability of civil liabilities**

The Company is a public limited company incorporated under the laws of England and Wales. None of the Company’s directors or officers are citizens or residents of the United States. In addition, the majority of the Company’s assets and all the assets of the Company’s directors and officers are located outside the United States. As a result, it may not be possible for U.S. investors to effect service of process within the United States upon the Company or its directors and officers located outside the United States or to enforce in the U.S. courts or outside the United States judgments obtained against them in U.S. courts or in courts outside the United States, including judgments predicated upon the civil liability provisions of the U.S. federal securities laws or the securities laws of any state or territory within the United States. There is doubt as to the enforceability in England and Wales, whether by original actions or by seeking to enforce judgments of U.S. courts, of claims based on the federal securities laws of the United States. In addition, punitive damages in actions brought in the United States or elsewhere may be unenforceable in England and Wales.

**Forward-looking statements**

Certain statements in this document are or may constitute forward-looking statements, including statements about current beliefs and expectations of the Directors. In particular, the words “envisage”, “projects”, “expect”, “anticipate”, “estimate”, “may”, “should”, “plan”, “intend”, “will”, “would”, “could”, “target”, “believe” and similar expressions (or in each case their negative and other variations or comparable terminology) can be used to identify forward looking statements. Such forward looking statements relate to matters that are not historical facts. They appear in a number of places throughout this document and include statements regarding the Board's expectations of external conditions and events, current business strategy, plans and the other objectives of management for future operations and estimates and projections of the Enlarged Group's financial performance. Though the Board believes these expectations to be reasonable at the date of this document, they may prove to be erroneous. Forward looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, achievements or performance of the Enlarged Group, or the industry in which the Enlarged Group operates, to be materially different from any future results, achievements or performance expressed or implied by such forward looking statements. Prospective investors are strongly recommended to read the risk factors set out in Part 3 of this document.

Any forward-looking statement in this document speaks only as of the date it is made. Save as required by law or regulation or the AIM Rules for Companies, the Company undertakes no obligation to publicly release the results of any revisions to any forward looking statements in this document that may occur due to any change in the Board's expectations or in order to reflect events or circumstances after the date of this document. Any forward looking statement in this document based on past or current trends and/or activities of the Enlarged Group should not be taken as a representation or assurance that such trends or activities will continue in the future. No statement in this document is intended to be a profit forecast or to imply that the earnings of the Enlarged Group for the current year or future years will match or exceed the historical or published earnings of the Enlarged Group.

**Rounding**

The financial information and certain other figures in this document have been subject to rounding adjustments. Therefore, the sum of numbers in a table (or otherwise) may not conform exactly to the total figure given for that table. In addition, certain percentages presented in this document reflect calculations based on the underlying information prior to rounding and accordingly may not conform exactly to the percentages that would be derived if the relevant calculations were based on the rounded numbers.

**Currency presentation**

In the document, references to "sterling", "£", "penny", "pence" and "p" are to the lawful currency of the UK, references to "€" and "euros" are to the lawful currency of certain of the countries within the EU and references to "US$" are references to the lawful currency of the United States. Unless otherwise indicated, the financial information contained in this document has been expressed in US$. The Existing Group presents its financial statements in US$.

**Market, industry and economic data**

The data, statistics and information and other statements in this document regarding the markets in which the Enlarged Group operates, or the Enlarged Group's position therein, are based on the Enlarged Group's records. In relation to these sources, such information has been accurately reproduced from the published information and, so far as the Directors are aware and are able to ascertain from the information provided by the suppliers of these sources, no facts have been omitted which would render such information inaccurate or misleading.

**No incorporation of website information**

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

**Interpretation**

Certain terms used in this document are defined and certain technical and other terms used in this document are explained at the section of this document under the heading "Definitions".

All times referred to in this document are, unless otherwise stated, references to London time.

All references to legislation in this document are to the legislation of England and Wales unless the contrary is indicated. Any reference to any provision of any legislation or regulation shall include any amendment, modification, re-enactment or extension thereof.

Words importing the singular shall include the plural and vice versa, and words importing the masculine gender shall include the feminine or neutral gender.

**Information to Distributors UK Product Governance Requirements**

Solely for the purposes of Paragraph 3.2.7R regarding the responsibilities of UK Manufacturers under the Product Governance requirements contained within Chapter 3 of the FCA Handbook Product Intervention and Product Governance Sourcebook (the "UK Product Governance Requirements") and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the UK Product Governance Requirements) may otherwise have with respect thereto, the Ordinary Shares have been subject to a product approval process, which has determined that the Ordinary Shares are: (i) compatible with an end target market of (a) retail investors, (b) investors who meet the criteria of professional clients and (c) eligible counterparties, each as defined in UK Product Governance Requirements; and (ii) eligible for distribution through all distribution channels as are permitted by UK Product Governance Requirements (the "UK Target Market Assessment"). Notwithstanding the UK Target Market Assessment, distributors should note that: the price of the Ordinary Shares may decline and investors could lose all or part of their investment; the Ordinary Shares offer no guaranteed income and no capital protection; and an investment in the Ordinary Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom.

The UK Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Placing.

For the avoidance of doubt, the UK Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to, the Ordinary Shares.

Each distributor is responsible for undertaking its own target market assessment in respect of the Ordinary Shares and determining appropriate distribution channels.

**EU Product Governance Requirements**

Solely for the purposes of the product governance requirements contained within MiFID II and Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II (the "EU Product Governance Requirements") and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the EU Product Governance Requirements) may otherwise have with respect thereto, the Ordinary Shares have been subject to product approval process, which has determined that the Ordinary Shares are: (i) compatible with an end target market of (a) retail investors, (b) investors who meet the criteria of professional clients and (c) eligible counterparties, each as defined in EU Product Governance Requirements; and (ii) eligible for distribution through all distribution channels as are permitted by EU Product Governance Requirements (the "EU Target Market Assessment"). Notwithstanding the EU Target Market Assessment, distributors should note that: the price of the Ordinary Shares may decline and investors could lose all or part of their investment; the Ordinary Shares offer no guaranteed income and no capital protection; and an investment in the Ordinary Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom.

The EU Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Placing.

Furthermore, it is noted that, notwithstanding the UK Target Market Assessment and the EU Target Market Assessment, the Brokers will only procure investors who meet the criteria of professional clients and eligible counterparties. For the avoidance of doubt, the EU Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Ordinary Shares. Each distributor is responsible for undertaking its own target market assessment in respect of the Ordinary Shares and determining appropriate distribution channels.

**CONTENTS**

## EXPECTED TIMETABLE OF PRINCIPAL EVENTS

| | |
|---|---|
| Publication of this document | 30 December 2021 |
| Restoration becomes effective and dealings in the Existing Ordinary Shares recommence on AIM[(1)] | 8.00 a.m. on 31 December 2021 |
| Placing Shares and Subscription Shares to be admitted to trading on AIM | 8.00 a.m. on 7 January 2022 |
| CREST accounts expected to be credited in respect of the Placing Shares and Subscription Shares | 7 January 2022 |
| Definitive share certificates expected to be despatched in respect of the Placing Shares and Subscription Shares (where applicable) | by 21 January 2022 |
| Expected latest time and date for receipt of Forms of Proxy | 10.30 a.m. on 20 January 2022 |
| Expected General Meeting date | 24 January 2022 |
| Ministerial Consent for the PETRONAS Acquisition expected by[(2)] | March 2022 |
| Ministerial Consent for the Exxon Acquisition expected by[(2)] | March 2022 |
| Merger approval from the CEMAC Council for Competition for the PETRONAS Acquisition expected by[(2)] | June 2022 |
| Completion of the PETRONAS Acquisition[(2)] | June 2022 |
| Completion of the Exxon Acquisition[(2)] | June 2022 |
| Re-Admission becomes effective and dealings in the Further Enlarged Share Capital expected to recommence on AIM[(2,3)] | June 2022 |

*Notes:*

(1) Restoration of the Existing Share Capital to trading on AIM will be sought by the Company following publication of this Admission Document, without the Completion of the Exxon Acquisition or the PETRONAS Acquisition.

(2) Indicative dates based on the Directors' best estimate of when these events will occur, and therefore there is no certainty these dates will not change.

(3) Re-Admission of the Further Enlarged Share Capital will become effective on Completion of the Exxon Acquisition and/or the PETRONAS Acquisition, which may occur in a single re-admission or in two stages (one post-Completion of each acquisition) or not at all, subject to, *inter alia*, the timetable for both acquisitions. The Company will advise how and when Re-Admission will occur as and when it is known.

References to times above are to London time unless otherwise stated. Each of the times and dates set out in the timetable above and mentioned throughout this document may be adjusted at the absolute discretion of the Company, Strand Hanson and the Joint Brokers. In the event of a change, the Company will make an appropriate announcement to a Regulatory Information Service giving details of any revised dates and details of the new times. Shareholders may not receive any further written communication.

## PLACING STATISTICS AND DEALING CODES

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| Number of Existing Ordinary Shares in issue at the date of this document | 996,408,412 |
| Closing mid-market price on the Last Practicable Date(1) | 19.35 pence |
| Market capitalisation as at the Last Practicable Date | £192.8 million |
| Placing Price | 19.35 pence |
| Number of Placing Shares to be issued by the Company | 237,276,474 |
| Number of Subscription Shares to be issued by the Company | 14,346,982 |
| Gross Proceeds of the Placing and Subscription | £48.7 million |
| Enlarged Share Capital | 1,248,031,868 |
| Market capitalisation following admission of the Placing Shares and Subscription Shares at the Placing Price | £241.5 million |
| Percentage of the Enlarged Share Capital represented by the Placing Shares and the Subscription Shares | 20.2 per cent. |
| Percentage of the Enlarged Share Capital held by the Directors | 4.6 per cent. |
| Percentage of the Enlarged Share Capital not in public hands (as defined by the AIM Rules) | 8.0 per cent. |
| Number of EBT Shares to be issued to the EBT(2) | 58,066,951 |
| Further Enlarged Share Capital (on admission to trading on AIM of the EBT Shares(2)) | 1,306,098,819 |
| Expected percentage of the Further Enlarged Share Capital not in public hands (as defined by the AIM Rules) | 12.1 per cent. |
| Number of new Ordinary Shares issuable by full exercise of Warrants | 101,113,992 |
| Number of new Ordinary Shares issuable by full exercise of Warrants as a percentage of the Further Enlarged Share Capital(2) | 7.7 per cent. |
| ISIN for the Ordinary Shares | GB00BP41S218 |
| SEDOL for the Ordinary Shares | BP41S21 |
| Trading symbol for the Ordinary Shares on AIM | SAVE |
| Legal Entity Identifier | 2138002YCJORSFH5YR43 |

(1) Being the mid-market price on suspension from trading on AIM of the Company's Ordinary Shares, following its announcement of the Exxon Acquisition on 2 June 2021.

(2) The EBT Shares are expected to be admitted to trading on AIM following the General Meeting, subject to, *inter alia*, passing of the relevant Resolutions.

## EXCHANGE RATES

The US$:GBP exchange rate used in this document is US$1.335:£1.000.

## DIRECTORS, SECRETARY AND ADVISERS

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| **Directors** | Steve Jenkins – *Non-Executive Chair*<br>Sir Stephen O'Brien – *Non-Executive Vice Chair*<br>Andrew Knott – *Chief Executive Officer*<br>David Clarkson – *Non-Executive Director*<br>Mark Iannotti – *Non-Executive Director*<br>David Jamison – *Non-Executive Director* |
| **Company secretary** | Nick Beattie |
| **Company's registered office** | 40 Bank Street<br>London E14 5NR |
| **Company's registered number** | 09115262 |
| **Financial & Nominated Adviser** | Strand Hanson Limited<br>26 Mount Row<br>London W1K 3SQ |
| **Brokers** | finnCap Ltd<br>One Bartholomew Close<br>London EC1A 7BL |
| | Panmure Gordon (UK) Limited<br>One New Change<br>London EC4M 9AF |
| **Solicitors to the Company as to UK law** | Burness Paull LLP<br>50 Lothian Road<br>Festival Square<br>Edinburgh EH3 9WJ |
| | Bracewell (UK) LLP<br>Tower 42<br>25 Old Broad Street<br>London EC2N 1HQ |
| **Solicitors to the Company as to Chad, Cameroon and Nigerien law** | EY Cameroon<br>1602 Bd de La Liberté<br>Akwa, Douala<br>Cameroon |
| **Solicitors to the Company as to Nigerian law** | The Law Crest LLP<br>Plot 98 Adeola Odeku Street<br>Victoria Island<br>Lagos, Lagos State<br>Nigeria |
| **Solicitors to the Company as to French law** | Fierville Ziadé<br>66 Av. Kléber<br>75116 Paris<br>France |
| **Solicitors to the Nominated Adviser and Joint Brokers as to UK law** | FieldFisher LLP<br>Riverbank House<br>2 Swan Lane<br>London EC4R 3TT |

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| **Solicitors to the Nominated Adviser and Joint Brokers as to US law** | Proskauer Rose LLP<br>110 Bishopsgate<br>London EC2N 4AY |
| **Reporting Accountants to the Company** | Crowe U.K. LLP<br>Second Floor<br>55 Ludgate Hill<br>London EC4M 7JW |
| **Financial PR to the Company** | Capital Market Communications Limited<br>Third Floor<br>Cannongate House<br>62-64 Cannon Street<br>London EC4N 6AE |
| **Registrar to the Company** | Computershare Investor Services plc<br>The Pavilions<br>Bridgwater Road<br>Bristol BS13 8AE |
| **Auditors to the Company** | BDO United Kingdom<br>55 Baker Street<br>London W1U 7EU |
| **Company's website** | www.savannah-energy.com |

## DEFINITIONS

The following definitions apply throughout this document, unless otherwise stated or the context requires otherwise:

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| **1962 Petroleum Code** | Ordinance n°7/PC/TP/MH dated 3 February 1962 relating to the exploration, exploitation and transportation by pipeline of hydrocarbons, and the fiscal regime of these activities within the territory of the Republic of Chad; |
| **1967 Implementing Decree** | Decree dated 10 May 1967 specifying the implementation modalities of Ordinance n°7/PC/TP/MH dated 3 February 1962; |
| **1988 Convention** | the convention covering a portion of Permit H described as "Lake Chad, Chari North, Chari South" between the Republic of Chad, EEPCI, PC Chad and SHT Petroleum Chad Company Limited dated 19 December 1988 (as amended on 19 May 1993, 12 March 1997, 21 June 2000 and 9 June 2017); |
| **2004 Convention** | the convention covering a portion of Permit H described as "Chari West, Chari East and Lake Chad" between the Republic of Chad, EEPCI, PC Chad and SHT Petroleum Chad Company Limited dated 10 May 2004 (as amended on 9 June 2017); |
| **2014 Long-Term Incentive Plan** or **2014 LTIP** | the Company's initial long-term incentive plan, which was established on 28 November 2014, further details on which are contained in paragraph 4 of Part 12 of this document; |
| **2015 Supplemental Plan** | the Company's supplemental long-term incentive plan, further details on which are contained in paragraph 4.4 of Part 12 of this document; |
| **Accugas Holdco** | Accugas Holdings UK PLC, a company incorporated under the laws of England and Wales with registered number 11950135, whose registered office is at 40 Bank Street, London E14 5NR; |
| **Accugas Limited** | Accugas Limited, a company incorporated under the laws of Nigeria with registered number 881197, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos; |
| **Accugas Midco** | Accugas UK Limited, a company incorporated under the laws of England and Wales with registered company number 12257421, whose registered office is at 40 Bank Street, London E14 5NR; |
| **Accugas Midstream Business** | the business currently operated by Accugas Limited, an indirect subsidiary of Accugas HoldCo, comprising a 200 MMscfpd gas processing facility and approximately 260 km gas pipeline network and associated gas processing infrastructure; |
| **Accugas Term Facility** | the US$370.8 million term facility provided to Accugas Limited (as amended and restated) and as more fully described in paragraph 6.1 and Part 14 of this document; |
| **Agadem Rift Basin** or **ARB** | the Agadem basin in South East Niger located within the Central African Rift System; |
| **AIIM** | African Infrastructure Investment Fund 3 GP Proprietary Limited, a vehicle managed by African Infrastructure Investment Managers Limited; |
| **AIM** | the AIM market operated by the London Stock Exchange; |

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| **AIM Rules for Companies** or **AIM Rules** | the London Stock Exchange's rules and guidance notes contained in its "AIM Rules for Companies" publication relating to companies whose securities are traded on AIM, as amended from time to time; |
| **AIM Rules for Nominated Advisers** | the London Stock Exchange's rules contained in its "AIM Rules for Nominated Advisers" publication relating to the nominated advisers of companies whose securities are traded on AIM, as amended from time to time; |
| **April 2020 Supplemental Admission Document** | the supplemental AIM admission document published by the Company on 30 April 2020; |
| **Articles** | the articles of association of the Company, as amended and restated from time to time; |
| **Authority** or **NMDPRA** | Nigerian Midstream and Downstream Petroleum Regulatory Authority; |
| **BEAC** | Bank of Central African States; |
| **Board** | the board of directors of the Company from time to time; |
| **Brokers** | finnCap Ltd and Panmure Gordon (UK) Limited |
| **Cameroon Transportation System** | the portion of the ETS located in the Republic of Cameroon operated by COTCo; |
| **Cameroonian Petroleum Code** | the code governing petroleum activities in Cameroon under Law N°2019/008 dated 25 April 2019; |
| **CEFC China** | CEFC Hainan International (HK) Limited; |
| **CEMAC** | Economic and Monetary Community of Central Africa; |
| **certificated** or **in certificated form** | an Ordinary Share which is not in uncertificated form (that is, not in CREST); |
| **CFA Franc** | Central African franc; |
| **CGCL** | Calabar Generation Company Limited, the operating company of the Calabar power station; |
| **CGG** | CGG Services (UK) Limited, the author of the Nigeria CPR, the Niger CPR and the Chad/Cameroon CPR; |
| **Chad** | Republic of Chad; |
| **Chad/Cameroon Assets** | the following assets to be acquired on completion of:<br>(i) the Exxon Acquisition, being:<br>(a) a 40 per cent. participating interest in the Doba OFDA in Chad; and<br>(b) 40.19 per cent. and 41.06 per cent. shareholding interest in TOTCo and COTCo (respectively), which own and operate the Chad-Cameroon Pipeline and the Kome Kribi 1 FSO; and<br>(ii) the PETRONAS Acquisition, being:<br>(a) a 35 per cent. participating interest in the Doba OFDA in Chad; and |

(b) 30.16 per cent. and 29.77 per cent. shareholding interest in TOTCo and COTCo (respectively), which own and operate the Chad-Cameroon Pipeline and the Kome Kribi 1 FSO;

**Chad/Cameroon Competent Person's Report** or **Chad/Cameroon CPR** — the competent person's report on the Chad/Cameroon Assets, as set out in Part 9 of this document;

**Chad-Cameroon ETS** or **ETS** — the Chad-Cameroon export transportation system comprising the Chad-Cameroon Pipeline and the Kome Kribi 1 FSO;

**Chad-Cameroon Pipeline** — the 1,081 km, 30 inch oil pipeline connecting the Doba Oil Project to the Kome Kribi 1 FSO, offshore Cameroon, with a nameplate capacity of 250 Kbopd;

**Chad Transportation System** — the portion of the ETS located in the Republic of Cameroon operated by TOTCo;

**Chadian Petroleum Code** — the code governing upstream, midstream and downstream activities under Law N°07-006 dated 2 May 2007 relating to hydrocarbons in Chad;

**Cliveden** — Cliveden Petroleum Co. Limited, a party to the Shipper Transportation Agreements;

**CNPC** — China National Petroleum Corporation, an oil and gas company with interests in Chad and that uses the Chad-Cameroon Pipeline;

**CNPC PSC** — the production sharing contract into which CNPC entered with the Government of Niger in 2008 in respect of the R1/R2 PSC Area and R3/R4 PSC Area;

**CNPCI** — CNPCI International (Chad) Co., Limited, a subsidiary of CNPC that is a Shipper;

**CNPCI Convention** — the Convention for Exploration, Exploitation and Transportation of Hydrocarbons between the Republic of Chad, CNPCI and Cliveden Petroleum Co. Ltd dated 23 February 1999, as amended from time to time;

**Commission** or **NUPRC** — Nigerian Upstream Petroleum Regulatory Commission;

**Companies Act** — the UK Companies Act 2006, as amended from time to time;

**Company** or **Savannah** — Savannah Energy PLC, a company incorporated in England and Wales with registered number 09115262, whose registered office is at 40 Bank Street, London E14 5NR;

**Completion** — the completion of the:

(i) Exxon Acquisition in accordance with the terms of the Exxon SPA; and

(ii) PETRONAS Acquisition in accordance with the terms of the PETRONAS SPA,

(as applicable);

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| **Compliance Laws** | the UK Bribery Act 2010, the Foreign Corrupt Practices Act of 1977 and all other relevant and applicable anti-corruption, anti-bribery, anti-money laundering, compliance laws and regulations, and other laws governing the conduct of business (including with Chadian, Cameroon, Nigerian and Nigerien government entities), including local laws, that apply to the Enlarged Group; |
| **Conventions of Establishment** | the COTCo Convention and TOTCo Convention; |
| **COTCo** or **Cameroon Pipeline Company** | Cameroon Oil Transportation Company, incorporated under the laws of the Republic of Cameroon, with registered company number M089700006137L, whose registered office is at 164 Rue Toyota, Bonapriso, Douala, Cameroon; |
| **COTCo Convention** | the Convention of Establishment between the Republic of Cameroon and COTCo dated 20 March 1998, as amended from time to time and which granted COTCo the right to construct, own, operate and maintain the Cameroon Transportation System; |
| **COTCo Transportation Agreement** | the transportation agreement between COTCo, the Republic of Chad, EEPCI, PC Chad and SHT dated 19 June 2000, which regulates the transportation services provided by COTCo to the Consortium members of the Cameroon Transportation System; |
| **COVID-19** | the infectious disease caused by SARS-CoV-2 virus, which first emerged in December 2019; |
| **CREST** | the computerised settlement system (as defined in the CREST Regulations) operated by Euroclear which facilitates the transfer of title to shares in uncertificated form; |
| **CREST Regulations** | the Uncertificated Securities Regulations 2001 (SI 2001/3755) including any enactment or subordinate legislation which amends or supersedes those regulations and any applicable rules made under those regulations or any such enactment or subordinate legislation for the time being in force; |
| **Debt Financing** | the up to US$400 million borrowing base facility agreement (initial commitment of US$300 million and US$100 million accordion) between, *inter alia*, Savannah Chad and the Senior Lender, which shall be utilised by Savannah Chad to partly fund the Exxon Acquisition and the PETRONAS Acquisition; |
| **December 2017 Admission Document** | the AIM admission document published by the Company on 22 December 2017; |
| **Directive** | the Directive on Takeover Bids (2004/25/EC); |
| **Directors** | those persons who have been appointed as executive or non-executive directors of the Company, as applicable, whose names are set out on page 12 of this document; |
| **Doba Consortium** | the unincorporated joint venture of EEPCI, PETRONAS Carigali (Chad EP) Inc. and SHT Petroleum Chad Company Limited, which explores, develops and produces hydrocarbons pursuant to the Upstream Conventions; |

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| **Doba JOA** | the operating agreement dated 7 April 2000 between EEPCI, PETRONAS Carigali (Chad EP) Inc. and SHT Petroleum Chad Company Limited, concerning the operation of the Doba Petroleum Consortium, (as amended on 1 September 2009 and 11 June 2014); |
| **Doba OFDA** or **Doba Oil Project** | the area known as the Doba oil field development area, consisting of the contractual areas covered by the Upstream Conventions; |
| **Doba Pipeline** | Doba Pipeline Investments Inc., incorporated under the laws of the Cayman Islands, whose registered office is at the Offices of Maples and Calder, Attorneys-at-Law, P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1, which holds 30.16 per cent. and 29.77 per cent. shareholding interests in TOTCo and COTCo respectively; |
| **DPR** | the Department of Petroleum Resources, a department of the MPR, in Nigeria and where applicable its successor bodies under the Petroleum Investment Act 2021, the Nigerian Upstream Petroleum Regulatory Commission or Nigerian Midstream and Downstream Petroleum Regulatory Authority; |
| **EBT** | the Savannah Energy Employee Benefit Trust, constituted by a trust deed dated 9 February 2015 or such other trust to be established by the Company from time to time; |
| **EBT Shares** | 58,066,951 new Ordinary Shares, which are proposed to be subscribed for by the EBT at nominal value and funded via a loan provided by the Company; |
| **EBT Subscription** | the proposed subscription for the EBT Shares by the EBT; |
| **ECL** | expected credit loss; |
| **Economic Effective Date** | 1 January 2021; |
| **EEPCI** | Esso Exploration and Production Chad Inc., incorporated in the Bahamas, which holds a 40 per cent participating interest in (and is the operator in respect of) the Doba Oil Project; |
| **EIA** | Energy Information Administration, being the statistical agency of the U.S. Department of Energy; |
| **Employee Plan 2018** | means the Savannah Energy PLC Employee Share Option Plan 2018, further details of which are contained in paragraph 4 of Part 12 of this document; |
| **Employee Plan 2021** | means the Savannah Energy PLC Employee Share Option Plan 2021, further details of which are contained in paragraph 4 of Part 12 of this document; |
| **Employee 2014/15 Replacement Plan** | means the Savannah Energy PLC Replacement Share Option Plan 2021 further details of which are contained in paragraph 4 of Part 12 of this document; |
| **English High Court** | the High Court of England and Wales; |
| **Enlarged Group** | the Company and its subsidiaries immediately following Completion; |

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| **Enlarged Share Capital** | the 1,248,031,868 Ordinary Shares in issue following admission to trading on AIM of the Placing Shares and the Subscription Shares, expected to take effect at 8.00 a.m. on 7 January 2022; |
| **EPIL** | Esso Pipeline Investments Limited, incorporated in the Bahamas and which holds a 40.19 per cent. and 41.06 per cent. shareholding interest in TOTCo and COTCo respectively; |
| **ESG** | environmental, social and governance; |
| **ESMA Recommendations** | European Securities and Markets Authority's update of the Committee of European Securities Regulators' recommendations for the consistent implementation of the EU Regulations on Prospectuses; |
| **Euro** or **€** | the official currency of the European Union; |
| **Euroclear** | Euroclear UK & Ireland Limited, a company incorporated in England and Wales with registered number 2878738, being the operator of CREST; |
| **Exercise Price** | 23.5 pence per Ordinary Share; |
| **Existing Group** | the Company and its subsidiaries prior to Completion; |
| **Existing Share Capital** or **Existing Ordinary Shares** | the 996,408,412 Ordinary Shares as at the date of this document; |
| **Exoro** | Exoro Holding B.V., a company incorporated in the Netherlands with registered number 2730262 which owns the entire issued share capital of Accugas Limited; |
| **ExxonMobil** | Exxon Mobil Corporation, being the parent company of the Exxon Target Companies; |
| **Exxon Acquisition** | the acquisition by Savannah Chad, a wholly owned subsidiary of the Company, of EEPCI and EPIL; |
| **Exxon Sellers** | Exxon Mobil Corporation, ExxonMobil International Holdings Inc. and Esso Exploration Holdings Inc.; |
| **Exxon SPA** | the share sale and purchase agreement dated 12 December 2021 between Exxon Mobil Corporation, ExxonMobil International Holdings Inc., Esso Exploration Holdings Inc. and Savannah Energy Chad Limited; |
| **Exxon Target Companies** | the companies being acquired by Savannah pursuant to the Exxon SPA, being EEPCI, EPIL, as applicable; |
| **Exxon Target Companies' Financial Information** | the audited combined historical IFRS financial information prepared by the Company for the financials of the Exxon Target Companies for the three years ended 31 December 2018, 31 December 2019 and 31 December 2020; |
| **Exxon Target Companies' Interim Financial Information** | the unaudited interim historical financial information of the Exxon Target Companies for the six-month period ended 30 June 2021; |
| **FCA** | the Financial Conduct Authority (formerly the Financial Services Authority) of the United Kingdom; |

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| **FIPL** | First Independent Power Limited; |
| **FIPL Afam** | FIPL Afam power plant; |
| **FOL Transaction** | the transaction between SEUGL and Frontier, under which SEUGL acquired 100 per cent. of the Uquo Field Gas Project (including associated condensate production), Frontier relinquished operatorship of the Uquo CPF to Accugas Limited and Frontier acquired 100 per cent. of the oil project at the Uquo Field; |
| **Frontier** | Frontier Oil Limited, a company incorporated under the laws of the Federal Republic of Nigeria with registered number 41178, whose registered office is at 9C Joseph Adu Street, Oniru Estate, Victoria Island, Lagos, Nigeria; |
| **FSMA** | the Financial Services and Markets Act 2000 of the UK (as amended), including any regulations made pursuant thereto; |
| **FUN Group** | Frontier, Universal and Network Exploration & Production Company Nigeria Limited; |
| **FUN Manifold** | the facilities for storing, handling and exporting crude oil on behalf of the FUN Group from the Uquo, Stubb Creek and Qua Iboe fields to QIT; |
| **Further Enlarged Share Capital** | the share capital of the Company as enlarged by issue of the Placing Shares, the Subscription Shares and the EBT Shares; |
| **General Meeting** | the general meeting of the Company to be held at the Company's offices at 40 Bank Street, London E14 5NR on 24 January 2022 at 10.30 a.m., formal notice of which is set out in this document; |
| **Glencore** | Glencore Exploration (DOB/DOI) Limited, an oil & gas company with interests in Chad; |
| **Glencore PSC** | the Production Sharing Contract dated 18 March 2011 between the Republic of Chad, Glencore, PCM and SHT, as amended from time to time; |
| **Group** | the Company and its subsidiaries from time to time; |
| **HSSE** | health, safety, security and environmental; |
| **IFRS** | International Financial Reporting Standards as adopted by the United Kingdom; |
| **Junior Loan Facility** | the US$32 million term loan facility entered into between the Company, as borrower, LCP4L as lender, and Lothian Capital Partners Holdings Limited dated 30 December 2021; |
| **Kome Kribi 1 FSO** | the Kome Kribi 1 floating storage and offloading facility which forms part of the ETS; |
| **Lafarge** | Lafarge Africa plc (previously known as United Cement Company of Nigeria Limited), a customer of Accugas Limited; |
| **Latest Practicable Date** | 29 December 2021, being the last practicable day prior to the publication of this document for the inclusion of certain information in this document; |

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| **London Stock Exchange** | London Stock Exchange plc; |
| **Marginal Field Guidelines** | the Guidelines for Farm-out And Operation of Marginal Fields 2001 published by the DPR in Nigeria; |
| **Market Abuse Regulations** | Market Abuse Regulation (Regulation 596/2014) (as it forms part of domestic UK law pursuant to the European Union (Withdrawal) Act 2018); |
| **Minister** | Minister of Petroleum and Mining of the Republic of Chad; |
| **Ministerial Consent** | the approval of the Minister for each of the Exxon Acquisition and the PETRONAS Acquisition in accordance with the 1962 Petroleum Code, the 1967 Implementing Decree, the Upstream Conventions and the TOTCo Convention, further details of which are set out in paragraph 6 of Part 2 of this document; |
| **MPN** | Mobil Producing Nigeria Unlimited, a subsidiary of ExxonMobil; |
| **MPR** | the Federal Ministry of Petroleum Resources in Nigeria; |
| **Mulak** | Mulak Energy Limited, a member of the Mansour Group, which is a Egyptian multinational conglomerate, which operates a compressed natural gas project in Nigeria; |
| **NDPHC** | the Niger Delta Power Holding Company, the owner of, *inter alia*, the Calabar power station; |
| **NERC** | the Nigerian Electricity Regulatory Commission; |
| **NFCCPC** | Nigerian Federal Competition and Consumer Protection Commission; |
| **NFCCPC Consent** | NFCCPC's consent to the Company's acquisition of 62.5 per cent. of Universal; |
| **NGN or Naira** | Nigerian Naira, the functional currency of Nigeria; |
| **Niger CPR** or **Niger Competent Person's Report** | the competent person's report on the Group's Nigerien assets, as set out in Part 11 of this document; |
| **Nigerian Assets** | the interest in the Uquo Gas Project owned by SEUGL, the interest in the Stubb Creek Field owned by Universal and the interest in the Accugas Midstream Business owned by Accugas Limited; |
| **Nigerian CPR** or **Nigerian Competent Person's Report** | the competent person's report on the Group's Nigerian assets, as set out in Part 10 of this document; |
| **NNDC** | New Nigeria Development Company Ltd., a conglomerate owned by the 19 Northern States of Nigeria, whose registered office is at Ahmed Talib House, 18/19 Ahmadu Bellow Way, Kaduna, Kaduna State, Nigeria; |
| **NNPC** | Nigerian National Petroleum Corporation, whose registered office is at NNPC Towers, Central Business District, Herbert Macaulay Way, P.M.B. 190, Garki, Abuja, Nigeria; |
| **NPDC** | Nigerian Petroleum Development Company, with its head office at 62/64 Sapele Road, Benin City, Edo State, Nigeria; |

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| **Notice of General Meeting** | formal notice convening the General Meeting, which is set out at the end of this document; |
| **Officers Plan 2020** | means the Savannah Energy PLC Share Option Plan 2020, further details of which are contained in paragraph 4 of Part 12 of this document; |
| **Official List** | the Official List maintained by the UK Listing Authority pursuant to Part VII of the FSMA; |
| **Ordinary Shares** | the ordinary shares of par value £0.001 each in the capital of the Company; |
| **OPEC** | the Organisation of the Petroleum Exporting Countries, comprising: Algeria, Angola, Congo, Ecuador, Equatorial Guinea, Gabon, IR Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela; |
| **OPEC+** | the Organisation of the Petroleum Exporting Countries Plus, comprising OPEC and Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan and Sudan; |
| **OPIC** | OPIC Overseas Petroleum and Investment Corporation, a wholly owned subsidiary of CPC Corporation, Taiwan, and a Shipper using the Chad-Cameroon Pipeline; |
| **Panel** | the UK Panel on Takeovers and Mergers; |
| **PC Chad** | PETRONAS Carigali (Chad EP) Inc., incorporated under the laws of the Cayman Islands, whose registered office is at the Offices of Maples and Calder, Attorneys-at-Law, P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1; |
| **PC Marketing** | PETRONAS Chad Marketing Inc., incorporated under the laws of the Cayman Islands, whose registered office is at the Offices of Maples and Calder, Attorneys-at-Law, P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1; |
| **PCCEPI** | PETRONAS Carigali Chad Exploration & Production Inc., incorporated under the laws of the Cayman Islands, whose registered office is at the Offices of Maples and Calder, Attorneys-at-Law, P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1; |
| **PCM** | PetroChad (Mangara) Limited; |
| **PETRONAS** | PETRONAS (E&P) Overseas Ventures SDN. BHD., incorporated under the laws of Malaysia, whose registered office is at Tower 1, PETRONAS Twin Towers, Kuala Lumpur City Centre, 5008, Kuala Lumpur, Malaysia; |
| **PETRONAS Acquisition** | the acquisition by Savannah Energy Chad Limited, a wholly owned subsidiary of the Company, of PCCEPI, PC Chad, Doba Pipeline and PC Marketing; |
| **PETRONAS SPA** | the share sale and purchase agreement dated 2 December 2021 between PETRONAS (E&P) Overseas Ventures SDN. BHD. and Savannah Energy Chad Limited; |

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| **PETRONAS Target Companies** | the companies being acquired by Savannah pursuant to the PETRONAS SPA, being PCCEPI, PC Chad, Doba Pipeline and PC Marketing, as applicable; |
| **PETRONAS Target Companies' Financial Information** | the audited combined historical financial information of the PETRONAS Target Companies for the three years ended 31 December 2018, 31 December 2019 and 31 December 2020; |
| **PETRONAS Target Companies' Interim Financial Information** | the unaudited interim historical financial information of the PETRONAS Target Companies for the six-month period ended 30 June 2021; |
| **PIA** | Petroleum Industry Act 2021 of Nigeria; |
| **Pipeline Companies** | TOTCo and COTCo; |
| **Placing** | the conditional placing of the Placing Shares by the Brokers at the Placing Price with institutional and other investors pursuant to the Placing Agreement; |
| **Placing Agreement** | the conditional placing agreement between the Company, the Directors, Strand Hanson and the Brokers relating to the Placing details of which are set out in paragraph 1.3 of Part 14 of this document; |
| **Placing Price** | 19.35 pence per Placing Share; |
| **Placing Shares** | 237,276,474 new Ordinary Shares subscribed for pursuant to the Placing; |
| **Pounds Sterling** or **£** | pounds sterling, the lawful currency of the UK from time to time; |
| **Pro Forma Financial Information** | the unaudited pro forma statement of net assets of the Company as at 30 June 2021; |
| **Promissory Note** | the US$11.5 million note issued by Accugas Holdco as more fully described in Part 14 of this document; |
| **Prospectus Directive** | Directive 2003/71/EC including any relevant implementing measures in each member state of the European Economic Area that has implemented Directive 2003/71/EC; |
| **Prospectus Regulation Rules** | the rules published by the FCA under FSMA governing the publication of a prospectus, as derived from the Prospectus Directive; |
| **QCA Code** | the Quoted Companies Alliance Corporate Governance Code for Small and Mid-Size Quoted Companies, as amended from time to time; |
| **QIT** | the Qua Iboe oil export terminal owned and operated by MPN, a subsidiary of ExxonMobil, located close to the Uquo Field, on the south coast of Nigeria; |
| **R1/R2 PSC** | the production sharing contract between Savannah Niger and the Government of Niger dated 3 July 2014, its amendment no. 1 dated 2 November 2015 and amendment no. 2 dated 26 October 2016 in respect of the R1/R2 PSC Area; |
| **R1/R2 PSC Area** | the R1/R2 areas in South Eastern Niger that are the subject of the R1/R2 PSC; |

**R1/R2 Signature Bonus** the payments of US$34 million and US$2.7 million made by the Group to the Government of Niger represented by the Ministry of Energy and Petroleum and their advisers on or around 4 August 2014 pursuant to the R1/R2 PSC;

**R1234 PSC** the amalgamation of the R1/R2 PSC with the R3/R4 PSC;

**R3/R4 PSC** the production sharing contract between Savannah Niger and the Government of Niger dated 30 July 2015 and its amendment no.1 dated 2 November 2015 and amendment no. 2 dated 26 October 2016 in respect of the R3/R4 PSC Area;

**R3/R4 PSC Area** the R3/R4 areas in South East Niger that are the subject of the R3/R4 PSC;

**R3/R4 Signature Bonus** the payments of US$28 million and US$2.24 million made by the Group to the Government of Niger represented by the Ministry of Energy and Petroleum and their advisers on or around 31 July 2015 pursuant to the R3/R4 PSC;

**R3 East** the R3 East portion of the R3/R4 PSC;

**Re-Admission** the re-admission of the Further Enlarged Share Capital to trading on AIM, following Completion, and such admission becoming effective in accordance with the AIM Rules for Companies;

**Registrar** Computershare Investor Services plc;

**Regulation S** Regulation S promulgated under the Securities Act;

**Resolutions** the resolutions to be proposed at the General Meeting, as set out in the Notice of General Meeting in Part 15 of this document;

**Restoration** the restoration of the Existing Share Capital to trading on AIM following publication of this Admission Document, expected to occur at 8.00 a.m. on or around 31 December 2021, with neither the Exxon Acquisition nor the PETRONAS Acquisition having completed;

**Savannah Chad** Savannah Energy Chad Limited, incorporated under the laws of England and Wales with registered number 13490881, whose registered office is at 40 Bank Street, London E14 5NR;

**Savannah Niger** Savannah Energy Niger S.A. a société anonyme unipersonelle incorporated under the laws of Niger with registered number RCCM: NI-NIA-2014-B 1940, whose registered office is at 124 Rue des Ambassades, BP11272, Niamey, Niger;

**Savannah PSCs** or **Savannah PSC** the R1/R2 PSC, the R3/R4 PSC and the R1234 PSC as applicable;

**SE1L** Savannah Energy 1 Limited, a company incorporated in Scotland with registered number SC453751, whose registered office is at 50 Lothian Road, Festival Square, Edinburgh, EH3 9WJ;

**SEC** US Securities and Exchange Commission;

**Securities Act** US Securities Act of 1933, as amended from time to time, and the rules and regulations promulgated thereunder;

**Senior Lender** Maddox DMCC, a global commodity trader headquartered in Dubai;

**Senior Managers** Nick Beattie and Antoine Richard, further details of whom are set out in paragraph 17 of Part 1 of this document;

**Seven** or **Seven Energy** or **SEIL** Seven Energy International Limited, a company incorporated in Mauritius with registered number 65304 C2/GBL, whose registered office is at c/o International Management (Mauritius) Ltd, Les Cascades Building, Edith Cavel Street, Port-Louis, Mauritius;

**Seven Group** Seven and its subsidiary entities;

**SEUGL** Savannah Energy Uquo Gas Limited (previously known as Seven Uquo Gas Limited and GOGE (Nig) Limited), a company incorporated under the laws of the Federal Republic of Nigeria, with registered number 659675, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos, Nigeria;

**Shareholders** the holders of Ordinary Shares from time to time;

**Share Options** options to subscribe for new Ordinary Shares and Ordinary Shares held by the EBT;

**Share Schemes** means the 2014 LTIP, the 2015 Supplemental Plan, the Employee Plan 2018, the Officers Plan 2020, the Employee Plan 2021, the Employee 2014/15 Replacement Plan, further details of which are set out in paragraph 4 of Part 12 of this Admission Document;

**Shell** Royal Dutch Shell PLC;

**Shippers** the Doba Consortium, Glencore, CNPCI and OPIC;

**SHT** or **Chad National Oil Company** Société des Hydrocarbures du Tchad;

**Significant Shareholder** a Shareholder holding three per cent. or more of the Ordinary Shares in issue from time to time;

**Sinopec** Sinopec International Petroleum Exploration and Production Company Nigeria Limited;

**Shipper Transportation Agreements** being:

(i) the transportation contract dated 19 June 2000 between COTCo, the Republic of Chad and the Doba Consortium;

(ii) the transportation contract between TOTCo, Republic of Chad and the Doba Consortium dated 21 June 2000, as amended on 11 October 2011;

(iii) the transportation contract dated 21 October 2013 between COTCo, Republic of Chad, Glencore, PCM and SHT;

(iv) the transportation contract dated 11 October 2013 between TOTCo, Republic of Chad, Glencore, PCM and SHT;

(v) the transportation contract dated 22 November 2013 between COTCo, Republic of Chad, CNPCI and Cliveden;

(vi) the transportation contract dated 22 November 2013 between TOTCo, Republic of Chad, CNPCI and Cliveden;

(vii) the transportation contract dated 28 January 2020 between TOTCo, Republic of Chad, OPIC Africa Corporation, CEFC Hainan International (HK) Limited and SHT; and

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| | (viii) the transportation contract dated 28 January 2020 between COTCo, Republic of Chad, OPIC Africa Corporation, CEFC Hainan International (HK) Limited and SHT; |
| **SPDC** | Shell Petroleum Development Company of Nigeria Limited; |
| **Strand Hanson** | Strand Hanson Limited, the Company's financial and nominated adviser, whose registered office is at 26 Mount Row, London W1K 3SQ; |
| **Stubb Creek EPF** | the early production facilities located at the Stubb Creek Field; |
| **Stubb Creek Field** | the Stubb Creek marginal field located in the OML 14 block onshore Nigeria; |
| **Stubb Creek JV** | the joint venture between Universal and Sinopec in connection with the Stubb Creek Field; |
| **Subscribers** | Andrew Knott (via a wholly-owned entity), Steve Jenkins, Sir Stephen O'Brien, David Clarkson and Mark Iannotti; |
| **Subscription** | the subscription for the Subscription Shares at the Placing Price to the Subscribers pursuant to the Subscription Letters; |
| **Subscription Letters** | the subscription letters entered into between the Company and each of the Subscribers; |
| **Subscription Shares** | 14,346,982 new Ordinary Shares subscribed for pursuant to the Subscription; |
| **Takeover Code** | the UK City Code on Takeovers and Mergers (as amended from time to time); |
| **TOTCo** or **Chad Pipeline Company** | Tchad Oil Transportation Company, incorporated under the laws of the Republic of Chad with registered company number 600 010 746, whose registered office is at 3223 Rue d'Abeche, B. P. 6321 N'Djamena, Tchad; |
| **TOTCo Convention** | the Convention of Establishment between the Republic of Chad and TOTCo dated 20 July 1998, as amended from time to time, which granted TOTCo the right to construct, own, operate and maintain the Chad Transportation System; |
| **TOTCo Transportation Agreement** | the transportation agreement between TOTCo, the Republic of Chad, EEPCI, PC Chad and SHT dated 11 June 2000 (as amended on 11 October 2011); |
| **Transportation Agreements** | the TOTCo Transportation Agreement and the COTCo Transportation Agreement; |
| **UK** or **United Kingdom** | the United Kingdom of Great Britain and Northern Ireland; |
| **UKLA** or **UK Listing Authority** | the FCA, acting in its capacity as the competent authority for the purposes of Part VI of the FSMA; |
| **uncertificated** or **in uncertificated form** | recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST; |

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| **United States** or **US** | the United States of America, its territories and possessions, any state of the United States of America and the district of Columbia and all other areas subject to its jurisdiction; |
| **Universal** or **UERL** | Universal Energy Resources Limited, a company incorporated under the laws of the Federal Republic of Nigeria with registered number 429120, whose registered office is 25 Idoro Ro. d, Uyo, Akwa Ibom State, Nigeria; |
| **Upstream Conventions** | the 1988 Convention and the 2004 Convention; |
| **Upstream GSA** | the gas sales agreement dated 6 November 2019 between SEUGL as seller and Accugas Limited as buyer relating to gas produced at the Uquo Field; |
| **Uquo CPF** | the 200 MMscfpd gas processing facilities, owned by Accugas Limited and located at the Uquo Field; |
| **Uquo Field** | the Uquo marginal field located in the OML 13 block onshore Nigeria; |
| **Uquo Gas Project** | the gas project at the Uquo Field; |
| **Uquo HoldCo** | Savannah Energy (Uquo) Limited, a company incorporated under the laws of England and Wales with registered company number 12292632, whose registered office is at 40 Bank Street, London E14 5NR; |
| **Uquo JOA** | the joint operating agreement between Frontier and SEUGL dated 9 January 2007 as amended from time to time, more particularly described in paragraph 7.3 of Part 14 of this document; |
| **Uquo JV** | the joint venture between SEUGL and Frontier in connection with the Uquo Field which governs the terms of the FOL Transaction on an ongoing basis; |
| **US Dollar, US$** or **$** | the legal currency of the United States from time to time; |
| **VAT** | valued added tax; |
| **Warrantholders** | the holders of Warrants from time to time; |
| **Warrants** | the Warrants to be granted to Andrew Knott (via LCP4L) under the terms of the Warrant Instrument; |
| **Warrant Instrument** | the warrant instrument entered into by the Company by way of deed poll on 30 December 2021; |
| **Warrant Shares** | the new Ordinary Shares to be issued to Warrantholders on exercise of the Warrants; |
| **Wood Mackenzie** | Wood Mackenzie Limited; |
| **World Bank Partial Risk Guarantee** or **Partial Risk Guarantee** | the guarantee of the payment obligations under the downstream GSA between Accugas Limited and Calabar Generation Company Limited, provided by the World Bank's International Development Association; and |
| **XOF** | West African CFA Franc, the functional currency of Niger. |

## GLOSSARY

The following table provides an explanation of certain technical terms and abbreviations used in this document. The terms and their assigned meanings may not correspond to standard industry meanings or sage of these terms.

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| **2D seismic** | geophysical data that depicts the subsurface strata in two dimensions; |
| **2P Reserves** | proven and probable reserves; |
| **3D seismic** | geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic; |
| **Adjusted EBITDA** | profit or loss before finance costs, investment revenue, foreign exchange gains or losses, expected credit loss and other related adjustments, fair value adjustments, gain on acquisition, taxes, transaction costs, depreciation, depletion, and amortisation and adjusted to include deferred revenue and other invoiced amounts. Management believes that the alternative performance measure of Adjusted EBITDA more accurately reflects the cash generating capacity of the business; |
| **API** | a standard measure of oil density, as defined by the American Petroleum Institute; |
| **appraisal well** | a well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field; |
| **barrels** or **bbl** | a unit of volume measurement used for petroleum and its products (for a typical crude oil 7.3 barrels = 1 tonne: 6.29 barrels = 1 cubic meter); |
| **Bscf** | billion standard cubic feet. 1 bscf is approximately equal to 166,667 boe or 23,618 tonnes of oil equivalent; |
| **Best Estimate** | the middle value in a range of estimates considered to be the most likely. If based on a statistical distribution, can be the mean, median or mode depending on usage; |
| **Block** | an area defined for exploration licensing; |
| **blow-out** | an uncontrolled flow of gas, oil, or other well fluids into the atmosphere or into an underground formation; |
| **Bnbbls** | billions of barrels of oil; |
| **Boe** | barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 6,000 scf of natural gas; |
| **bopd** | barrels of oil per day; |
| **Brent** | major trading classification of sweet light crude oil; |
| **carbonates** | a sedimentary rock composed primarily of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite); |

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| **Central African Rift System** | the rift system composed of two coeval Cretaceous rift sub-systems in Central Africa; |
| **Chance of Success** or **CoS** | the estimated chance, or probability, of making an oil and gas discovery in an exploration well; |
| **Clastics** | sediments formed by the breakdown of large rock masses by climatological processes, physical or chemical; |
| **Condensate** | light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas and are a mixture of pentane and higher hydrocarbons; |
| **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 due to one or more contingencies; |
| **Cretaceous** | geological strata formed during the period 140 million to 65 million years before the present; |
| **crude oil** | hydrocarbons that at atmospheric temperature and pressure are in a liquid state, including crude mineral oil, asphalt and ozokerites, and liquid hydrocarbons that are obtained by the separation treatment, processing or extraction; |
| **DCQ** | daily contract quantity; |
| **debottlenecked** | process of identifying specific areas and/or equipment in oil and gas facilities that limit the flow of product and optimising them so that overall capacity in the plant can be increased; |
| **Deltaic** | sediments deposited in an ancient (or present day) river delta; |
| **Dip** | the inclination of a horizontal structure from the horizontal; |
| **discovery well** | an exploration well which has encountered hydrocarbons for the first time in a structure; |
| **Doba Basin** | the oil basin in southern Chad, which forms part of the West and Central African Rift System; |
| **drilling rig** | the derrick or most drawworks, and attendant surface equipment of a drilling or workover unit; |
| **dwt** | dead weight tonnage, a measure of the weight a ship is able to carry; |
| **EBITDA** | earnings before interest and tax, depreciation and amortisation; |
| **EBITDAX** | earnings before interest and tax, depreciation, amortisation and exploration expense; |
| **EOR** | Enhanced Oil Recovery; |
| **E&P** | exploration and production; |
| **Eocene horizon** | stratigraphic section of Eocene age (approx. 55 – 34 mybp); |
| **EPS** | Early Production Scheme; |

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| **Exploration Risk Factor** | the estimated probability of discovering hydrocarbons within an exploration prospect. Also known as Chance of Success, or CoS; |
| **exploration well** | a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir; |
| **fault** or **faulting** | a displacement (vertical, inclined or lateral) below the earth's surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons; |
| **Field** | an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition; |
| **Formation** | a layer or unit of rock. A productive formation in the context of reservoir rock; |
| **FSO** | floating storage and offloading vessel; |
| **full tensor gravity** | a form of gravimetric survey; |
| **GDP** | gross domestic product; |
| **geophysical** | measurement of the earth's physical properties to explore and delineate hydrocarbons by means of electrical, seismic, gravity and magnetic methods; |
| **gross resources** | the total estimated petroleum that is potentially recoverable from a field or prospect; |
| **GSA** | gas sales agreement; |
| **heavy crude** | oil of high specific gravity, an API gravity of less than 22 degrees and viscosity of less than 100 centipoise; |
| **HSE** | health, safety and environment; |
| **hydrocarbon** | a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate; |
| **IMF** | International Monetary Fund; |
| **investment grade** | a rating that indicates that a municipal or corporate bond has a relatively low risk of default; |
| **IT** | information technology |
| **Kboepd** | thousands of barrels of oil equivalent per day; |
| **Kbopd** | thousands of barrels of oil per day; |
| **km** | kilometre; |
| **km$^2$** | square kilometers; |
| **Lacustrine** | sediments deposited in an ancient (or present day) freshwater lake; |

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| **Lead** | a conceptual exploration idea usually based on minimal data but with sufficient support from geological analogues and the like to encourage further data acquisition and/or study on the basis that hydrocarbon accumulations of unknown size may be found in the future; |
| **licence** | an exclusive right to search for or to develop and produce hydrocarbons within a specific area and/or a pipeline licence, as the context requires. Usually granted by the State authorities and may be time limited; |
| **Lower Cretaceous** | stratigraphic section of Early Cretaceous age (approximately 145 – 100 mybp); |
| **LTI** | lost time injury; |
| **M&A** | mergers and acquisitions; |
| **M** | thousand; |
| **Mscf** | thousand standard cubic feet of natural gas; |
| **MMbbls** | millions of barrels of oil; |
| **MMboe** | millions of barrels of oil equivalent; |
| **MMBtu** | millions of British Thermal Units; |
| **MMscfpd** | millions of standard cubic feet per day; |
| **MMstb** | millions of standard stock tank barrels of oil; |
| **MOU** | memorandum of understanding; |
| **Mscf** | thousand standard cubic feet (equivalent to 1.037 MMBtu); |
| **mybp** | millions of years before present; |
| **natural gas** | hydrocarbon that at a standard temperature of sixty degrees Fahrenheit (60ºF) and a standard pressure of one atmosphere are in a gaseous state, including wet mineral gas and dry mineral gas, casing head gas, residual gas remaining after separation treatment, processing, or extraction of liquid hydrocarbons; |
| **NPV** | Net Present Value; |
| **oil equivalent** | international standard for comparing the thermal energy of different fuels. 1 boe = 6,000scf; |
| **Operator** | the entity that has legal authority to drill wells and undertake production of hydrocarbons found. The operator is often part of a consortium and acts on behalf of this consortium; |
| **Paleocene** | period of geological time, approximately 65 to 55 mybp; |
| **Petroleum** | a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products; |
| **permeability** | a measure of the ability of a material (such as rocks) to transmit fluids; |

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| **pinch-out** | to taper to a zero edge; |
| **Play** | a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects; |
| **Porosity** | the percentage of void in a porous rock compared to the solid formation; |
| **Possible Reserves** | those additional Reserves that analysis of geoscience and engineering data suggest 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) Reserves, which is equivalent to the high-estimate scenario; |
| **Probable Reserves** | those additional Reserves which analysis of geoscience and engineering data indicate 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); |
| **Prospect** | a project associated with a potential accumulation of oil or natural gas that is sufficiently well defined to represent a viable drilling target; |
| **Prospective Resources** | those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects; |
| **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 known reservoirs and under defined technical and commercial conditions; |
| **PSC** | Production Sharing Contract; |
| **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; |
| **Reservoir** | a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system; |
| **Resources** | deposits of naturally occurring hydrocarbons which, if recoverable, include those volumes of hydrocarbons either yet to be found (prospective) or if found the development of which depends upon a number of factors (technical, legal and/or commercial) being resolved (contingent); |
| **RFT** | Repeat Formation Tester; |
| **Scf** | standard cubic feet; |
| **Seal** | a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system; |

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| **seismic survey** | a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two or three-dimensional form; |
| **stratigraphic** | a mode of trapping hydrocarbons which is not dependent on structural entrapment; |
| **sweet crude** | the New York Mercantile Exchange designates petroleum with less than 0.5 per cent. sulfur as sweet; |
| **Tscf** | trillion standard cubic feet; |
| **Tertiary** | geological strata formed during the period from 65 to 1.8 mybp; |
| **TVDSS** | true vertical depth sub-sea; |
| **UN** | United Nations; |
| **UN SDG** | United Nations Sustainable Development Goals; |
| **Upper Cretaceous** | period of geological time, approximately 100 to 65 mybp; |
| **up-dip** | up the plane of the dip; |
| **USGS** | US Geological Survey; |
| **Volcanics** | rocks derived from an ancient (or present day) volcano; |
| **WTI** | West Texas Intermediate, a light, sweet crude oil; and |
| **Yet-to-find** or **YTF** | estimated volumes of hydrocarbons which are as yet undiscovered. |

## PART 1

## LETTER FROM THE NON-EXECUTIVE CHAIR OF SAVANNAH

# SAVANNAH ENERGY PLC

*(Incorporated and registered in England and Wales under the Companies Act 2006 with registered number 09115262)*

| *Directors:* | *Registered address:* |
|---|---|
| Steve Jenkins *(Non-Executive Chair)* | 40 Bank Street |
| Sir Stephen O'Brien *(Non-Executive Vice Chair)* | London E14 5NR |
| Andrew Knott *(Chief Executive Officer)* | |
| Mark Iannotti *(Non-Executive Director)* | |
| David Jamison *(Non-Executive Director)* | |
| David Clarkson *(Non-Executive Director)* | |

30 December 2021

***To the holders of Existing Ordinary Shares and, for information only, to holders of Share Options***

Dear Shareholder,

**PROPOSED ACQUISITION OF EXXONMOBIL'S AND PETRONAS'S ENTIRE UPSTREAM AND MIDSTREAM ASSET PORTFOLIO IN CHAD AND CAMEROON, PLACING AND SUBSCRIPTION OF 251,623,456 NEW ORDINARY SHARES AT 19.35 PENCE PER SHARE, NOTICE OF GENERAL MEETING AND RE-ADMISSION OF THE FURTHER ENLARGED SHARE CAPITAL TO TRADING ON AIM FOLLOWING SATISFACTION OF CONDITIONS PRECEDENT**

### 1. Introduction

On 13 December 2021, the Company announced that it had entered into agreements to acquire ExxonMobil's and PETRONAS's interests in the Doba Oil Project and the Chad-Cameroon ETS for considerations of US$360 million (with a further oil price contingent payment of up to US$50 million), subject to other adjustments, and US$266 million subject to working capital and customary adjustments, respectively. Completion of the Exxon Acquisition and the PETRONAS Acquisition are each conditional upon, *inter alia*, Shareholder approval at the General Meeting, the waiver of pre-emption rights by other participants in the Doba Consortium and approval by the Ministry of Petroleum and Energy of the Republic of Chad. Completion of the PETRONAS Acquisition also requires receipt of merger approval from the CEMAC Council for Competition. The Exxon Acquisition and the PETRONAS Acquisition are not inter-conditional.

Under the terms of the Exxon SPA, the Company will acquire a 40.00 per cent. operated interest in the Doba Oil Project, a 40.19 per cent. interest in the Chad Pipeline Company and a 41.06 per cent. interest in the Cameroon Pipeline Company. Under the terms of the PETRONAS SPA, the Company will acquire a 35.00 per cent. interest in the Doba Oil Project, a 30.16 per cent. interest in the Chad Pipeline Company and a 29.77 per cent. interest in the Cameroon Pipeline Company.

In aggregate, Savannah will acquire, on Completion of both the Exxon Acquisition and the PETRONAS Acquisition:

- a 75.00 per cent. participating interest in the Doba Oil Project which comprises seven producing oil fields with 186.5 MMstb of 2P Reserves and 2C Resources and which produced an average gross daily production of 33.7 Kbopd (net 25.3 Kbopd) in 2020;
- a 70.34 per cent. equity interest in the Chad Pipeline Company which owns the 178 km section of the Chad-Cameroon ETS that runs from the Doba Oil Project to the Cameroon border; and
- a 70.83 per cent. equity interest in the Cameroon Pipeline Company which owns the 903 km section of the Chad-Cameroon ETS that runs from the border, through Cameroon and the associated export facilities, including the Kome Kribi 1 FSO.

Due to their size and nature, both the Exxon Acquisition and the PETRONAS Acquisition individually constitute reverse takeover transactions pursuant to AIM Rule 14.

The General Meeting to approve each of the Exxon Acquisition and the PETRONAS Acquisition will be held at 10.30 a.m. on 24 January 2022 at the offices of the Company, being 40 Bank Street, London E14 5NR, notice of which is set out at the end of this document. The Exxon Acquisition and the PETRONAS Acquisition are not inter-conditional and therefore one, both or neither transaction may complete.

Completion of the Exxon Acquisition is conditional upon, *inter alia*, Shareholder approval at the General Meeting and Ministerial Consent, which is expected to be received by March 2022. The Exxon Acquisition is also conditional upon an IT systems transition process, which is expected to take approximately six months from the signature of the Exxon SPA. Therefore, Completion of the Exxon Acquisition is expected to take place during or around June 2022.

Assuming Completion of the Exxon Acquisition (such that all conditions precedent are satisfied), the Company's existing quotation on AIM will be cancelled and re-admission of the then Group (including the PETRONAS Target Companies to the extent the PETRONAS Acquisition has completed), as enlarged by the Exxon Acquisition, will become effective.

Completion of the PETRONAS Acquisition is conditional upon, *inter alia*, Shareholder approval at the General Meeting and Ministerial Consent, which is expected to be received by March 2022. Completion of the PETRONAS Acquisition also requires receipt of merger approval from the CEMAC Council for Competition (Conseil Communautaire de la Concurrence), and such approval can take up to six months to be determined, following submission of the notification by Savannah Chad, which is expected to be made shortly after publication of this document. Therefore, should the CEMAC Council for Competition take the full six months to provide its approval, Completion of the PETRONAS Acquisition would be expected to take place during or around June 2022.

Assuming Completion of the PETRONAS Acquisition (such that all conditions precedent are satisfied), the Company's existing quotation on AIM will be cancelled and re-admission of the then Group (including the Exxon Target Companies, to the extent the Exxon Acquisition has completed), as enlarged by the PETRONAS Acquisition, will become effective.

On Completion of each of the Exxon Acquisition and the PETRONAS Acquisition, the Company shall be required to publish a supplementary admission document pursuant to the AIM Rules.

Further details on the Exxon Acquisition and the PETRONAS Acquisition are set out in paragraphs 3, 4 and 5 of this Part 1 and Part 2 of this document. The purpose of this document is to set out the details of, and reasons for, the Exxon Acquisition and the PETRONAS Acquisition and explain why the Directors consider both transactions to be in the best interests of the Company and its Shareholders and recommend that Shareholders vote in favour of the Resolutions to be proposed at the General Meeting.

The considerations payable for the Exxon Acquisition and the PETRONAS Acquisition will be funded by a combination of the Debt Financing, Placing, Subscription and the Junior Loan Facility, further details of which are set out in paragraphs 8, 9 and 10 of this Part 1.

The Company has announced today that it has raised from new and existing investors via the Placing and Subscription net proceeds of approximately US$63.7 million at the Placing Price of 19.35 pence per share. Restoration to trading on AIM of the Existing Ordinary Shares is expected to become effective at 8.00 a.m. today and trading in the Placing Shares and Subscription Shares is expected to commence at 8.00 a.m. on 7 January 2022. Neither the Placing nor the Subscription is conditional on the Exxon Acquisition or the PETRONAS Acquisition completing. Further details on the Placing and the Subscription are set out in paragraph 8 of this Part 1.

**You should read the whole of this document and not just rely on the information contained in this letter. In particular, you should consider carefully the "Risk Factors" set out in Part 3 of this document.**

## 2. Key investment proposition

Savannah is a British energy company focused around the delivery of ***Projects that Matter*** in Africa. Our Business model is currently focused around the delivery of material long-term returns for our stakeholders through the sustainable development and ultimate monetisation of high-quality, high-potential energy projects.

The Directors believe that an investment in the Company should be attractive to prospective investors for the following reasons:

### 2.1 The Exxon Assets and the PETRONAS Assets

***The Doba Oil Project***

- The Doba Oil Project has gross Proved Reserves (1P) of 100.6 MMstb and gross Proved & Probable (2P) Reserves of 138.4 MMstb, estimated by CGG:
  - o of which, Proved Reserves (1P) of 40.2 MMstb and Proved & Probable (2P) Reserves of 55.4 MMstb are attributable to the Exxon Target Companies, and Proved Reserves (1P) of 35.2 MMstb and Proved & Probable (2P) Reserves of 48.4 MMstb are attributable to the PETRONAS Target Companies; and
  - o the Doba Oil Project includes 120.4 MMstb of gross 2P Reserves that are categorised as requiring "No Further Investment" to be produced.
- CGG estimates 2022 gross production of 30.1 Kbopd from the Doba Oil Project, with 12.0 Kbopd attributable to the Exxon Target Companies and 10.5 Kbopd attributable to the PETRONAS Target Companies.
- CGG estimates average annual upstream asset free cashflow over the next nine years of US$39.1 million attributable to the Exxon Target Companies and US$32.9 million attributable to the PETRONAS Target Companies.
- Additional enhanced oil recovery (EOR), drilling, production and facilities optimisation exists to develop the full field potential of the assets.
- The Exxon Target Companies and the PETRONAS Target Companies each have concession terms through to 2050.
- Each of the Exxon Acquisition and the PETRONAS Acquisition provides a platform for the Company to build a material business with further in-country consolidation opportunities in Chad.

***The Chad-Cameroon ETS***

- Midstream project facilities in a mature hydrocarbon basin with established infrastructure including a 1,081 km pipeline with 250 Kbopd nameplate capacity and high operational reliability since 2003:
  - o being the only international export route for oil production in Chad (pipeline used by ExxonMobil, CNPC, Glencore, OPIC and PETRONAS); and
  - o potential for new adjacent operations to utilise the Chad-Cameroon Pipeline, including a number of undeveloped discoveries in Chad.
- CGG estimates average annual midstream asset free cashflow over the next nine years of US$37.4 million attributable to the Exxon Target Companies and US$27.2 million attributable to the PETRONAS Target Companies:
  - o 49 per cent. of the total Exxon Target Companies and 45 per cent. of PETRONAS Target Companies' cash-flow is derived from long-dated, non-oil-price dependent revenue streams.
- In aggregate, across the Doba Oil Project and the Chad-Cameroon ETS assets, CGG estimates average annual asset free cashflow over the next nine years of US$76.6 million attributable to the Exxon Target Companies and US$60.1 million attributable to the PETRONAS Target Companies.

### 2.2 Savannah's existing predictable base revenue stream

- Two high-quality, high-growth business units in Nigeria and Niger.
- Achieved revenue of US$169.0 million, all from the Nigerian assets, in the year ended 31 December 2020.
- Nigerian Assets' future contracted revenues are derived from fixed price, long-term gas sales agreements with a weighted average remaining contract life of 16 years and over US$4.0 billion of remaining life-of-contract revenues, of which 95 per cent. of current contracted revenues are with customers providing investment grade credit guarantees.

### 2.3 Savannah's proven track record of delivery

- Strong and functionally arranged operating platform, with a purposeful and performance-driven culture and highly experienced Board and senior management team.
- Proven track record of delivering improved performance from acquired assets:
  - 2020 Adjusted EBITDA increased 19 per cent. compared to pro forma Adjusted EBITDA in 2019.
- Track record of delivering capital projects on time and budget and of exploration excellence, including:
  - five discoveries from the five exploration wells drilled in Niger; and
  - R3 East exploration drilling programme in 2018 delivered on time and on budget.

### 2.4 Making a sustainable impact

- The Company is seeking to deliver energy projects in emerging markets, which make meaningful positive socio-economic contributions to its host countries.
- The Company strives to manage all of its operations in a safe, secure and environmentally sustainable manner.
- The Company's carbon intensity and diversity metrics are industry-leading.
- The Company's sustainability strategy is aligned with 13 of the 17 United Nations Sustainable Development Goals, where the Board believes it can have the biggest economic, environmental, social and governance impact to achieve a better and more sustainable future for its host nations in Africa.

### 2.5 Strong organic growth potential on Completion

- In Nigeria, the Directors expect to continue to deliver significant organic growth from a combination of increased sales to existing customers and sales to new customers.
- In Niger, the Directors expect to progress the R3 East development and the Board believes that there is significant additional longer-term growth potential associated with its bank of 146 identified exploration targets within its licence area, with export via the Niger-Benin pipeline currently under construction.
- The Company's growth ambitions are underpinned by the Enlarged Group's asset base:
  - the Nigerian Assets have a 29.2-year combined Reserve and Resource life; and
  - following completion of the Exxon Acquisition and the PETRONAS Acquisition, the Enlarged Group would have net Proved Reserves (1P) of 130.8 MMboe, net Proved & Probable (2P) Reserves of 183.1 MMboe and net Contingent Resources (2C) of 176.0 MMboe as presented in the table below.

| MMboe | *1P Net* | *2P Net* | *2C Net* |
|---|---|---|---|
| Existing Group | 55.4 | 79.3 | 93.3 |
| Exxon Target Companies | 40.2 | 55.4 | 44.1 |
| PETRONAS Target Companies | 35.2 | 48.4 | 38.6 |
| Enlarged Group(1) | 130.8 | 183.1 | 176.0 |
| **Percentage increase** | **+136%** | **+131%** | **+89%** |

*Notes:*

(1) Assuming Completion of both the Exxon Acquisition and the PETRONAS Acquisition.

- In Chad, the Directors expect to enhance asset performance through optimisation of operations and the application of alternative production technologies to improve and extend its economic life.

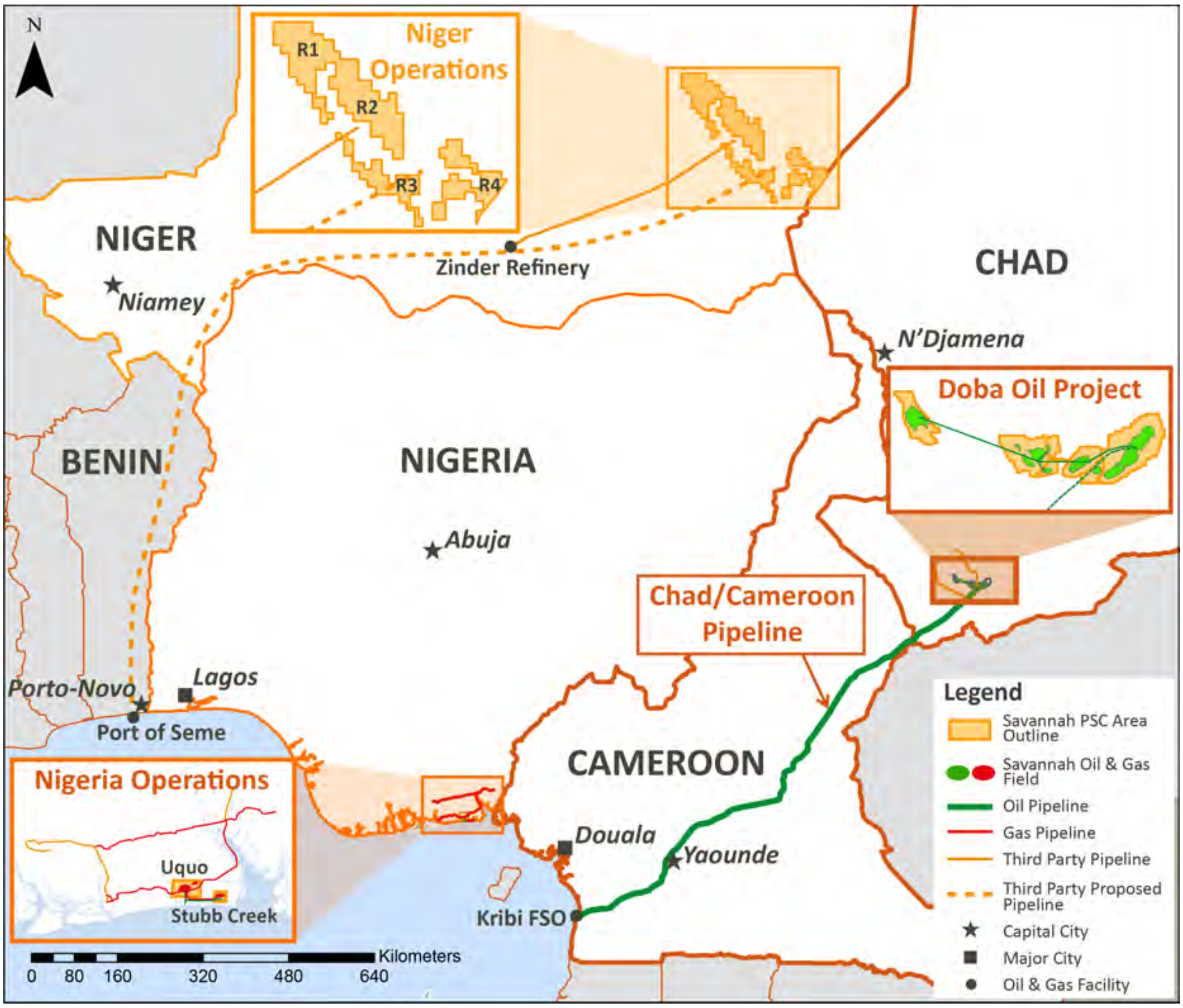
**2.6 Strong inorganic growth potential**

- The Company continues to actively review new projects and acquisition opportunities in its core African region focused predominantly on:
  - o cash-generative, or near-term cash-generative, upstream and midstream assets;
  - o "bolt-on" assets for which there is significant synergistic value to the Existing Group's operations; and/or
  - o greenfield renewable power projects.
- The Board believes that the Company's strong operating platform and industrial reputation, access to finance and regional relationships place it well to acquire further assets in the current environment, where the seven supermajors in the industry alone have announced divestment programmes reported to amount to over US$100 billion. The supermajors are rationalising their portfolios and divesting assets that are no longer deemed to be core and, due to the limited buyer universe, the Board believes that there are opportunities to acquire high quality assets at attractive valuations. The Board sees significant value creation potential in such transactions, with the performance improvements it has delivered in its Nigerian asset base post-acquisition being a prime example of how this can be achieved.

## 3. Information on the Chad/Cameroon Assets

The Chad/Cameroon Assets, comprising the Doba Oil Project and the Chad-Cameroon ETS, are located in Central and West Africa, bordering the Existing Group's operations in Nigeria and Niger.

*Figure 1, Location of the Chad/Cameroon Assets relative to the Existing Group's operations*




*Source: Company materials*

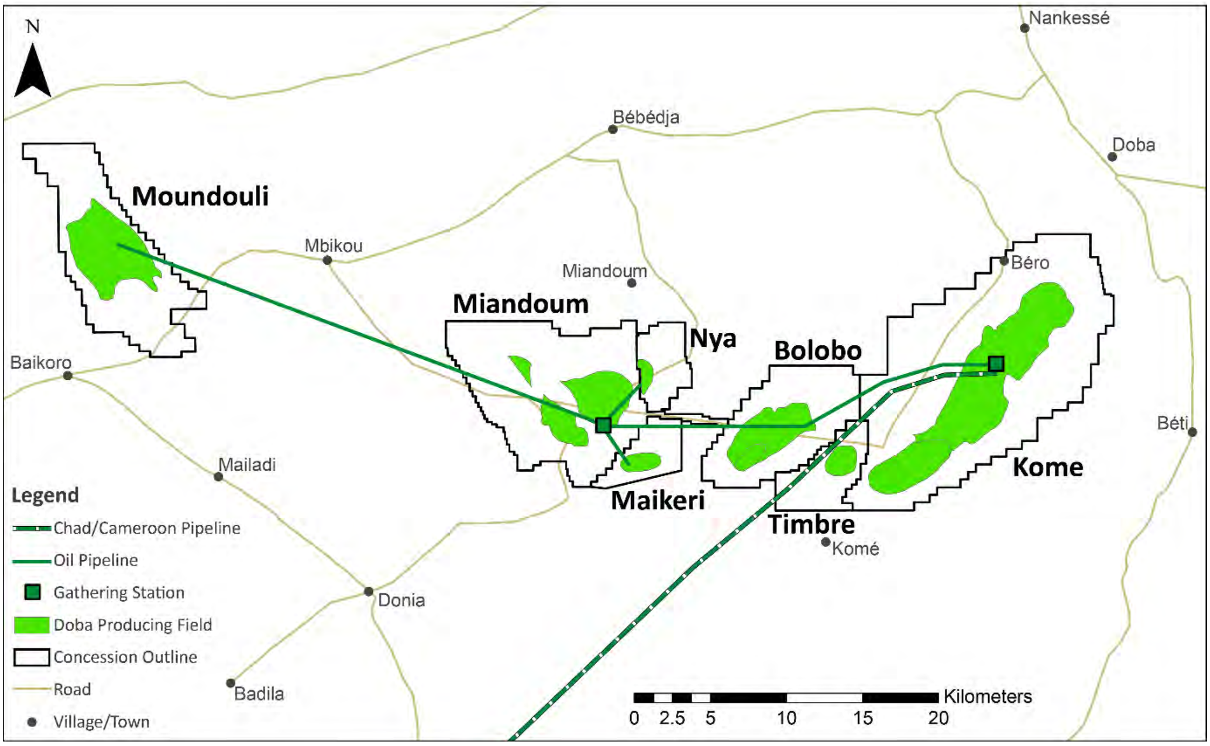
### 3.1 The Doba Oil Project

***Overview and background***

The Doba Oil Project, located in Southern Chad's established Doba Basin, is a material development, having produced 631 MMstb of crude oil since 2003 from approximately 3.8 Bnbbls of oil initially in place. The Doba Oil Project is owned by the Doba Consortium, comprised of ExxonMobil (EEPCI) as operator (40 per cent.), PETRONAS (PC Chad) (35 per cent.) and Chad National Oil Company (SHT) (25 per cent.). CGG estimates expected 2022 production of 30.1 Kbopd and remaining gross 2P Reserves and 2C Resources of 138.4 MMstb and 110.2 MMstb, respectively. The oil produced is exported to international markets via the Chad-Cameroon Pipeline and then the Kome Kribi 1 FSO, offshore Cameroon.

The development comprises seven producing fields: Miandoum, Kome, Bolobo, Moundouli, Nya, Maikeri and Timbre. The first discoveries, Miandoum and Kome, were made by Conoco in 1975. ExxonMobil took operatorship in 1982 and subsequent successful exploration and appraisal increased discovered resources to over 3 Bnbbls of oil initially in place enabling a bespoke export solution with construction of the 1,081 km Chad-Cameroon Pipeline.

*Figure 2, Location of the Doba Oil Project fields*




*Source: Chad/Cameroon CPR*

***Historical Production***

Production started in 2003 from the Miandoum field and the full start-up of project facilities and production from the Kome and Bolobo fields was achieved in 2004. Crude oil from all fields is collected at the Miandoum and Kome gathering stations. Processing and power generation is centralised at the Kome facility from where crude oil is exported through the Chad-Cameroon Pipeline. Peak production of over 200 Kbopd was achieved in 2004, the success of which led to further drilling campaigns and the development of the Nya, Moundouli, Maikeri and Timbre fields, the last of which was brought into commercial production in 2009. Drilling continued until 2015, when ExxonMobil stopped drilling activities and implemented a polymer flooding scheme in the Kome and Miandoum fields to enhance oil recovery and extend the economic life of the fields. In 2020, the average gross production was 33.7 Kbopd from approximately 300 wells.

*Figure 3, Doba Oil Project fields information*

| *Field* | *Area (km²)* | *Discovery* | *Production start-up* |
|---|---|---|---|
| Miandoum | 101 | 1975 | 2003 |
| Kome | 186 | 1975 | 2004 |
| Bolobo | 53 | 1989 | 2004 |
| Nya | 13 | 2002 | 2005 |
| Moundouli | 74 | 2001 | 2006 |
| Maikeri | 15 | 2005 | 2007 |
| Timbre | 22 | 2005 | 2009 |

*Source: modified from the Chad/Cameroon CPR*

To date, approximately 16 per cent. of the discovered Reserves and Resources have been recovered from the Doba Oil Project. Further Reserves and Resources could be developed through the application of infill drilling, optimisation of water and polymer injection, alternative well completion and intervention technologies, work-over and recompletions of existing non-producing wells, or further enhanced oil recovery applications.

***Reserves and Resources***

As further detailed in the Chad/Cameroon CPR, included in Part 9 of this document, a summary of the gross and net 2P Reserves and 2C Resources and the expected asset free cashflows of the seven fields are set out below. Approximately 85 per cent. of the 2P Reserves are Proved Developed Reserves that are categorised as requiring "No Further Investment" to be produced.

*Figure 4, Summary of Gross and Net(1) 2P Reserves and 2C Resources of the Doba Oil Project*

| | *2P Reserves* | | *2C Resources* | |
|---|---|---|---|---|
| | *Gross* | *Net(1)* | *Gross* | *Net(1)* |
| Moundouli, Nya | 13.6 | 10.2 | 23.2 | 17.4 |
| Maikeri, Timbre | 4.9 | 3.7 | 4.6 | 3.5 |
| Miandoum, Bolobo, Kome | 119.9 | 89.9 | 82.4 | 61.8 |
| **Total (MMstb)** | 138.4 | 103.8 | 110.2 | 82.7 |
| **Exxon Acquisition** | | **55.4** | | **44.1** |
| **PETRONAS Acquisition** | | **48.4** | | **38.6** |

*Source: Chad/Cameroon CPR*

*Notes:*

(1) Net to Savannah, assuming Completion of the Exxon Acquisition and the PETRONAS Acquisition.

***Expected Asset Level Free Cashflow(1)***

*Figure 5, Summary of Expected Net Free Cashflows from the Doba Oil Project*

| | *Exxon Target Companies US$m* | *PETRONAS Target Companies US$m* | *Aggregate US$m* |
|---|---|---|---|
| 2022 | 78.6 | 46.4 | 125.0 |
| 2023 | 58.5 | 24.1 | 82.6 |
| 2024 | 9.7 | 32.3 | 42.0 |
| 2025 | 61.6 | 26.6 | 88.2 |
| 2026 | 20.4 | 32.3 | 52.7 |
| 2027 | 66.0 | 40.5 | 106.5 |
| 2028 | 28.5 | 39.2 | 67.7 |
| 2029 | 30.1 | (3.6) | 26.5 |
| 2030 | (1.2) | 58.4 | 57.2 |

*Source: Chad/Cameroon CPR*

*Notes:*

(1) Expected Asset Level Free Cashflow Is the pre-debt service net cashflow derived directly from the assets (and excludes any indirect revenues and costs). The marked variations in annual cashflows are in part caused by projected timings of oil liftings.

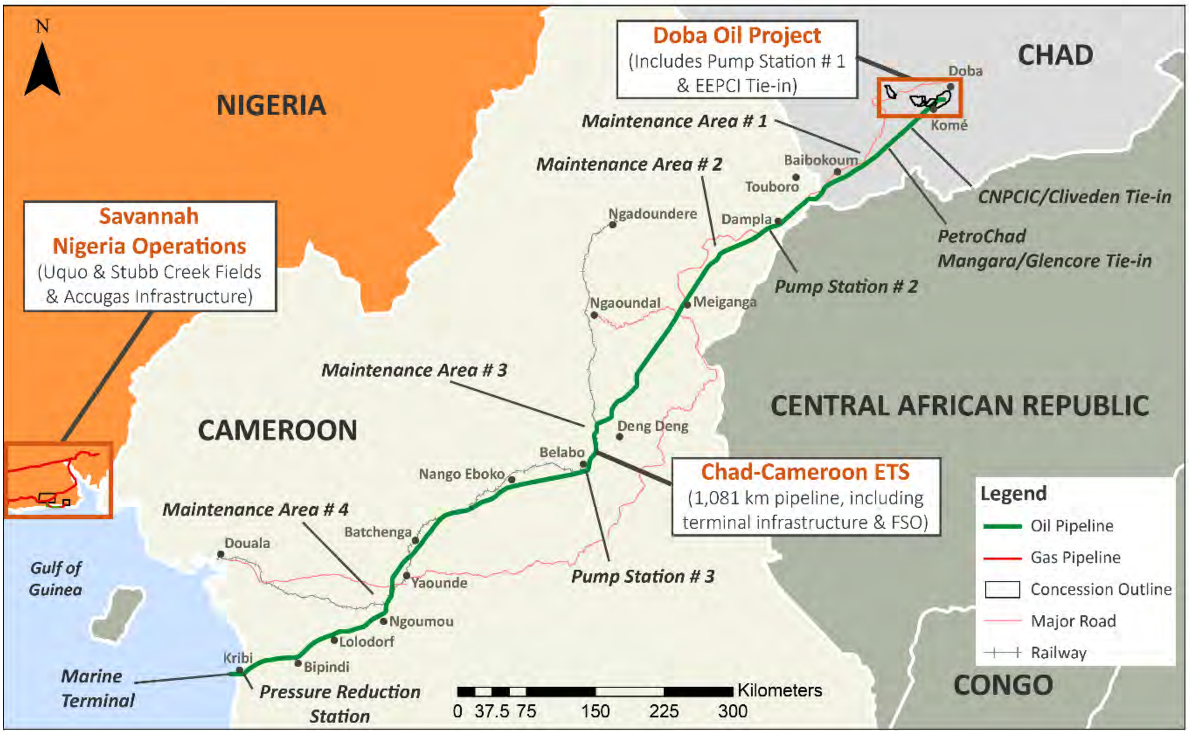
CGG has conducted a review of the value of the interests to be acquired in the Doba Oil Project, which has been incorporated in the Chad/Cameroon CPR. The base case NPV10 for Savannah's interest in the Doba Oil Project, based on 2P Reserves, assuming completion of the Exxon Acquisition and the PETRONAS Acquisition, has been assessed at US$484.8 million with (US$245.4 million attributable to the Exxon Acquisition and US$239.4 million attributable to the PETRONAS Acquisition). The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2 per cent. per year.

### 3.2 Chad-Cameroon Export Transport System

***ETS overview***

The Chad-Cameroon ETS is a crude oil export pipeline, which connects Chad to the Atlantic Ocean port of Kribi in Cameroon, and an offshore moored floating storage and offloading facility ("FSO") and terminal infrastructure. The total length of the pipeline is 1,081 km (178 km in Chad, 903 km in Cameroon including a 12 km offshore section). The nameplate capacity of the ETS is 250 Kbopd and it can transport relatively heavy crude oil. The ETS is the only pipeline connecting landlocked oil-producing assets in Chad to the international market.

*Figure 6, The Chad-Cameroon Export Transportation System*




*Source: Chad/Cameroon CPR*

Construction of the Chad-Cameroon pipeline, which is buried below the ground, started in 2000 and was completed in 2003, a year ahead of schedule. The total cost of the pipeline project was US$2.2 billion and several US and European Export/Import Credit agencies and the World Bank supported the construction and implementation of this major infrastructure project. There are three pumping stations along the length of the pipeline and a pressure reduction station at Kribi. The first pumping station is located at the Kome field, the second and third pumping stations are located in Cameroon.

*Figure 7, Chad Pipeline Company and Cameroon Pipeline Company ownership*

| *Shareholder* | *TOTCo* | *COTCo* |
|---|---|---|
| ExxonMobil (EPIL) | 40.19% | 41.06% |
| PETRONAS (Doba Pipeline) | 30.16% | 29.77% |
| Chad National Oil Company (SHT) | 21.54% | 21.26% |
| Chad Government | 8.12% | 2.74% |
| Cameroon National Oil Company (SNH) | 0% | 5.17% |

*Source: Company materials*

***Historical ETS throughputs***

The primary objective of the ETS was to export oil production from the Doba Oil Project, but since 2013 other producers in Chad (including CNPC, OPIC and Glencore) have started transporting crude oil through the pipeline. Third-party throughput reached approximately 100 Kbopd in 2020 with a number of further development projects expected to be brought onstream in the short to medium term.

The Kome Kribi 1 FSO is a converted crude tanker with a nameplate storage capacity of 2.5 MMbbl. The Kome Kribi 1 FSO is able to accommodate tandem-berthed 80,000-320,000 dwt export tankers with typical loading times of 20 to 40 hours. Currently, there are on average four liftings per month from the FSO, with both EPIL and PCCEPI lifting on average four times per year.

The ETS is managed by two joint-venture companies, the Chad Pipeline Company (TOTCo) which manages transportation across the Chad route of the pipeline and the Cameroon Pipeline Company (COTCo) which manages transportation across the Cameroon route of the pipeline. Following Completion of the Exxon

Acquisition, Savannah Chad will be responsible for appointing the general manager of COTCo and TOTCo under the terms of service agreements that EPIL and EEPCI will be parties to.

COTCo and TOTCo both charge shippers a tariff to transport their crude oil which covers the costs of operating and maintaining the infrastructure. Third-party shippers pay an additional tariff element in recognition of the Doba Consortium's historical investment in the pipeline.

The governments of Chad and Cameroon have the right to acquire their respective portions of the Chad-Cameroon Pipeline following renunciation of the transportation authorisations by TOTCo and COTCo. If such rights are exercised, TOTCo and COTCo are not required to decommission the pipeline.

***Expected Asset Level Free Cashflow***

*Figure 8, Summary of Expected Net Free Cashflows from the Chad-Cameroon ETS*

| | *Exxon Target Companies US$m* | *PETRONAS Target Companies US$m* | *Aggregate US$m* |
|---|---|---|---|
| 2022 | 34.4 | 25.0 | 59.4 |
| 2023 | 35.2 | 25.6 | 60.8 |
| 2024 | 35.7 | 25.9 | 61.6 |
| 2025 | 37.6 | 27.3 | 64.9 |
| 2026 | 40.0 | 29.0 | 69.0 |
| 2027 | 41.3 | 30.0 | 71.3 |
| 2028 | 40.4 | 29.3 | 69.7 |
| 2029 | 38.4 | 27.9 | 66.3 |
| 2030 | 34.0 | 24.7 | 58.7 |

*Source: Chad/Cameroon CPR*

CGG has conducted a review of the value of the interests to be acquired in the Chad-Cameroon ETS, which has been incorporated in the Chad/Cameroon CPR. The base case NPV10 for Savannah's interest in the Chad-Cameroon ETS, assuming completion of the Exxon Acquisition and the PETRONAS Acquisition, has been assessed at US$497.6 million with (US$288.3 million attributable to the Exxon Acquisition and US$209.3 million attributable to the PETRONAS Acquisition).

For further information about the Chad/Cameroon Assets, refer to Part 4 and Part 9 of this document.

## 4. Chad and Cameroon Opportunity

### 4.1 Acquisition of strong cash generative oil producing asset

The Doba Oil Project has gross Proved Reserves (1P) of 100.6 MMstb and gross Proved & Probable (2P) Reserves of 138.4 MMstb, estimated by CGG. This includes 120.4 MMstb of gross 2P Reserves that are categorised as requiring "No Further Investment" to be produced. CGG estimates 2022 gross production of 30.1 Kbopd from the Doba Oil Project, with 12.0 Kbopd attributable to the Exxon Target Companies and 10.5 Kbopd attributable to the PETRONAS Target Companies.

CGG estimates asset free cashflow of US$352.2 million attributable to the Exxon Target Companies interests in the Doba Oil Project and US$296.2 million attributable to the PETRONAS Target Companies' interests in the Doba Oil Project over the next nine years.

### 4.2 Acquisition of a material interest in and operational control over the Chad-Cameroon ETS, with significant spare capacity

The Chad-Cameroon ETS, which includes a 1,081 km pipeline with 250 Kbopd nameplate capacity, is the only international export route for oil production in Chad, which is used by the Doba Consortium and other third-party shippers, including CNPC, Glencore and OPIC. Based on throughput in 2020, there is spare capacity of in excess of 100 Kbopd in this export route and the Board believes there is potential for new adjacent operations to utilise the export pipeline, including a number of undeveloped discoveries in Chad. Third-party consultant, Wood Mackenzie, has forecasted Chad-Cameroon Pipeline volumes, denoted as the "Upside" case in the Chad-Cameroon CPR, for the 2022 to 2030 period as approximately 30 per cent. higher than Savannah's base case assumed profile, with most of the upside coming from existing third-party shippers.

CGG estimates asset free cashflow of US$337.0 million is attributable to the Exxon Target Companies interests in the Chad-Cameroon ETS and US$244.7 million is attributable to the PETRONAS Target Companies interests in the ETS over the next nine years under Savannah's base case.

### 4.3 An asset portfolio with significant upside potential

In addition to the available capacity in the Chad-Cameroon ETS, there is additional undeveloped upside in the Doba Oil Project. No wells have been drilled on the fields by the current operator since 2015 and Savannah intends to make further investments in the fields, including drilling an average of 12 wells per year from 2023. Savannah is also considering various production techniques to improve and enhance oil recovery. The Doba Oil Project has gross Proved Undeveloped Reserves (1P) of 15.7 MMstb and gross Proved & Probable Undeveloped (2P) Reserves of 23.9 MMstb, estimated by CGG.

CGG estimates combined asset free cashflow from the Doba Oil Project and the Chad-Cameroon ETS of US$113.0 million is attributable in aggregate to the Exxon Target Companies in 2022 and US$689.2 million over the next nine years. CGG further estimates combined asset free cashflow from the Doba Oil Project and the Chad-Cameroon ETS of US$71.4 million is attributable to the PETRONAS Target Companies in 2022 and US$540.9 million over the next nine years. CGG estimates that 49 per cent. of the Exxon Target Companies and 45 per cent. of PETRONAS Target Companies' cashflow is derived from long-dated, non-oil-price dependent revenue streams.

### 4.4 Make a material contribution to the economic development of Chad and Cameroon

The oil industry has a significant, wide-ranging impact on Chad's economy and the Doba Oil Project has been at the forefront of this. In addition to the billions of dollars of revenues, royalties and taxes that have flowed directly to the Chadian government, the Doba Oil Project has contributed to the growth of the economy through local employment, the training and development of thousands of workers, purchases of hundreds of millions of dollars of goods and services from local providers and the transfer of business and technical knowledge. The Board believes that Savannah's plans for further investment into the Doba Oil Project will make a material contribution to the economic development of Chad. Likewise, continued transportation of oil through the Chad-Cameroon Pipeline will provide long-term employment and training opportunities for local providers.

### 4.5 Platform for further growth in Chad with synergies with the Existing Group's businesses

The Board considers that the Exxon Acquisition and the PETRONAS Acquisition will provide a platform to build a material business with further regional consolidation opportunities in Chad with synergies with the Existing Group's businesses and operations in Nigeria and Niger.

## 5. Chad and its Oil and Gas Industry

### 5.1 Reserves and Resources

Chad has a proven petroleum system and ranks as the tenth-largest oil reserve holder among African countries, with 1.5 billion barrels of Proved Reserves as of 2020 and average production of over 140 Kbopd in 2020. Chad's undeveloped but discovered Resources are estimated by Wood Mackenzie to be 366 MMbbls. These are mainly held by CNPC, OPIC and Glencore in southern Chad. In addition, the EIA and Advanced Resources International Inc. estimate that Chad holds around 40 Bnbbl of oil and 40 Tscf of gas of potential yet-to-find, conventional resource, which suggests that further discoveries should be possible. Of this, the recoverable amounts could be of the order of 10 Bnbbls of oil and over 20 Tscf of gas.

### 5.2 Production

Chad became an oil producing nation in 2003 when the Doba Oil Project came onstream, exporting oil via the Chad-Cameroon ETS.

In 2011, CNPC developed the Block H fields in southern Chad. Initially production supplied a 20 Kbopd new-build refinery outside the capital, N'Djamena, jointly owned by CNPC (60 per cent.) and SHT (40 per cent.), via a 311 km pipeline. With increasing production, CNPC started exporting surplus oil in 2013 via the Chad-Cameroon ETS and is currently the largest producer in Chad with approximately 100 Kbopd produced in 2020.

In 2013, Glencore brought the Badila and Mangara fields onstream and the Taiwanese Chinese Petroleum Corp (operating as OPIC) started production and exports from the Benoy development in 2020.

### 5.3 Oil sector contribution to Chad's economy

The oil industry has a significant, wide-ranging impact on Chad's economy. Since the introduction of oil production, the previously agrarian economy's GDP per capita has grown from US$221 in 2002 to US$710 in 2019. While the oil sector accounts for 18 per cent. of Chad's GDP, it constitutes a much higher share of Chad's balance of payments (being equivalent to 83 per cent. of foreign direct investment, 79 per cent. of exports and 65 per cent. of services).

In addition to the billions of dollars of revenues, royalties and taxes which have flowed directly to the Chadian government, the oil industry has contributed to the growth of the economy through local employment, training and development of thousands of workers, purchases of hundreds of millions of dollars of goods and services from local providers and the transfer of business and technical knowledge.

For further information about Chad and Cameroon and the Chad/Cameroon Assets, refer to Part 4 of this document.

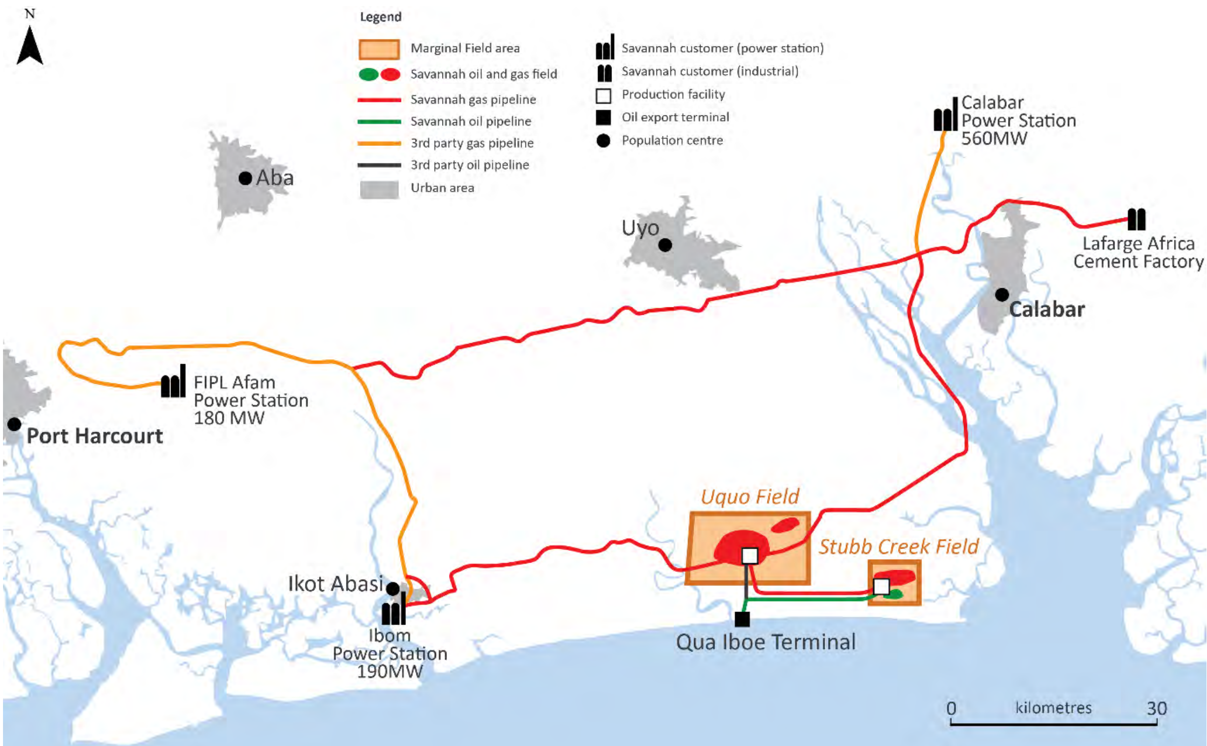
## 6. Company History and Existing Assets

Savannah is a leading, Africa-focused, British independent energy company quoted on AIM. The Company is the holding company of the Existing Group and currently operates from offices in the UK (London), Nigeria (Abuja, Lagos, Eket and Uyo) and Niger (Niamey).

The Company currently has two high-quality and high-growth business units located in Nigeria and Niger.

### 6.1 Nigeria

*Figure 9, Savannah's Operations in South East Nigeria*




*Source: Company materials*

In Nigeria, the Company has a significant controlling interest in a large-scale integrated gas production and distribution business which is currently supplying gas to facilitate over 10 per cent. of Nigeria's thermal power generation. The Company acquired the Nigerian Assets in November 2019 (refer to the April 2020 Supplemental Admission Document for further information).

The Nigerian Assets comprise interests in two large-scale oil and gas fields, the Uquo non-associated gas field and the Stubb Creek oil and gas field, with net 2P Reserves and net 2C Resources, as estimated by CGG in the 2021 Nigeria CPR, of 79.3 MMboe and 60.0 MMboe respectively and the Accugas Midstream Business, all of which are located in South East Nigeria.

In relation to the Nigerian Assets, Savannah indirectly holds:

- **Uquo Field** – an 80 per cent. economic interest in the exploration, development and production of gas within the Uquo Field. The remaining 20 per cent. economic interest in the Uquo Field is held by AIIM.
- **Stubb Creek Field** – a 51 per cent. interest in the Stubb Creek Field. The remaining 49 per cent. interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited.
- **Accugas Midstream Business** – an 80 per cent. interest in the Accugas Midstream Business. The remaining 20 per cent. of the Accugas Midstream Business is held indirectly by AIIM.

Gas produced from the Uquo Field is processed and transported through Accugas Limited's infrastructure, which includes a 200 MMscfpd processing facility and an approximate 260 km gas pipeline network to end user gas customers. The Company's five current gas sales agreements are with the Calabar Electricity Generation Company Ltd, which owns and operates the Calabar power station, Lafarge Africa PLC, which owns the Mfamosing cement plant, Ibom Power, the operator of the Ibom power station, FIPL, the owner of the FIPL Afam power station, and Mulak Energy to supply gas to their proposed Compressed Natural Gas ("CNG") project in Nigeria.

The Stubb Creek Field comprises both a producing oil field and an undeveloped gas field. Oil production is exported via ExxonMobil's Qua Iboe Terminal. It is intended that the gas field will be developed when required in the future to supplement gas production from the Uquo Field.

*Figure 10, Summary of Nigeria Gross and Net(1) 2P Reserves and 2C Resources*

| | *2P Reserves* | | *2C Resources* | |
|---|---|---|---|---|
| ***Oil (MMstb)*** | *Gross* | *Net* | *Gross* | *Net* |
| Uquo | 0.6 | 0.5 | – | – |
| Stubb Creek | 13.4 | 3.1 | – | – |
| | 14.0 | 3.6 | – | – |
| **Gas (Bscf)** | | | | |
| Uquo | 567.3 | 453.9 | 82.8 | 66.2 |
| Stubb Creek | – | – | 515.3 | 293.7 |
| | 567.3 | 453.9 | 598.1 | 359.9 |
| **Total (MMboe)** | **108.6** | **79.3** | **99.7** | **60.0** |

*Source: Nigeria CPR*

*Notes:*

(1) Net to Savannah

### 6.2 Niger

The Company's interests in Niger are located in the highly prospective Agadem Rift Basin ("ARB") in South East Niger and cover an area of approximately 13,655 km$^2$. The ARB, which is comparable in scale to the North Sea rift system and forms part of the Central African Rift System, has proven to be one of the world's most successful exploration provinces since 2008 with an estimated 1 Bnbbls 2P Reserve base established and an exploration success rate of over 80 per cent. The Central African Rift System runs through Niger, Chad, Sudan, South Sudan and also Nigeria, with over 6 Bnbbls of oil discovered to date.

The Company's interests, which were acquired during 2014 and 2015, cover approximately 50 per cent. of the ARB, and of the original Agadem PSC area which was compulsorily relinquished by CNPC in July 2013. The Company has proven its ability to operate in Niger, delivering a highly successful exploration drilling programme in 2018 on R3 East with five discoveries from five wells across five fields. The Company also conducted a 36,948 km full tensor gravity survey over the ARB as well as 806 km$^2$ 3D seismic over part of the R3 portion of the R3/R4 PSC Area. The Company has a strong operational track record in Niger, with all projects having been delivered with no lost-time incidents and ahead of budgeted time. The initial term of the Exclusive Exploration Authorisation on the R1/R2 PSC, as extended in 2018, expired on 5 August 2019. Furthermore, the term of the Exclusive Exploration Authorisation on the R3/R4 PSC, expired on 31 August 2021. Since the expiration of the Exclusive Exploration Authorisation of both the R1/R2 PSC and R3/R4 PSC the Company held negotiations with the Niger government to renew the PSCs and, on 29 September 2021, the Company reached an agreement in principle with the Ministry of Petroleum to formally renounce the R1/R2 PSC and the R3/R4 PSC and to combine the R1/R2 PSC Area with the R3/R4 PSC Area into one amalgamated R1234 PSC. This resets the Company's PSC licence validity periods to up to 10 years for the exploration phase, comprising an initial term of four years, with the option to extend this term by two further terms of two years each. In addition, one of these three terms can be extended by the Company for a further two years. The amalgamated R1234 PSC was approved by the Council of Ministers in Niger on 16 December 2021 and is now subject to the payment of a signature bonus by the Company. The Company anticipates that the R1234 PSC will become effective in Q1 2022.

The Company's current focus in Niger is the delivery of first production and cashflows from the planned R3 East early production scheme to be located at the Amdigh field and initially commencing in 2022, subject to market conditions and financing. The Board believes that significant further potential exists on its licence area in Niger with an exploration portfolio containing a total of 146 potential exploration targets with a total Unrisked Best Estimate of approximately 6.7 Bnbbls Oil Initially In Place. The Board believes that this has the potential to deliver meaningful cashflows to the Group in the future.

Further information on the Company's Nigerian Assets is set out in this Part 1, Part 5 and Part 10 of this document. Further information on the Company's Nigerien Assets is set out in this Part 1, Part 6 and Part 11 of this document.

## 7. Oil Price History and Forecast

The price of oil is affected by numerous factors including global supply and demand, together with expectations regarding future supply and demand for oil and the availability of alternative sources of energy. The price of oil is also affected by the desire of members of OPEC and, more recently, OPEC+ to set and maintain specified levels of production to support the oil price. Oil prices have fluctuated significantly over the last 20 years and this has been accentuated over the last two years as a result of the COVID-19 pandemic.

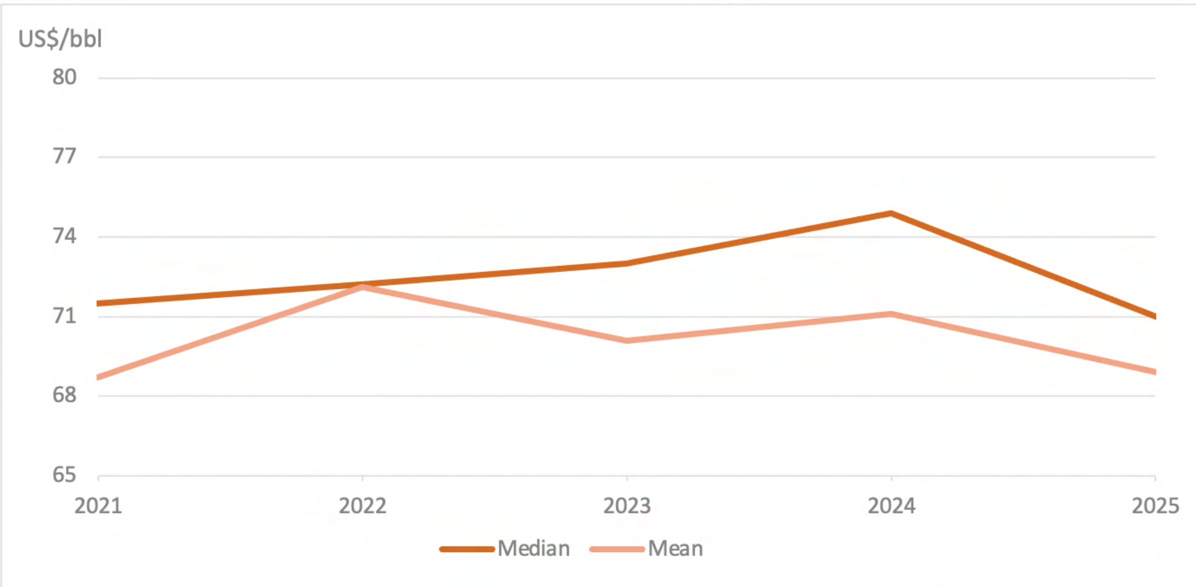
During the first quarter of 2020, global oil consumption experienced a downturn as a result of the COVID-19 pandemic. By April 2020, the demand for oil was 20 MMbopd less than pre-COVID-19 levels and the imbalance in demand and supply caused Brent prices to reach a low of US$9.12/bbl. At the end of April 2020, the members of OPEC+ agreed to cut production and non-OPEC nations such as the United States also significantly cut production, resulting in the balancing of supply and demand and the stabilisation of oil inventory levels, with oil prices recovering to approximately US$50/bbl by the end of 2020. Since then, oil prices continued to rise following an increase in demand due to the rollout of vaccination programmes and the recommencement of global economic activities. The Brent price is currently trading at approximately US$75/bbl, which is some 50 per cent. higher than its value of one year ago.

There is no direct link between the cost of sales (excluding depreciation and depletion which are non-cash items and the 2 per cent. statistical tax) for the Doba Oil Project and the oil price, with the costs being largely fixed plus an element of costs related to produced volumes. In circumstances where oil prices fall substantially, the Board expects that costs may be reduced, as industry activity levels decrease leading to services being offered at a lower price.

*Figure 11, Historical Brent Crude Price from 2000 to December 2021*


*Source: EIA*

*Figure 12, Bloomberg's Consensus Forecast Brent Price*




*Source: Bloomberg, December 2021*

The Exxon Acquisition and the PETRONAS Acquisition will increase the Enlarged Group's exposure to the oil price on an ongoing basis. The economic evaluation of the interests to be acquired in the Doba Oil Project as summarised in this Part 1 and included in Part 4 of this document is based on an oil price of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024, respectively. Beyond 2024, the price is escalated at 2 per cent. per year. The Chad/Cameroon CPR included in Part 9 of this document illustrates the effect of changing oil price assumptions on the future cashflows and underlying value of the Exxon Target Companies' and the PETRONAS Target Companies' assets.

## 8. Details of the Placing and Subscription

The Placing will raise net proceeds of approximately US$60.1 million for the Company. The Placing Shares are being placed with certain existing and new institutional and other sophisticated investors.

The Company has placed the Placing Shares at the Placing Price conditional on their admission, which is expected to occur at 8.00 a.m. on 7 January 2022. The Placing Shares will be issued pursuant to the existing pre-emption disapplication authority granted to the Directors by Shareholders at the annual general meeting of the Company held on 30 June 2021. The Placing Shares represent approximately 19.0 per cent. of the Company's Enlarged Share Capital.

The Placing Shares will rank *pari passu* in all respects with the Existing Ordinary Shares, including the right to receive all dividends and other distributions declared, paid or made after the date of issue, and will be placed free of any expenses and stamp duty.

In the case of investors receiving Placing Shares in uncertificated form, it is expected that the appropriate CREST accounts will be credited with the Placing Shares with effect from 7 January 2022. In the case of investors receiving Ordinary Shares in certificated form, it is expected that certificates will be dispatched by post, within 14 days of the date of admission.

Further details of the Placing Agreement are set out in paragraph 1.3 of Part 14 of this document.

Under the terms of the Placing Agreement, each purchaser of Placing Shares in the United States will be deemed to have represented and agreed as follows:

- The purchaser (a) is a qualified institutional buyer, or QIB, as defined in Rule 144A under the U.S. Securities Act of 1933, as amended, or a broker-dealer acting for the account of a QIB, (b) is acquiring such securities for its own account or for the account of a QIB, and (c) is aware that the securities are restricted within the meaning of the Securities Act and may not be deposited into any unrestricted depositary facility, unless at the time of such deposit the securities are no longer restricted.
- The purchaser is aware that the securities have not been and will not be registered under the U.S. Securities Act of 1933, as amended, and are being offered in the United States only to QIBs in a transaction not involving any public offering in the United States within the meaning of the Securities Act.
- The purchaser understands and agrees that the Placing Shares may not be offered, sold, pledged or otherwise transferred, except (a) to a person that the seller and any person acting on its behalf reasonably believe is a QIB purchasing for its own account or for the account of another QIB or (b) outside the United States in accordance with Regulation S under the U.S. Securities Act of 1933, as amended, or (c) pursuant to an exemption from registration under the Securities Act, or (d) pursuant to an effective registration statement under the Securities Act.

The Subscribers have agreed, pursuant to the Subscription Letters, to subscribe for the Subscription Shares at the Placing Price to raise approximately £2.77 million for the Company (net of commissions and expenses). The Subscription Shares shall rank *pari passu* in all respects with the Existing Ordinary Shares, including the right to receive all dividends and other distributions declared, paid or made after the date of issue and will be placed free of expenses or stamp duty.

The Placing and Subscription are not conditional on either or both of the Exxon Acquisition or the PETRONAS Acquisition completing.

## 9. Details of the Debt Financing

On 30 December 2021, Savannah Chad and the Senior Lender entered into an agreement pursuant to which the Senior Lender has agreed to provide to Savannah Chad an up to US$400 million borrowing base facility (US$300 million initial commitment with a US$100 million accordion). Savannah Chad intends to utilise the facility to partly fund the Exxon Acquisition and the PETRONAS Acquisition. Further details of the terms of the Debt Financing are set out in paragraph 3.1 of Part 14 of this document.

## 10. Details of the Junior Loan Facility and Warrant Instrument

On 30 December 2021, the Company entered into the Junior Loan Facility and the Warrant Instrument. Pursuant to the Junior Loan Facility, the Company's Chief Executive Officer, Andrew Knott, has committed to lend to the Company (via his wholly owned company, Lothian Capital Partners 4 Limited ("LCP4L")): (i) US$17 million to finance the Exxon Acquisition; and (ii) US$15 million to finance the PETRONAS Acquisition.

Warrants will be granted to Andrew Knott (via LCP4L) as lender under the Junior Loan Facility with a 90 month term and an exercise price of 23.5 pence. The number of Warrants to be issued is 101,113,992, calculated as the total value of the Junior Loan Facility (at the prevailing exchange rate on the date of signature) divided by the Exercise Price.

In structuring Andrew Knott's investment in the Junior Loan Facility, the Company consulted with Shareholders in the Company collectively holding more than 50 per cent. of the Existing Ordinary Shares who, having reviewed the terms of the Junior Loan Facility and Warrant Instrument, have indicated their support. The Company's entry into the Junior Loan Facility and the associated issue of Warrants is classified as a related party transaction pursuant to the AIM Rules – refer to paragraph 29 of this Part 1 for the Related Party Transaction opinion in this regard from the Directors, other than Andrew Knott, following consultation with the Company's Nominated Adviser, Strand Hanson.

Further details of the terms of the Junior Loan Facility and the Warrants are set out in paragraphs 3.2 and 3.3 of Part 14 of this document.

## 11. Use of Proceeds

The Company is raising gross proceeds of approximately US$65 million from the Placing and Subscription, which are currently intended to be used as listed in the table below:

| *Use of Proceeds* | *US$m* |
|---|---|
| Debt repayment | 15 |
| Corporate infrastructure investment | 10 |
| Exxon Acquisition and the PETRONAS Acquisition considerations and costs | 5 |
| General corporate purposes, including the Niger R3 East development, costs associated with the Placing, Subscription and Re-Admission to the date of this document | 35 |

The remainder of the Exxon Acquisition and the PETRONAS Acquisition considerations payable will be funded by the Junior Loan Facility and the Debt Financing.

It is noted that the Placing and Subscription is not conditional on either or both the Exxon Acquisition or the PETRONAS Acquisition completing. In the event that neither acquisition completes, the Company anticipates deploying the remaining net proceeds towards its existing asset base.

## 12. Summary Financial Information of the Exxon Target Companies and the PETRONAS Target Companies

The summary financial information presented below has been extracted without material adjustment from the historical financial information of the Exxon Target Companies and the PETRONAS Target Companies as set out in Part 7 of this document.

A review of the recent trading performance of the Exxon Target Companies and the PETRONAS Target Companies is set out in paragraph 15 of this Part 1.

### 12.1 Exxon Target Companies

The summary financial information presented below is an extract of the historical financial information of Exxon Target Companies as set out in Parts 7B and 7C of this document. The summary financial information for the year ended 31 December 2020 has been derived from Exxon Target Companies' Financial Information. The summary financial information for the six months ended 30 June 2021 has been derived from the Exxon Target Companies' Interim Financial Information.

*Figure 13, Summary Financial Information of the Exxon Target Companies*

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME SELECTED LINE ITEMS**

| | *Year ended 31 December 2020 US$'000* | *Six months ended 30 June 2021 US$'000* |
|---|---|---|
| Revenue | 133,468 | 122,110 |
| Operating (loss)/profit | (585,006) | 209,501 |
| (Loss)/profit before tax | (601,396) | 201,513 |
| (Loss)/profit after tax | (241,304) | 77,977 |

**CONSOLIDATED STATEMENT OF FINANCIAL POSITION SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Total assets | 1,081,745 | 1,119,231 |
| Total liabilities | 733,277 | 692,786 |
| Net assets | 348,468 | 426,445 |

**CONSOLIDATED CASH FLOW STATEMENT SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Cash used in operating activities | (45,400) | (42,024) |
| Cash provided by investing activities | 9,305 | 29,128 |
| Cash provided by financing activities | 36,080 | 12,889 |
| Net cash outflow | (15) | (7) |

### 12.2 PETRONAS Target Companies

The summary financial information presented below is an extract of the historical financial information of PETRONAS Target Companies as set out in Parts 7E and 7F of this document. The summary financial information for the year ended 31 December 2020 has been derived from the PETRONAS Target Companies' Financial Information. The summary financial information for the six months ended 30 June 2021 has been derived from the PETRONAS Target Companies' Interim Financial Information.

*Figure 14, Summary Financial Information of the PETRONAS Target Companies*

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME SELECTED LINE ITEMS**

| | *Year ended 31 December 2020 US$'000* | *Six months ended 30 June 2021 US$'000* |
|---|---|---|
| Revenue | 170,656 | 132,002 |
| Operating (loss)/profit | (531,280) | 54,197 |
| (Loss)/profit before tax | (529,470) | 56,873 |
| (Loss)/profit after tax | (277,858) | 54,295 |

**CONSOLIDATED STATEMENT OF FINANCIAL POSITION SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Total assets | 429,178 | 457,154 |
| Total liabilities | 204,236 | 217,917 |
| Net assets | 224,942 | 239,237 |

**CONSOLIDATED CASH FLOW STATEMENT SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Cash generated from operating activities | 1,106 | 36,995 |
| Cash provided by investing activities | 2,521 | 22,328 |
| Cash used in financing activities | (25,000) | (40,000) |
| Net cash (outflow)/inflow | (21,373) | 19,323 |

### 13. Summary Financial Information of the Existing Group

The summary financial information presented below is an extract without material adjustment from the audited consolidated financial statements for the Existing Group for the year ended 31 December 2020 and the unaudited interim financial information for the six months ended 30 June 2021.

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME SELECTED LINE ITEMS**

| | *Year ended 31 December 2020 US$'000* | *Six months ended 30 June 2021 US$'000* |
|---|---|---|
| Revenue | 169,005 | 99,386 |
| Operating profit | 93,310 | 53,993 |
| Profit before tax | 10,908 | 7,688 |
| Loss after tax | (5,974) | (1,377) |

**CONSOLIDATED STATEMENT OF FINANCIAL POSITION SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Total assets | 1,207,209 | 1,238,230 |
| Total liabilities | 980,272 | 1,011,123 |
| Net assets | 226,937 | 227,107 |

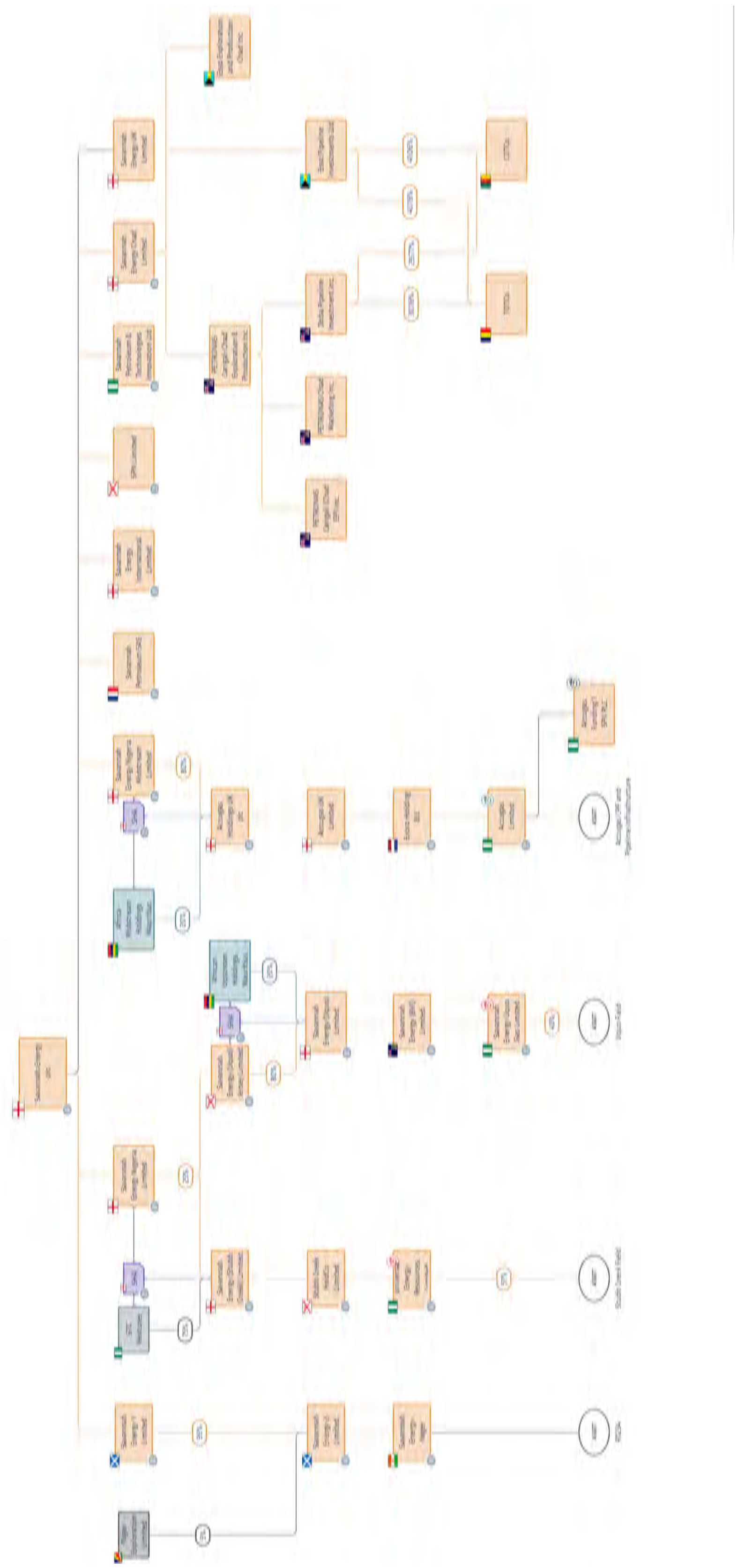
**CONSOLIDATED CASH FLOW STATEMENT SELECTED LINE ITEMS**

| | | |
|---|---|---|
| Cash generated from operating activities | 115,569 | 65,183 |
| Cash used in investing activities | (11,325) | (4,849) |
| Cash used in financing activities | (76,719) | (53,682) |
| Net cash inflow | 27,525 | 6,652 |

### 14. Anticipated Corporate Structure

Following Completion of both the Exxon Acquisition and the PETRONAS Acquisition, the anticipated structure of the Enlarged Group is shown in Figure 15.

*Figure 15, Anticipated Enlarged Group Structure Chart*



*Source: Company materials*

## 15. Current trading of the Enlarged Group

### 15.1 Existing Group

Average gross daily Nigeria production in the year-to-date period ended 31 October 2021 was 21.9 Kboepd, a 16 per cent. increase from the average gross daily production of 19.0 Kboepd in the same period in 2020. Of the total average gross daily production of 21.9 Kboepd in the year-to-date period, 88 per cent. was gas, including a 16 per cent. increase in production from the Uquo gas field compared to the same period last year, from 99.5 MMscfpd (16.6 Kboepd) to 115.6 MMscfpd (19.3 Kboepd).

The Nigerian Assets year-to-date cash collections for the period ended 13 December 2021 amount to US$201.3 million. This is 7 per cent. higher than FY20 cash collections of US$187.4 million and 20 per cent. higher than FY20 cash collections when an adjustment is made for the non-recurring US$20 million contract re-negotiation payment received from Lafarge Africa in FY20.

The Uquo-11 gas producer well has been drilled and was completed in the D1.0 and D1.3/D1.4 reservoirs on 16 November 2021. The well total net pay thickness was 71ft above prognosis, with a total thickness of 355ft for the main reservoirs' targets (C9.0, D1.0 and D1.3/D1.4 reservoirs).

The Existing Group also started ordering compression equipment for the Accugas gas processing plant during the first half of 2021. Factory Acceptance Tests for the two compressor packages have been successfully carried out, the Front-End Engineering Design is in progress and Long Lead Items are expected to be ordered before the year end. Both the drilling and compression projects will ensure Savannah's continued ability to deliver gas at current and anticipated future increased contracted volumes to satisfy customer demand.

Refer to the earlier text of this document on the current state of the Existing Group's Nigerien Assets.

The Existing Group is progressing towards refinancing its US$371 million Accugas Term Debt Facility, which currently has a maturity date of 31 December 2025, into a multi-tranche, Naira denominated borrowing structure. It is currently anticipated that the refinancing will complete during the first half of 2022, although there can be no guarantee this will occur. The intended structure is summarised as follows:

- **Tranche 1:** (approximately 25 per cent. of total) Bilateral loan up to a15-year tenor and indicatively priced around 10-year Nigeria government bond rate plus 3.5 per cent.
- **Tranche 2:** (approximately 50 per cent. of total) Nigerian listed bond, up to 12-year tenor.
- **Tranche 3:** (approximately 25 per cent. of total) Bank loan, up to 5-year tenor.

Once completed, this refinancing would align the currencies of the Existing Group's principal revenue streams with its debt service obligations and would significantly reduce the Existing Group's foreign exchange exposure. It would also bring further benefits through the significant increase in tenor and intended removal of the cash sweep structure. The Existing Group currently holds certain Naira denominated cash balances and approximately US$109.0 million will be paid for debt service from these accounts.

### 15.2 Recent performance of the Exxon Target Companies and the PETRONAS Target Companies

The tables below have been extracted from the Exxon Target Companies' Financial Information, the Exxon Target Companies' Interim Financial Information, the PETRONAS Target Companies' Financial Information and the PETRONAS Target Companies' Interim Financial Information and expands on the summary financial information referred to in paragraph 12 above and in Part 7 of this document.

The tables below show the underlying EBITDA performance (and EBITDA adjusted for impairment where relevant), for both the Exxon Target Companies and PETRONAS Target Companies for the year ended 31 December 2020 and for the six months ended 30 June 2021. The relative increase is principally due to the improvement in the oil price which is discussed in paragraph 7 of this Part 1 (Oil Price History and Forecast Overview).

***Exxon Target Companies***

| | *Audited Year ended 31 December 2020 US$'000* | *Unaudited Six months ended 30 June 2021 US$'000* |
|---|---|---|
| (Loss)/profit before tax | (601,396) | 201,513 |
| Add back: | | |
| Depletion and depreciation | 114,171 | 135,454 |
| Finance income | (511) | (165) |
| Finance costs | 20,900 | 11,783 |
| EBITDA | (466,836) | 348,585 |
| Add back: | | |
| Impairment/(impairment reversal) | 471,693 | (267,109) |
| | **4,857** | **81,476** |

***PETRONAS Target Companies***

| | *Audited Year ended 31 December 2020 US$'000* | *Unaudited Six months ended 30 June 2021 US$'000* |
|---|---|---|
| (Loss)/profit before tax | (529,470) | 56,873 |
| Add back: | | |
| Depletion and depreciation | 44,375 | 15,648 |
| Finance income | – | (26) |
| Finance costs | 1,702 | – |
| EBITDA | (483,393) | 72,495 |
| Add back: | | |
| Impairment | 547,007 | 3,638 |
| | **63,614** | **76,133** |

In the six months ended 30 June 2021, the Exxon Target Companies lifted 1.911 MMbbls of crude oil at an average price of US$63.84/bbl, compared to 3.771 MMbbls in the year ended 31 December 2020 at an average price of US$35.27/bbl. The PETRONAS Target Companies lifted 1.959 MMbbls of crude oil in the six months ended 30 June 2021 at an average price of US$67.38/bbl, compared to 3.826 MMbbls in the year ended 31 December 2020 at an average price of US$44.69/bbl.

With respect to current production, average daily gross production for the year-to-date period ended 30 September 2021 from the Doba Oil Project amounted to 28.8 Kbopd compared to 34.1 Kbopd during the same period in 2020. The reduction in production in 2021 has primarily been due to a workforce strike and unscheduled downtime at the Miandoum Gathering Station requiring additional maintenance work. However, the increase in oil price in 2021 compared to 2020 has offset the financial impact of the lower production volumes.

## 16. Future prospects of the Company

Savannah is focused on the delivery of projects that matter in Africa. The Enlarged Group will have a valuable and stable asset base that provides a strong platform for future and sustainable growth and the Directors believe that energy companies can create substantial value by acquiring or discovering oil and gas reserves and resources at a significant discount to the net present value per share of the cashflows that they are capable of subsequently realising from those reserves and resources.

The Company continues to actively review new acquisition opportunities in its core African region focused predominantly on:

- cash-generative, or near-term cash-generative, upstream and midstream assets; and/or
- "Bolt-on" assets for which there is significant synergistic value to its existing operations.

In the case of the former, typically larger opportunities, the Company's focus is on those that:

- are being offered by vendors who are divesting assets for strategic reasons; and
- significantly enhance the Company's ability to commence and accelerate shareholder distributions, by way of dividend and share buy-backs.

The Company also keeps under review the best avenue for developing its Nigerien Assets and Nigerian Assets, which may, in due course, result in the Company seeking independent finance for each business.

Savannah's business model is underpinned by the Company's entrepreneurial and proactive culture. Savannah focuses on generating long-term value over short-term results and aims to move quickly to take advantage of opportunities that arise and to react promptly to changes in the business environment.

## 17. Directors and Senior Managers

### 17.1 Directors

**Stephen ("Steve") Ian Jenkins,** aged 63 – *Independent Non-Executive Chair*

Steve joined Savannah as Non-Executive Chairman in July 2014. In the Board's view, he is widely recognised as one of the most capable oil and gas executives in the UK, having delivered for his investors as CEO of Nautical Petroleum plc a £414 million sale to Cairn Energy plc in Q3 2012. Prior to Nautical Petroleum, Steve held a variety of senior roles at Nimir Petroleum Co. Ltd, an emerging-markets focused private Saudi Arabian company with extensive global exploration and production interests. Steve is a geologist by profession and is currently Chair of the Oil and Gas Independents' Association, one of the principal oil and gas trade bodies in the UK.

**Rt. Hon. Sir Stephen Rothwell O'Brien,** aged 64 – *Independent Non-Executive Vice Chair*

Sir Stephen is a former UN Under-Secretary-General for Humanitarian Affairs and Emergency Relief Coordinator. Prior to this role he was a British MP, during which time he served as Parliamentary Under-Secretary of State for International Development and as the Prime Minister's Envoy & UK Special Representative for the Sahel as well as a series of shadow ministerial roles. Before entering politics, Sir Stephen was International Director and Group Secretary of the FTSE 100 listed global building materials company, Redland plc. Sir Stephen began his career as a corporate lawyer with Freshfields Bruckhaus Deringer LLP. He currently is Chair of Motability Operations Group plc and the Innovative Vector Control Consortium, a Non-Executive Board Member of the UK's Department for International Trade and advises a number of international companies, non-profits and academic institutions. Sir Stephen is a serving member of the Privy Council and was knighted in 2017 for his achievements and commitments to international development, global health advocacy and malaria control.

**Andrew Allister Knott,** aged 41 – *Chief Executive Officer*

Andrew is the principal founder of Savannah, becoming a Director of the Company in July 2014. Andrew has led all of the Company's key growth initiatives, including the country entries to Niger, Nigeria, Chad and Cameroon. Prior to establishing Savannah, Andrew was Head of Global Energy Investments for GLG Partners/MAN Group which, in December 2012, was the largest listed hedge fund in the world by assets. Andrew previously held various roles at Merrill Lynch and Dresdner Kleinwort Wasserstein.

**David Clarkson,** aged 69 – *Independent Non-Executive Director*

David was formerly a member of BP's Group Leadership Team and Senior Vice President for Projects and Engineering (Upstream). He built his career creating value by delivering complex major infrastructure projects in frontier areas and gained a deep knowledge of the oil and gas industry and the need for engaging with local communities, government authorities and NGOs to build mutual trust and respect. Over the course of his BP career, David held a variety of other senior project management and delivery roles in countries including Iraq, Indonesia, Colombia, the USA, and the UK. He joined the Savannah Board in December 2017 as Non-Executive Director. Between June 2018 and December 2019, David acted as the Company's

Chief Operating Officer and during that time led Savannah's operations as the Company carried out its five well Niger drilling campaign as well as the integration of the Nigerian Assets. In December 2019 he resumed his Non-Executive Director role. In September 2020 he joined Storegga Geotechnologies Limited, an independent focused on the development and deployment of carbon reduction and carbon removal technologies, as Chief Operating Officer. He was appointed to the Storegga board in July 2021. David is a Chartered Engineer and Fellow of the Institute of Mechanical Engineers.

**Marco ("Mark") Iannotti,** aged 53 – *Independent Non-Executive Director*

Mark was appointed to the Board of Savannah in July 2014. He is an experienced capital markets professional with over 20 years' experience in EMEA equities, which has been largely focused on the oil and gas sector. Mark has held senior management positions at Canaccord Genuity Group Inc where he was Managing Director and Head of Securities, UK & Europe and Bank of America Merrill Lynch where he was a member of its EMEA Executive Committee and Head of its EMEA Equity Research Division. Mark began his career at Wood Mackenzie Consultants, focusing on the Asian and Indian sub-Continent energy markets. He subsequently held senior equity research positions at Cazenove & Co, Credit Suisse and Citigroup. Mark is currently Non-Executive Chair of Djado Gold plc.

**David Lawrence Jamison,** aged 77 – *Independent Non-Executive Director*

David was appointed to the Board of Savannah in July 2014. He was one of the founders of the modern-day Vitol, having executed a management buyout of the company alongside three partners in 1976. He left Vitol in 1986 to operate as an independent venture capitalist in the upstream oil and gas industry. David's principal investment vehicle today is DLJ Partners Ltd which seeks to act as agent and advisor on upstream oil and gas transactions. Previous companies at which David has held integral roles include Russian focused oil and gas company Sibir Energy plc (founder director) and independent gasoline company Blue Ocean Associates Limited (founder director).

### 17.2 Senior Managers

In addition to the Directors, the following Senior Managers will ensure that the Enlarged Group has appropriate expertise and experience for the management of its business.

**Nicholas ("Nick") Beattie,** aged 48 – *Interim Chief Financial Officer*

Nick is the Company Secretary and Interim CFO. Nick joined Savannah in 2019 from another AIM quoted E&P company and has an extensive background in financing oil and gas companies including seven years with BNP Paribas where he was a Managing Director in the Upstream Oil and Gas team in London and responsible for leading the bank relationships with UK focused independent E&P companies. Nick is a Fellow of the Chartered Banker Institute and a Member of the Chartered Institute for Securities and Investment.

**Antoine Richard,** aged 54 – *Chief Operating Officer*

Antoine joined Savannah in 2016. Antoine has over 25 years' experience working for both major and independent oil and gas companies worldwide, having worked for Total Energies SE and Perenco SAs, with over 10 years' experience in West Africa. He has a strong operational background, with a focus on production optimisation, onshore and offshore facilities design and operation and management of drilling campaigns and seismic acquisition programs. His previous positions within Perenco included Global HSE Manager and General Manager roles for Congo, Egypt and Venezuela. Antoine acted as Savannah's VP Operations from 2016 until 2018, over which time he delivered the Company's 806 $km^2$ R3 East 3D seismic acquisition campaign with no lost-time incidents and within budgeted time and also left Savannah well-placed to deliver its successful five well R3 East exploration campaign which achieved a 100 per cent. success rate. As Chief Operating Officer, Antoine has responsibility for group-wide operations.

### 17.3 Appointment of permanent CFO

The Board intends, within H1 2022 and, in any event, ahead of the anticipated Completion of the Exxon Acquisition and the PETRONAS Acquisition, to appoint a permanent CFO, which will also be a board level position. Further updates will be made as and when appropriate.

### 17.4 Appointment of new Directors

Pursuant to a process initiated in H1 2021, the Company intends to appoint up to four new Non-Executive Directors to its Board in H1 2022.

## 18. Environmental, Social and Governance

Savannah is committed to managing its operations in a safe, secure, reliable and environmentally sustainable manner, and to act in a responsible manner towards its stakeholders. Savannah considers that a high standard of health and safety performance and environmental protection is critical to the ongoing success of the Company and the Enlarged Group. The Company has Environmental, Social and Governance ("ESG") policies in place and reports its performance to the Board through the Health, Safety, Security and Environmental ("HSSE") Committee and to its stakeholders through its Annual Report and other corporate updates. The Company expects its employees, contractors and partners to comply with these policies and to enforce similarly high standards.

The Company also has a robust HSSE management system in place which aligns with international management system standards and local legislation, takes a proactive approach to the identification and management of HSSE risks and is underpinned by on-site leadership and through a leading indicator monitoring approach to building safe working practices.

In 2020, Savannah undertook a thorough review of its sustainability strategy, taking into account the feedback of an extensive consultation exercise conducted with the Company's key external and internal stakeholder groups. Following this exercise, the Company refocused its sustainability strategy around four strategic pillars which are aligned with the United Nations Sustainable Development Goals ("UN SDGs") that the Company believes it can have the biggest economic, environmental, social and governance impact to achieve a better and more sustainable future for all. While anchoring the sustainability strategy around the 13 most relevant UN SDGs to Savannah, the Company has integrated six additional sustainability reporting standards into its new performance and reporting framework. These were selected on the basis of those most relevant for the sector and of most importance to stakeholders and include the Global Reporting Index, International Petroleum Industry Environmental Conservation Association, the International Association of Oil & Gas Producers, Sustainability Accounting Standards Board, Task Force on Climate Related Disclosures and the International Finance Corporation key performance standards.

During 2021, the Company has been rolling out the new sustainability performance and reporting framework across the Group and plans to provide measurable, verifiable and trackable performance metrics for this going forward. This will allow the Company to set meaningful sustainability performance targets for the Group and track its progress against these, which will form the basis of the Company's sustainability reporting from 2022 onwards. As an initial step on this path, the Company reported performance against key sustainability metrics in the 2020 Annual Report for carbon intensity (12.8kg CO2e/boe versus industry average 17.0kg CO2/boe), senior management gender diversity (35 per cent. female) and local employee ratios (99 per cent.), all of which were industry leading.

## 19. Summary of competition

Savannah's operations are currently focused on West Africa, specifically, Niger and Nigeria, and should the Exxon Acquisition or the PETRONAS Acquisition complete, also Chad and Cameroon.

On Completion of both the Exxon Acquisition and the PETRONAS Acquisition, the Enlarged Group will have a 75 per cent. operated interest in the Doba Oil Project and 70.34 per cent. and 70.83 per cent. interests respectively in TOTCo and COTCo, which collectively own the Chad-Cameroon ETS. The Chad-Cameroon ETS, which is currently operated by the Exxon Target Companies under the TOTCo and COTCo Conventions, is the sole oil export infrastructure, spanning nearly 1,100 km, for all oil production from Chad. The Chad-Cameroon ETS has a nameplate capacity of 250 Kopd and production from the Doba Oil Project has priority over third party shippers using this export system. Based on 2020 throughput, there is in excess of 100 Kbopd spare capacity in the Chad-Cameroon ETS.

Historically, the oil and gas industry has been highly competitive, particularly for acquiring assets and for securing trained and experienced personnel and services. However, the Board believes that the level of competition in the industry and in West Africa generally has reduced significantly and that this creates an opportunity for Savannah to acquire additional oil and gas assets over time, at attractive valuations. The seven super-major oil companies have all announced significant divestment programmes, including a number of assets and portfolios on the African continent, as they refocus their strategies through the energy transition to accelerate investments in renewable fuels and reduce their focus on fossil fuels. The Board believes that there is a relatively small group of independent energy companies with the necessary expertise and access to the capital required to acquire and operate these assets and to exploit these opportunities. Furthermore, the Board believes that the barriers to entry into the sector in Africa are high and, therefore, that Savannah has a competitive advantage over new entrants into the market.

### 20. Corporate governance

The Board recognises its responsibility for the proper management of the Company and the importance of sound corporate governance, proportionate to the size and nature of the Company and the interests of its shareholders. As an AIM-quoted Company, the Board is committed to maintaining high standards of corporate governance and has adopted the QCA Code as the basis of the Group's governance framework.

Refer to Part 13 of this document for a detailed description of the Company's corporate governance structure and practices.

### 21. The Takeover Code

The Company is a public limited company incorporated in England and Wales and is admitted to trading on AIM. Accordingly, the Takeover Code applies to the Company.

Under the Takeover Code a concert party arises when persons acting together pursuant to an agreement or understanding (whether formal or informal) cooperate to obtain or consolidate control of, or frustrate the successful outcome of an offer for, a company subject to the Takeover Code. Control means an interest or interests in shares carrying an aggregate of 30 per cent. or more of the voting rights of the company, irrespective of whether the holding or holdings give *de facto* control.

Under Rule 9 of the Takeover Code, where any person acquires, whether by a series of transactions over a period of time or not, an interest in shares which (taken together with shares in which persons acting in concert with that person are interested) carry 30 per cent. or more of the voting rights of a company which is subject to the Takeover Code, that person is normally required to make a general offer to all the shareholders of that company to acquire their shares. Similarly, when any person, together with persons acting in concert with him, is interested in shares which, in aggregate, carry not less than 30 per cent. of the voting rights of a company and does not hold shares carrying more than 50 per cent. of such voting rights and such person, or any person acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested, a general offer will normally be required in accordance with Rule 9.

An offer under Rule 9 must be made in cash (or be accompanied by a cash alternative) and at not less than the highest price paid by the person required to make the offer, or any person acting in concert with that person, for any interest in shares of the company during the 12 months prior to the announcement of the offer.

The Panel has previously deemed that a concert party is in existence between Andrew Knott and his family members, Aralia Capital SA (which also includes the holding of Peleng Holding Corporation, wholly owned by the same investor as Aralia Capital SA) and Luzon Investments S.A. (the "Existing Concert Party"). The Existing Concert Party is currently interested, so far as the Company is aware, in aggregate, in 48,836,749 Ordinary Shares, representing 4.90 per cent. of the Existing Share Capital.

Further details on the members of the Existing Concert Party are disclosed in the Company's circular to shareholders dated 11 March 2015.

Further information on the provisions of the Takeover Code can be found in paragraph 17 of Part 12 of this document.

### 22. Shareholder returns policy

The Directors view Savannah as a high cashflow growth company and expect to re-invest the majority of internally generated post-debt service cashflows in organic and in-organic growth projects consistent with our corporate strategy. However, the Directors also recognise the importance of paying a regular and growing dividend to Shareholders. Over the course of the next 12 months, the Company expects to formalise and announce a dividend policy centred around its underlying free cashflow generation, with the anticipation being that a minimum dividend of US$10 million would be paid in H1 2023 in respect of the financial year ending 31 December 2022.

## 23. UK Taxation

Information regarding UK taxation is set out in paragraph 16 of Part 12 of this document. This information is intended as a general guide only to the current tax position in the United Kingdom regarding withholding taxes and is not intended to constitute personal tax advice for any person. Prospective investors are strongly advised to consult their own independent professional tax advisers regarding the tax consequences of purchasing and owning Ordinary Shares.

## 24. Share Options

The Company considers it essential that its Directors, Senior Managers and employees are appropriately incentivised to create future value for the Shareholders. This is also relevant in the context of the Enlarged Group, whereby it will be important that key employees of the Exxon Target Companies and the PETRONAS Target Companies who become part of the Enlarged Group are appropriately incentivised.

### 24.1 Proposed amendments to existing awards

The Company disclosed in the December 2017 Admission Document, and reiterated in the April 2020 Supplemental Admission Document, an intention to amend the vesting and hurdle conditions of the 2014 Long-Term Incentive Plan and the 2015 Supplemental Plan (together the "Original Plans", details of the which are set out in paragraph 4 of Part 12 of this document), such that the exercise price for the options awarded under such Plans would be harmonised across both schemes at 38 pence per share, conditional upon the Company's Ordinary Shares meeting a hurdle vesting price condition of 42 pence per share (the "Proposed Amendments").

The Company did not subsequently implement the Proposed Amendments, and the Board has resolved that it would be preferential to replace the Original Plans for current employees and Directors with one new incentive plan (being the Employee 2014/15 Replacement Plan). The Employee 2014/15 Replacement Plan is designed to provide its participants with broadly similar economic exposure to that to which they would have been entitled to had the Proposed Amendments to their awards under the Original Plan been implemented. The new options proposed to be granted under the Employee 2014/15 Replacement Plan will have a hurdle vesting price condition of 42 pence per share and an exercise price of 38 pence per share. Further details of the Employee 2014/15 Replacement Plan are set out in paragraph 4 of Part 12 of this document.

The approval of Shareholders to the issue of the new Ordinary Shares, which will be issued in the event of the exercise of the options proposed to be granted under the Employee 2014/15 Replacement Plan, will be sought pursuant to Resolutions 6 and 11 to be proposed at the General Meeting. It is intended that all such options will be granted following the passing of Resolutions 6 and 11 at the General Meeting.

### 24.2 Proposed grant of new awards

Given the expected growth in activity and headcount in the Company, on 23 December 2021, the Company adopted the Employee Plan 2021. This plan is being put in place principally to enable the Company to continue to attract and retain high quality personnel. Awards of options under the Employee Plan 2021 will be granted over Ordinary Shares held by the EBT. As set out in paragraph 4.9.1 of Part 12 of this document, it is proposed that the EBT subscribes for a further 58,066,951 new Ordinary Shares at nominal value following the passing of Resolutions 4 and 8 at the General Meeting.

### 24.3 Proposed adoption of an Employee Share Incentive Plan

The Company intends in due course to adopt an Employee Share Incentive Plan (the "SIP") for the benefit of employees of the Enlarged Group. Further details of the SIP will be made available to Shareholders in due course.

## 25. General Meeting

Set out at the end of this document is a notice convening the General Meeting to be held at the offices of the Company, being 40 Bank Street, London E14 5NR, at 10.30 a.m. on 24 January 2022 at which the following Resolutions will be proposed:

- Resolution 1: an ordinary resolution to approve the Exxon Acquisition for the purposes of Rule 14 of the AIM Rules for Companies;
- Resolution 2: an ordinary resolution to approve the PETRONAS Acquisition for the purposes of Rule 14 of the AIM Rules for Companies;
- Resolution 3: an ordinary resolution to authorise the Directors to allot further Ordinary Shares representing up to 33 per cent. of the Enlarged Share Capital;
- Resolution 4: an ordinary resolution to authorise the Directors to allot the EBT Shares;
- Resolution 5: an ordinary resolution to authorise the Directors to allot the Warrant Shares;
- Resolution 6: an ordinary resolution to authorise the Directors to allot up to 23,853,457 new Ordinary Shares to satisfy awards to be granted under the Employee 2014/15 Replacement Plan;
- Resolution 7: a special resolution to disapply statutory pre-emption rights in relation to the allotment of further Ordinary Shares representing up to 33 per cent. of the Enlarged Share Capital;
- Resolution 8: a special resolution to disapply statutory pre-emption rights in relation to the allotment of the EBT Shares;
- Resolution 9: a special resolution to disapply statutory pre-emption rights in relation to the allotment of the Warrant Shares; and
- Resolution 10: a special resolution to disapply statutory pre-emption rights in relation to the allotment of up to 23,853,457 new Ordinary Shares to satisfy awards to be granted under the Employee 2014/15 Replacement Plan.

If Resolution 1 is not passed, the Exxon Acquisition will not proceed. If Resolution 2 is not passed, the PETRONAS Acquisition will not proceed. If Resolutions 5 and 9 are not passed, one or both of the Exxon Acquisition and the PETRONAS Acquisition may not proceed.

To be passed:

- Resolution 1 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 2 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 3 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 4 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 5 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 6 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 7 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour;
- Resolution 8 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour;
- Resolution 9 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour; and
- Resolution 10 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour.

The Company is planning to hold the General Meeting in person but, given the continued impacts of COVID-19, recommends that Shareholders do not attend the General Meeting in person and instead appoint the Chair of the General Meeting to act as their proxy.

The Company has been and will continue to closely monitor the continued impacts of COVID-19 and the related restrictions on public gatherings and the public health guidance issued by the UK Government. The Company is optimistic Shareholders will be able to attend in person, but given the continued uncertainty, there is a possibility that the Government may make changes to their current guidance which could impact this.

A decision that Shareholders are unable to attend the General Meeting in person, and any other necessary changes, will only be made if the Directors believe this is the most reasonable course of action when considering the current UK Government Guidance at the time of the General Meeting.

Any changes to the General Meeting arrangements will be communicated to Shareholders before the meeting through our website www.savannah-energy.com and, where appropriate, by RIS announcement.

Shareholders who plan to attend the meeting in person are asked not to attend the General Meeting if they are displaying any symptoms of COVID-19 or have recently been in contact with anyone who has tested positive. In order to further reduce the risk of the spread of the virus, the Company is encouraging shareholders who plan to attend the meeting in person to take a lateral flow test beforehand, on the day of the meeting. The General Meeting will also be more streamlined than previous meetings and we will not be serving refreshments. Shareholders are advised to arrive at the venue in plenty of time in order to complete registration formalities and comply with the venue's health and safety procedures.

**26. Restoration, Admission of the Placing Shares and Subscription Shares, settlement and CREST**

It is expected that Restoration will become effective and dealings in the Existing Share Capital will commence at 8.00 a.m. on 31 December 2021.

Application has been made for the admission of the Placing Shares and Subscription Shares to trading on AIM, which is expected to become effective and dealings in the Enlarged Share Capital will commence at 8.00 a.m. on 7 January 2022.

CREST is a paperless settlement system enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by written instrument in accordance with the CREST Regulations.

The Ordinary Shares are eligible for CREST settlement. Accordingly, following Restoration, settlement of transactions in the Ordinary Shares may continue to take place within the CREST system if a Shareholder so wishes.

CREST is a voluntary system and Shareholders who wish to receive and retain share certificates are able to do so.

For more information concerning CREST, Shareholders should contact their stockbroker.

**27. Risk factors and Additional Information**

Your attention is drawn to the additional information set out in Parts 2 to 14 (inclusive) of this document. **You are recommended to read all the information contained in this document and not just rely on the key or summarised information. In particular Shareholders should read in full the Risk Factors set out in Part 3 of this document.**

The technical information contained in this document, which has been extracted from the Competent Person's Reports in Parts 9 to 11 of this document, has been reviewed and approved by CGG. CGG has consented to the inclusion of the technical information extracted from the Competent Person's Reports in this document in the form and context in which it appears.

**28. Action to be taken**

In order to be valid, a proxy appointment must be made and returned by one of the following methods:

(a) by completion of the Form of Proxy, in hard copy form by post, or by courier to the registrar, Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol BS99 6ZY ("the Registrar");

(b) in the case of CREST members, by utilising the CREST electronic proxy appointment service in accordance with the procedures set out below; or

(c) by appointing your proxy electronically via the Registrar's website at www.investorcentre.co.uk/eproxy. You will need your Control Number, SRN & PIN which can be found on your Form of Proxy, and in each case, the appointment must be received not less than 48 hours before the time for holding of the General Meeting. In calculating such 48-hour period, no account shall be taken of any part of a day that is not a working day. A Shareholder that appoints a person to act on its behalf under any power of attorney or other authority and wishes to use method (a), (b) or (c) must return such power of attorney or other authority to Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol BS99 6ZY prior to using such method and in any event not less than 48 hours before the time of the General Meeting. If you hold your Ordinary Shares in uncertificated form (that is, in CREST) you may appoint a proxy by completing and transmitting a CREST message (a "CREST Proxy Instruction") in accordance with the procedures set out in the CREST manual so that it is received by the Registrar by no later than 10.30 a.m. on 20 January 2022, being 48 hours (excluding weekends and public holidays) before the time appointed for the holding of the General Meeting.

The completion and return of the Form of Proxy will not preclude Shareholders from attending the General Meeting and voting in person should they wish to do so. Accordingly, whether or not Shareholders intend to attend the General Meeting they are urged to complete and return the Form of Proxy as soon as possible.

**29. Related party transactions under the AIM Rules**

The participation in the Subscription by certain of the Directors, the Company's entry into the Junior Loan Facility and the associated issue of Warrants to Andrew Knott (through a vehicle controlled by him) are considered related party transactions pursuant to the AIM Rules.

The Directors independent of each of the above related party transactions, being David Jamison in relation to the participation of certain Directors in the Subscription, and all of the Non-Executive Directors in relation to the Company's entry into the Junior Loan Facility and the associated issue of Warrants, consider, having consulted with Strand Hanson Limited, the Company's Nominated Adviser, that the respective terms of each of the related party transactions are fair and reasonable insofar as Shareholders are concerned.

**30. Directors' recommendation and voting intention**

The Directors consider that the Exxon Acquisition and the PETRONAS Acquisition is in the best interests of the Shareholders and the Company as a whole, and, accordingly, the Directors recommend that Shareholders vote in favour of the Resolutions to be proposed at the General Meeting, as they have irrevocably undertaken to do so in respect of their own beneficial holdings, following the Subscription, of 57,461,087 Ordinary Shares, representing approximately 4.6 per cent. of the Enlarged Share Capital.

**Shareholders should note that in the event Resolutions 1, 2, 5 and/or 9 are not approved, amongst other things, one or both of the Exxon Acquisition and the PETRONAS Acquisition (as applicable) may not proceed. For this reason, the Company strongly encourages Shareholders to vote in favour of Resolutions 1, 2, 5 and/or 9 and the other Resolutions to be proposed at the General Meeting.**

Yours faithfully,

**Steve Jenkins**
*Independent Non-Executive Chair*

## PART 2

## EXXON ACQUISITION AND THE PETRONAS ACQUISITION OVERVIEW

**1. Exxon Acquisition**

1.1. On 12 December 2021, Savannah Chad and the Exxon Sellers entered into the Exxon SPA relating to the acquisition by Savannah Chad:

1.1.1. from Exxon Mobil Corporation, of a 100 per cent. shareholding interest in EEPCI, which holds a 40 per cent. participating interest in, and is operator of, the Doba OFDA; and

1.1.2. from ExxonMobil International Holdings Inc. and Esso Exploration Holdings Inc., of a 100 per cent. shareholding interest in EPIL, which in turn holds a:

1.1.2.1. 40.19 per cent. shareholding interest in TOTCo; and

1.1.2.2. 41.06 per cent. shareholding interest in COTCo.

1.2. Descriptions of the key terms of the Exxon SPA are set out in paragraph 2.1 of Part 14 of this document. Subject to Completion occurring, the Exxon SPA has an economic effective date of 1 January 2021.

***Acquisition Consideration***

1.3. The total approximate consideration payable by the Company for the Exxon Acquisition shall consist of:

1.3.1. US$255,600,000 in cash for the entire issued share capital of EEPCI (plus interest); plus

1.3.2. US$104,400,000 in cash for the entire issued share capital of EPIL (plus interest); plus or less *(as applicable)*

1.3.3. the sum of certain completion date adjustments (plus interest on certain of these adjustments), including: (i) a positive adjustment for (EEPCI's underlift position) of US$11.9 million as at the Economic Effective Date; (ii) a negative adjustment for any leakage from the Exxon Target Companies during the interim period; (iii) a positive adjustment for any contributions made to the Exxon Target Companies by the Exxon Sellers during the interim period; (iv) a negative adjustment for certain agreed cash amounts extracted from the Exxon Target Companies by the Exxon Sellers immediately prior to Completion; and (v) a negative adjustment to compensate for EEPCI failing to achieve its target production between 1 November 2021 and Completion; plus

1.3.4. to the extent that EEPCI fails to achieve its target production (should the effect on production capacity, following an incident affecting the water handling system at the Miandoum gathering station, not have been rectified) a negative adjustment at Completion proportionate to the extent to which the then current production falls short on the target production, followed by a contingent positive post-Completion non-interest bearing payments payable from the proceeds of EEPC's crude oil over a four year period post-Completion should the target production be re-achieved; plus

1.3.5. up to an aggregate of US$50,000,000 of non-interest bearing contingent consideration, by means of payment to ExxonMobil of 25 per cent. of the proceeds of sale of EEPCI's entitlement to crude oil (net of any royalty barrels or royalty payments due to the Government of Chad) received by EEPCI above US$55 per bbl and up to US$80 per bbl, between 1 January 2021 and 31 December 2023. The first of such payments shall be made at Completion.

***Conditions to Completion***

1.4. Completion of the Exxon Acquisition remains subject to a number of conditions, the most substantive of these outstanding conditions being:

1.4.1. Ministerial Consent;

1.4.2. waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the transfer of shares in EEPCI, or confirmation of the expiry of the relevant period within which such preferential rights may be exercised, without such rights having been exercised;

1.4.3. shareholder approval at the General Meeting;

1.4.4. EEPCI obtaining a settlement between EEPCI and the Government of Chad with respect to certain items, including all taxes or similar levies in relation to the activities of EEPCI prior to the Economic Effective Date, or an alternative arrangement having been agreed between the Exxon Sellers and Savannah Chad; and

1.4.5. material completion of the transfer of Exxon's IT systems used in the operation of the Exxon Target Companies and the Pipeline Companies to Savannah Chad that have been agreed to be transferred.

1.5 A description of the key terms of the Exxon SPA are set out in paragraph 2.1 of Part 14 of this document.

1.6 The Company has provided to the Exxon Sellers a parent company guarantee to guarantee the obligations of Savannah Chad under the Exxon SPA.

**2. PETRONAS Acquisition**

2.1. On 2 December 2021, Savannah Chad and PETRONAS entered into the PETRONAS SPA relating to the acquisition by Savannah Chad from PETRONAS of a 100 per cent. shareholding interest in PCCEPI, which holds:

2.1.1. a 100 per cent. shareholding interest in PC Chad, which holds a non-operating 35 per cent. participating interest in the Doba OFDA;

2.1.2. a 100 per cent. shareholding interest in Doba Pipeline, which in turn holds a:

2.1.2.1. 30.16 per cent. shareholding interest in TOTCo; and

2.1.2.2. 29.77 per cent. shareholding interest in COTCo; and

2.1.3. a 100 per cent. shareholding interest in PC Marketing, which purchases all of PC Chad's entitlement to crude oil under an offtake agreement. PC Marketing has appointed PETCO Trading (UK) Limited (PETRONAS' marketing entity) to market such offtake, such marketing agency agreement will be terminated at Completion.

***Acquisition Consideration***

2.2. The total approximate consideration payable by the Company for the PETRONAS Acquisition shall consist of:

2.2.1. US$266,000,000 in cash for the entire issued share capital of PCCEPI (plus interest); *plus or less (as applicable)*

2.2.2. the sum of certain completion date adjustments, including: (i) a positive working capital adjustment for cash in the PETRONAS Target Companies as at the Economic Effective Date; (ii) a positive adjustment for the working capital balance of the PETRONAS Target Companies as at the Economic Effective Date; (iii) a negative adjustment of US$4.5 million for the overlift as at the Economic Effective Date; (iv) a negative adjustment for any leakage from the PETRONAS Target Companies during the interim period; (v) a positive adjustment for any contributions to the PETRONAS Target Companies made by PETRONAS during the interim period; and (vi) a negative adjustment for certain agreed cash amounts extracted from the PETRONAS Target Companies by PETRONAS immediately prior to Completion. The sum of (i), (ii) and (iii), net off the cash extraction in respect of these amounts is a positive adjustment of US$16.8 million.

2.3. A description of the key terms of the PETRONAS SPA are set out in paragraph 2.2 of Part 14 of this document. Subject to Completion occurring, the PETRONAS SPA has an economic effective date of 1 January 2021.

2.4. The Company has provided to PETRONAS a parent company guarantee to guarantee the obligations of Savannah Chad under the PETRONAS SPA.

***Conditions to Completion***

2.5. Completion of the PETRONAS Acquisition remains subject to a number of conditions, the most substantive of these outstanding conditions being:

2.5.1. Ministerial Consent;

2.5.2. waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the transfer of shares in PC Chad, or confirmation of the expiry of the relevant period within which such preferential rights may be exercised, without such rights having been exercised; and

2.5.3. shareholder approval at the General Meeting.

2.6 In addition to the above, Completion of the PETRONAS Acquisition may also be delayed pending receipt of merger approval from the CEMAC Council for Competition.

## 3. Adjustment upon Completion

Given the difference between the Economic Effective Date of the transaction of 1 January 2021 and the anticipated Completion date of the Exxon Acquisition and the PETRONAS Acquisition of 1 July 2022, there is expected to be a significant completion adjustment to the sums ultimately to be paid to ExxonMobil and PETRONAS at Completion relating to, *inter alia*, the cash generation of the acquired assets during this period and the sweeping by ExxonMobil and PETRONAS of certain of the upstream target companies' cash balances just prior to Completion. As at the date of re-admission and consistent with the economic and commercial assumptions outlined in the Chad/Cameroon CPR, the Completion date adjustment is expected to be approximately US$321 million.

## 4. The Enlarged Group Post-Completion

4.1. The Exxon Acquisition and the PETRONAS Acquisition are entirely separate and independent. Failure to satisfy the conditions under one of the acquisitions will not impact the ability of the Company to achieve Completion under the other acquisition.

4.2. Following completion of the Exxon Acquisition and PETRONAS Acquisition, the Enlarged Group will hold:

4.2.1. a 75 per cent. participating interest in, and be the operator of, the Doba OFDA;

4.2.2. a 70.34 per cent. shareholding interest in TOTCo; and

4.2.3. a 70.83 per cent. shareholding interest in COTCo.

4.3. A simplified structure chart of the Enlarged Group following Completion is shown in paragraph 14 of Part 1 of this document.

## 5. Acquisition Financing

The Company intends to fund the considerations payable for the Exxon Acquisition and the PETRONAS Acquisition through a combination of the Debt Financing, the Junior Loan Facility, the Placing and the Subscription.

***Debt Financing***

5.1 On 30 December 2021, Savannah Chad and the Senior Lender entered into an agreement pursuant to which the Senior Lender agreed to provide Savannah Chad with an up to US$400 million borrowing base facility (US$300 million initial commitment with a US$100 million accordion). Descriptions of the key terms of the Debt Financing are set out in paragraph 3.1 of Part 14 of this document.

***Junior Loan Facility***

5.2 On 30 December 2021, the Company entered into the Junior Loan Facility. The Company's Chief Executive Officer, Andrew Knott, has committed to lend to the Company (via LCP4L): (i) US$17 million immediately prior to Completion of the Exxon Acquisition; and (ii) US$15 million immediately prior to

Completion of the PETRONAS Acquisition. Further details of the terms of the Junior Loan Facility are set out in paragraph 3.2 of Part 14 of this document.

***Placing and Subscription***

5.3 The Company is raising net proceeds of approximately US$63.7 million from the Placing and Subscription, which is intended to be used to, *inter alia*, partly fund the Exxon Acquisition and the PETRONAS Acquisition. Further details of the Placing and Subscription are set out in paragraph 8 of Part 1 of this document.

**6. Shareholder Approval**

6.1. Due to their size and nature, each of the Exxon Acquisition and the PETRONAS Acquisition independently constitutes a reverse takeover transaction pursuant to AIM Rule 14.

6.2. Each of the Exxon Acquisition and the PETRONAS Acquisition are, therefore, subject to Shareholder approval at the General Meeting, notice of which is set out at the end of this document. The General Meeting will be held at 10.30 a.m. on 24 January 2022 at the offices of the Company, being 40 Bank Street, London E14 5NR. At the General Meeting, the following Resolutions will be proposed in respect of the Exxon Acquisition and the PETRONAS Acquisition:

6.2.1. Resolution 1: an ordinary resolution to approve the Exxon Acquisition for the purposes of Rule 14 of the AIM Rules for Companies; and

6.2.2. Resolution 2: an ordinary resolution to approve the PETRONAS Acquisition for the purposes of Rule 14 of the AIM Rules for Companies.

6.3. If Resolution 1 is not passed, the Exxon Acquisition will not proceed. If Resolution 2 is not passed, the PETRONAS Acquisition will not proceed. If Resolutions 5 and 9 are not passed one or both of the Exxon Acquisition and the PETRONAS Acquisition may not proceed.

**7. Ministerial Consent**

Ministerial Consent for each of the Exxon Acquisition and the PETRONAS Acquisition is required prior to Completion. The Minister has 60 days following notification to grant or deny consent, following which, consent is deemed to have been given. EEPCI, in respect of the Exxon Acquisition, and PC Chad, in respect of the PETRONAS Acquisition, have each provided notification to the Minister seeking Ministerial Consent. Refer to paragraphs 4.1.10 and 4.2.9 of Part 14 of this document for further detail.

# PART 3

# RISK FACTORS

**The investment detailed in this document may not be suitable for all of its recipients and involves a high degree of risk. Before making an investment decision, prospective investors are advised to consult an authorised professional adviser who specialises in advising on investments of the kind described in this document. Prospective investors should consider carefully whether an investment in the Company is suitable for them in the light of their personal circumstances and the financial resources available to them.**

**The Enlarged Group's business, financial condition or results of operations could be materially and adversely affected by any of the risks described below. In such cases, the market price of the Ordinary Shares may decline and investors may lose all or part of their investment.**

**In addition to the other relevant information set out in this document, the Directors consider that the following risk factors, which are not set out in any particular order of priority, magnitude or probability, are of particular relevance to the Enlarged Group's activities and to any investment in the Company. The risks and uncertainties described below are not the only ones the Enlarged Group faces. Additional risks and uncertainties of which the Enlarged Group is not aware or that the Enlarged Group currently believes are immaterial may also adversely affect the Enlarged Group's business, financial condition and results of operations. If any of the possible events described below were to occur, the Enlarged Group's business, results of operations, cashflows, financial condition and prospects could be materially and adversely affected. If that happens, the value of the Enlarged Group may diminish and investors could lose all or part of the investment. Any one or more of these risk factors could have a materially adverse impact on the value of the Enlarged Group.**

**There can be no certainty that the Enlarged Group will be able to implement successfully the strategy set out in this document. No representation is or can be made as to the future performance of the Enlarged Group and there can be no assurance that the Enlarged Group will achieve its objectives.**

**This document also contains forward looking statements that involve risks and uncertainties. The Enlarged Group's actual results may differ materially from those anticipated in these forward looking statements as a result of various factors, including the risks described below and elsewhere in this document. In general, investing in securities of companies in emerging market countries such as Chad, Cameroon, Nigeria and Niger involves certain risks not typically associated with investing in the securities of companies operating in more developed economies.**

**To the extent the description in this section relates to government data or third-party sources, such information has been extracted from official government publications or other third-party sources and has not been independently verified by the Enlarged Group.**

The risk factors have been grouped as follows:

1. Risks related to the Exxon Acquisition and/or the PETRONAS Acquisition
2. General risks associated with the operations and business of the Enlarged Group and COVID-19
3. Risks associated with the Chad/Cameroon Assets and doing business in Chad and Cameroon
4. Risks associated with the Nigerian Assets and doing business in Nigeria
5. Risks associated with the Niger Assets and doing business in Niger
6. Risks relating to the Ordinary Shares

## 1. Risks related to the Exxon Acquisition and/or the PETRONAS Acquisition

### 1.1 There is a risk that the Exxon Acquisition and/or the PETRONAS Acquisition will not be implemented on a timely basis or at all.

Completion of the Exxon Acquisition is conditional upon, *inter alia*: (i) Ministerial Consent; (ii) waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the transfer of shares in EEPCI, or confirmation of the expiry of the relevant period within which such preferential rights may be exercised, without such rights having been exercised; (iii) shareholder approval approving the Exxon Acquisition at the General Meeting; (iv) the Exxon Sellers obtaining a settlement between EEPCI and the Government of Chad with respect to all taxes or similar levies in relation to the activities of EEPCI prior to the Economic Effective Date; and (v) material completion of the transfer of Exxon's IT systems used in the operation of the Exxon Target Companies and the Pipeline Companies to Savannah Chad that have been agreed to be transferred.

Completion of the PETRONAS Acquisition is conditional upon, *inter alia*: (i) Ministerial Consent; (ii) waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the transfer of shares in PC Chad, or confirmation of the expiry of the relevant period within which such preferential rights may be exercised, without such rights having been exercised; and (iii) shareholder approval approving the PETRONAS Acquisition at the General Meeting. In addition, Completion of the PETRONAS Acquisition may also be delayed pending receipt of merger approval from the CEMAC Council for Competition.

There is a risk that the conditions for each of Exxon Acquisition and the PETRONAS Acquisition will not be satisfied on a timely basis or at all. If such conditions are not satisfied, or, where applicable, not waived, the Exxon Acquisition and/or the PETRONAS Acquisition (as applicable) will not be implemented, the benefits expected to result from the Exxon Acquisition and/or the PETRONAS Acquisition will not be achieved and the market price of the Ordinary Shares may be affected. In addition, with respect to the PETRONAS Acquisition, there is a risk that the Company does not receive merger approval from the CEMAC Council for Competition, and therefore the PETRONAS Acquisition will not be implemented.

In particular, although the Company expects to receive Ministerial Consent for the Exxon Acquisition and the PETRONAS Acquisition, there is a risk that governmental policy on oil and gas fields may change and Ministerial Consent will not be obtained on time or at all.

1.2 **If the Exxon Acquisition and/or the PETRONAS Acquisition are/is completed, the Enlarged Group may experience difficulties in integrating the existing businesses carried on by the Company, ExxonMobil and PETRONAS.**

The Existing Group, ExxonMobil and PETRONAS operate and, until completion of the Exxon Acquisition and/or the PETRONAS Acquisition, will continue to operate, as separate and independent businesses. Completion of the Exxon Acquisition and/or the PETRONAS Acquisition will lead to the integration of the businesses with the Existing Group, and the success of the Enlarged Group will depend, in part, on the effectiveness of the integration process and the ability of the Enlarged Group and the Directors to realise the anticipated advantages from combining the respective businesses.

The integration of the assets, organisations, systems and facilities of the Company, the Exxon Target Companies and the PETRONAS Target Companies, as well as the development of new systems and procedures for the Enlarged Group, requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurance that the Company will realise the potential benefits of the Exxon Acquisition and/or the PETRONAS Acquisition.

The integration of the Exxon Target Companies will include the transition, handover and/or replacement of certain IT systems, infrastructure and services used by the Exxon Target Companies, including IT systems and services that are currently provided centrally by the ExxonMobil group and will need to be transitioned onto new systems to be installed and implemented by the Enlarged Group. These IT systems include systems critical to the day-to-day operations and production management, maintenance, inventory management, HSE, HR, accounting, financial reporting, treasury and supply chain management. These new systems will need to be in place by the time the Exxon Acquisition completes. If they are not, there is a risk that there will be disruption to the acquired businesses which could impact on the Enlarged Group's operations, results, cashflows and prospects.

The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect the Enlarged Group's ability to achieve the anticipated advantages of the Exxon Acquisition and/or the PETRONAS Acquisition.

Moreover, some of the potential challenges in combining the businesses may not become known until after Completion of the Exxon Acquisition and/or the PETRONAS Acquisition, in particular due to the substantial increase in the scale of the combined operations and the number of projects which the Enlarged Group would operate. The geographical spread of the Enlarged Group's operations may make it more difficult to implement and impress upon local workforces the Enlarged Group's policies on matters such as health and safety and can present challenges in the effective supervision of sub-contracted employees. Uncertainty about the effects of the Exxon Acquisition and/or the PETRONAS Acquisition, including effects on employees, partners, contractors, regulators and customers may adversely affect the business and operations of the Enlarged Group. These uncertainties could cause customers, business partners, regulators and other parties that have business relationships with the Enlarged Group to defer the consummation of other transactions or other decisions concerning those businesses, or to seek to change existing business relationships.

1.3 **Costs related to the Exxon Acquisition and the PETRONAS Acquisition may exceed the Company's expectations.**

Costs related to the Exxon Acquisition and/or the PETRONAS Acquisition may exceed the Company's expectations. These costs will include execution, integration and post-Completion costs in order to acquire the Exxon Target Companies and the PETRONAS Target Companies and combine with the operations of the Existing Group. The actual costs of the acquisition execution and integration process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Exxon Acquisition and/or the PETRONAS Acquisition. In addition, the Company will incur legal, accounting, transaction fees and other costs relating to the Exxon Acquisition and the PETRONAS Acquisition, some of which are payable whether or not the Exxon Acquisition and/or the PETRONAS Acquisition completes.

1.4 **The Enlarged Group will have increased indebtedness.**

Following Completion, the Enlarged Group will have increased indebtedness and interest and debt repayment obligations. This is addressed further in paragraph 2.6 below.

1.5 **Certain figures included in the Chad/Cameroon CPR are modelled on assumptions that may turn out to be incorrect.**

The hydrocarbon Reserve and Resource estimates, and economic valuations associated with these estimates included in the Chad/Cameroon CPR are based upon certain assumptions, including, *inter alia*, future oil prices, geological and geophysical assumptions of the performance of the subsurface, demand, maintenance requirements and timing and amount of future capital expenditure requirements. There can be no guarantee that these assumptions are correct. There are uncertainties inherent in estimating the quantity of Reserves and Resources, and in projecting future rates of production. Estimating the amount of hydrocarbon Reserves and Resources, and the expected cost to exploit these Reserves and Resources, is an interpretive process and, in addition, results of drilling, testing and production subsequent to the date of an estimate may result in material revisions to an estimate.

No assurance can be given that hydrocarbon Resources and Reserves included in the Chad/Cameroon CPR are, or will be, present as estimated, will be recovered at the rates estimated nor that they can be brought into profitable production. Hydrocarbon Resource and Reserve estimates may require revisions (either up or down) based on actual production experience and in light of the prevailing market price of oil and gas. Hydrocarbon Resource and Reserve estimates are highly subjective, and there is a risk that there are discrepancies between those estimates and the Resources and Reserves which are ultimately identified, both in terms of volume of Resources and Reserves identified, and in terms of the potential for recovery of such resources to be economically recoverable. A decline in the market price for oil and gas could render Reserves uneconomic to recover and may ultimately result in a reclassification of Reserves as Resources.

1.6 **Advice from Professional advisers.**

The Directors and the Enlarged Group have relied upon advice from various professional advisers engaged by the Enlarged Group in relation to the acquisition of the Exxon Target Companies and the PETRONAS Target Companies and the preparation of this Admission Document. Such professional advisers' liability is subject to limitations. Accordingly, in the event any such advice proves to have been incorrect, any amounts recoverable from the relevant adviser(s) may not be sufficient to cover all of the Enlarged Group's resulting losses. This could have a material adverse effect on the Enlarged Group's business and operations, financial condition and prospects.

1.7 **The Enlarged Group may become liable for unforeseen liabilities including potential unknown historical violations of applicable law by the Exxon Target Companies and the PETRONAS Target Companies, TOTCo and/or COTCo.**

During the course of the Exxon Acquisition and the PETRONAS Acquisition, the Enlarged Group has undertaken, and engaged professional advisors to undertake on its behalf, extensive due diligence (including tax, financial, human resources, compliance, legal, technical and environmental) on the Exxon Target Companies and the PETRONAS Target Companies, the Pipeline Companies and the Chad-Cameroon Assets. Such due diligence has involved reviewing publicly available information and information disclosed by the Exxon Sellers and PETRONAS, as well as site visits. Under the terms of the Exxon SPA and the PETRONAS SPA, the Enlarged Group also has the benefit of warranty protection with respect to certain substantive issues relating to the Exxon Target Companies, the PETRONAS Target Companies and the Chad/Cameroon Assets, including warranties relating to title, litigation, environmental, operational, employees and tax.

However, notwithstanding the due diligence undertaken by the Company with respect to the Exxon Acquisition and the PETRONAS Acquisition, there is no assurance that the Exxon Target Companies and the PETRONAS Target Companies, the Pipeline Companies and the Chad-Cameroon Assets are not subject to obligations or liabilities or third-party rights or claims of which the Enlarged Group is currently unaware. The warranty protection afforded to the Enlarged Group under each sale purchase agreement is a negotiated package and is subject to limitations of liability claims, including financial caps, time limitations and various exclusions of liability. Such limitations could result in restricting the Enlarged Group from: (i) bringing a warranty claim under a sale purchase agreement; and/or (ii) recovering the full amount of losses suffered from a breach of the relevant warranty.

In order to offer Exxon and PETRONAS a clean-break from the Exxon Target Companies and the PETRONAS Target Companies and their operations in Chad and Cameroon, Savannah Chad has provided the Exxon Sellers (and its affiliates) and PETRONAS (and its affiliates) with an indemnity in respect of all liabilities (save for certain exceptions) whether they relate to pre or post Completion, suffered by the Exxon Sellers (or their affiliates) and the PETRONAS Sellers (or its affiliates) in relation to the Chad-Cameroon Assets.

Any obligations or liabilities or third-party rights or claims which the Enlarged Group becomes subject to post-Completion of either Exxon Acquisition and the PETRONAS Acquisition, either directly or as a result of the indemnity provided to Exxon (and its affiliates) or PETRONAS (and its affiliates), could have a material adverse effect on the Enlarged Group's business, financial condition and/or prospects.

1.8 **Future litigation.**

Through the acquisition of the PETRONAS Target Companies, the Company will inherit the PETRONAS Target Companies' obligation to keep EEPCI (in its capacity as an Operator of the Doba Consortium) whole for PC Chad's participating interest share of liabilities arising from existing litigation that has been brought against EEPCI. The conduct of such litigation is within the sole control of EEPCI and therefore the PETRONAS Target Companies have no control over the ultimate outcome and consequent exposure of the PETRONAS Target Companies for their proportionate share of a negative outcome. However, should the Exxon Acquisition complete, the Company would acquire EEPCI and therefore have sole control of EEPCI and the conduct of litigation.

## 2. General risks associated with the operations and business of the Enlarged Group

2.1 **Risks relating to the Enlarged Group's activities in the oil and gas industry.**

There are numerous factors which may affect the success of the Enlarged Group's business which are beyond its control including local, national and international economic, legal and political conditions. The Enlarged Group's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The operations of the Enlarged Group in Central and West Africa may expose it to potential civil unrest and political or currency risks.

2.2 **Drilling for and producing oil and gas are high-risk activities with many uncertainties which may result in the Enlarged Group's expenses increasing and projected cashflows decreasing.**

The Enlarged Group's future success partially depends on its ability to develop and produce from its oil and gas fields in a timely and cost-effective manner. As part of its strategy, the Enlarged Group intends to pursue the further development of its existing assets, which include undeveloped Reserves and Resources and prospective Resources, and/or future opportunities to obtain or acquire further assets. This is expected to be achieved by further drilling and exploiting its existing fields, which the Directors believe will enable the Enlarged Group to grow its Reserves and production levels. However, drilling for and producing oil and gas are high-risk activities with many uncertainties, which may result in the Enlarged Group's expenses increasing and projected cashflows decreasing.

2.3 **Oil prices.**

The marketability and price of oil and natural gas that may directly or indirectly be acquired or discovered by the Enlarged Group will be affected by numerous factors beyond the control of the Enlarged Group, but which include: global and regional supply and demand, together with expectations regarding future supply and demand, for oil and gas; global and regional economic conditions; political, economic and military developments in oil and gas producing regions; prices and availability of alternative sources of energy; geopolitical uncertainty; speculative activities and trends in the financial community; and the ability and desire of members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices. Low oil prices will reduce the projected economic value of the Enlarged Group's assets, make it harder for the Company to attract partners and/or capital and reduce the cashflows of the Enlarged Group's assets once developed.

2.4 **Governmental relations may change and retention of key business relationships.**

In order to protect the Enlarged Group's licences and permits to operate and its ability to secure new resources, it is important that the Enlarged Group should maintain strong positive relationships with the governments of, and communities in, the countries where its business is conducted. Failure – real or perceived – to maintain these relationships could harm the Enlarged Group's reputation, which could, in turn, impact the Enlarged Group's licences, financing and access to new opportunities.

Although the Company believes that it has good relations with its host governments, there can be no assurance that the actions of present or future governments in these countries, together with governments of other countries in which the Enlarged Group may operate, directly or indirectly, in the future and supra-national authorities (such as CEMAC), will not materially adversely affect the business or financial condition of the Enlarged Group.

The Enlarged Group will rely significantly on strategic relationships with other entities, on good relationships with regulatory and governmental departments and upon third parties to provide essential contracting services. There can be no assurance that its existing relationships will continue to be maintained or that new ones will be successfully formed, and the Enlarged Group could be adversely affected by changes to such relationships or difficulties in forming new ones. Any circumstance that causes the early termination or non-renewal of one or more of these key business alliances or contracts could adversely impact the Enlarged Group, its business, operating results and prospects.

2.5 **The Enlarged Group operates in a capital-intensive industry and its growth may require additional funding to meet both expected and unanticipated costs, which the Enlarged Group may not be able to raise.**

The Enlarged Group's business requires significant capital for appraisal, development, maintenance, production, processing infrastructure and transportation expenditures and, in the future, the Enlarged Group may seek additional financing to fund its future exploration, development, acquisition and/or construction plans beyond its current committed and planned expenditures.

There can be no assurance that the Enlarged Group will be able to generate or raise sufficient funds to meet required capital expenditures in the longer term or to do so at a reasonable cost. Moreover, in circumstances where such funding is not available, the Enlarged Group may be required to amend its appraisal, development and other capital expenditure plans. The Enlarged Group's ability to arrange future financing, and the cost of financing generally, will depend on many factors, including: political, economic and capital markets conditions and the global political pressures towards energy transition; the availability of finance for fossil fuel projects; oil and gas prices; investor confidence in the oil and gas industry generally and in Chad, Cameroon, Nigeria, Niger, specifically, and in the Enlarged Group; business performance; regulatory developments, including tax and securities laws that are conducive to raising capital; and credit available from banks and other lenders.

Furthermore, the ability of many companies to arrange financing and the cost of financing is subject to events affecting the global financial markets. Also, the cost of and terms and conditions on which future funding or financing may be made available may not be acceptable to the Enlarged Group or funding or financing may not be available at all, and any additional debt financing may involve financing costs including prepayment fees or restrictive covenants and ratios that could limit or affect our operational flexibility.

Any inability in the longer term to procure sufficient financing could adversely affect the Enlarged Group's ability to expand its business and meet its production targets, may result in unexpected costs and delays in relation to project development and/or construction plans, or may result in an inability to implement the plans as currently contemplated. If the reductions in financing levels are severe enough, they could adversely affect the Enlarged Group's ability to maintain production at current levels and limit its cash available to service its indebtedness.

If the Enlarged Group's revenue or Reserves declines, it may be unable to raise additional funds (or any external debt or equity financing may not be available on acceptable terms) or have the capital necessary (either from internal sources or through external debt or equity financing) to undertake or complete future drilling and development programs or acquisitions.

The occurrence of any of these events could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

2.6 **The Enlarged Group's leverage and debt service obligations could adversely affect its business and prevent it from fulfilling its obligations under the debt facilities.**

As of 30 November 2021, the Existing Group had gross debt of US$529.8 million and, to finance the Exxon Acquisition and the PETRONAS Acquisition, it is proposed that the Enlarged Group will take on a further US$432 million of gross debt.

This amount of debt could have significant consequences for the Enlarged Group's business including, but not limited to:

- making it more difficult for it to satisfy its obligations with respect to the various financing arrangements;
- increasing the Enlarged Group's vulnerability to, and reducing its flexibility to respond to, general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of the Enlarged Group's cashflow from operations to the payment of principal of, and interest on, indebtedness, thereby reducing the availability of such cashflow for other uses;
- limiting the Enlarged Group's ability to obtain additional financing to fund working capital, capital investments, acquisitions, other debt service requirements, business ventures or other general corporate purposes;
- limiting its flexibility in planning for, or reacting to, changes in its business and the competitive environment and the industry in which the Enlarged Group does business;
- placing the Enlarged Group at a competitive disadvantage compared to its competitors that have lower leverage or greater financial resources;
- negatively impacting credit terms with its creditors; and

– limiting the Enlarged Group's ability to borrow additional funds and subjecting it to financial and other restrictive covenants or pay dividends to Shareholders.

These consequences could have a material adverse effect on the Enlarged Group's business, prospects, financial condition and results of operations and on its ability to satisfy its obligations under the various financing agreements.

Furthermore, the Enlarged Group requires a significant amount of cash to service its debt and to sustain its operations, and its ability to generate sufficient cash depends on many factors beyond its control. The Enlarged Group's ability to make payments on, or repay or refinance, its debt, and to fund working capital and capital investments, will depend on its future operating performance and ability to generate sufficient cashflow. This depends on the success of the Enlarged Group's business strategy and on general economic, financial, operational, competitive, market, legislative, regulatory, technical and other factors discussed in these "Risk factors", many of which are beyond the control of the Company.

A breach of any covenant or restriction or a failure to make scheduled payments of principal or interest on any of the Enlarged Group's indebtedness could result in a default that would permit the lender or noteholder to declare all amounts borrowed to be due and payable, together with accrued and unpaid interest. In addition, since certain of the financing arrangements are (or, upon Completion of the Exxon Acquisition and/or the PETRONAS Acquisition will be) secured by various security agreements, such as pledges over shares of certain subsidiaries (and, in particular, Savannah Chad, Accugas, SEUGL and Universal), any enforcement action taken by a lender could include the sale by such lenders of the property securing such debt if the Enlarged Group is unable to pay the outstanding debt on demand. Accordingly, payment default or covenant breaches and the subsequent exercise by the relevant lenders of their rights under the various financing agreements could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

2.7 **Exploration, appraisal, development and production risks.**

With respect to the Enlarged Group's operations in Niger, in particular, there can be no guarantee that hydrocarbons will be discovered in commercial quantities, or that those discovered will be developed into profitable production. Hydrocarbon deposits may not ultimately contain economically recoverable volumes of resources and even if they do, delays in the construction and commissioning of production projects or other technical difficulties may result in any projected target dates for production being delayed or further capital expenditure being required. There is also the risk that the Enlarged Group may not be awarded exclusive exploitation rights in respect of resources which are ultimately identified.

The operations and planned drilling activities of the Enlarged Group and its partners may be disrupted, curtailed, delayed or cancelled by a variety of risks and hazards which are beyond the control of the Enlarged Group, including unusual or unexpected geological formations, formation pressures, geotechnical and seismic factors, environmental hazards such as accidental spills or leakage of petroleum liquids, gas leaks, ruptures or discharge of toxic gases, industrial accidents, occupational and health hazards, technical failures, mechanical difficulties, equipment shortages, labour disputes, fires, power outages, compliance with governmental requirements and extended interruptions due to inclement or hazardous weather and ocean conditions, explosions, blow-outs, pipe failure and other acts of God.

Any one of these risks and hazards could result in work stoppages, damage to, or destruction of, the Enlarged Group's or its partners' facilities, personal injury or loss of life, severe damage to or destruction of property, environmental damage or pollution, clean-up responsibilities, regulatory investigation and penalties, business interruption, monetary losses and possible legal liability which could have a material adverse impact on the business, operations and financial performance of the Enlarged Group. Although precautions to minimise risk are taken, even a combination of careful evaluation, experience and knowledge may not eliminate all of the hazards and risks. In addition, not all of these risks are insurable.

2.8 **Hydrocarbon resource and reserve estimates.**

No assurance can be given that hydrocarbon Resources and Reserves reported by the Company previously, now or in the future, are, or will be, present as estimated, will be recovered at the rates estimated or that they can be brought into profitable production. Hydrocarbon Resource and Reserve estimates may require revisions (either up or down) based on actual production experience and in light of the prevailing market price of oil and gas. Hydrocarbon Resource and Reserve estimates are highly subjective, and there is a risk that there are discrepancies between those estimates and the Resources and Reserves which are ultimately identified, both in terms of volume of Resources and Reserves identified, and in terms of the potential for recovery of such resources to be economically recoverable. A decline in the market price for oil and gas could render Reserves uneconomic to recover and may ultimately result in a reclassification of Reserves as Resources.

2.9 **Capital and operating expenditure estimates may not be accurate.**

Estimated capital and operating expenditure requirements are estimates based on anticipated costs and made on certain assumptions. Given the inherent uncertainties as to Savannah's future work programmes and associated capital expenditures (in particular, following the integration of the Exxon Target Companies and PETRONAS Target Companies' businesses following Completion), the uncertain time frame during which the capital expenditures will be made and sources of finance will be made available to the Enlarged Group, and the general correlation between oil and gas capital expenditures and global commodity markets, there is a risk that currently assessed capital and operating expenditures as referenced in the CPRs included as Parts 9, 10 and 11 in this document may prove to be inaccurate. In addition, given the pragmatic approach of Savannah's Board and executive management team, nearer term capital and operating expenditure may be subject to change if Savannah's Board and management believe such a change is in the best interests of the Enlarged Group.

Should the Enlarged Group's capital and operating expenditure requirements turn out to be higher than currently anticipated, the Enlarged Group or its partners may need to seek additional funds which it may not be able to secure on reasonable commercial terms to satisfy the increased capital expenditure requirements. If this happens, the Enlarged Group's business, cashflow, financial condition and operations may be materially adversely affected.

2.10 **Exploration activities are capital intensive and there is no guarantee of success.**

Exploration activities are capital intensive and their successful outcome cannot be assured. The Enlarged Group may undertake exploration activities and incur significant costs with no guarantee that such expenditures will result in the discovery of commercially deliverable oil or gas. The Enlarged Group may explore in geographic areas, where environmental conditions are challenging and costs can be high. The costs of drilling, completing and operating wells are often uncertain. As a result, there may be cost overruns or requirements to curtail, delay or cancel drilling operations because of many factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with environmental regulations, governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. Capital expenditure commitments may vary (or be increased) as a result of actual exploration performance. The risk of incurring such costs and the failure of such exploration may adversely affect the Enlarged Group's profitability.

2.11 **Appraisal and development results may be unpredictable.**

Appraisal results for discoveries are also uncertain. Appraisal and development activities involving the drilling and testing of wells across a field may be unpredictable and may not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of the entire field be fully understood.

2.12 **Increase in drilling costs and the availability of drilling equipment.**

The oil and gas industry historically has experienced periods of rapid cost increases. Increases in the cost of exploration and development would affect the Enlarged Group's ability to invest directly or indirectly in prospects and to purchase or hire equipment, supplies and oil and gas specific services.

In addition, the availability and cost of drilling rigs and other equipment and services, including access to seismic survey equipment and related professionals, is affected by the level and location of drilling activity around the world.

An increase in drilling operations outside or in the Enlarged Group's intended area of operations may reduce the availability, and increase the cost, of such equipment and services to the Enlarged Group and to the companies with which it operates. The reduced availability of such equipment and services may delay the Enlarged Group's ability, directly or indirectly, to exploit Reserves and adversely affect the Enlarged Group's operations and profitability.

2.13 **Delays in production, marketing and transportation.**

Various production, marketing and transportation conditions may cause delays in oil and gas production and adversely affect the Enlarged Group's business. Drilling wells in areas remote from distribution and production facilities may delay production from those wells until sufficient Reserves are established to justify expenditure on construction of the necessary transportation and production facilities. The Enlarged Group's inability directly or indirectly to complete wells in a timely manner would result in production delays.

The Enlarged Group is also subject to market fluctuations in the prices of oil and natural gas, deliverability uncertainties related to the proximity of reserves to adequate pipeline and processing facilities, and extensive government regulations relating to price, taxes, royalties, licences, land tenure, allowable production, the export of oil and natural gas, and many other aspects of the oil and natural gas business. Moreover, weather conditions may impede the transportation and delivery of oil by sea. Any or all of these factors may result in an adverse impact on the financial returns anticipated by the Enlarged Group.

2.14 **Decommissioning costs may be greater than initially estimated.**

The Enlarged Group, through its licence interests, has certain obligations in respect of the decommissioning of its wells, fields and related infrastructure. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Enlarged Group to make provisions for, set aside funds and/or underwrite the liabilities relating to such decommissioning. It is difficult to forecast accurately the costs that the Enlarged Group will incur in satisfying its decommissioning obligations. When its decommissioning liabilities crystallise, the Enlarged Group will not hold ring fenced funds nor will it have contributed to any reserves for meeting its decommissioning obligations for the Accugas Midstream Business, the Doba Oil Project or the Chad/Cameroon Pipeline Companies and it will be liable either on its own or jointly and severally with its then partners in the field. In the event that it is jointly and severally liable with other partners and such partners default on their obligations, the Enlarged Group will remain liable and its decommissioning liabilities could increase significantly through such default. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its financial condition.

The Company does not have a decommissioning or abandonment fund in respect of any of its assets in Nigeria or Niger and does not intend to establish such a fund for the Chad/Cameroon Assets on Completion of the Exxon Acquisition and/or the PETRONAS Acquisition. However, there can be no guarantee that, in certain of the jurisdictions in which the Company operates, the Company will not be required to put in place a fund of this nature in the future.

2.15 **Natural disasters.**

Any interest held by the Enlarged Group is subject to the impacts of any natural disaster such as earthquakes, epidemics, fires and floods etc. No assurance can be given that the Enlarged Group will not be affected by future natural disasters.

2.16 **Environmental factors.**

The Enlarged Group's operations are, and will be, subject to environmental regulation in Chad, Cameroon, Nigeria and Niger and any other regions in which the Enlarged Group may operate. Environmental regulations may evolve in a manner that will require stricter standards and enforcement measures being implemented, increases in fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their directors and employees. Compliance with environmental regulations could increase the Enlarged Group's costs. Should the Enlarged Group's operations not be able to comply with this mandate, financial penalties may be levied. Environmental legislation can provide for restrictions and prohibitions on spills, releases of emissions of various substances produced in association with oil, condensate and natural gas operations. In addition, certain types of operations may require the submission and approval of environmental impact assessments. The Enlarged Group's operations will be subject to such environmental policies and legislation.

Environmental legislation and policy may be periodically amended. Such amendments may result in stricter standards of enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects may carry a heightened degree of responsibility for companies and their directors, officers and employees. The costs of compliance associated with changes in environmental regulations could require significant expenditure, and breaches of such regulations may result in the imposition of material fines and penalties. In an extreme case, such regulations may result in temporary or permanent suspension of production operations. There can be no assurance that these environmental costs or effects will not have a materially adverse effect on the Enlarged Group's future financial condition or results of operations.

2.17 **Any expansion via acquisition may not be successful and anticipated benefits of acquisitions may not be realised.**

The Enlarged Group may enter into future acquisitions, particularly to increase its oil and gas reserves and resources through acquisitions of interests in further oil and gas assets that have significant resource potential and are near high demand areas. Any such future acquisitions may be achieved through licence awards following bidding rounds, transfers of participating or other economic interests by an existing licence holder, or direct or corporate acquisitions. No assurance can be given that the Enlarged Group will be able to identify attractive acquisition opportunities or, even if the Enlarged Group does identify attractive opportunities, that it will be able to complete acquisitions, or do so on commercially acceptable terms.

Furthermore, the Enlarged Group could encounter difficulties integrating acquired assets, including operations, systems, management and other personnel and technology associated with such acquired assets with its own. Such difficulties could disrupt the Enlarged Group's ongoing business, distract its management and employees and/or increase its expenses.

2.18 **Dependence on key executives and personnel.**

The future performance of the Enlarged Group will to a significant extent be dependent upon its ability to retain the services and personal connections or contacts of key executives, to attract, recruit, motivate and retain other suitably skilled, qualified and industry experienced personnel to form a high-calibre management team and to develop a succession plan for key executives. Such key executives are expected to play an important role in the development and growth of the Enlarged Group, in particular, by maintaining good business relationships with regulatory and governmental departments and essential partners, contractors and suppliers.

Attracting and retaining highly skilled talent is expected to be fundamental to the successful implementation of the Company's strategy and continued growth. The Company anticipates substantially growing its headcount in the coming years across both its operational and support functions. There is intense competition for high calibre individuals and there can be no guarantee that the Company will be successful in identifying and recruiting individuals necessary to continue to grow its business and implement its strategy.

Many of the Enlarged Group's competitors are larger, have greater financial and technical resources, as well as staff and facilities, and have been operating in a market-based competitive economic environment for much longer than the Enlarged Group.

There can be no assurance that the Enlarged Group will retain the services of any key executives, advisers or personnel who have entered into service agreements or letters of appointment with the Enlarged Group. The loss of the services of any of the key executives, advisers or personnel may have a material adverse effect on the business, operations, relationships and/or prospects of the Enlarged Group. In particular, given the importance of the direction and leadership of its existing Chief Executive Officer as founder of the Company, his local knowledge, his relationships in the oil and gas industry in West Africa, his relationships with financing partners and his industry expertise, the future success of the Enlarged Group is, to an extent, dependent upon the continued service of the Chief Executive Officer. The Enlarged Group currently has no succession plan in place and, therefore, there is a risk that the unexpected departure or loss of this individual could have a material adverse effect on the business, financial condition and results of operations of the Enlarged Group, and there can be no assurance that the Enlarged Group will be able to attract or retain a suitable replacement.

2.19 **Health & safety.**

Developing oil and gas resources and reserves into commercial production involves a high degree of risk. The Enlarged Group's operations are subject to all the risks common in its industry. These hazards and risks include encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, uncontrollable flows of oil, natural gas or well fluids, explosions, fires, improper installation or operation of equipment and equipment damage or failure, including failure to comply with regulatory requirements expected of a Western country (such as comprehensive health and safety processes). Personal injuries suffered as a result of the foregoing are likely to be exacerbated as a result of a lack of access to medical care facilities and healthcare professionals.

If any of these types of events were to occur, they could result in loss of production, environmental damage, injury to persons and loss of life.

They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to equipment owned or used by the Enlarged Group and personal injury, wrongful death or other claims related to loss being brought against the Enlarged Group. These events could result in the Enlarged Group being required to take corrective measures, incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Enlarged Group and/or its officers. The Enlarged Group may also be required to curtail or cease operations on the occurrence of such events. Any of the above could have a material adverse effect on the Enlarged Group's business, prospects, financial condition or results of operations.

While the Enlarged Group has implemented certain policies and procedures to identify and mitigate such hazards, and developed appropriate work plans and approvals for high-risk activities to prevent accidents from occurring, these procedures may not be sufficiently robust or appropriately followed by the Enlarged Group's staff or third-party contractors to prevent accidents.

2.20 **Labour relations.**

Any labour disputes, unrest or strike activity at any of the Enlarged Group's oil and gas production processing and/or transportation operations or situated at, or affecting, the operations of any third-party which the Enlarged Group utilises for its business, could adversely affect its ongoing operations and the Enlarged Group's ability to explore for, produce, transport and market oil and gas production or cause cost increases. All of these factors could adversely affect the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

2.21 **Managing growth and executing strategy.**

There can be no assurance that the Enlarged Group will be able to manage effectively the expansion of its operations or that the Enlarged Group's current personnel, systems, procedures and controls will be adequate to support the Enlarged Group's operations. Any failure of the Board to manage effectively the Enlarged Group's growth and development could have a material adverse effect on the Enlarged Group's business, financial condition and results of operations. There is no certainty that all or, indeed, any of the elements of the Enlarged Group's current strategy will develop as anticipated and that the Enlarged Group will be profitable.

2.22 **The Group may be negatively impacted by the failure of its information technology and communications systems and related operational processes, including through cyber-attacks.**

There can be no assurance that the Existing Group's or the Enlarged Group's IT systems are or will continue to be able to support the Group's business whether due to general or specific systems failure or through failure to develop in an adequate manner. While the Existing Group has in place business continuity procedures and security measures in the event of IT failures or disruption, including backup IT systems to reduce and contain the risk through the use of technical and assurance-based controls, there can be no guarantee that its systems in the future will continue to support all of the Enlarged Group's activities. Disruption to or failure of the Enlarged Group's IT systems could result in loss of business or damage to the Group's reputation, resulting in a material adverse effect on the Enlarged Group's reputation, business, financial condition and results of operations.

The Group's operations rely on the effective management and the secure processing, storage and transmission of financial, personal and other information in its information systems and networks. In addition, the use of computers and connected sensors is essential to the safe running of upstream production facilities.

The Enlarged Group may be the target of attempted cyber-attacks. While the Existing Group maintains systems and controls designed to detect and prevent such events from occurring, the Group may not be able to anticipate, detect or implement effective preventive measures against all cyber threats. Cyber-attacks can take many forms across a wide range of channels and their initiators can be varied, including opportunists, state-sponsored or, as a hydrocarbons producer, the Enlarged Group may be the target of "eco-hacktivists". Cyber-attacks are typically designed to deny service, obtain unauthorised access to confidential information, manipulate or destroy data, disrupt or destroy IT or production control systems or steal money. There have been in the past highly publicised cases where hackers have requested "ransom" payments in exchange for not disclosing customer information or for restoring access to information or systems, including systems critical to the day-to-day operations of the business. Cyber-attacks are increasingly sophisticated, rapidly evolving and may be far reaching and difficult to prevent and they may not be recognised until launched. Further, third parties may seek to gain access to the Group's systems either directly or using equipment or security passwords belonging to the Group's personnel or third-party service providers. If a cyber-attack or other information security breach were to occur, this could have a material adverse effect on the Group, including, the misappropriation of confidential information belonging to the Group, damage to the Group's computer systems infrastructure and production control systems, environmental damage, fines, penalties and other financial loss to the Group. The Group's reputation may also be adversely affected resulting in a loss of business opportunities. The Group may also become exposed to litigation and regulatory sanctions.

2.23 **Emerging markets, such as Chad, Cameroon, Nigeria and Niger, are subject to greater risks than more developed markets.**

Investing in securities of issuers whose operations and assets are located in emerging markets, such as Chad, Cameroon, Nigeria and Niger, can typically involve a higher degree of risk than investments in securities of corporate or sovereign issuers from more developed countries and carries risks that are not typically associated with investing in more mature markets. Investors should exercise particular care in evaluating the risks involved and must decide for themselves whether, in light of those risks, their investment is appropriate. Emerging markets can be subject to rapid change and the information set out in this document may become outdated relatively quickly.

Financial turmoil in an emerging market country can adversely affect companies operating within those markets, as investors move their money to more stable, developed markets. As has happened in the past, financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in any of Chad, Cameroon, Nigeria or Niger and adversely affect their economies. In addition, during such times of loss of market confidence, companies that operate in emerging markets can face severe liquidity constraints as foreign funding sources are withdrawn. In Nigeria, for example, there has been periodic issues with FX market liquidity as a result of macro-economic challenges.

As a result of the Enlarged Group's operations in Central and West Africa, it may be particularly susceptible to disruptions in the capital markets and the reduced availability of credit or increased cost of debt, which could result in it experiencing financial difficulty. In addition, the availability of credit to entities operating within emerging markets is significantly influenced by levels of investor confidence in such markets as a whole and thus any factors that impact market confidence (for example, a decrease in credit ratings, state or central bank intervention or foreign funding sources being withdrawn) could negatively affect the price or availability of funding to it.

Financial turmoil in any of the Company's host jurisdictions or the capital markets generally could adversely affect the Enlarged Group's business.

2.24 **The judicial systems in which the Enlarged Group operates may create an uncertain environment for investment and business activity.**

As with a number of developing countries, the legal systems of the countries in which the Enlarged Group operates continue to develop and mature. As a result, the Enlarged Group may become subject to certain difficulties in obtaining effective or consistent legal redress due to a number of factors out of its control. Such difficulties may include delay, the level of discretion that may be exercised by the courts or governmental authorities, insufficient judicial or administrative guidance on interpreting applicable rules and regulations, inconsistencies or conflicts between and within various existing laws, regulations, decrees, orders and resolutions and/or the relative inexperience of the judiciary and courts in commercial matters. In addition, the enforcement of laws or the Enlarged Group's statutory or contractual rights may depend on, and be subject to, the interpretation of, the relevant local authority, and such interpretation may differ from the advice given to the Enlarged Group by local lawyers and potentially result in unexpected outcomes. For example, there is no assurance that all contracts governed by international law and/or with the benefit of international arbitration dispute resolution procedures will be recognised or enforced by local courts in the host countries in which the Enlarged Group operates, or that the Enlarged Group would be successful in subjecting counterparties to the jurisdiction of another country.

It is possible that any adverse finding against the Enlarged Group, or any restriction placed on the Enlarged Group in exercising its contractual or statutory rights, could have a material adverse effect on the Enlarged Group's business, financial condition and/or prospects.

2.25 **Actual and perceived risks of corruption may adversely affect the Enlarged Group's operations and ability to attract capital.**

The Enlarged Group is subject to Compliance Laws, including the UK Bribery Act 2010 (the "Bribery Act"), the Foreign Corrupt Practices Act of 1977 ("FCPA") and other laws and regulations that prohibit companies and their intermediaries from making improper payments or offers of payments to foreign governments and their officials and political parties, or others for the purpose of obtaining or retaining business and other benefits. Nigeria, Niger, Chad and Cameroon are ranked 149, 123, 160 and 149 (respectively) out of 180 countries in Transparency International's 2020 Corruption Perceptions Index and placed 131, 132, 182 and 167 (respectively) out of 190 countries in the World Bank's Doing Business 2020 report.

By doing business in these countries, there is a risk that the Enlarged Group may face, directly or indirectly, corrupt demands by officials, militant groups or private entities. Consequently, the Enlarged Group faces the risk that one or more of the Enlarged Group's employees, agents, intermediaries or consultants may make or receive unauthorised payments given that such persons may not always be subject to the Enlarged Group's control. In addition, it is possible that post-Completion the Enlarged Group could be held liable for successor liability for the violation of any Bribery Act, FCPA and/or other Compliance Laws committed (if any were to exist) by the Exxon Target Companies, PETRONAS Target Companies or the Pipeline Companies. Although the Enlarged Group has policies and procedures designed to ensure that the Enlarged Group, its employees, agents, intermediaries and consultants adhere to Compliance Laws and will implement policies and procedures with respect to all applicable Chad and Cameroon anti-corruption legislation, there is no assurance that such policies or procedures will work effectively all of the time or protect the Enlarged Group against liability under any such legislation for actions taken by our agents, employees, intermediaries and consultants with respect to the Enlarged Group's business. If the Enlarged Group is not in compliance with the Bribery Act, the FCPA or other Compliance Laws governing the conduct of business with Nigeria, Niger, Chad and Cameroon government entities (including local laws), the Enlarged Group may be subject to criminal and civil penalties and other remedial measures.

Furthermore, any remediation measures taken in response to potential or alleged violations of Compliance Laws, including any necessary changes or enhancements to the Enlarged Group's procedures, policies and controls and potential personnel changes and/or disciplinary actions, may result in increased compliance costs. Any such findings, or any alleged or actual involvement in corrupt practices or other illegal activities by the Enlarged Group or its commercial partners or anyone with whom the Enlarged Group conducts business could damage its reputation and its ability to do business, including by affecting the Enlarged Group's rights and title to assets or by the loss of key personnel, and together with any increased compliance costs, could adversely affect the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

There is concern in the oil and gas industry that, following the letter of the law, the Bribery Act prohibits certain practices which are not covered by (a) the FCPA, or (b) the anti-corruption legislation and regulations of the relevant host jurisdiction (to which the Enlarged Group is bound), but which are regarded as standard industry practice (for example, facilitation payments). It may not be possible for the Enlarged Group to detect or prevent every instance of fraud, bribery or corruption. Failure to detect or prevent any such instances may expose the Enlarged Group to potential civil or criminal penalties under relevant applicable law and to reputational damage, which may have a material adverse effect on the Enlarged Group's business, prospects, financial condition or results of operations.

2.26 **Risk of crime and disruption to the Enlarged Group's operations.**

Countries in Central and West Africa can experience high levels of criminal activity and oil and gas companies operating in Central and West Africa may be particular targets of criminal or terrorist actions. Criminal, corrupt or terrorist action against the Enlarged Group and its directly or indirectly held properties or facilities could have a material adverse effect on the Enlarged Group's business, results of operations or financial condition. In addition, the fear of criminal or terrorist actions against the Enlarged Group could have an adverse effect on the ability of the Enlarged Group adequately to staff and/or manage its operations or could substantially increase the costs of doing so. The Enlarged Group faces a threat of terrorism as a result of its proximity and accessibility to various regional Islamist insurgencies. Whilst these insurgencies have not impacted Savannah's operations historically, there can be no guarantee this continues to be the case in the future.

2.27 **Licensing and other regulatory requirements.**

The Enlarged Group's direct and/or indirect intended future operations will be subject to, licences, production sharing contracts, operating permits, regulations and approvals of governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil, taxation, and environmental and health and safety matters. The Enlarged Group cannot guarantee that such documents applied for will be granted or, if granted, will not be subsequently withdrawn or made subject to possibly onerous conditions, or their availability to the Enlarged Group or its associated companies may adversely affect the Enlarged Group's assets, plans, targets and projections.

The Enlarged Group will be subject to extensive government laws and regulations (which may be subject to change) governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and many other aspects of the oil business. There can be no assurance that the actions of present or future governments in which the Group operates, or of governments of other countries in which the Enlarged Group may operate in the future, will not materially adversely affect the Enlarged Group's ability to comply with such laws and regulations or that there will not be a challenge to the Enlarged Group's title to any interest it may have.

2.28 **Expiry of contracts.**

The Enlarged Group is party to various contracts and arrangements that will expire at points in time in the future in accordance with their terms. There can no assurance that such contracts will, if required, be renewed either on the same terms or otherwise.

2.29 **The taxation and customs systems in the countries in which the Enlarged Group operates may be subject to change and the rules of those systems may be subject to different interpretation.**

The Enlarged Group operates in emerging market economies and the regulations on, and laws relating to, taxation, customs and excise duties in these countries may change from time to time as considered necessary for its further development. The Enlarged Group's existing effective tax rate and revenues may be affected by changes in such policies, laws or regulation. The Enlarged Group has subsidiaries located in multiple jurisdictions and has relied upon external professional advice in relation to the applicable taxation regime in each jurisdiction. The Enlarged Group cannot be certain that this advice will ultimately prove to be correct. Furthermore, local tax authorities' interpretation of, and/or decisions with respect to applicable tax laws or regulations may differ from the Enlarged Group's interpretation of such laws or regulations. Such interpretations or decisions could result in additional tax becoming due or payable in the future by the Enlarged Group.

Changes in applicable policies on taxation, customs and excise duties, as well as differences in interpretation of and decisions relating to tax laws, may have an adverse effect on the Enlarged Group's business, results of operations, financial position and prospects.

2.30 **Exchange rate fluctuations.**

Currency fluctuations may affect the Enlarged Group's operating cashflow since certain of its costs and revenues are denominated in currencies other than Pounds Sterling, such as US Dollars, Euros, Naira, Central African CFA Franc and West African CFA Franc. Fluctuations in exchange rates between currencies in which the Enlarged Group operates may cause fluctuations in its cashflows and financial results (which are reported in US Dollars). In particular, under the terms of the Enlarged Group's gas sales agreements, which are US Dollar denominated, the customer has the option to settle in Naira at the relevant prevailing exchange rate immediately prior to settlement; therefore the Enlarged Group is exposed to any adverse exchange rate differential or movement in exchange rate in converting Naira back into US Dollars, for example, for servicing US Dollar denominated debt. Such exposure increases if local currencies like the Naira are not freely convertible into US Dollars or other hard currencies and there is a devaluation of the local currency. The Enlarged Group does not currently have a foreign currency hedging policy in place. Refer to paragraph 2.36 of this Part 3 for further information.

The Company's share price is quoted on AIM, a sub-market of the London Stock Exchange, in Pounds Sterling. As a consequence, shareholders may experience fluctuation in the market price of the Ordinary Shares as a result of, amongst other factors, movements in the exchange rate between Pounds Sterling, US Dollars, Euros, Naira, Central African CFA Franc and West African CFA Franc.

2.31 **Insurance coverage and uninsured risks.**

While the Board will determine appropriate insurance coverage from time to time, it may elect not to have insurance for certain risks due to the high premium costs associated with insuring those risks or for other reasons, including an assessment in some cases that the risks are remote.

No assurance can be given that the Enlarged Group will be able to obtain insurance coverage at reasonable rates or with reasonable deductibles (or at all), or that any coverage it or the relevant operator obtains or the proceeds of insurance claims will be adequate and available to cover any losses arising. The Enlarged Group may become subject to liability for pollution, blow-outs or other hazards against which it has not insured or cannot insure itself against, including those in respect of past activities for which it was not responsible. The Enlarged Group will exercise due care in the conduct of its business and obtain insurance prior to commencing operations in accordance with industry standards to cover certain of these risks and hazards. However, insurance is subject to deductibles and limitations on liability and, as a result, may not be sufficient to cover all of the Enlarged Group's losses. The occurrence of a significant event against which the Enlarged Group is not fully insured, or the insolvency of the insurer of such event, could have a material adverse effect on the Enlarged Group's business, financial condition, results of operations and prospects. Any indemnities the Enlarged Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources. In the event that insurance coverage is not available or the Enlarged Group's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, or indemnities are difficult to enforce, the Enlarged Group's business and operations, financial results or financial position may be disrupted and adversely affected. Further, even where the Enlarged Group is insured, its contractors may themselves be insufficiently insured, or uninsured, in respect of damage they may cause to the Enlarged Group's property or operations. In such cases, the Enlarged Group may be required to incur additional costs to extend its cover to its contractors, from whom it may be unsuccessful in recovering such costs in full or at all.

The payment by the Enlarged Group's insurers of any insurance claims may result in increases in the premiums payable by the Enlarged Group for its insurance cover and adversely affect the Enlarged Group's financial performance. In the future, some or all of the Enlarged Group's insurance coverage may become unavailable or prohibitively expensive.

Operational insurance policies are usually placed in one-year contracts and the insurance market can withdraw cover for certain risks which can greatly increase the costs of risk transfer. Such increases are often driven by factors unrelated to the Enlarged Group such as well control elsewhere in the world and windstorm damage.

2.32 **Litigation.**

From time to time, the Existing Group has been or is, and the Enlarged Group may be, subject directly or indirectly to litigation arising out of its business and proposed operations. Damages claimed under such litigation may be material or may be indeterminate, and the outcome of such litigation may materially impact the Enlarged Group's business, results of operations or financial condition. While the Enlarged Group assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Enlarged Group's business.

2.33 **The ongoing COVID-19 pandemic could have a material adverse effect on the Enlarged Group's results of operations and financial condition.**

The COVID-19 pandemic has had a negative impact on economic conditions globally and there remains concerns for prolonged economic uncertainty and tightening of global financial conditions as countries continue to experience extended waves of increased infection rates.

Although the Company is continuing to take measures to mitigate the broader public health risks associated with COVID-19 to its business and employees, including through self-isolation of employees where possible in line with the recommendations of relevant health authorities, the continued and long term adverse impact this may have on the Enlarged Group's workforce and key suppliers and its impact on the global economy (including the Chadian, Cameroonian, Nigerian and Nigerien economies) and the oil and gas industries is unknown. As a result of the ongoing COVID-19 pandemic, there may be short-term impacts on the Enlarged Group's supply chain and planned work programmes. Similarly, government-imposed travel restrictions may impair the ability of certain of the

Enlarged Group's employees and advisors to conduct physical inspections of existing operations and visit in-country offices.

As the impact of the COVID-19 pandemic continues, there can be no assurances that contract counterparties will not seek to renegotiate contractual terms or seek to claim force majeure to excuse performance of their contractual obligations to the extent that they are affected by the COVID-19 outbreak.

Given the continually evolving nature of the COVID-19 pandemic and resultant government restrictions around the world, there can be no assurances that there will not be a material adverse effect on the Enlarged Group's results of operations and financial condition.

2.34 **Reliance on Third Party Service Providers and Contractors.**

The Enlarged Group will rely on a relatively concentrated group of oil field services providers and contractors to provide materials and services across its existing operations and also in Chad and Cameroon. Any competitive pressures on the oilfield service providers (or increases in the cost of raw materials) could result in a substantial increase in the costs to conduct the Company's business. Similarly, shortages of raw materials could lead to delays in implementing projects and/or increases in costs which could adversely impact upon the operations of the Enlarged Group.

2.35 **Debt Counterparty and Commercial Risk.**

The Company is reliant upon debt providers to finance its operations and has entered into certain loan documentation to finance both the Exxon Acquisition and the PETRONAS Acquisition, and as the Company continues to grow, it expects to enter into further debt facilities in the future. The Company seeks to minimise counterparty and commercial risk when entering into such debt facilities, such as, for example, by retaining debt facility specialist employees and employing experienced professional advisors. However, there can be no guarantee that monies will be advanced under a facility due to circumstances outside of the Enlarged Group's control. This may result in the Enlarged Group being unable to finance its business as anticipated and require it to seek alternative funding sources which may or may not be available at the point in time such alternative finance is sought.

2.36 **Hedging policy may prove ineffective at managing price risk.**

The Company is expecting to establish a commodity hedging programme which could see up to 60 per cent. of forward production volumes associated with the assets being acquired pursuant to the Exxon Acquisition and the PETRONAS Acquisition being hedged for the forward 12 months. The Senior Lender under the Debt Financing may additionally request or require further hedging be undertaken at various times. The intention of the hedging policy is to minimise exposure to fluctuations in commodity prices through the use of various derivative based hedging instruments (most likely put options). No speculative hedging is anticipated to be undertaken.

While the Company will seek to only hedge its forward exposure through transactions with credit worthy parties, there can be no guarantee that such parties will prove credit worthy over time and therefore that the intended hedging program could be effective. Further, while the Enlarged Group has a clear intention to enter into hedging contracts, there can be no guarantee that it will be able to enter into appropriately priced hedging contracts and therefore that the hedging program would be entered into in full or at all.

2.37 **Climate Change legislative changes.**

The growing political attention surrounding climate change and legislative changes being seen could have adverse impacts on the success of the Enlarged Group. International agreements, national and regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. The Enlarged Group may be exposed to additional costs from compliance with legislation and best practice. The growing awareness amongst end consumers of climate change may also lead ultimately to diminished demand for oil and gas.

The Enlarged Group may be subject to climate related activism from groups who are campaigning against fossil fuel extraction which could negatively impact upon the Enlarged Group's business.

2.38 **The Importance of maintaining a "social licence to operate" in host communities.**

The Company operates an engagement policy with the communities in which it operates and provides benefits to these communities through employment, training and other local projects. Given the proximity of operations to communities, ongoing interaction is important to maintain the social licence to operate and the trust of the communities. Failure to maintain this relationship though could lead to disruption to our operations and the ability of the Company to execute its projects in a timely manner.

## 3 Risks associated with the Chad/Cameroon Assets and doing business in Chad and Cameroon

3.1 **Production from the Doba Oil Project may be affected by unforeseen events including facilities and infrastructure failure and labour disputes.**

The Doba Oil Project is in a remote location and has been on production since 2003 and, therefore, some of the production and storage facilities require increasingly regular maintenance and may be more susceptible to failure. The Doba Oil Project is also dependent on its workforce, comprising employees and contractors and the uninterrupted availability of certain critical infrastructure, including the oil field gathering stations, on-site power generation and the Chad-Cameroon ETS, to sustain production rates and to export the crude oil production to the international markets. Any labour disputes, unrest or strike activity involving the employees and contractors on the Doba Oil Project could adversely affect its ongoing operations. For example, in June, July and October 2021 the Doba Consortium experienced labour disputes which resulted in reduced production (which, to the extent of the EEPCI participating interest share in the Doba Oil Project, the Company has been compensated for through the consideration payment structure under the Exxon SPA (see paragraph 2.1 of Part 14 of this document for a summary of the Exxon SPA)).

The failure of any key infrastructure could result in some or all of the production from the Doba Oil Project being shut in, either temporarily or for a longer period of time whilst repairs are made, or replacement equipment is sourced and brought to location. All these factors could have a material adverse impact on the Enlarged Group's business results of operations, cashflows, financial condition and prospects.

For example, an incident occurred in early November 2021 at the Miandoum gathering Station (MGS), which affected the water handling system. Production from the Miandoum, Moundouli, Maikeri and Nya fields which are gathered at the MGS was temporarily shut-in and resumed in early December 2021. The operator of the project is currently implementing a solution to replace the water handling system at Miandoum, with the aim that production will ramp-up to pre-incident levels in the coming weeks.

The Company has been compensated for this temporary reduction in production through the consideration payment structure under the Exxon SPA (see paragraph 2.1.5 of Part 14 of this document for a summary of the agreed payment structure).

3.2 **The co-mingling of third-party crude oil may negatively affect the commercial value of the crude oil produced from the Doba Oil Project and impact the revenue of the Enlarged Group.**

Crude oil produced from the Doba Oil Project and transported by the Chad-Cameroon Pipeline is commingled with the crude oil of other shippers, such that no shipper is entitled to receive the identical crude oil that was delivered on behalf of such shipper into the Chad-Cameroon Pipeline. From the Company's due diligence, it is understood that there is no quality bank agreement in place between the Pipeline Companies and the Shippers to provide for adjustments to be made to the respective lifting entitlements, to equitably account for quality differences in crude. Consequently, there is a risk that the quality and ensuing sales price of the Company's crude oil might be diminished by other shippers' crude oil.

3.3 **The Enlarged Group will be reliant on the Chad-Cameroon Pipeline and Kome Kribi 1 FSO to export its production from the Doba Oil Project.**

The Enlarged Group's route to market for its production from the Doba Oil Project will be dependent on transportation through the Chad-Cameroon Pipeline and offloading at the Kome Kribi 1 FSO for sale to international markets. There is no other viable alternative route to market for crude oil produced from the Doba Oil Project. If, for any reason, the Enlarged Group was not able to access the Chad-Cameroon Pipeline and Kome Kribi 1 FSO this could have a material adverse impact on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

3.4 **The success of the Doba Oil Project and profitability of TOTCo and COTCo relies on the Enlarged Group's relationship and alignment with its joint venture partners and other shareholders.**

After Completion of both the Exxon Acquisition and the PETRONAS Acquisition, the Enlarged Group would have a 75 per cent. operated interest in the Doba Oil Project and 70.34 per cent. and 70.83 per cent. interests respectively in TOTCo and COTCo, which collectively own the Chad-Cameroon ETS. The Doba Oil Project and Chad-Cameroon ETS are run and operated through a number of contracts governing the relationship between the: (i) joint venture partners to the Doba Consortium; and (ii) shareholders of TOTCo and COTCo. The Doba Oil Project is operated by EEPCI (and the day-to-day management and operations of TOTCo and COTCo is the responsibility of the General Managers, who (after completion of the Exxon Acquisition) will be appointed by EPIL and EEPCI). If either of the Exxon Acquisition or the PETRONAS Acquisition does not complete, the Enlarged Group will not have control of either TOTCo or COTCo and will not be in a position to single handedly pass or block board or shareholder resolutions, or, likewise, single handedly pass or block decisions under the Doba JOA. Furthermore, if the Exxon Acquisition does not complete, the Enlarged Group will not obtain operatorship of the Doba Oil Project or the right to appoint the General Managers of TOTCo or COTCo.

As is typical of these arrangements, there are certain material decisions which will require super majority approval of the other joint venture partners and shareholders (as applicable). Accordingly, any delay, absence of engagement, withholding of consent, breach, objections or disagreement by or with any of the joint venture partners or shareholders (as applicable) could adversely impact the success of the Doba Oil Project, profitability of TOTCo and COTCo and/or have a material adverse effect on the Enlarged Group's business, future cashflows, results of operations, financial condition and prospects.

3.5 **The Enlarged Group has not maintained decommissioning arrangements and/or security funds.**

The Board understands that:

- no security abandonment fund is currently in place, nor has EEPCI or PC Chad been separately reserving for future decommissioning obligations, in relation to the Doba Oil Project; and
- the Pipeline Companies have not been separately reserving the decommissioning contributions received from Shippers, which are made through an abandonment fee included in the tariff charged by the Pipeline Companies under the respective transportation agreements.

The Enlarged Group's valuation of the Exxon Acquisition and/or the PETRONAS Acquisition has been made on the basis that no such abandonment security funds are in existence. However, if such abandonment and decommissioning costs and expenses are higher than expected, or the Enlarged Group incurs penalties for failure to abandon and/or decommission its properties as required, this may adversely impact the Enlarged Group's business, prospects and/or financial condition.

Under the terms of the Midstream Conventions, the governments of Chad and Cameroon (respectively) have the right to acquire their respective portions of the Chad-Cameroon Pipeline following renunciation of the transportation authorisations by TOTCo and COTCo. If such rights are exercised, TOTCo and COTCo are not required to decommission the Chad-Cameroon Pipeline. The Enlarged Group would likely seek to exercise its shareholder rights (to the extent possible) in TOTCo and COTCo in order to facilitate future discussions with the governments of Chad and Cameroon (respectively) on this issue when appropriate.

3.6 **The profitability of TOTCo and COTCo is dependent on its third-party customers continuing to produce oil from their upstream operations.**

The profitability of TOTCo and COTCo is wholly dependent on the revenues received from shippers utilising the Chad-Cameroon ETS. The tariff payments due to TOTCo and COTCo for transportation of crude oil under the Shipper Transportation Agreements are determined by usage and throughput rates, rather than on a capacity reservation basis. Consequently, TOTCo and COTCo's future revenues are dependent on the level of production from, and field life of, those fields operated by the existing Shippers and any new fields operated by new or existing Shippers who require access to the Chad-Cameroon ETS. Under the Shipper Transportation Agreements, the shippers are not obliged to make any minimum nominations, and consequently any shipper could nominate zero once it no longer requires transportation services through the Chad-Cameroon Pipeline (which could significantly impact the cashflow position of TOTCo and COTCo).

Given that the Chad-Cameroon ETS is presently the only economically viable transportation option to market each shipper's crude oil to the international market, the Enlarged Group's view is that the risk that the existing Shippers (and future shippers) will no longer require the transportation services of TOTCo and COTCo in the immediate to mid-term is low.

3.7 **Any political instability and/or unrest may adversely impact the operation of the Chad/Cameroon Assets.**

Any political instability and/or unrest in Chad and/or Cameroon has the potential to adversely impact the operation of the Chad/Cameroon Assets.

In Chad, there has been a period of political instability following the death of President Idriss Déby Itno on 20 April 2021, which led to the dissolution of the existing government. Although a transition government is now in place in Chad, there can be no guarantee that this political instability will not return and adversely impact the operation of the Chad/Cameroon Assets.

Since 2016, Cameroon has been subject to political instability in the North West and South West regions due to the Anglophone crisis. Although, to the best of the Board's knowledge, the Chad-Cameroon Pipeline infrastructure has not been subject to any terrorist activities to date, there can be no guarantee that this will continue to be the case in future.

3.8 **Militant activity could destabilise oil production in Chad and/or Cameroon and adversely affect the Enlarged Group's operations and Chad's and/or Cameroon's economy.**

3.8.1 ***Chad***

Militant activity, violence and civil disturbances have, in the past, caused intermittent problems in Chad. In the recent past, the most prominent local rebel activity was essentially localised in the north of the Chad Territory and the related battles between the rebels and the army led notably to the death of Chad's then president, President Idriss Déby Itno, and the instability in-country due to presidential vacancy.

The Doba Oil Project and Chad-Cameroon Pipeline are located in Southern Chad and they have not been subjected to any militant activity. However, in spite of this fact and the Chadian government's efforts, unlawful acts may be directed at oil and gas industry participants and there is no assurance that militant acts will not occur in the future. In addition, any militant action against the Enlarged Group's assets or operations could result in significant damage to the environment, negatively impact its relationships with local communities and result in a temporary or permanent closure of all or part of those facilities.

The occurrence of any of the above could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

3.8.2 ***Cameroon***

Although there has been unlawful and militant activities in the North West, South West and far North regions of Cameroon, the Board does not expect that it will affect the activities of the Enlarged Group in Cameroon.

3.9 **The governments of Chad and Cameroon have significant influence over their domestic oil and gas sectors, and their decisions and/or actions may directly or indirectly adversely impact the operations of the Enlarged Group in these countries.**

The governments of Chad and Cameroon play a significant role in regulating their respective oil and gas industries. Accordingly, any action or decisions taken by such governments concerning the oil and gas industry, or economy more generally, could have an unexpected and materially adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects. Such risks include expropriation or re-nationalisation, breach, abrogation or renegotiation of concession/project agreements, denials of required permits and approvals, changes in law or policy, increases in royalty rates and taxes and the application of exchange or capital controls.

There can be no assurance that, post-Completion of the Exxon Acquisition and/or the PETRONAS Acquisition, the Enlarged Group will be able to establish and maintain a supportive and cooperative relationship with either of the Chad and/or Cameroon governments.

3.10 **The Enlarged Group may have to contend with logistical and operational difficulties as a result of carrying out its operations in Chad and Cameroon.**

As with many emerging economies, access to, and the condition of, public infrastructure (including roads, bridges and utilities) across Chad and Cameroon is limited. There can be no assurance that the operations of the Exxon Target Companies, PETRONAS Target Companies and/or the Pipeline Companies will not be materially impacted due to the state of relative infancy and/or repair of such public infrastructure. To date, the majority of the infrastructure required for exploration, operations and transportation of production across the two countries has been privately constructed by the Doba Consortium and/or Pipeline Companies, and the operations of the Enlarged Group in Chad and Cameroon is dependent on it. Such private infrastructure requires substantial expenditure to build and maintain, and construction and repair work is often subject to delays.

3.11 **The Chad and Cameroon judicial system may create an uncertain environment for investment and business activity.**

The legal systems in Chad and Cameroon, as with many developing countries, continue to develop and mature.

As a result, the Enlarged Group may become subject to certain difficulties in obtaining effective or consistent legal redress due to a number of factors out of its control. Such difficulties may include delay, the level of discretion that may be exercised by the courts or governmental authorities, insufficient judicial or administrative guidance on interpreting applicable rules and regulations, inconsistencies or conflicts between and within various existing laws, regulations, decrees, orders and resolutions and/or the relative inexperience of the judiciary and courts in commercial matters. In addition, the enforcement of laws or the Enlarged Group's statutory or contractual rights may depend on, and be subject to the interpretation of, the relevant local authority, and such interpretation may differ from the advice given to the Enlarged Group by local lawyers and potentially result in unexpected outcomes. Any disputes arising under the Upstream Conventions or the Conventions of Establishment are subject to the exclusive jurisdiction of an ICC arbitral panel seated in Paris. Whilst Cameroon is a party to the New York Convention, Chad is not and therefore there can be no guarantee that an ICC award made against Chad for the benefit of the Company would be recognised or enforced by the Chadian courts. However, such an award could be enforced in any other New York Convention state. Similarly, whilst there is a bilateral investment treaty in force between Cameroon and the UK, there is no such bilateral investment treaty in force between Chad and the UK.

It is possible that any adverse finding against the Enlarged Group, or any restriction placed on the Enlarged Group in exercising its contractual or statutory rights, could have a material adverse effect on the Enlarged Group's business, financial condition and/or prospects.

### 3.12 EEPCI (as Operator of the Doba Consortium) is currently subject to a number of labour related claims

EEPCI is currently subject to a number of labour related litigation matters in the Chadian courts. The practice of claimants in Chad is often to bring vastly inflated and meritless claims against defendants and it appears to be the case that, even when claimants are successful in their claims, the amount of any award is significantly less than the amount claimed. To date, EEPCI's approach has been to rigorously contest all such claims brought against the Doba Consortium. The Company understands that the amount paid out by EEPCI (gross to all members of the Doba Consortium) during the six year period 2016 to 2021 was for an amount less than 1 per cent. of the total amount of claims currently being brought or threatened against EEPCI.

Following Completion of the Exxon Acquisition and PETRONAS Acquisition, there can be no certainty that EEPCI will be successful in its defence of all ongoing claims or any new claims brought against it. It is possible that claimants may seek seizure or freezing orders over its or Doba Consortium property or other injunctive remedies in support of their claims for damages. A successful claim by one or more claimants may have a materially adverse impact on the Enlarged Group's business, ability to operate or financial condition. However, the Company intends to continue EEPCI's ongoing approach to actively contest all existing (and any new) claims that it considers lack merit.

### 3.13 Potential effect of the CEMAC Forex Regulation.

Foreign exchange matters within the Economic and Monetary Community of Central Africa Countries (CEMAC) area are dealt with in Act N°2/18/CEMAC/UMAC/CM dated 21 December 2018 and applicable as from 1 March 2019 (the "CEMAC Forex Regulation"). The application of the CEMAC Forex Regulation to entities falling within the hydrocarbons and mining sectors (the "extractive companies") has however been postponed since 2019 but it is intended to come into full force and effect as of 1 January 2022. In the past two years, representatives of the hydrocarbons and mining industries have engaged in discussions with the Bank of Central African States (the "BEAC") and the CEMAC authorities to review the principles and related requirements enacted by the CEMAC Forex Regulations in the context of their operations. The outcome of these discussions resulted so far in the adoption of three separate instructions by the Governor of the BEAC on 13 December 2021 that apply to the extractive companies in connection with (a) the conditions and modality of opening and maintaining foreign currency accounts and (b) the domiciliation of the importation and exportation of goods and services. The CEMAC Forex Regulation as amended by the new instructions provides, *inter alia*, several new obligations for the extractive companies:

– the prior authorisation from the BEAC for opening and maintaining foreign currency accounts outside and within the CEMAC zone and in relation to any existing foreign currency accounts existing as of 13 December 2021, the extractive companies have a grace period of 10 months from 31 December 2021 to comply with the newly adopted relevant instruction;

– the prior declaration and the repatriation of any borrowings (principal, interests repayments) made to a resident entity by a non-resident;

– the prior authorisation from the BEAC for any loan from a resident to a non-resident in the CEMAC zone and the declaration and repatriation of any revenues (including any repayments) from such loan within the CEMAC zone;

– the domiciliation of all importations and exportation of goods or services with a local credit institution when the amount is at least XAF 10 million;

– the repatriation of any export revenues within the CEMAC zone within 150 days of receipt; and

– the declaration to the Central Bank and the ministry in charge of money and credit of all transfer exceeding XAF 100 million out of the CEMAC zone 30 days prior to their realization.

The CEMAC Forex Regulation is a regional cross-border regulation which, from a hierarchy of norms' perspective, supersedes and prevails on the national provisions of each country. The Company will, following Completion of the Exxon Acquisition and PETRONAS Acquisition, review the structure of its operations in Chad and Cameroon to ensure compliance with the CEMAC Forex Regulation as amended and in particular once all regulations that are expected to be adopted by the CEMAC countries by the year end have been so adopted.

3.14 **The taxation and customs systems in Chad and/or Cameroon may be subject to change and the rules of those systems may be subject to different interpretation.**

Chad and Cameroon are both emerging market economies, and their policies and regulations on, and laws relating to, taxation, customs and excise duties may change from time to time as considered necessary for its further development.

More specifically, tax and customs rules usually evolve on an annual basis through annual finance laws, as considered necessary for further development and the realisation of their budgetary objectives.

Changes in applicable policies on taxation, customs and excise duties, as well as differences in interpretation of and decisions relating to tax laws, may have an adverse effect on the Enlarged Group's business, results of operations, financial position and prospects.

**4. Risks associated with the Nigerian Assets and doing business in Nigeria**

4.1 **The Enlarged Group's future Nigerian cashflows depend on certain key end users and such key end users may fail to fulfil their contractual obligations to the Enlarged Group or the Enlarged Group could fail to obtain replacement customers.**

The Enlarged Group has entered into four long-term take-or-pay gas sales agreements and one short-term interruptible gas sales agreement, and the Enlarged Group expects these five agreements will contribute a very significant portion of its future revenue. The inability of any of the key contractual counterparties to meet their obligations to the Enlarged Group or failure to make timely payments may affect the Enlarged Group's financial results, cashflows and ability to service its debt.

In the event that the Enlarged Group's existing customers do not fulfil their obligations under the respective gas sales agreements, or in the event that any of these entities become insolvent or subject to liquidation, the Enlarged Group may seek to enforce the terms of the agreements, including the NDPHC letter of credit and the World Bank Partial Risk Guarantee provided in respect of the Calabar NIPP gas sales agreement. There can be no assurance as to how long an enforcement action may take, or whether at the time of such enforcement, the relevant guarantor will be able to meet its obligations. In addition, in the event that any of the Enlarged Group's customers change ownership, the contractual obligations of that counterparty may transfer to the new owner and may expose the Enlarged Group to different payment and credit risks.

To the extent any of Accugas's material downstream customers breach or disavow their respective contracts with Accugas, there is a scarcity of potential new customers to contract with Accugas for the supply of gas on a similar scale to these existing customers. This may impact Accugas's ability to pay its creditors. Also, sales and transportation of the Enlarged Group's gas is dependent on pipelines and other infrastructure facilities enabling it to supply to customers, and new infrastructure might be required to be installed to re-route production to alternative or additional end users. Any requirement to install new infrastructure would require further capital expenditure by Accugas that may not be available.

In addition, the Upstream GSA, under which SEUGL sells gas from the Uquo Field to Accugas, is structured on a 'pay-when-paid' basis. Therefore, if Accugas's customers fail to pay or are late in paying Accugas, this may impact SEUGL's ability to pay its creditors.

The occurrence of any of these events could have a material adverse effect on the Enlarged Group's business, future cashflows, results of operations, financial condition and prospects.

4.2 **A significant proportion of the Enlarged Group's cashflow is supported by the World Bank Partial Risk Guarantee.**

A significant proportion of the Existing Group's cashflow, those arising under the Calabar GSA, is supported by the World Bank Partial Risk Guarantee, provided by the International Development Agency to Accugas, backed by a letter of credit (as further described in Part 14 of this document).

Under the terms of the Partial Risk Guarantee and associated documents, the Federal Government of Nigeria has provided an indemnity to the International Development Agency in the event that Accugas have to call on the letter of credit. Accugas has historically experienced payment delays in respect of the supply of gas to Calabar NIPP and as at the date of this document US$98.2 million is currently due under the Calabar GSA. The Company is working with NDPHC to settle this amount in a timely fashion without recourse to the Partial Risk Guarantee.

Under the terms of the Partial Risk Guarantee agreements, there is a risk that the International Development Agency could, after giving notice, suspend this guarantee and, ultimately, terminate the guarantee if Accugas does not comply with its terms. The Directors believe that the Enlarged Group has the policies and procedures in place to ensure compliance with the relevant representations, covenants and obligations, which largely relate to environmental and social practices and anti-bribery and corruption standards.

4.3 **A significant proportion of the Enlarged Group's revenue is derived from the sale of gas to the Nigerian power sector.**

The Nigerian power sector suffers from numerous problems, such as limited access to infrastructure, low connection rates, inadequate power generation capacity, lack of capital for investment, insufficient transmission and distribution facilities, high technical, commercial and collection losses and vandalism. These problems contributed to Nigeria ranking by the World Bank in 2020 as the 171st most difficult country in which to obtain access to electricity. These problems have created liquidity issues throughout the power value chain, from the distribution companies to the thermal power generating companies, which have resulted in delays in payments to the gas suppliers and dependence on financial assistance being provided to the sector from the Federal Government and the World Bank. Further reforms of the power sector are being proposed, but there is no guarantee that these reforms will be effective and so continued liquidity challenges for the sector could impact on the Enlarged Group's cashflows, financial condition and prospects.

4.4 **There can be no certainty in relation to future levels of growth in Nigerian domestic demand for gas.**

Whilst the Board believes that utilisation of domestic gas in Nigeria will be important in solving Nigeria's shortage of domestic power, the expected growth in demand for domestic gas may be less or slower than anticipated. In particular, if the Nigeria government's Gas Master Plan and Power Sector Recovery Program are not successful in promoting the development and utilisation of gas in Nigeria and improving electric power generation and supply, or if the Nigerian government decides to amend its stated policy so as to move away from domestic gas as a key component of tackling Nigeria's shortage of domestic energy, expected growth in demand for domestic gas could be materially impacted.

4.5 **The Enlarged Group's upstream interests in Nigeria are concentrated on two oil and gas fields.**

The Enlarged Group's upstream interests in Nigeria are concentrated on two oil and gas fields, namely the Uquo Field and the Stubb Creek Field. As a result, the Enlarged Group's success in Nigeria will be heavily reliant on it being able to continue to successfully exploit existing oil and/or natural gas reserves and/or maintaining valid legal title in these two fields. There can be no guarantee that the Enlarged Group can or will be able to, or that it will be commercially advantageous for the Enlarged Group to continue to exploit the Uquo Field and the Stubb Creek Field.

Furthermore, with both the Uquo Field and the Stubb Creek Field being located in South East Nigeria, the Enlarged Group's revenues may be impacted by issues generally affecting oil and gas operations in the region.

4.6 **Operational impediments or damage to, or the shut-down of, processing and transport infrastructure may hinder the Enlarged Group's access to oil and gas markets or delay or cease production.**

The Enlarged Group is reliant on the Uquo CPF and the Stubb Creek EPF to process natural gas and crude oil respectively and its pipeline infrastructure to transport gas and oil to its gas customers and to the oil the export terminal. Any sudden loss of, or significant interruption to, processing at the Uquo CPF or the Stubb Creek EPF, or the transportation of crude oil and/or natural gas through the pipelines that the Enlarged Group uses could result in an inability to meet gas contract obligations and to sell its oil production. In particular, a significant interruption to crude oil and/or natural gas processing at the Stubb Creek EPF or the Uquo CPF could occur if any essential piece of equipment for which the Enlarged Group lacks a replacement should break down for a substantial period of time or if multiple breakdowns were to occur at the same time. Furthermore, there can be no assurance that the Enlarged Group will be able to find a replacement or arrange necessary repairs on a timely or cost-effective basis.

The Enlarged Group may also be required to shut-in wells for regulatory reasons or due to a lack of demand or inadequacy or unavailability of a gas pipeline, gathering system or processing capacity. If a shut in were to occur, the Enlarged Group would be unable to realise revenue from those wells until suitable arrangements were made to transport and market that production.

Any significant delay, interruption or stoppage to the Enlarged Group's oil and gas operations could damage the Enlarged Group's relationships with one or more of its key customers, harm its reputation and cause the Enlarged Group to be liable for breach of contract for a failure to meet its contractual obligations.

The occurrence of any of these events could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

4.7 **The Enlarged Group is, or could potentially in the future be, reliant on third-party owned or operated infrastructure for the transport of its oil and natural gas liquids from the Uquo Field and the Stubb Creek Field to export terminals.**

The Enlarged Group is reliant on certain joint-venture owned or third party operated infrastructure for its oil and gas operations, in particular the transportation of Uquo and Stubb Creek oil and natural gas liquids (or condensate) sold through QIT for export. The Enlarged Group's oil and condensate volumes are stabilised through the FUN Manifold, which is jointly owned by the Uquo JV, the Stubb Creek JV and a third-party joint venture.

The inadequacy or unavailability of such oil and condensate pipeline capacity and infrastructure, and/or the necessary licences to operate and export, could require the Enlarged Group to shut-in wells, leading to the Enlarged Group being unable to realise revenues from sales of oil and gas from those wells until suitable alternative transportation arrangements can be made.

Accugas also uses third-party owned and operated gas transportation pipelines to access other customers and gas markets in the region and will do so in the future in order for Accugas to access new customers and markets.

4.8 **The Enlarged Group's operations in marginal fields are subject to indigenous ownership restrictions.**

The Uquo Field and the Stubb Creek Field are subject to the rules and requirements of the Marginal Field Guidelines, which govern Nigeria's marginal field programme. The Marginal Field Guidelines provide, among other things, that marginal fields may only be awarded to, and operated by, indigenous companies that are "substantially Nigerian". Furthermore, in 2014 the DPR issued guidelines for obtaining ministerial consent to the assignment of interests in Oil and Gas assets in Nigeria. The guidelines provide that the total interest assignable to a foreign entity in a marginal oil field in Nigeria shall not exceed 49 per cent. of the total overall interest in the asset.

Following the recent enactment of the PIA in 2021, the interpretation of the Marginal Field Guidelines will now be carried out by the Commission (the newly-formed Nigerian upstream regulatory authority that has replaced the DPR). Although the Directors believe that the current ownership structures of both the Stubb Creek Field and the Uquo Field satisfy the "substantially Nigerian" requirement, to the extent the Commission changes its policy in this regard or the ownership structure changes due to changes in the Enlarged Group or its joint venture partners in the relevant field, there is a risk that the Company and its respective joint venture partners could be forced to relinquish their interest in these assets.

4.9 **The Enlarged Group has not maintained decommissioning arrangements and/or security in respect of the Uquo Field and the Stubb Creek Field.**

By the provisions of the PIA, it is now a statutory obligation for the Enlarged Group to make adequate provisions for and establish a Decommissioning and Abandonment Fund with the funds to be set aside in escrow and funded on a straight-line basis over the remaining economic life of the Uquo Field and Stubb Creek Field. The Enlarged Group is required to submit the Decommissioning plans to the regulator within 12 months of the PIA becoming effective.

Under the terms of the Enlarged Group's existing contractual arrangements with respect to the Uquo Field and the Stubb Creek Field, the Enlarged Group and its joint venture partners in such fields are obliged to maintain certain decommissioning arrangements/security in respect of potential future decommissioning liabilities. To date, and in line with a number of other operators of marginal fields, these provisions have not been strictly enforced and such decommissioning arrangements/security arrangements have not been put in place. If a notice of breach were received in respect of these decommissioning arrangements/security arrangements then each of the contracts allow a 90-day period in order to remedy the breach, which may be achieved by making the relevant payments into escrow.

4.10 **The Enlarged Group is subject to risks involving third party operators, contract counterparties, partners and other project participants. Furthermore, disagreements with, or the exercise of termination rights by, any of the Enlarged Group's partners or contract counterparties may result in delays, losses or additional costs to the Enlarged Group.**

Both the Enlarged Group and its partners are obliged to comply with the requirements of the applicable contracts, joint operating agreements, farm-out agreements and other arrangements governing their respective relationships.

Co-operation and agreement among project participants on existing or future projects is important for the smooth operation and financial success of such projects and if one or more project participants were to fail to cooperate, it may delay or disrupt existing or future projects. Further, operators, partners and other project participants that own interests in assets in which the Enlarged Group has interests may have economic or business interests or objectives that are inconsistent or conflict with those of the Enlarged Group and may elect not to participate in certain activities relating to those assets or withhold their consent in circumstances when their consent is required, which may limit the ability of the Enlarged Group and other interest holders to explore, appraise or develop such assets as planned.

Although the Stubb Creek Field is operated by Universal, the joint operating agreement in respect of the Stubb Creek Field requires decisions of the project management committee to be made jointly, thereby requiring both the Enlarged Group and Sinopec to vote in favour of key decisions of the project management committee (save for non-associated gas developments in respect of which Universal has the casting vote). Sinopec is currently required to provide 80 per cent. of funding in relation to crude oil and associated natural gas developments pursuant to the terms of the joint operating agreement in respect of the Stubb Creek Field. There is a risk that Sinopec may not vote in favour of oil development plans for the Stubb Creek Field. The Enlarged Group may suffer unexpected costs or other losses if Sinopec or any future partner does not meet its obligations. For example, other participants may experience financial or other difficulties or otherwise default on their obligations to meet capital or other funding obligations in relation to assets in which the Enlarged

Group has interests. Furthermore, any failure by a third-party operator or the Enlarged Group to carry out its obligations with respect to a field could put the licence for that asset at risk.

In addition, certain of the Enlarged Group's contractual arrangements may permit the counterparty to terminate the relationship under certain circumstances. Any loss of a third-party operator (and any resulting loss of the licence to the field operated by such operator) or partner could also impact the Enlarged Group's ability to develop the field in accordance with the development plans, or at all, which could impact oil and gas production at a given field and could lead to the Enlarged Group being unable to deliver gas to customers in accordance with its contractual obligations. This, in turn, could impact the revenues earned by the Enlarged Group with respect to the field. Furthermore, contract counterparties may seek to renegotiate contractual terms in the event of changes in their business or operating environment, economic hardship or financial distress. In such circumstances, the Enlarged Group may have to resort to legal process to enforce its contractual rights and such processes can be time consuming and costly and could result in an adverse outcome for the Enlarged Group.

The occurrence of any of the above could have a material adverse effect on the Enlarged Group's business, results of operation, financial condition and prospects.

4.11 **Deferred payments to Frontier.**

As part of the FOL Transaction and pursuant to the terms of the agreement with Frontier, SEUGL is required to pay Frontier a deferred cash call equal to the Naira equivalent of US$4.13 million. Failure by SEUGL to pay Frontier the deferred cash call will give rise to the right for Frontier to require SEUGL to transfer a portion of its economic interest in the Uquo Gas Project as a default remedy.

4.12 **Revenue recognition under take-or-pay gas sales agreements.**

The Enlarged Group may be in position to deliver contracted gas volumes when its customers are not ready or able to receive those volumes. The take-or-pay provisions in the gas sales agreements bind the purchaser to pay for certain quantities of gas even when undelivered, from the date on which the gas is available for delivery. However, title to gas sold only passes on the date of delivery and, as the risk of ownership only transfers upon delivery, revenue from the sale of the gas is recognised only on a delivered basis. In circumstances which the Enlarged Group receives payments pursuant to take-or-pay provisions and gas is not delivered to the contractual counterparties, the Enlarged Group is unable to recognise this income as revenue for accounting purposes and instead accrues it as deferred revenue.

4.13 **The Enlarged Group may attract spurious claims and media coverage and is therefore subject to reputation risk.**

Prominent businesses operating in Nigeria can attract significant attention from the Nigerian media, which can be of an adverse nature. Such media coverage can often be spurious and/or politically motivated, putting forward allegations which are unfounded due to the limited nature of the country's libel laws.

The Enlarged Group has been subject to spurious litigation in the past and there can be no assurance that other negative publicity relating to the Enlarged Group will not arise and harm Savannah's reputation with its operating partners, other project participants, existing customers (some of whom are state-owned), prospective customers, regulators, suppliers, host communities, the wider Nigerian oil and gas industry, lenders and shareholders, regardless of the inaccuracy of, or lack of grounds for, any such negative publicity. Any such damage to the Enlarged Group's reputation could have a material adverse effect on its business, results of operations, financial condition and prospects and could have a material adverse effect on the prevailing market price of the Ordinary Shares.

Other proceedings have been brought against members of the Seven Group which Savannah did not acquire. Although these proceedings have not been brought in relation to companies within the Enlarged Group, there is a residual risk that claimants may attempt to extend their claims to the Enlarged Group.

4.14 **There is a risk that the Enlarged Group could be held liable for successor liability for violations of Compliance Laws.**

It is possible that the Enlarged Group could be held liable for successor liability for violations of Compliance Laws, if such violations have been committed in the past by companies within the Seven Group, or by their employees, directors, representatives or agents, in relation to the Nigerian Assets. There have, in the past, been allegations and investigations into companies in the Seven Group which are not included in the Nigerian Assets and did not relate to the Nigerian Assets. It is the Company's belief that none of these investigations are ongoing in Nigeria and there are no other investigations ongoing in relation to companies in the Nigerian Assets in any other jurisdiction. In addition, the Company's due diligence did not find any evidence of violations of Compliance Laws by the Seven Group or such persons or in relation to the Nigerian Assets. However, there remains a risk that the Company's due diligence may not have identified all issues which may have occurred over the life and in all aspects of the business of the Seven Group. The Company may also be negatively impacted if, in the future, allegations or investigations were to suggest violations of Compliance Laws had occurred in the past in relation to the Seven Group and/or the Nigerian Assets, whether or not such allegations or investigations were founded in fact.

4.15 **The Enlarged Group must manage logistical and operational difficulties as a result of carrying out its operations in Nigeria.**

The Enlarged Group must manage logistical and operational difficulties as a result of carrying out operations in Nigeria. Persistent problems with power generation, transmission and distribution, a deteriorating and congested road network, congested ports and obsolete rail infrastructure have severely constrained socio-economic development in Nigeria.

Moreover, infrastructure in South Eastern Nigeria is limited and unreliable. Rail and road infrastructure is relatively limited and restricts the movement of people and goods within those regions thereby increasing the time it takes to mobilise workforces and deliver supplies or equipment. The lack of reliable infrastructure also limits the Enlarged Group's ability (and that of its partners, contractors, customers and suppliers) to respond quickly to unforeseen situations, which can lead to delays and production stoppages.

4.16 **South East Nigeria periodically experiences adverse weather conditions and natural disasters.**

South East Nigeria, in which the Uquo Field and Stubb Creek Field are both based, periodically experiences adverse weather conditions and natural disasters, mainly in the form of floods, which further limits the use of available infrastructure, particularly during the rainy season (March to November), and increases the likelihood of disruption during that part of year. In addition, flooding in the Niger Delta has also led to outbreaks of disease which, coupled with the ongoing security concerns in relation to the region (see paragraphs 4.21 and 4.22 of this Part 3), may affect the Enlarged Group's ability to staff its operations with qualified Nigerian and overseas individuals if such individuals were deterred from relocating to the Niger Delta, or to Nigeria more generally, as a result of health or security concerns.

4.17 **The Nigerian economy is dependent on oil production in Nigeria and global prices of oil.**

The Nigerian economy is highly dependent on oil production in Nigeria and global prices of oil. Reductions in oil revenues could have a material adverse effect on the Nigerian economy, and in turn on the Enlarged Group's business and results of operations. The Nigerian government relies heavily on oil revenue to fund its budget and the decline in prices has resulted in a high rate of unemployment, reduction in foreign exchange and government revenue, as well as significant budgetary constraints, leading to less investment in key projects such as infrastructure.

4.18 **The Nigerian government has significant influence over, and dependency upon, Nigeria's oil and gas industry, exposing the Enlarged Group to adverse sovereign action by the Nigerian government.**

According to the IMF, oil and natural gas export revenue, which was estimated at US$65 billion in 2019, has accounted for 48 per cent. of Nigeria's total government revenue on average between 2010 to 2019. Oil and natural gas revenue has been the country's main source of foreign exchange, making up more than 93 per cent. of Nigeria's total exports to the world within this period.

The Nigerian government's ownership of Nigeria's mineral wealth is reinforced by an array of laws and regulations, including the Petroleum Act and the Petroleum Investment Act. As a consequence, the Nigerian government plays a key role in determining the extent to which anyone participates in the Nigerian oil and gas industry. There can be no assurance that the Enlarged Group will continue to benefit from the support of the Nigerian government, which could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

Accordingly, petroleum companies in Nigeria face the risks of expropriation or re-nationalisation, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks. Possible future changes in the Nigerian government, major policy shifts or increased security arrangements in Nigeria could have, to varying degrees, a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

4.19 **Production of oil in Nigeria may be impacted by OPEC and other production quotas.**

Nigeria is a member of OPEC, which, from time to time constrains its members' ability to produce oil through the imposition of production quotas. NNPC allocates production quotas among oil producers based on the aggregate technical production limits of all producing wells, which are negotiated between the producer and the Nigerian government. In the event that technical production exceeds Nigeria's OPEC quota, the quota is allocated to the producers on a *pro rata* basis based on their respective technical production levels. If production allocations are exceeded, it is possible to apply for additional quotas from the Nigerian government, but there can be no assurance that the additional quotas will be granted. Nigeria also has the power to implement export quotas. As a result, the Enlarged Group may be constrained in exporting oil through such quotas in the future, which could have a material adverse effect on the Enlarged Group's business, prospects, results of operations, cashflows, financial condition and prospects.

4.20 **Local content legislation in Nigeria may impact upon the Enlarged Group's ability to recruit suitably qualified individuals.**

The Nigerian Local Content Act, which was enacted in April 2010, provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry. The Local Content Act prescribes minimum thresholds for Nigerian participation in oil and gas activities and also impacts the day-to-day management of companies operating in the oil and gas industry by imposing requirements concerning, among others, the use and involvement of Nigerian labour in their operations. This may adversely impact on the Enlarged Group's ability to hire suitably qualified persons and, consequently, the costs of the Enlarged Group's operations in Nigeria.

4.21 **Political instability, religious differences, ethnicity, regionalism and internal security in Nigeria pose risks that impact Nigerian oil and gas production.**

Following the adoption of a new presidential constitution in May 1999, Nigeria is experiencing its longest period of civilian rule since obtaining independence from the United Kingdom in 1960. Political tensions and incidents, including civil unrest, have been seen around the time of, or leading up to, previous elections held in Nigeria, and there can be no assurance that similar incidents will not take place in relation to future elections. In the past, results of elections in Nigeria have been subject to criticism by both opposition candidates and international election observers. Further, if there are allegations of fraud or other irregularities in connection with the presidential elections and such allegations are not properly handled in an orderly manner, such allegations may undermine the legitimacy of the new administration.

The outcome of future elections, the next one of which is currently due in 2023, may have a significant impact on Nigeria's political stability and may adversely affect its economy, and no assurance can be given that the reforms and policies that are proposed or taking place will continue. Any post-election administration may pursue different policies and priorities, alter or reverse certain reforms or take actions (including a highly unlikely expropriation or nationalisation (which in any case is required to be with adequate compensation), breach or abrogation of project agreements) that make domestic and foreign investment in Nigeria less attractive or lead to protests, violence or other unrest. Any significant changes in the political climate in Nigeria, including changes affecting the stability of the Nigerian Government or involving a rejection, reversal or significant modification of policies, favouring the privatisation of state-owned enterprises, reforms in the power, banking or oil and gas sectors, may have negative effects on the economy, government revenues or foreign reserves and, as a result, a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

Religious differences, particularly between the mainly Muslim North and broadly Christian South, pose additional risks to the stability of Nigeria and the political landscape. Certain Northern states have adopted Sharia law since the return to civilian rule in 1999, which has resulted in further alienation of the Christian minorities in these states. Hundreds of lives have been lost in a series of terrorist attacks, primarily by way of bombings carried out by religious militia groups against both civilians and state institutions. In addition, religious militia groups have carried out armed attacks and kidnappings against foreigners working in Nigeria.

Furthermore, Boko Haram, a militant Islamist group operating in northern Nigeria, has become increasingly active engaging in mass kidnappings, raids on villages with high fatalities and cross border attacks in Cameroon. Suspected members of the Boko Haram have reportedly conducted kidnappings and attacks in the North Eastern part of the country and the Federal Capital Territory.

While terrorist attacks linked to religious and/or ethnic differences have in the past primarily been carried out in the north of the country, no assurances can be given that such violence will not spread to southern Nigeria where the Enlarged Group's operations are based. These conflicts may adversely affect Nigeria's political stability which may, in turn, affect the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

4.22 **Militant and unlawful activity could destabilise oil production in Nigeria and adversely affect the Enlarged Group's operations and Nigeria's economy.**

Militant and unlawful activity, violence and civil disturbances have, in the past, caused intermittent problems in the Niger Delta. Various militant groups have conducted guerrilla attacks on crude oil pipelines and other related infrastructure, kidnapping oil and gas workers for ransom and generally disrupting the activities of oil and gas companies with operations in the Niger Delta, and more broadly throughout Nigeria. Militant and unlawful activity has, in the past, resulted in companies being forced to decrease production or to even consider ceasing their operations in Nigeria as a result of attacks on, or threats to, their operations and staff.

There is a risk that, in the future, and in spite of the Nigerian government's efforts (which have included offering an amnesty to militants who surrender their weapons), militant acts in the Niger Delta may continue to be directed at oil and gas industry participants and there is no assurance that militant acts will not occur in the future.

If the Enlarged Group, its employees or employees of its operating partners is the subject of any attacks, kidnappings or other security threats, the Enlarged Group's operations and production of oil and gas in the Niger Delta could be materially adversely affected. Unrest in the Niger Delta region may lead to lower Nigerian oil and gas production, deter foreign direct investment, lead IOCs to curtail their operations in Nigeria or lead to increased political instability and unrest, and such unrest could have a material adverse effect on Nigeria's economy. The fear of militant attacks could have an adverse effect on the Enlarged Group's ability to adequately staff and/or manage its operations and could substantively increase the costs of doing so. In addition, any militant action against the Enlarged

Group's assets or operations could result in significant damage to the environment, negatively impact its relationships with local communities and result in a temporary or permanent closure of all or part of those facilities.

The occurrence of any of the above could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

4.23 **The Enlarged Group may be subject to currency controls which may limit its ability to service US Dollar denominated debt, to transfer funds out of country, to attract appropriately skilled staff or to purchase required services.**

The Nigerian Government has imposed foreign exchange restrictions to control the flow of US Dollars in and out of the country. The controls prohibit the use of currencies other than the Naira as a means of payment for certain items. The imposition of foreign exchange controls may have an adverse effect on the Enlarged Group's ability to convert Naira into US Dollars to service US Dollar denominated debt, to transfer funds out of country and to attract and retain appropriately skilled staff and pay for required services in Nigeria. The occurrence of any of the above could have a material adverse effect on the Enlarged Group's business, results of operations, cashflows, financial condition and prospects.

4.24 **Importance of maintaining good title to licence interests.**

The Enlarged Group's right to explore and exploit its licence interests and Accugas's ability to operate the Accugas Midstream Business is reliant on the establishment and maintenance of good title to the licence interests both entities purport to hold including, in particular, any licence fees that become due. Whilst the Enlarged Group seeks to ensure that it has good title to the participating interests that it owns, it cannot completely eliminate the risk of future title disputes or challenges. A successful challenge to the Enlarged Group's title to assets may result in the Enlarged Group being required to halt development or production or operations or, ultimately, in the loss of such assets.

4.25 **Foreign subsidiaries.**

The ability of the Company's subsidiaries to make payments to the Company may be constrained by, among other things, the level of taxation, particularly in relation to corporate profits and withholding taxes, in the jurisdiction in which any other Group company operates, and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

4.26 **The Nigerian judicial system may create an uncertain environment for investment and business activity.**

Nigerian law is predicated on the common law system, with its roots being derived from the English legal system.

The Nigerian legal system continues to develop but faces a number of challenges including delays in the judicial process, as most cases, even spurious claims, take a considerable period of time to be concluded. As a result, obtaining effective legal redress may be delayed and there is a high degree of uncertainty due to some level of discretion that may be exercised by the courts. There is also a lack of judicial or administrative guidance on interpreting applicable rules and regulations, inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions and relative inexperience of the judiciary and courts in commercial matters. However, recent years have witnessed considerable reform of the judiciary, especially in Lagos State with the setting up of commercial courts and the introduction of new rules to cut down on delays in the judicial process.

The slow judicial process may sometimes affect the enforceability of judgments obtained. In addition, the enforcement of laws may depend on, and be subject to the interpretation of, the relevant local authority, and such interpretation may differ from the advice given to the Enlarged Group by local lawyers.

There can be no assurance that contracts, joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of Nigerian government authorities and the effectiveness and enforcement of such arrangements in Nigeria. A number of the asset and joint venture documents to which we are a party are not standard form documents, which makes interpretation of disputed provisions less certain. These and other issues arising out of Nigeria's legal system subject the Enlarged Group's business to greater risks and uncertainties than if the Enlarged Group's operations were conducted in jurisdictions with a more mature legal system.

4.27 **Nigeria is a federal state, and the Enlarged Group's operations are located across two states, exposing the Enlarged Group to varying, potentially adverse, state and local government policies.**

The Enlarged Group's operations are located across two states of Nigeria, both of which have their own governments. Within those states, there are multiple local government authorities within the Enlarged Group's areas of operation. In addition, the Enlarged Group presently contracts with certain state-owned entities, such as Ibom Power, which is owned by Akwa Ibom State. Each of these states has a varying political dynamic. Political changes at the state and local level can affect the Enlarged Group's contracts with these local governments or entities they own or control, including the potential risk of expropriation. While the powers of the various tiers of government to levy and collect taxes are set forth in the Nigerian constitution, it is not unusual for state and local government agencies to seek to levy and collect taxes that they are not constitutionally authorised to levy and collect. These factors, combined with potential conflicts between federal, state and local governments, could have a material adverse effect on the Enlarged Group's business, results of operations, financial position, cashflows and prospects.

**5. Risks associated with the Niger Assets and doing business in Niger**

5.1 **Licensing and other regulatory requirements in Niger.**

The Nigerien Government owns the country's mineral Resources and grants hydrocarbon exploration and production rights under fixed term production sharing contracts, which can be renewed in accordance with their terms. It therefore retains control over the exploration and exploitation of hydrocarbon Reserves. Any adverse changes in the Nigerien Government's policy with respect to the oil and gas industry, including any which may occur following the proposed review of the current Petroleum Code, may adversely impact the interests of the Enlarged Group.

The new PSC covering the R1, R2, R3 and R4 areas, named the R1234 PSC, has been approved by the Minister of Petroleum, Energy and Renewables Energies and the Niger Council of Ministers through a decree. Savannah Niger is now liable to pay a signature bonus, which constitutes a condition precedent for the entry into force of the R1234 PSC. Unless and until all conditions precedent are met, including the signature bonus paid by Savannah, Savannah is limited in its ability to carry out activities in the R1234 PSC area and there is a risk that the new R1234 PSC will not be awarded.

Exploration and development activities in developing countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political risks and expropriation, nationalisation or renegotiation of existing contracts. The two main protections granted to Savannah under the R1234 PSC are (1) the stability of the legislation and the terms agreed under the R1234 PSC and the commitment that the Nigerien Government shall never (a) directly or consequently increase the obligations and responsibilities imposed on Savannah Niger nor (b) infringe the latter's economic rights and advantages resulting from Law of 2017 and the R1234 PSC, without Savannah's prior consent, and (2) (a) a conciliation procedure which shall ultimately be resolved by means of arbitration conducted in accordance with the Arbitration Rules of the International Centre for Settlement of Investment Disputes (ICSID Rules) in accordance with the Convention on the settlement of investment disputes between States and nationals of other States, the "Washington Convention", and (b) an arbitration procedure for any dispute which cannot be settled amicably. The R1234 PSC provides that the dispute shall be resolved in accordance with its provisions, the provisions of the petroleum legislation in force at the date of entry into force of the R1234 PSC, the provisions of laws in force at the signature date of the R1234 PSC other than the petroleum laws and social and environmental laws, as well as the provisions of international law applicable in the area. The R1234 PSC specifically provides for any such arbitration to be heard in Paris, France.

5.2 **Title matters and payment obligations.**

Although the Savannah PSC, and various international treaties to which Savannah Niger is a signatory, offers strong protection to the Enlarged Group, an unforeseen defect in title, changes in law (or interpretations thereof), regulatory consents or political events may arise or occur to defeat or impair the claim of the Enlarged Group to some or all of the rights in properties which it currently owns or is interested or may acquire which could result in a material adverse effect on the Enlarged Group, including a reduction in any revenues generated.

5.3 **Early stage of operations.**

The Enlarged Group's operations in Niger are at an early stage of development and future success will depend, *inter alia*, on the Directors' ability to successfully manage and exploit the current asset portfolio and to take advantage of further opportunities which may arise. There can be no guarantee that the Enlarged Group can or will be able to, or that it will be commercially advantageous for the Enlarged Group to, develop its Nigerien assets.

Further, the Enlarged Group's future success in developing the existing discoveries and making additional discoveries of oil and/or natural gas, is dependent on accessing the appropriate sources of future funding, including, but not limited to, equity markets and bank debt. Whilst the Directors are optimistic about the Enlarged Group's prospects in Niger, there is no certainty that sustainable revenue streams and sustainable profitability will be achieved.

The Enlarged Group's business plan to exploit and commercialise its Nigerien assets will require significant capital expenditure for the identification, acquisition, appraisal, exploration, development and production of oil and gas resources and/or reserves in the future. The Enlarged Group's inability to access sufficient capital for its operations may have a material adverse effect on its business, financial condition, results of operations and prospects.

5.4 **Foreign subsidiaries.**

The Enlarged Group conducts most of its operations in Niger through its subsidiary, Savannah Niger, which is located outside of the United Kingdom. At the point of production commencement, the ability of Savannah Niger to make payments to the Company may be constrained by, among other things, the level of taxation, particularly in relation to corporate profits and withholding taxes, in the jurisdiction in which it or any other Group company operates, and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

5.5 **Exchange controls in Niger.**

Savannah Niger is subject to the common foreign exchange regime provided for by Regulation N°09/2010/CM/UEMOA relating to external financial relations of the WAEMU member States dated October 01, 2010 (the "WAEMU Foreign Exchange Regulation"), which, *inter alia,* may restrict the flow of funds out of country.

5.6 **Oil exploration and production in Niger and the sale of such production depends on adequate infrastructure.**

Reliable roads, bridges, power sources and water supplies are important determinants which affect capital and operating costs. Generally speaking, Niger suffers from underdeveloped infrastructure, communication problems (particularly internet access), energy shortages and high energy costs. Inadequate infrastructure could impact the Enlarged Group's plans in Niger and could have an adverse impact on the Enlarged Group's business and prospects.

5.7 **Interruptions in availability of exploration, production or supply infrastructure in Niger.**

The Enlarged Group may suffer, indirectly, from delays or interruptions due to lack of availability of drilling rigs or construction of infrastructure, including pipelines, storage tanks and other facilities, which may adversely impact the operations and could lead to fines, penalties, criminal sanctions against the Enlarged Group and/or its officers or its current or future licences or interests being terminated. Despite assurances given by the Nigerien Government in the Savannah PSC, there is the risk of delays in obtaining licences, permissions and approvals required by the Enlarged Group or its partners in the pursuance of its business objectives which could likewise have a material adverse impact on the Enlarged Group's business and the results of its operations.

5.8 **Failure to meet contractual work commitments may lead to penalties.**

The Enlarged Group is subject to contractual work commitments, including those specified within the Savannah PSC, which includes a minimum work programme to be fulfilled within certain time restraints. Specifically, these commitments may cover certain depths of wells to be drilled, seismic surveys to be performed and other data acquisition. Failure to comply with such obligations, whether inadvertent or otherwise, may lead to fines, penalties, restrictions and withdrawal of licences with consequent material adverse effects.

5.9 **Political, economic, fiscal, legal, regulatory and social environment risk.**

The Enlarged Group's interests in Niger are likely to be exposed to political, economic, fiscal, legal, regulatory and social environment risk. The Enlarged Group's business will involve a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. These risks include, but are not limited to, corruption, civil strife or labour unrest, armed conflict, terrorism, limitations or price controls on oil exports, and limitations or the imposition of tariffs or duties on imports of certain goods. If the existing body of laws and regulations in Niger is interpreted or applied, or relevant discretions exercised, in an inconsistent manner by the courts or applicable regulatory bodies, this could result in ambiguities, inconsistencies and anomalies in the enforcement of such laws and regulations, which, in turn, could hinder the long-term planning efforts of the Enlarged Group and may create uncertainties in its operating environment.

The strategy and business of the Enlarged Group in Niger depends on it maintaining good relationships and cooperating with the relevant Nigerien authorities. While the Company believes that it has an effective working relationship with the Niger authorities, there is no guarantee that this positive relationship will continue or that actions by current or future governments will not seriously affect the business or financial position of the Enlarged Group. This relationship could be adversely impacted by future changes in the personnel or management of the Enlarged Group or the Nigerien authorities.

5.10 **Uncertainties in the interpretation and application of laws and regulations.**

The Savannah PSC is governed by Niger law. The courts in Niger may offer less certainty as to the judicial outcome or a more protracted judicial process than is the case in more established economies. However, the Savannah PSC offers the option of recourse to an international arbitration procedure. Nevertheless, the Enlarged Group could face risks, such as: (i) difficulty of obtaining effective legal redress in the courts, whether in respect of a breach of law or regulation, or in an ownership dispute, (ii) a higher degree of discretion on the part of governmental authorities and, therefore, less certainty, and (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations. Enforcement of laws in Niger may also depend on and be subject to the interpretation placed upon such laws by the relevant local authority, and such authority may adopt an interpretation of an aspect of local law which differs from the advice that has been given to the Enlarged Group by local lawyers or even previously by the relevant local authority itself.

## 6. Risks relating to the Ordinary Shares

6.1 **Suitability.**

Investment in the Ordinary Shares may not be suitable for all readers of this document. Readers are accordingly advised to consult a person authorised under FSMA who specialises in investments of this nature before making any investment decisions.

6.2 **Investment in AIM-traded shares.**

Investment in shares traded on AIM involves a higher degree of risk, and such shareholdings may be illiquid. The AIM Rules are different and may be less demanding than those rules that govern companies admitted to the Premium Segment of the Official List. It is emphasised that no application is being made for the admission of the Company's securities to the Official List. An investment in the Ordinary Shares may be difficult to realise. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market price of the Ordinary Shares may not reflect the underlying value of the Company. Investors may therefore realise less than, or lose all of, their investment. The Board cannot assure investors that the Ordinary Shares will always continue to be traded on AIM or on any other exchange. If such trading were to cease, certain investors may decide to sell their Ordinary Shares, which could have an adverse impact on the price of the Ordinary Shares. Additionally, if in the future the Company decides to obtain a listing on another exchange in addition or as an alternative to AIM, the level of liquidity of the Ordinary Shares traded on AIM could decline.

6.3 **Share price volatility and liquidity.**

The Company's entire issued share capital is admitted to trading on AIM but there can be no assurance that an active or liquid trading market for the Ordinary Shares will develop or, if developed, that it will be maintained. AIM is a market designed primarily for emerging or smaller growing companies which carry a higher-than-normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List or some other stock exchanges. The Ordinary Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List and the share price may be subject to greater fluctuations than might otherwise be the case. An investment in shares traded on AIM carries a higher risk than those listed on the Official List.

The Company is principally aiming to achieve capital growth and, therefore, Ordinary Shares may not be suitable as a short-term investment. Consequently, the share price may be subject to greater fluctuation on small volumes of shares traded, and thus the Ordinary Shares may be difficult to sell at a particular price. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market price of the Ordinary Shares may not reflect the underlying value of the Company. There can be no guarantee that the value of an investment in the Company will increase. Investors may therefore realise less than, or lose all of, their original investment.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Ordinary Shares are quoted and the price which investors may realise for their Ordinary Shares may be influenced by a large number of factors, some of which are general or market specific, others which are sector specific and others which are specific to the Enlarged Group and its operations. These factors include, without limitation, (i) the performance of the Company and the overall stock market, (ii) large purchases or sales of Ordinary Shares by other investors, (iii) results of exploration, development and appraisal programmes and production operations, (iv) changes in analysts' recommendations and any failure by the Enlarged Group to meet the expectations of the research analysts, (v) changes in legislation or regulations and changes in general economic, political or regulatory conditions (particularly in Chad, Cameroon, Nigeria and/or Niger), and (vi) other factors which are outside of the control of the Company.

6.4 **Dilution.**

Shareholders not participating in future offerings may be diluted and pre-emptive rights may not be available to Shareholders, including, but not limited to Shareholders resident in jurisdictions with restrictions which means that they will not be granted subscription rights in connection with, or be able to subscribe for new shares in, such offerings. Statutory pre-emptive rights have been waived up to certain stated amounts as detailed in the Company's 2021 AGM circular. The Company may in the future issue warrants and/or options (in addition to the existing awards made by the Company under its share incentive scheme, as well as the further intended awards, which are set out in Part 12 of this document) to subscribe for new Ordinary Shares, including (without limitation) to certain advisers, employees, directors, senior management and consultants. The exercise of such warrants and/or options would result in dilution of the shareholdings of other investors.

6.5 **Dividends.**

The Enlarged Group has announced its intention to commence payment of an annual dividend. The Enlarged Group intends to provide further information on its intended forward dividend policy in due course, however there can be no assurance as to the level of future dividends.

6.6 **Overseas shareholders may be subject to exchange rate risks.**

The Ordinary Shares are, and any dividends to be paid on them will be, denominated in Pounds Sterling. An investment in Ordinary Shares by an investor whose principal currency is not Pounds Sterling exposes the investor to foreign currency exchange rate risk. Any depreciation in the value of Pounds Sterling in relation to such foreign currency will reduce the value of the investment in the Ordinary Shares or any dividends in relation to such foreign currency.

6.7 **Impact of research on share price.**

If securities or industry analysts do not publish research or publish unfavourable or inaccurate research about the business, the Company's share price and trading volume of the Ordinary Shares could decline.

The trading market for the Ordinary Shares will depend, in part, on the research and reports that securities or industry analysts publish about the Company or its business. The Directors may be unable to sustain coverage by well-regarded securities and industry analysts. If either none or only a limited number of securities or industry analysts maintain coverage of the Company, or if these securities or industry analysts are not widely respected within the general investment community, the trading price for the Ordinary Shares could be negatively impacted. In the event that the Company obtains securities or industry analyst coverage, if one or more of the analysts who cover the Company downgrade the Ordinary Shares or publish inaccurate or unfavourable research about the Group's business, the share price would be likely to decline.

If one or more of these analysts cease coverage of the Company or fail to publish reports regularly, demand for the Ordinary Shares could decrease, which might cause the share price and trading volume to decline.

6.8 **The ability of non-UK resident Shareholders to bring actions or enforce judgments against the Company may be limited.**

The Company is a public limited company incorporated in England and Wales.  he rights of Shareholders are governed by the Articles and English law and these rights may differ from those which would be typical in some non-UK corporations. Notably, English law significantly limits the circumstances under which shareholders of English companies may bring derivative actions. Nor does English law afford approval rights to dissenting shareholders in the form typically available to shareholders in a US corporation.

**It should be noted that the risk factors listed above are not intended to be exhaustive and do not necessarily comprise all of the risks to which the Enlarged Group is or may be exposed or all those associated with an investment in the Company. In particular, the Company's performance is likely to be affected by changes in market and/or economic conditions, political, judicial, and administrative factors and in legal, accounting, regulatory and tax requirements in the areas in which it operates and holds its major assets. There may be additional risks and uncertainties that the Directors do not currently consider to be material or of which they are currently unaware which may also have an adverse effect upon the Enlarged Group.**

**If any of the risks referred to in this Part 3 crystallise, the Enlarged Group's business, financial condition, results or future operations could be materially adversely affected. In such case, the price of its Ordinary Shares could decline and investors may lose all or part of their investment.**

**Although the Directors will seek to minimise the impact of the risk factors listed above, investment in the Enlarged Group should only be made by investors able to sustain a total loss of their investment.**

## PART 4

## CHAD/CAMEROON COUNTRY OVERVIEW AND ASSETS

### 1. CHAD COUNTRY OVERVIEW

#### 1.1 Introduction

Chad is a landlocked Sahelian country in Central Africa comprising 23 provinces with its capital city, N'Djamena, located in the South Western region of the country. Chad borders Libya to the north, Sudan to the east, Central African Republic to the south and Cameroon, Nigeria, and Niger to the west.

Historically, Chad emerged from a collection of kingdoms that controlled the Sahelian belt around the 9th century. The modern state was formed during French colonial rule which began in the 19th century. France incorporated the northern arid region, the Lake Chad Basin and South Eastern Chad into French Equatorial Africa. In 1956, the French National Assembly passed the Overseas Reform Act which resulted in greater self-rule for Chad and the country formally became independent in 1960.

Chad has a total population of approximately 17 million people, with the majority of the population residing in the southern region of the country, as the north is a desert zone. The Chadian population consists of approximately 200 ethnic groups with the Sara, Arab and Daza being the largest groups. Over 120 different languages and dialects are spoken in-country with Arabic and French serving as the official languages. The country is approximately equally divided between Christianity and Islam.

Chad has a diverse supply of natural resources, primarily being reserves and resources of oil present in the Doba, Bongor and Doseo basins in the south and also in the Lake Chad region to the west. Chad became an oil-producing country in 2003 and, since then, its economy has been heavily dependent on oil production. Oil accounts for approximately 80 per cent. of Chad's export revenues, while cotton, cattle, livestock and gum arabic provide the majority of Chad's non-oil export earnings.

#### 1.2 Oil and Gas Industry

***Reserves and Resources***

Chad has a proven petroleum system and ranks as the tenth-largest oil reserve holder among African countries, with 1.5 billion barrels of Proved Reserves as of 2020 and average production of over 140 Kbopd in 2020. Chad's undeveloped but discovered Resources are estimated by Wood Mackenzie to be 366 MMbbls. These are mainly held by CNPC, OPIC and Glencore in southern Chad. In addition, the EIA and Advanced Resources International Inc. estimate that Chad holds around 40 Bnbbl of oil and 40 Tscf of gas of potential yet-to-find, conventional resource, which suggests that further discoveries should be possible. Of this, the recoverable amounts could be of the order of 10 Bnbbls of oil and over 20 Tscf of gas.

***Production***

Chad became an oil producing nation in 2003 when the Doba Oil Project came onstream, exporting oil via the Chad-Cameroon ETS. In 2011, CNPC developed the Block H fields in southern Chad. Initially production supplied a 20 Kbopd new-build refinery outside the capital, N'Djamena, jointly owned by CNPC (60 per cent.) and SHT (40 per cent.), via a 311 km pipeline. With increasing production, CNPC started exporting surplus oil in 2013 via the Chad-Cameroon ETS and is currently the largest producer in Chad with approximately 100 Kbopd produced in 2020. In 2013, Glencore brought the Badila and Mangara fields onstream and the Taiwanese Chinese Petroleum Corp (operating as OPIC) started production and exports from the Benoy development in 2020.

***Oil sector contribution to Chad's economy***

The oil industry has a significant, wide-ranging impact on Chad's economy. Since the introduction of oil production, the previously agrarian economy's GDP per capita has grown from US$221 in 2002 to US$710 in 2019. While the oil sector accounts for 18 per cent. of Chad's GDP, it constitutes a much higher share of Chad's balance of payments (being equivalent to 83 per cent. of foreign direct investment, 79 per cent. of exports and 65 per cent. of services).

In addition to the billions of dollars of revenues, royalties and taxes which have flowed directly to the Chadian government, the oil industry has contributed to the growth of the economy through local employment, training and development of thousands of workers, purchases of hundreds of millions of dollars of goods and services from local providers and the transfer of business and technical knowledge.

### 1.3 Government and political environment overview

Chad became a republic on 28 November 1958 and gained independence from France on 11 August 1960, with Francois Tombalbaye serving as the first post-independence Head of State. His authoritarian rule and restriction on political parties led to a series of civil wars which lasted for around 30 years. In 1996, Chad held its first multi-party presidential election in which President Idriss Déby Itno and his party, the Patriotic Salvation Movement, was elected.

Chad's current constitution was enacted in 1996 and provides the president with the power to appoint the Prime Minister and the cabinet. The constitution also gives the president influence over judicial appointments and the selection of generals, provincial officials and heads of para-state firms. The constitution was amended in 2005 to remove the presidential service term limit and again in 2018 to remove the Prime Minister role and reimpose a six-year term, subject to a limit of two terms for the president.

Following the death of President Idriss Déby Into in April 2021 (who had served as Head of State for the previous 25 years) his son, Mahamat Déby, was selected by the Transitional Military Council to assume the role of Head of State, for an interim period ahead of parliamentary and presidential elections expected to be held in Q3 2022. The interim period is renewable once for a period of 18 months. The international community, particularly France, has accepted these transition arrangements and Mahamat Déby has reappointed the same civilian-dominated government which was in place with his late father. The legislative power in Chad is vested in the National Transition Council which has replaced the Parliament. It has 93 members including many members of the former parliament, including its President. Its members are called National Counselors and seek to control the executive power, and adopt the new constitution and laws. Its existence will cease once a new Parliament is elected.

### 1.4 Economic environment

The United Nations Human Development Report 2020 ranked Chad as the third poorest country of those that it ranks in the world and the World Bank's Spring 2020 Economic and Poverty Update states that approximately 42 per cent. of the population live below the poverty line. Chad's landlocked location results in high transportation costs for imported goods and the dependence on neighbouring countries for the transportation of goods and services.

The Chadian economy is heavily reliant on oil exports. Following the beginning of oil production in 2003, Chad's previously agrarian economy saw per capita GDP grow from about US$221 in 2002 to US$709 in 2019, an annual average growth rate of 7 per cent. The COVID-19 pandemic led to a decline in growth of 0.9 per cent. in 2020. The Chadian government has taken several steps to revive the economy, including reaching a staff level agreement with the IMF on a four-year extended credit facility programme which aims at delivering policies and reforms to improve the country's response to the pandemic as well as creating the foundation for a green, inclusive economic recovery measures and restoring debt sustainability.

Chad has faced increasing financial challenges and requested restructuring of certain of its debts in January 2021, following the effects of COVID-19 and depressed oil prices. Chad's debt was previously restructured twice, in 2015 and 2018. The IMF considers Chad's total debt of approximately US$3 billion to be unsustainable. Glencore represents more than 98 per cent. of Chad's commercial debt, most of which is from oil-for-cash deals contracted in 2013 and 2014.

### 1.5 Religion and socio-economy

Chad has approximately 200 ethnicities, which can be loosely divided between those who follow Islam, generally in the central and northern regions, and those who inhabit the southern regions who are Christian or Animist, with conflict being present between the groups.

Since the Libyan civil war in 2011 that led to Gaddafi's removal, Libya has become the primary source of instability to Chad, however French and Chadian militaries are likely to resist military threat from Libya as was achieved with Front for Change and Concord in Chad ("FACT"), which entered Chad from Libya on 11 April 2021. Despite this leading to President Idriss Déby Itno's death in combat, fighting FACT's insurgency, FACT was successfully defeated. FACT is an offshoot of an earlier rebel group that invaded Chad from Sudan in 2006.

Chad has a relatively poor record for human rights, political freedom and freedom of speech. In addition, Chad suffers from significant terrorist activity, most prominently carried out by Boko Haram, a jihadist group based in North East Nigeria, and Jamaat Nursrat al-Islam wal Muslimeen.

### 1.6 Capital market

The official currency in Chad is the CFA Franc. The CFA Franc is the common currency issued by the Bank of Central African States ("BEAC"), for the members of CEMAC, which was created in 1994 as part of an initiative to boost regional integration and policy effectiveness amongst the Central African countries. The six member countries consist of Chad, Cameroon, Central African Republic, Republic of Congo, Equatorial Guinea and Gabon.

Member countries share a common financial, regulatory, and legal structure, as well as a common external tariff on imports from non-CEMAC countries. Tariffs have been eliminated on trade within CEMAC, however, the full implementation of this is yet to be achieved. The CFA Franc is pegged to the Euro and guaranteed in Euros by the French Treasury at the fixed exchange rate of 655.96 CFA Francs to one Euro.

### 1.7 National Legislative Framework

Petroleum activities in Chad include:

- Upstream activities (including, *inter alia*, the exploration, exploitation, storage and processing of hydrocarbons);
- Midstream activities, specifically the transportation of hydrocarbons; and
- Downstream activities (refining of hydrocarbons, transport, distribution, imports, exports and control of petroleum products – governed by the Decree N°2000/935/PM of 13 November 2000, which sets out the conditions for the exercise of activities in the downstream petroleum sector).

Upstream, midstream and downstream activities are all governed by Law N°07-006 dated 2 May 2007 relating to hydrocarbons (the "Chadian Petroleum Code"). The Chadian Petroleum Code indeed provides that its purpose is to define the legal and fiscal regime for prospecting, research, exploitation, transport by pipeline, processing of hydrocarbons, marketing and storage of hydrocarbons, refining, distribution of petroleum products, as well as the carrying out of works and installations allowing the exercise of all these activities in Chad.

The Chadian Petroleum Code was amended and completed by Ordinance N°001/PR/2010 dated 30 September 2010 pertaining to the approval of the standard Production Sharing Contract governing the activities of exploration and exploitation of liquid and gaseous hydrocarbons in the Republic of Chad. The implementing modalities of the Chadian Petroleum Code are laid down in Decree N°10-796 PR/PM/MPE dated 30 September 2010.

The Chadian Petroleum Code as further amended and completed and its implementing decree are enforced by the agents of the following Directions of the Ministry of Oil and Energy ("MINPE"):

- Direction of Exploration and Production;
- Direction of Refining, Storage and Distribution.

The Chadian oil industry is governed by the MINPE, which also implements the policies. The MINPE represents the Chad government in all oil and gas industry dealings and investments.

For downstream activities, specifically, a regulation authority was created by Ordinance N°005/PR/2012 dated 7 February 2012: this is the Authority of Regulation of the Petroleum Downstream Sector in Chad which seeks to ensure the regularity, control and monitoring of operating standards and operators in the downstream oil sector, particularly those of refineries, oil depots, distribution stations and sales outlets. It also ensures the organisation of and export of petroleum products and their derivatives and the respect of the principle of equal treatment of users by all companies in the downstream oil sector.

In Chad, apart from private operators, a main stakeholder in the upstream oil and gas sectors is the State of Chad, which operates through the following three major state companies:

- SHT: the national oil company, which activities consist in the exploration, research, development, production and transportation of liquid and gaseous hydrocarbons, refining, transportation, storage and distribution of finished products and the marketing of hydrocarbons and finished products.

  The SHT and the MINPE are the main contact points when it comes to the oil and gas sector in Chad. The involvement of the State of Chad in the petroleum sector is materialised by the participation of SHT in petroleum contracts concluded by the State of Chad;
- The Chadian Company of Petroleum Deposits, which is active in guaranteeing and securing the storage and distribution of petroleum products, regulating hydrocarbons and ensuring energetic security; and
- The N'Djamena Refining Company, which operates in refining of petroleum products.

Regarding the transportation of hydrocarbons by pipeline, the sole operating company in Chad to date is TOTCo, whose purpose is the transportation of crude oil produced in Chad oil fields for export to international markets.

## 2. CAMEROON COUNTRY OVERVIEW

### 2.1 Introduction

Cameroon is a country in West Africa with its South West border along the Gulf of Guinea (Atlantic Ocean). Cameroon is divided into ten semi-autonomous regions with its capital city, Yaoundé, located in the central region of the country. Geographically, Cameroon borders Chad to the North East, the Central African Republic to the east, Equatorial Guinea, Gabon and the Republic of the Congo to the south and Nigeria to the North West.

Historically, Cameroon was ruled by powerful chiefdoms before becoming a German colony in 1884, known as Kamerun. Following World War I, the territory was divided between France and the UK as part of the League of Nations mandates. In 1960, French Cameroon became independent as the Republic of Cameroon with British Cameroon voting to merge with the new country to form the Federal Republic of Cameroon in 1961.

Cameroon is a member of CEMAC as opposed to the Economic Community of West African States.

Cameroon has a total population of approximately 27.5 million people. The Cameroonian population consists of approximately 250 ethnic groups with the Bamileke-Bamu, Beti/Bassa, Mbam and Biu-Mandara being the largest groups. The population is predominantly Christian, accounting for approximately 70 per cent. of the population's religion. The country has 24 major African language groups, with English and French serving as the official languages.

Cameroon has a high level of social and political stability relative to other African nations. Its industries include agriculture, aluminium, the service sector, timber and the oil industry. Oil is the country's main export commodity, accounting for 40 per cent. of Cameroon's exports.

## 2.2 Government and political environment overview

French Cameroon gained Independence on 1 January 1960 with Ahmadou Ahidjo serving as the nation's first president and leading reunification of the country with British Cameroon in February 1961, creating the Federal Republic of Cameroon. President Ahidjo instituted a one-party system and served as president until 1982 when he was succeeded by current President Paul Biya.

In 1984, by presidential decree, the country became the Republic of Cameroon. The government adopted legislation in 1997 to authorise the formation of multiple political parties, however, the Cameroon People's Democratic Movement has remained in power since its creation in 1985.

The current constitution was amended in 2008 and provides the president with the power to appoint the Prime Minister and other members of government. The constitution also gives the president power over the armed forces and power to declare a state of emergency and take any measures they may deem necessary. The president is elected for a mandate of seven years with no term limits on re-election. In 2018, President Paul Biya won a seventh term at the age of 85, making him sub-Saharan Africa's oldest leader.

The legislative structure in Cameroon is made up of a parliament consisting of the Senate and the National Assembly. There are 100 seats in the Senate with 30 members appointed by the president and 180 members of the National Assembly with all members serving a 5-year term. The government recognises the authority of traditional chiefs, Fons, and Lamibe to govern at the local level and to resolve disputes as long as such rulings do not conflict with national law.

## 2.3 Economic environment

Cameroon has one of the largest economies of the Central African states due to its oil resources, favourable agricultural conditions and strong service sector. The oil industry accounts for about 40 per cent. of export earnings while the commodity and service sectors contribute to more than 15 per cent. and 51 per cent. of GDP, respectively. Over the last decade, Cameroon's GDP has grown at an average rate of 4 per cent. per annum. However, the COVID-19 pandemic and subsequent fall in oil prices caused growth to decrease to 0.73 per cent. in 2020.

The BEAC has taken various measures to support Cameroon and the economies of its member states. These measures included lowering the interest rate from 3.50 per cent. to 3.25 per cent. in 2020 and increasing the country's foreign exchange reserves. Since the late 1980s, Cameroon has been following programmes advocated by the World Bank and IMF to reduce poverty, privatise industries and increase economic growth.

## 2.4 Capital market

The official currency in Cameroon is the CFA Franc which is issued by BEAC. The BEAC was created on 22 November 1972 to promote the financial stability of the six Central African countries. The BEAC defines and conducts the monetary policy of the CEMAC and is supervised by the French Treasury, which guarantees the convertibility of the local currency at a rate of 655.96 CFA Francs to one Euro.

The Douala Stock exchange is the official market for securities in Cameroon. The stock exchange was established in December 2001. It is Africa's smallest stock exchange market with three listings since inception.

## 2.5 National Legislative Framework

Petroleum activities in Cameroon include:

- Upstream activities (including, *inter alia*, the exploration, exploitation, storage, processing of hydrocarbons);
- Midstream activities, specifically the transportation of hydrocarbons; and
- Downstream activities (refining of hydrocarbons, transport, distribution, imports, exports, and control of petroleum products – governed by the Decree N°2000/935/PM of 13 November 2000, which sets out the conditions for the exercise of activities in the downstream petroleum sector).

***Upstream activities***

Upstream activities were previously governed by Law N°99-013 dated 22 December 1999, which was repealed and replaced by Law N°2019/008 dated 25 April 2019 (the Cameroonian Petroleum Code). The Cameroonian Petroleum Code lays down the framework of upstream petroleum activities, which activities cover the following: prospection, exploration, exploitation, transportation by pipeline or by any other mean (excluding transportation activities governed by Law N°96/14 dated 5 August 1996 – see below), storage and processing of hydrocarbons pertaining to the upstream petroleum sector.

The implementing decree of the Cameroonian Petroleum Code has not been published to date. Therefore, reference is still made to Decree N°485/PM/2000 dated 20 June 2000 which laid down the modalities of application of Law N°99-013 dated 22 December 1999.

***Transportation of hydrocarbons***

The transportation of hydrocarbons is governed in Cameroon by:

- Law N°96/14 dated 5 August 1996 relating to the transportation by pipeline of hydrocarbons originating from third countries. The modalities of application of this Law are laid down by Decree N°97/116 dated 7 July 1997.
- Law N°2019/008 dated 25 April 2019 pertaining to the Cameroonian Petroleum Code, with regards to the transportation by pipeline or by any other mean of hydrocarbons extracted in Cameroon to points of collection, export, processing, refining, storage or of delivery on the Cameroonian territory, excluding transportation activities governed by Law N°96/14 dated 5 August 1996.

The Cameroon oil industry is governed by the Ministry in charge of Mining, Industry and Technical Development (the "MINMIDT") which also implements the policies. MINMIDT represents the Government in all oil and gas industry dealings and investments.

In Cameroon, apart from private operators, the main stakeholder in the upstream oil and gas sectors is the State of Cameroon, which notably operates through the following three major state companies:

- SNH: the National Hydrocarbons Company which activities consist in the promotion, development and monitoring of petroleum activities throughout the national territory, the management of the State's interests in the petroleum sector and the marketing and sale on the international market, of its personal and State's share of national crude oil production.

  The National Hydrocarbons Company and the MINMIDT are the main contact points when it comes to the oil and gas sector in Cameroon. The National Hydrocarbons Company usually works in association with international companies involved in E&P activities in the oil and gas sector in Cameroon.
- National Refining Company which activities consist in the refining of crude oil and making available refined petroleum products on the market such as butane, gasoline, jet fuel, kerosene, gas oil, distillate and fuel oil in order to meet local needs.
- Cameroonian Company of Petroleum Deposits which is active in guaranteeing and securing the storage and distribution of petroleum products throughout the national territory.

Regarding the transportation of hydrocarbons through Cameroon by pipeline from other countries, the sole operating company in Cameroon to date is COTCo, whose purpose is to transport the crude oil produced in Chadian oil fields for export to international markets.

Law N°2019/008 dated 25 April 2019 pertaining to the Cameroonian Petroleum Code and Law N°96/14 dated 5 August 1996 relating to the transportation by pipeline of hydrocarbons originating from other countries are enforced by the agents of the Direction of Mining at the MINMIDT. The Direction of Mining is divided into the following three sub-directions:

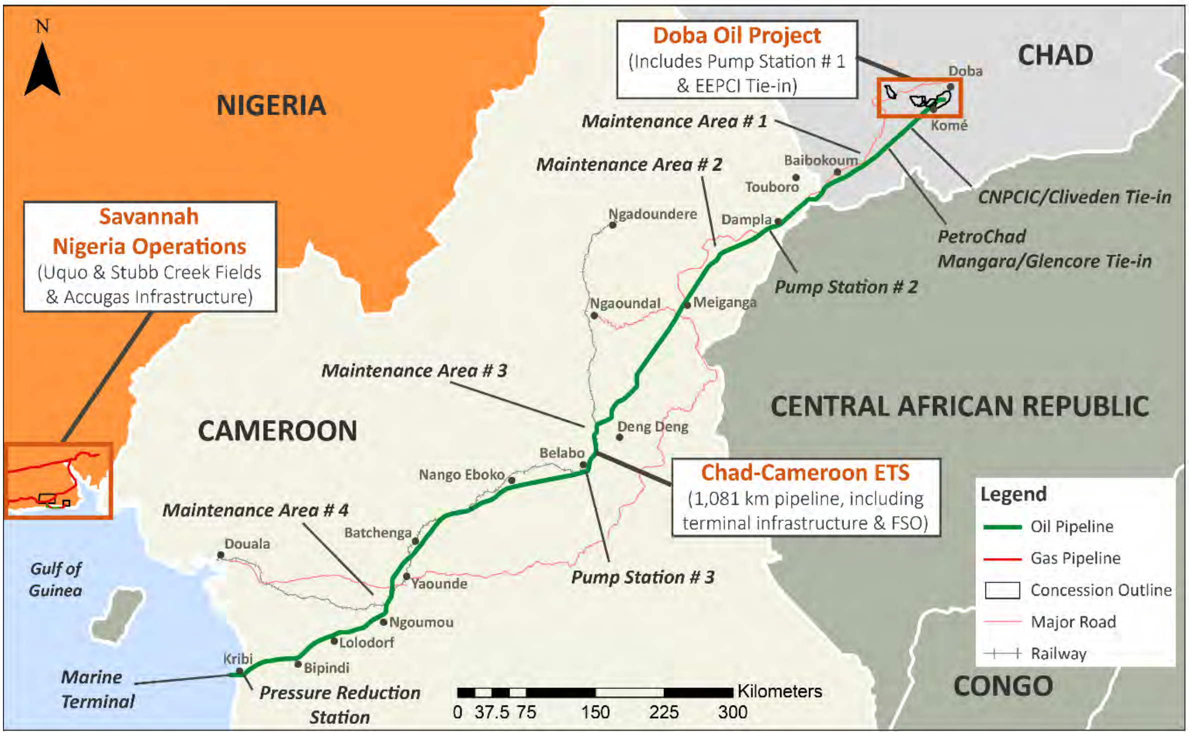
- the Sub-Direction of Mining Activities;
- the Sub-Direction of Hydrocarbons; and
- the Sub-Direction of Mining Register.

## 3. THE CHAD/CAMEROON ASSETS

### 3.1 Introduction

The Chad/Cameroon Assets are comprised of seven oil fields including surface facilities in southern Chad which constitute the Doba Oil Project, and a 1,081 km long export pipeline between Chad and Cameroon and a terminal infrastructure known as the Chad-Cameroon Export Transportation System as shown in Figure 16 below.

*Figure 16, Overview map of the Doba Oil Project and Chad-Cameroon Export Transportation System*




*Source: Chad/Cameroon CPR*

The Doba Oil Project includes the following oil fields: Kome, Miandoum, Bolobo, Moundouli, Maikeri, Nya and Timbre as shown in Figure 16. As at 30 September 2021, the Doba Oil Project fields have produced 631 MMstb of relatively heavy sweet crude. Two gathering stations are installed, one at Kome, the other at Miandoum, with production from the other fields tied-back. A Central Treatment Facility, along with power generation, is present at Kome, where processed crude enters the Chad-Cameroon Pipeline.

The ETS is comprised of an export pipeline, the offshore moored Kome Kribi 1 FSO vessel and terminal infrastructure. The ETS is used to export all crude from the Doba Oil Project as well as crude from other operators including Glencore, CNPC and OPIC.

### 3.2 Licence interests

On Completion of the Exxon Acquisition, the Enlarged Group will hold a:

(a) 100 per cent. equity interest in EEPCI which holds a 40 per cent. operated interest in the Doba Oil Project; and

(b) 100 per cent. equity interest in EPIL which holds a:

  i. 40.19 per cent. shareholding interest in TOTCo; and

  ii. 41.06 per cent. shareholding interest in COTCo.

On Completion of the PETRONAS Acquisition, the Enlarged Group will hold a:

(c) 100 per cent. equity interest in. PCCEPI which indirectly holds a:

i. 35 per cent. shareholding interest in the Doba Oil Project;

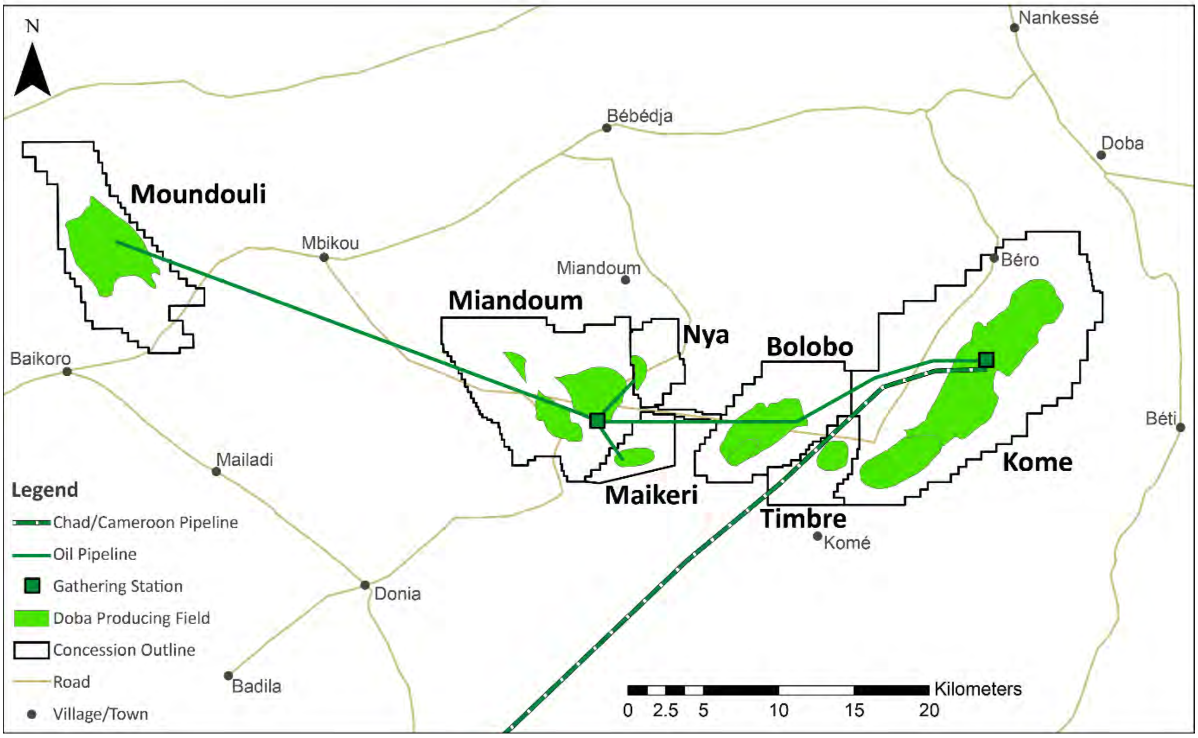
ii. 30.16 per cent. shareholding interest in TOTCo; and

iii. 29.77 per cent. shareholding interest in COTCo.

The Doba Consortium has rights, under the Conventions, to develop the Doba OFDA, comprised of EEPCI as operator (40 per cent.), PC Chad (35 per cent.), and SHT (25 per cent.), an affiliate of the Chad National Oil Company.

TOTCo is responsible for the 178 km Chadian portion of the Chad-Cameroon Pipeline and the pumping station at Kome and is owned by JV partners comprising EPIL (40.19 per cent.), Doba Pipeline (30.16 per cent.), SHT (21.54 per cent.) and Republic of Chad (8.12 per cent.). COTCo is responsible for the 903 km Cameroonian portion of the Chad-Cameroon Pipeline, two pumping stations and the Kome Kribi 1 FSO and is owned by JV partners comprising EPIL (41.06 per cent.), Doba Pipeline (29.77 per cent.), SHT (21.26 per cent.), Cameroon National Oil Company (5.17 per cent.) and Republic of Chad (2.74 per cent.).

*Figure 17: Location map showing the seven oil fields of the Doba Oil Project and associated main pipelines*




*Source: Chad/Cameroon CPR*

### 3.3 Reserves and Resources

Gross field and net attributable oil Reserves and Resources of the Doba Oil Project, as determined by CGG in the Chad/Cameroon CPR are shown in Figures 12 and 19. The Reserves are separated into three concessions which have varying fiscal terms. Attributable volumes are calculated from an economic model, incorporating all the elements of the fiscal terms applicable. Production is assumed to cease at the earlier of the economic limit or the expiry of the Concessions in September 2050.

*Figure 18, Reserves of EEPCI and PCCEPI (as at 1 October 2021)*

| | *Gross on Licence* | | | *Net Attributable to EEPCI* | | | *Net Attributable to PCCEPI* | | | *Operator* |
|---|---|---|---|---|---|---|---|---|---|---|
| | *1P* | *2P* | *3P* | *1P* | *2P* | *3P* | *1P* | *2P* | *3P* | |
| Moundouli, Nya | 7.9 | 13.6 | 22.2 | 3.2 | 5.4 | 8.9 | 2.8 | 4.8 | 7.8 | EEPCI |
| Maikeri, Timbre | 3.3 | 4.9 | 5.3 | 1.3 | 2.0 | 2.1 | 1.2 | 1.7 | 1.8 | EEPCI |
| Miandoum, Bolobo, Kome | 89.4 | 119.9 | 160.1 | 35.7 | 48.0 | 64.1 | 31.3 | 42.0 | 56.1 | EEPCI |
| **Total (MMstb)** | **100.6** | **138.4** | **187.7** | **40.2** | **55.4** | **75.1** | **35.2** | **48.4** | **65.7** | |

*Source: Adapted from the Chad/Cameroon CPR*

There are further Contingent Resources which can be recovered from the three concessions from additional infill drilling and deployment of polymer skids. Contingent Resources as determined by CGG in the Chad/Cameroon CPR are summarised in Figure 19.

*Figure 19, Contingent Resources of EEPCI and PCCEPI*

| | *Gross on Licence* | | | *Net Attributable to EEPCI* | | | *Net Attributable to PCCEPI* | | | *Risk Factor* | *Operator* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1C | 2C | 3C | 1C | 2C | 3C | 1C | 2C | 3C | | |
| Moundouli, Nya | 11.6 | 23.2 | 34.8 | 4.6 | 9.3 | 13.9 | 4.1 | 8.1 | 12.2 | medium | EEPCI |
| Maikeri, Timbre | 2.1 | 4.6 | 6.7 | 0.8 | 1.8 | 2.7 | 0.7 | 1.6 | 2.3 | medium | EEPCI |
| Miandoum, Bolobo, Kome | 48.0 | 82.4 | 117.4 | 19.2 | 33.0 | 47.0 | 16.8 | 28.8 | 41.1 | low | EEPCI |
| **Total (MMstb)** | **61.7** | **110.2** | **158.8** | **24.7** | **44.1** | **63.5** | **21.6** | **38.6** | **55.6** | | |

*Source: Adapted from the Chad/Cameroon CPR*

### 3.4 Economic Evaluation

***Doba Oil Project***

The NPV of future cashflows derived from the exploitation of the Reserves are presented in Figure 20. The values stated are net to EEPCI and PCCEPI's interest after deduction of crude consumed in operations, royalties and taxes. The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2 per cent. per year. All other relevant assumptions, including price forecasts, are provided in the Chad/Cameroon CPR.

*Figure 20, NPV10 (US$MM) of Reserves of EEPCI and PCCEPI (as at 1 October 2021)*

| | *NPV10 (US$MM) of Reserves net to EEPCI* | | | *NPV10 (US$MM) of Reserves net to PCCEPI* | | | *NPV10 (US$MM) of Reserves net to Savannah*[(1)] | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1P | 2P | 3P | 1P | 2P | 3P | 1P | 2P | 3P |
| Moundouli, Nya | 12.5 | 25.9 | 49.2 | 11.7 | 24.0 | 44.8 | 24.2 | 49.9 | 94.0 |
| Maikeri, Timbre | 5.6 | 8.9 | 11.8 | 6.5 | 9.6 | 12.1 | 12.1 | 18.5 | 23.9 |
| Miandoum, Bolobo, Kome | 157.1 | 210.6 | 297.7 | 156.3 | 205.8 | 280.3 | 313.4 | 416.4 | 578.0 |
| **Total** | **175.2** | **245.4** | **358.7** | **174.5** | **239.4** | **337.2** | **349.7** | **484.8** | **695.9** |

*Source: Adapted from the Chad/Cameroon CPR*

*Notes:*

(1) Assuming Completion of both the Exxon Acquisition and the PETRONAS Acquisition.

***Chad-Cameroon Export Transportation System***

An indicative NPV of estimated after-tax future cashflows accruing to EPIL and PCCEPI's shares of the Chad and Cameroon Pipeline companies have been calculated by CGG. Values have been estimated for a base and an upside case scenario of the third-party production throughput based on a Wood Mackenzie study* commissioned by Savannah. In each scenario, the Proved and Probable Doba Oil Project forecasted volumes have also been considered.

All cases account for approximately 17,000 bopd crude oil from CNPC being routed to the Djermaya Refinery, near N'Djamena, as well as crude consumed in operations. An indicative NPV of estimated after-tax future cashflows accruing to EPIL and PCCEPI's share of the Chad and Cameroon Pipeline companies are presented in Figure 21. There are no Reserves or Resources associated with EPIL and PCCEPI's share of the Chad and Cameroon Pipeline companies. All other relevant assumptions are provided in the Chad/Cameroon CPR.

*Figure 21, Indicative NPV10 (US$MM) of EPIL and PCCEPI's share of the Chad and Cameroon Pipeline companies' cashflows (as at 1 October 2021)*

| | *NPV10 (US$MM) net to EPIL* | | *NPV10 (US$MM) net to PCCEPI* | | *NPV10 (US$MM) net to Savannah[(1)]* | |
|---|---|---|---|---|---|---|
| | *Base* | *Upside* | *Base* | *Upside* | *Base* | *Upside* |
| Chad Pipeline Company | 10.8 | 11.0 | 8.1 | 8.3 | 18.9 | 19.3 |
| Cameroon Pipeline Company | 277.5 | 358.3 | 201.2 | 259.8 | 478.7 | 618.1 |
| **Total** | **288.3** | **369.3** | **209.3** | **268.0** | **497.6** | **637.3** |

*Source: Adapted from the Chad/Cameroon CPR*

*Notes:*

(1) Assuming Completion of both the Exxon Acquisition and the PETRONAS Acquisition.

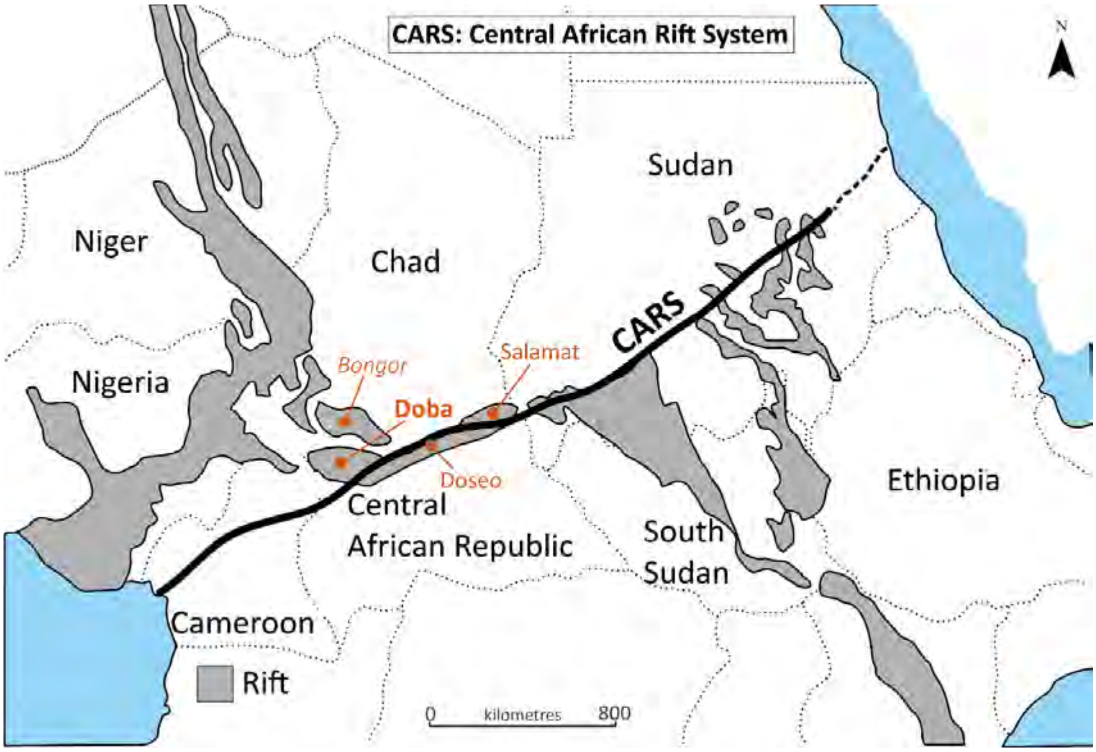
* *The data and information provided by Wood Mackenzie should not be interpreted as advice or relied on for any purpose. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for the use of this data and information.*

### 3.5 Geological Overview

The Doba Basin is part of the Central African Rift System presented in Figure 22, which consists of a series of highly oil prolific Cretaceous and Tertiary rifts throughout Niger, Chad, Sudan and South Sudan with over 6 Bnbbls of oil discovered to date. The basin covers an area of approximately 17,000 $km^2$ and contains up to 7.5 km of continental clastic sediments which record the complex tectonic and climatic evolution of the region from the Early Cretaceous to the present.

The African continent was affected by crustal movements associated with the opening of the Southern Atlantic Ocean around 130 million years ago. The staged opening resulted in strike-slip stresses forming a series of rift system sedimentary basins along pre-existing lines of weakness in the crust. The sedimentary basins of Doba, Doseo, Bongor and Salamat in Southern Chad are all part of the Central African Rift System.

*Figure 22, Location map of the Central African Rift System and Doba Basin setting*




*Source: Chad/Cameroon CPR*

The Doba Basin has a basement of Pre-Cambrian metamorphic rocks overlain by a thin Lower Cretaceous section and thick Upper Cretaceous deposits. The Lower Cretaceous contains lacustrine sediments of interbedded sandstone and shales charting the alternation of lake expansion and contraction, with sediments being sourced from nearby eroding highlands. Reservoirs in the Lower Cretaceous are filled with light oil/gas (>40° API). The thicker Upper Cretaceous is dominated by stacked fluvial sandstones interbedded by alluvial plain mudstones. The "M sands" form the primary reservoirs in the Doba fields and have a much higher degree of vertical and lateral channel stacking as opposed to the "YO sands" which are often discrete channels encased in shale and form secondary reservoirs. The fields are broken up by variable trending normal faults, creating a series of fault blocks. Reservoir traps are typically faulted anticline structures with the primary reservoirs in the Upper Cretaceous filled with sweet viscous crude (17-27° API).

### 3.6 Doba Oil Project History

The first discoveries, Miandoum and Kome, were made by Conoco in 1975. ExxonMobil took over the operatorship of the discoveries in 1982 and continued with exploration and appraisal drilling. A substantial resource base was established and the Funding Development Plan was approved in 2000 and included development wells, surface facilities, export pipeline and an FSO.

*Figure 23, Field Discovery and First Production Dates of the Doba Oil Project fields*

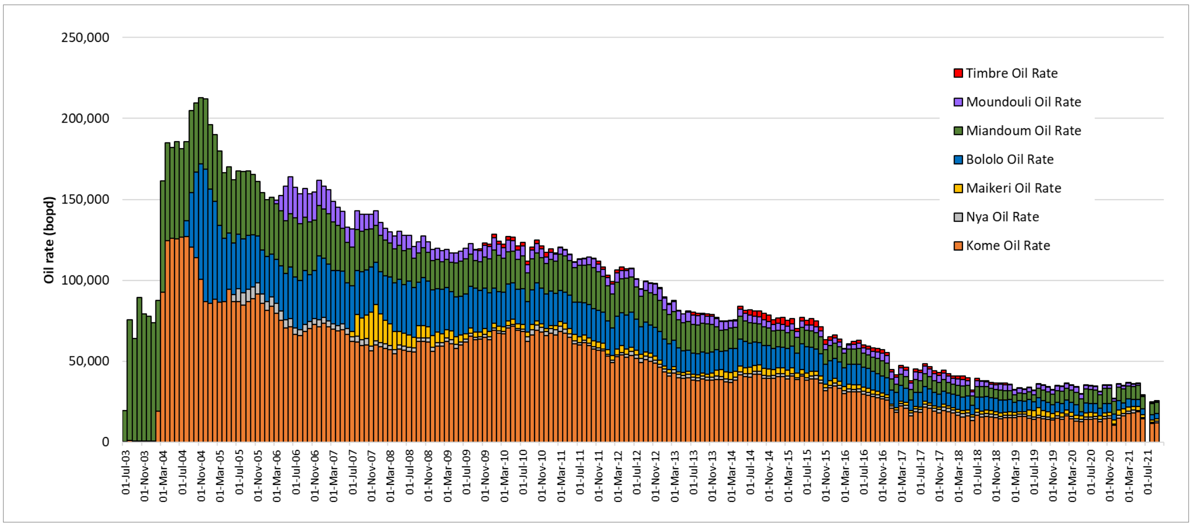
| *Field* | *Miandoum* | *Kome* | *Bolobo* | *Nya* | *Moundouli* | *Maikeri* | *Timbre* |
|---|---|---|---|---|---|---|---|
| Year of discovery | 1975 | 1975 | 1989 | 2002 | 2001 | 2005 | 2005 |
| Production Start-up | Jul-2003 | Feb-2004 | Aug-2004 | Jun-2005 | Mar-2006 | Jul-2007 | Sep-2009 |

*Source: Adapted from the Chad/Cameroon CPR*

Oil production started in July 2003 from the Kome and Miandoum fields with the Bolobo field coming on stream in 2004. A peak production of over 200,000 bopd was achieved in 2004 soon after production started at the Bolobo field. The two main gathering and pre-processing stations are located at Miandoum and Kome respectively with production from Bolobo tied back to the Kome gathering station. The processing and power generation is centralised at Kome in a Central Treating Facility before crude is exported through the ETS. Oil production from the three fields was initially under natural depletion, with water injection implemented in 2004 to maintain reservoir pressures in reservoirs with poor aquifer support. Continuous drilling took place from 2003 to 2015 with a total of around 1,100 wells drilled to date. The smaller satellite fields of Nya, Moundouli, Maikeri and Timbre came on-stream between 2005 and 2009 with production tied back to either the Miandoum or Kome Gathering Stations. With the combination of infill well drilling and satellite fields being brought on stream, the oil production rate between 2004 to 2012 was over 100,000 bopd. Virtually all production wells targeting the Upper Cretaceous reservoirs have artificial lift installed with the preferred method being Electrical Submersible Pump.

Between 2015 and 2018, a polymer flood pilot on Kome was conducted and demonstrated the technical and commercial viability of a polymer development. The principle of polymer flood is to add polymer in the injection water to increase the viscosity of the injected water in order to improve the mobility ratio between the oil and injected fluid, and thus improve the volumetric reservoir sweep efficiency. This reduces the tendency of the injected fluid to bypass or finger through the oil and instead move through the reservoir in a piston like manner. This improves the sweep efficiency, displaces more oil towards producer wells and increases the overall recovery factor. A total of three polymer skids are now operational on the Kome and Miandoum fields. As at 30 September 2021, a total of 631 MMstb of oil has been produced from the Doba Oil Project, primarily from the Upper Cretaceous reservoirs.

*Figure 24, Historical production from the Doba Oil Project*

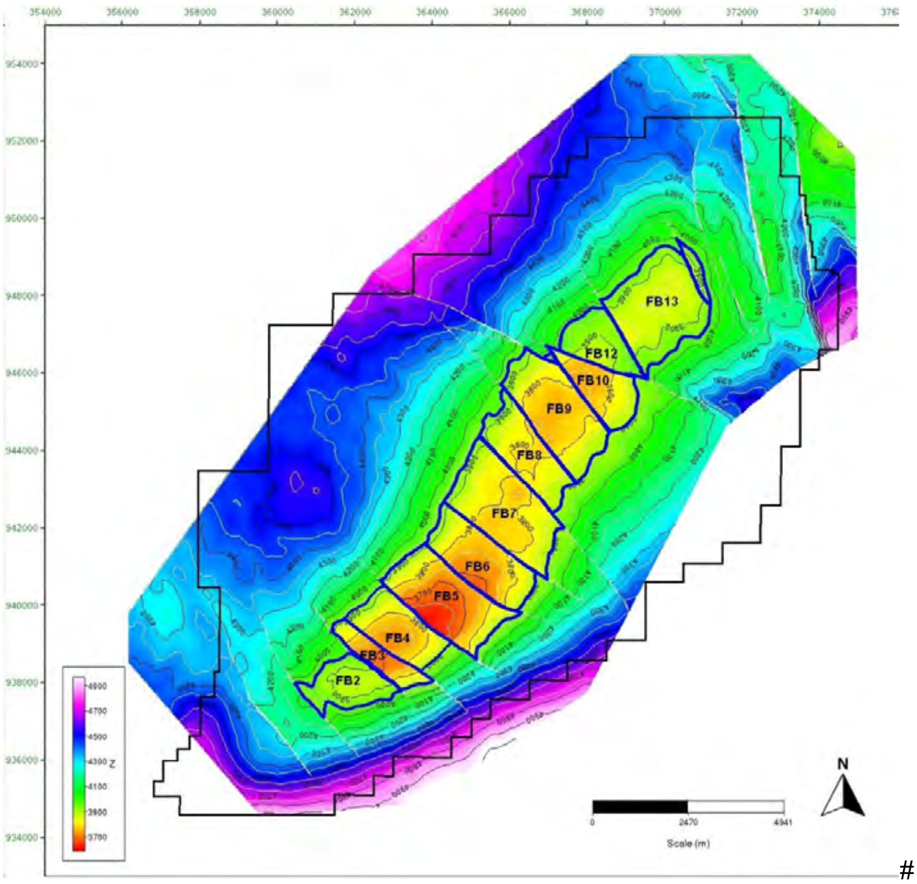



*Source: Adapted from Chad/Cameroon CPR*

***Kome field***

The Kome field is a North East – South West trending elongate anticline and is the largest field in the Doba Oil Project with a STOIIP of around 2,000 MMstb. The field is intersected by North West – South East perpendicular faults which subdivide the field into thirteen separate fault compartments and cause pressure isolation leading to different oil-water contacts across the field (Figure 25).

*Figure 25, Kome field depth structure map at top M1-20 reservoir zone*



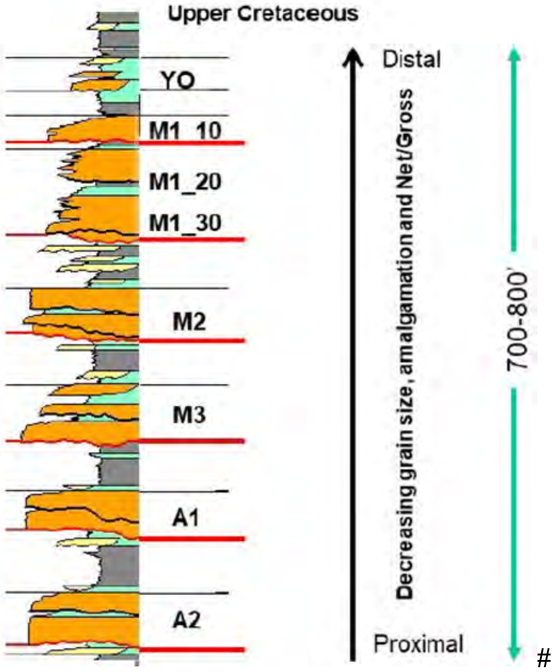

*Source: Chad/Cameroon CPR*

The main reservoir unit is the M1 sands which is a series of stacked channels forming part of a semi-arid braided fluvial depositional system, with channels flowing in a northwest direction to an inland lake. Channel stacking density is high in the M1 unit and results in a more continuous sand deposit with minor shale baffles. Shale beds which document periods of lake expansion, further subdivide the M1 unit into M1_10, M1_20, M1_30 reservoirs. Additional productive units are the deeper M2 sands which have a similar reservoir architecture to the M1 and the shallower Lower YO sands which are more discrete individual channels.

The shallower reservoirs of the M1 unit and Lower YO sands have insufficient aquifer support to maintain reservoir pressures with pressure support historically implemented through water injection. The deeper M2, M3 and A units generally have good aquifer support apart from more isolated channel reservoirs in the Bolobo and Miandoum Fields.

Production wells across the Doba Oil Project are typically a single completion type and perforated in multiple reservoir formations with production from the different reservoirs commingled. The majority of the development wells have been drilled close to vertical with total depths ranging between 1800 and 3700 m.

*Figure 26, Kome field – vertical reservoir architecture*




*Source: Adapted from the Chad/Cameroon CPR*

### 3.7 Chad-Cameroon Export Transportation System Overview

The ETS is a crude export system comprised of an export pipeline, an offshore moored FSO vessel and terminal infrastructure. The Chad-Cameroon Pipeline linking the Doba Basin in Chad to the port of Kribi on the coast of Cameroon, has a diameter of 30” and a total length of 1,081 km (178 km in Chad and 903 km in Cameroon) with a nameplate capacity of 250,000 bopd and it can transport relatively heavy crude. This pipeline is connected to the Doba Oil Project oil fields and is the only pipeline connecting landlocked Chad to the Kome Kribi 1 FSO for international exports. The ETS is used to export all crude from the Doba Oil Project as well as crude from other operators including Glencore, CNPC and OPIC.

The Chad-Cameroon Pipeline includes three pumping stations, a small pressure reduction station, as well as four maintenance areas as shown in Figure 16 and is equipped with a leak detection system. The first pumping station is located at the Kome facilities along with a fiscal metering system and is the main historical entry to the ETS infrastructure. The second and third pumping stations are located in Cameroon, at 215 km and 880 km along the pipeline.

Construction of the pipeline, which is buried below the ground, started in 2000 and was completed in 2003, a year ahead of schedule. The total cost of the pipeline project was US$2.2 billion and several US and European Export/Import Credit agencies and the World Bank supported the construction and implementation of this major infrastructure project.

The Kome Kribi 1 is the offshore moored FSO vessel and is part of the ETS infrastructure. The FSO is a converted crude tanker with a nameplate storage capacity of 2.5 MMbbl and is connected to a single-point mooring system. The Kome Kribi 1 FSO is able to accommodate tandem-berthed export tankers up to 320,000 tonnes deadweight.

*Figure 27, The Kome Kribi 1 FSO*

*Source: Chad/Cameroon CPR*

## PART 5

## NIGERIA COUNTRY OVERVIEW AND ASSETS

### 1. Introduction

Nigeria is a country in West Africa comprising thirty-six states and the Federal Capital Territory, Abuja. Abuja is primarily a governmental and administrative city, with Lagos recognised as the commercial capital of the country. Historically, Nigeria was made up of kingdoms and tribal states; the modern state was formed during British colonial rule beginning in the 19th Century, and the merging of the Southern Nigeria Protectorate and Northern Nigeria Protectorate in 1914. Nigeria became a formally independent federation in 1960.

Geographically, Nigeria borders Cameroon and Chad to the East, the Republic of Benin to the West, and Niger to the North. It also has a coast in the south that lies on the Gulf of Guinea in the Atlantic Ocean. Nigeria has an abundant supply of natural resources, primarily oil and gas out of the Niger Delta. The country benefits from a developed financial and legal system, and the second largest stock exchange in Africa. Currently, the petroleum industry contributes to approximately 90 per cent. of all export value in Nigeria.

The country has a large, mostly young and urbanised population, estimated, in 2020 to be approximately 206 million people, and it is currently Africa's most populous country, and the seventh most populous country in the world. Nigeria's population consists of over 250 ethnic groups, with the Hausa/Fulani, Yoruba and Igbo being the largest ethnic groups. Nigeria is relatively evenly divided between Christianity and Islam, with the Christian population living mostly in the southern part of the country and the Muslim population living mostly in the north. English is the official language of Nigeria. In addition to English, Hausa, Yoruba and Igbo languages are also spoken in the northern, western and eastern parts of the country, respectively.

### 2. Government and political environment overview

#### 2.1 The Government

Nigeria gained independence from the United Kingdom on 1 October 1960 and became a republic in 1963. The current Constitution of Nigeria was enacted on 29 May 1999, under Nigeria's Fourth Republic.

The Constitution provides for three tiers of government, namely the Federal Government at the centre, the governments of the respective 36 States and the municipal authorities in the 774 local government or area councils that make up the 36 States and the Federal Capital Territory.

At all the levels of government, there is a separation of powers among the executive, the legislative and judicial arms of government. The executive powers of the Federal Government are vested in the President who is elected for a four-year term, subject to a limit of two terms. The legislative powers are given to the National Assembly which comprises two chambers, namely: (i) the Senate; and (ii) the House of Representatives, while the judicial powers are vested in various courts with the Supreme Court of Nigeria being the highest court in-country.

#### 2.2 Elections and Change of Government

The country has experienced numerous political changes since its independence, including a series of military coups. In 1999, after 39 years of independence (28 of which were under military rule characterised by political instability), there was a peaceful transition to civilian government and democracy was re-introduced with the election in February 1999 of retired General Olusegun Obasanjo as President.

In April 2007, Umaru Musa Yar'Adua was elected President of Nigeria marking the first handover from one democratically elected government to another. Following the death of President Umaru Yar'Adua in 2010, the then Vice President, Goodluck Jonathan, was sworn in as President in accordance with the Constitution and was re-elected in the general elections that were held in April 2011.

In April 2015, Muhammadu Buhari, a member of the All Progressives Congress, a retired General and previous governor of the North Eastern State, was elected as President. Mr. Buhari's election marked the first successful transition of power between opposing parties in Nigeria's democratic history and also the first time an incumbent, democratically elected president in Nigeria lost a re-election bid.

As part of his manifesto, President Buhari announced an intention to combat corruption and develop a fiscal framework that protects and encourages foreign investment in the Nigerian oil and gas industry, an industry that is of vital importance to Nigeria's economy, by encouraging indigenous Nigerian companies in-country's upstream oil and gas sector. President Buhari was previously the Federal Commissioner for Petroleum and Natural Resources and Chairman of the NNPC in the 1970s.

### 2.3 **Economic Environment**

Nigeria is the largest economy in Africa and, until 2014, had one of the fastest growing economies on the continent. Nigeria's GDP grew at 4.3 per cent. in 2012, 5.4 per cent. in 2013 and 6.3 per cent. in 2014. However, after entering a recession by the end of the second quarter of 2016, Nigeria experienced five consecutive quarters of GDP contraction. Nigeria's economy came out of recession in Q2 2017 and sustained relatively stable quarterly GDP growth of between 0.7 per cent and 2.6 per cent. (year-on-year) for 12 quarters until Q2 2020, when the country suffered GDP contraction of 6.1 per cent., due to the effects of COVID-19. Nigeria's GDP growth has recovered, with only two quarters of negative growth in 2020 and, in 2021, is expected to be 2.6 per cent.

Nigeria's currency is the Naira. Since late 2014, the Central Bank of Nigeria has taken a number of measures aimed at addressing the downward pressure on the Naira as a result of the steep decline in foreign currency revenue accruing to the Government of Nigeria from the oil and gas industry. These measures included currency devaluations and various currency restrictions. In June 2016, the Central Bank of Nigeria removed its currency peg to the US Dollar and created a system of multiple exchange rates in order to relieve foreign exchange shortages and prevent further economic recession, effectively causing a devaluation of the Naira. The Naira exchange rate has devalued from 360 Naira per US$1.00 at the beginning of 2020 to the current rate of 410 Naira per US$1.00 largely following the decrease in oil prices and Nigeria's oil exports and consequent economic contraction as a result of COVID-19. In 2021, the Central Bank of Nigeria launched a digital currency called the eNaira.

### 2.4 **Capital Market**

The Nigerian capital market is primarily regulated by the Nigerian Securities and Exchange Commission while the Nigerian Stock Exchange, a self-regulatory organisation incorporated as a company limited by guarantee, is an exchange registered with the Nigerian Securities and Exchange Commission and offers listing, trading, licensing and similar services for both equities and debt issuance. Additionally, the FMDQ OTC plc, another self-regulatory organisation, was registered by the Nigerian Securities and Exchange Commission as an over-the-counter securities exchange.

## 3. **Nigeria's Oil & Gas Industry**

### 3.1 **Overview of the oil industry**

Oil was first discovered in Nigeria in the 1950s with first production coming from the Oloibiri field in 1958. Oil and gas industry contractors have been operating in Nigeria since this time, and a well-established oil service sector exists in-country. Nigeria continues to produce significant amounts of oil and gas, producing 1.8 MMbopd of oil and 4.8 Bscfpd of gas in 2020.

At the end of 2020, Nigeria's proven oil reserves were estimated at approximately 37 billion barrels, the second largest in Africa and eleventh largest reserve in the world. In 2020, Nigeria produced, on average, 1.8 MMbbls per day of oil, making it the largest oil producer in Africa that year, with the majority of production coming from the Niger Delta region. As a member of OPEC since 1971, Nigeria has agreed to oil production limits that have varied over the years but are currently set at approximately 1.6 MMbbls per day although, historically, actual production has been largely unaffected by the quota system.

There has been a general trend for international oil companies, particularly Shell, Total, Eni, Chevron, and ConocoPhillips, to sell their interests in marginal onshore and shallow water oil fields, mostly to Nigerian companies and smaller international oil companies, and to focus their investments on deepwater projects, which tend to have more favourable fiscal regimes to encourage investment.

Over the last few years, also in conjunction with an increased focus of the Nigerian government on indigenisation of the Nigerian oil and gas industry, a number of indigenous players have emerged, growing their asset base through acquisition of assets from the majors who are gradually withdrawing from the Niger Delta. NNPC is the state-owned oil company and it, or its subsidiary NPDC, has interests in most joint ventures and production sharing contracts.

### 3.2 **Overview of regulatory and fiscal regime**

***A well-established oil and gas industry benefiting from the new Petroleum Industry Act 2021***

After more than a decade of the Federal Government of Nigeria seeking to overhaul the oil and gas industry, on 16 August 2021, His Excellency President Muhammadu Buhari signed the PIA into law. Nigeria has passed into law the PIA to streamline and consolidate the regulatory, governance and fiscal frameworks within the petroleum industry in order to attract additional investment into the country. The PIA has repealed and amended several pieces of legislation that, prior to August 2021, regulated specific aspects of the petroleum industry. Certain of the laws repealed by the PIA (some of which are subject to transitional conditions) include the Petroleum Products Pricing Regulatory Agency (Establishment) Act, the Deep Offshore and Inland Basin Production Sharing Contract Act, the Petroleum Profit Tax Act and the Nigerian National Petroleum Commission Act. The PIA provides that a holder of an Oil Prospecting Licence ("OPL") or Oil Mining Lease may enter into a contract for the voluntary conversion of an OPL or OML to a petroleum prospecting licence or petroleum mining lease (respectively) in order to benefit from the fiscal provisions of the PIA. Thus, under the PIA, the Petroleum Act remains in effect until the termination or expiration of all OPLs and OMLs held by holders that do not wish to voluntarily convert them.

The PIA covers five areas: (i) Governance and Institutions which subdivides the Nigerian petroleum industry into a midstream and upstream sector for governance purposes with the upstream overseen by the Nigerian Upstream Regulatory Commission and the midstream overseen by Nigerian Midstream and Downstream Petroleum Regulatory Authority; (ii) Administration, which focuses on the transparent and efficient administration and management of the industry; (iii) Host Community Development which deals with providing social and economic benefits to host communities; (iv) Petroleum Industry Fiscal Framework which overhauls the existing framework and is designed to encourage investment into the industry; and (v) Miscellaneous provisions. The objective is to enhance the sector's attractiveness for new investment.

Under the PIA, the petroleum sector has been segmented into two sub-sectors, namely the upstream sub-sector and the midstream and downstream sub-sector. The PIA establishes two separate and independent bodies to regulate and oversee petroleum activities within these sub-sectors, with the Minister of Petroleum having general oversight functions over the entire petroleum industry. The upstream industry is governed by the Nigerian Upstream Regulatory Commission, and the midstream and downstream sub-sector is regulated by the Nigerian Midstream and Downstream Petroleum Regulatory Authority. In furtherance of the transition from the previous single-regulator model, the Federal Government recently scrapped the Department of Petroleum Resources.

One of the important innovations of the PIA is the obligation of the Commission and the Authority to establish, maintain and make publicly available a register of leases, licences, permits and authorisations issued, revoked, suspended, surrendered or withdrawn and any modification or exemption granted in respect of any lease, licence, permit or authorisation under the PIA.

Fiscal terms in Nigeria are presently varied, with concessions, production sharing contracts, production sharing agreements and service contracts related to oil and gas ownership and extraction all in use. The PIA has introduced a new fiscal framework in the taxation of profits made from petroleum activities, which is immediately applicable to PPLs, PMLs, OPLs and OMLs that have been converted.

The key laws and regulations governing oil and gas activities in Nigeria include: (a) the 1999 Constitution (as amended); (b) the Petroleum Industry Act; (c) the Petroleum (Drilling & Production) Regulations; (d) Nigerian Oil and Gas Industry Content Development Act; (e) Deep Water Block Allocations to Companies (Back-in-Rights) Regulations; and (f) the Companies Income Tax Act. The Petroleum Act, the Petroleum Profits Tax Act, the Deep Offshore & Inland Basin Production Sharing Contract Act and the Oil Pipelines Act shall continue to apply pending the termination/expiration of existing OPLs and OMLs that have not been voluntary converted to PPLs and PMLs (respectively).

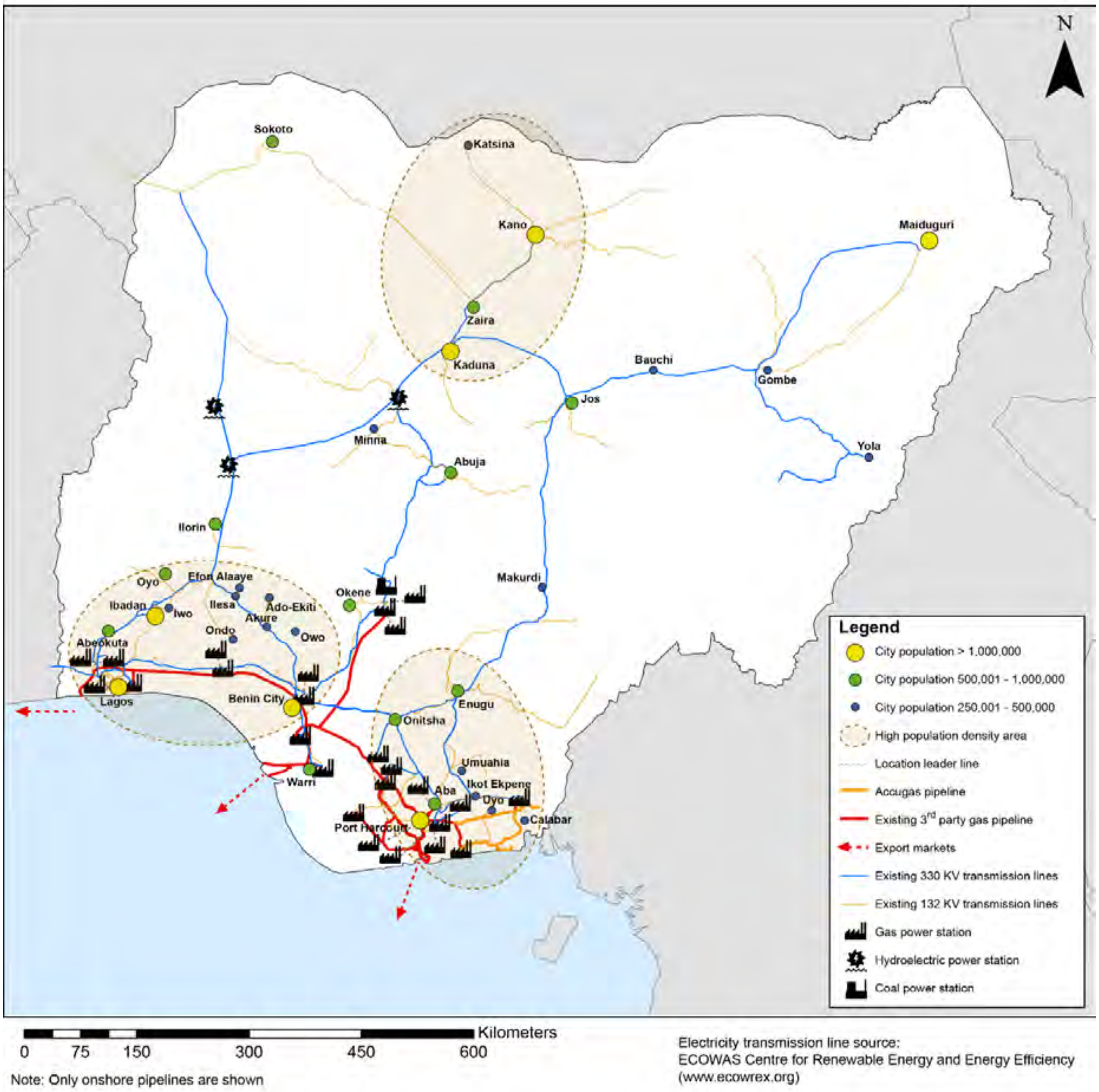
Refer to Appendix A of this document for an overview of Nigeria's National Legislative Framework.

## 3.3 Gas production and development

As at the end of 2020, Nigeria was estimated to hold 193 Tscf of proved natural gas reserves, which made it the tenth largest gas reserve holder in the world and the largest in Africa.

The majority of gas produced in Nigeria is considered associated gas, a by-product of oil production. In 2020, Nigeria's total gas production was 1.75 Tscf, equivalent to, on average, 4.8 Bscf per day, which significantly increased in recent years as a result of infrastructure projects to improve access to and utilisation of gas but this still represents only 1.28 per cent. of global gas production. Nigerian oil and gas industry participants have not yet capitalised on the country's substantial gas reserves to supply its domestic gas market, leaving significant potential for gas development.

*Figure 28, Map of Nigeria showing Gas Demand and Infrastructure*




*Source: modified after NNPC*

### 3.4 **Domestic Gas Market**

The Nigerian government has stated that it sees the provision of adequate gas supply as a means of increasing industrial output and electricity supply, and hence economic growth, prosperity, and employment opportunities.

The development of gas supply for the domestic market has also been identified by successive Nigerian governments as a priority, as demonstrated by a number of reforms and initiatives. The Gas Master Plan, developed by NNPC in 2008, aimed to:

1. Stimulate the multiplier effect of gas in the domestic economy;
2. Position Nigeria competitively in high value export markets; and
3. Guarantee the long-term energy security of Nigeria.

The Gas Master Plan also called for the construction of new cost competitive gas infrastructure, including pipelines and central processing facilities across the country.

In October 2016, the Federal Government launched the 7 Big Wins Initiative. This reinforced Nigeria's commitment to continue political support for general reform of the oil and gas sector. Subsequently in June 2017, the Federal Government approved the new National Gas Policy which had the foundations of the policy goals of the 7 Big Wins Initiative and has since overshadowed the Gas Master Plan.

The National Gas Policy articulates the goals, strategies and implementation plan of the Federal Government of Nigeria to reposition Nigeria as an attractive gas based industrialised nation through the prioritisation of local gas demand requirements. Particularly, the National Gas Policy is geared towards harnessing Nigeria's vast gas resources by removing the barriers undermining investment and development in the gas sector. If properly implemented, the National Gas Policy will drive the institutional reforms and regulatory changes necessary for Nigeria to evolve into a gas-based industrialised nation and consequently create an opportunity for financial institutions to finance some of the gas development projects in Nigeria.

The National Petroleum Fiscal Policy was proposed to the petroleum sector in 2017, with a view to ensuring that gas prices are adjusted based on the applicable inflation rate. The provisions of the proposed policy have now been incorporated in the PIA. The PIA treats gas as a standalone commodity, separate from oil.

In March 2021, President Muhammadu Buhari, together with Vice President Yemi Osinbajo and the Minister of State for Petroleum Resources, Timipre Sylva, formally launched a new initiative declaring 2021 to 2030 as "the Decade of Gas Development for Nigeria". Many now believe that Nigeria's largely untapped, natural gas resources could provide the means for the country to fund its way through the global energy transition. The mission of the Federal Government is to:

- diversify the nation's oil and gas industry through the strategic exploitation of its vast and easily developed natural gas resources; and
- transform Nigeria into a gas-based industrialised nation driven by projects and policies such as the Presidential Power Initiative, the National Gas Expansion Programme, the Nigerian Gas Transportation Network Code, the Nigerian Gas Flare Commercialisation Programme and the National Gas Policy.

In a bid to actualise the mission highlighted above, the PIA: (i) generally makes it an offence for a licensee, lessee or marginal field operator to flare or vent natural gas; (ii) makes it an obligation for a licensee or lessee producing natural gas to submit a natural gas flare elimination and monetization plan within 12 months of the effective date of the PIA; and (iii) mandates the Commission to issue a regulation or guideline that prescribes or allocates the domestic gas delivery obligation among all lessees before 1 March each year based on gas demand requirements; however the obligation is required to be discontinued by the Nigerian Upstream Regulatory Commission where the Nigerian Midstream and Downstream Petroleum Regulatory Authority determines that the natural gas market has attained full market status.

## 4. The Nigerian opportunity

### 4.1 **World class geology**

As at the end of 2020, Nigeria's proved oil reserves were estimated at approximately 37 Bnbbl oil. The majority of Nigeria's oil and gas reserves are located in the Niger Delta, one of the world's largest and most prolific hydrocarbon deltas, covering an area of c. 75,000 km$^2$. Hydrocarbon reservoirs in the Niger Delta lie mainly within the Agbada Formation, which extends from onshore to shallow water. The Uquo Field and the Stubb Creek Field both lie within structural targets in the Agbada Formation. This formation includes interbedded sandstones and claystones, forming sequences of reservoirs and seals where oil and gas are then trapped by faulting and associated folding. The Akata Formation is a deeper water claystone unit which, together with claystones in the Agbada formation, form prolific source rocks for the delta.

Although the Niger Delta is mature in terms of drilling and seismic density, it remains extremely prospective and continues to offer significant upside, with the US Geological Survey estimating Yet-to-Find resources in the province at 25 Bnbbls of oil (P50).

### 4.2 **The Company has existing strong and growing relationships in Nigeria**

The Company entered Nigeria in November 2016 with the signature of an MOU with NNPC and NNDC, and, at this time, indicated its strategic intent to pursue other potential opportunities in-country over the course of the coming years. The Company, through the acquisition of its Nigerian Assets, has built and enhanced its relationships with key stakeholders in-country. The Company has continued to deliver gas to three established customers and has since signed gas sales agreements with two additional customers, requiring close co-operation with government bodies. It is expected that these, and other, relationships will facilitate successful and continued growth for the Company's operations in Nigeria.

### 4.3 **Nigeria has a growing population and a need for affordable and reliable power**

Nigeria's growing economy requires a reliable and affordable power supply. The development of gas for use in power generation and industry is expected to create multiple benefits for stakeholders, including:

- gas is a cleaner fuel than other hydrocarbons and is an abundant under-exploited local resource;
- gas is a cheaper source of fuel than diesel, almost all of which is imported;
- as the gas pipeline system is developed so the economics and logistical issues in transporting gas from producers to consumers will ease, thus encouraging more consumers to switch to gas, in turn leading to development of gas resources for gas-to-power and industrial customers;
- Nigeria is, with some success, actively promoting the reduction of flaring, however the lack of gas infrastructure in country results in some 0.7 Bscfpd of gas being flared. Developed gas infrastructure will accelerate this process;
- reliable power will mean more jobs can be created; and
- the urbanising population is leading to a growing demand for cement and steel; both of these industries are highly energy intensive.

The potential for the development of gas resources in Nigeria is immense and exists across the value chain, from exploitation of undeveloped gas fields, through construction and operation of gas processing and transportation infrastructure to developing the market for gas.

Accugas Limited's facilities and pipelines have significant spare capacity which, combined with the attractive price of gas as a source for power generation and industrial uses, provides a compelling investment opportunity.

## 5. The Nigerian Gas Market Opportunity

### 5.1 **Overview**

Nigeria has 193 Tscf of proved gas reserves, yet only produces 4.8 Bscf per day, the majority of which is exported as LNG. With a gas reserves to production ratio of approximately 110 years, the under-developed gas resources of Nigeria represent a significant opportunity to be exploited, in particular for the benefit of the domestic economy. The important distinction between oil and gas is that, while oil production and export provides a source of foreign exchange for the country, it does not offer the local economic multiplier benefits that gas does for the domestic market.

Nigeria's growing economy requires a reliable and affordable power supply. The Board believes that the potential for the development of gas resources in Nigeria is significant and exists across the value chain, from exploitation of underdeveloped gas fields, through to construction and operation of gas processing and transportation infrastructure to developing the market for gas.

The gas distribution network in Nigeria is a significant factor holding back the development of gas. This lack of infrastructure discourages development of gas fields due to the high cost of building pipelines and the lack of supply likewise discourages potential major energy consumers from switching from, for example, diesel or coal to gas.

The Board believes that the business model developed by Accugas Limited encapsulates this opportunity, having installed a 200 MMscfpd processing facility at the Uquo Field, and an approximately 260 km pipeline network, at a total cost of US$1 billion. Accugas Limited is currently supplying gas to enable over 10 per cent. of Nigeria's daily thermal power generation.

### 5.2 **Population growth and electricity supply**

Nigeria is the largest economy in Africa with its population growing rapidly and forecast to reach 392 million people by 2050[18]. The growing Nigerian population is urbanising rapidly and the country is beset with chronic electricity shortages. Based on the country's GDP and global trends, electricity consumption is expected to grow to approximately 90,000 MWh by 2040, which is approximately seven times higher than it was in 2018. Over half of the population has no access to grid-connected electricity and those who are connected suffer extensive power outages. To improve the power sector, the Nigerian government has undertaken long-term structural reforms focused on privatising legacy power assets and instituting regulatory reform.

Nigeria has one of the lowest rates of grid-based electricity generation capacity per capita in the world. According to the Federal Government's Power Sector Recovery Program Report of April 2017, Nigeria has 13,014 MW of installed power generation capacity for a population of 206 million people but has a national grid transmission capacity of just 8,100 MW. However, less than 4,000 MW is actually dispatched on average on a daily basis due to combined constraints in gas supply, electricity transmission and distribution. Approximately 85 per cent.[22] of installed capacity is from 22 gas-thermal power plants and the remainder is hydro-electric. Non-availability of capacity is driven by gas supply, maintenance and repair issues. At present, the domestic and industrial demand for electricity is satisfied through an estimated 8 GW – 14 GW generated by decentralised diesel generators, which are expensive to run and far more polluting than grid-based gas-fired power stations. After taking into account collection losses, approximately 46 per cent. of electricity generated is lost across the value chain through technical, commercial and collection issues.

### 5.3 **Power sector reforms**

Over the last fifteen years, the Federal Government has made significant investments in the sector and undertaken a number of major reforms to target growth in power generation capacity. This commenced with the enactment of the 2005 Electric Power Sector Reform Act ("EPSR Act"), which provided for the unbundling of the national power utility company into six generation companies, eleven distribution companies and a national power transmission company, ahead of the planned privatisation of these companies. The Power Holding Company of Nigeria ("PHCN") was established as a transitional corporation for this purpose. The EPSR Act also established an independent regulator, the Nigerian Electricity Regulatory Commission. In 2005, the Federal Government also launched the National Integrated Power Projects ("NIPP") programme, an emergency intervention scheme to tackle the power problem in-country, funding the construction of ten new gas-fired power plants with a planned generating capacity of in excess of 4,700 MW. The NIPP programme is under the management of Niger Delta Power Holding Company and includes the Calabar power plant for which Accugas Limited is the exclusive gas supplier.

The EPSR Act was complemented in 2008 by the Gas Master Plan and in 2010 by the Roadmap for Power Sector Reform. The central objective of the Roadmap for Power Sector Reform was, among other objectives, to remove obstacles to private sector investment in the power sector (including through the provision of credit enhancement and the establishment of an appropriate pricing regime) and to permit the privatisation of existing generation and distribution companies. As part of the privatisation process, during the course of 2013 and 2014, the state owned PHCN was broken up with the generation companies and distribution companies being privatised and the Federal Government retaining ownership of the transmission company, Transmission Company of Nigeria ("TCN").

TCN manages the transmission system with responsibility for the development and maintenance of transmission infrastructure, management of the flow of electricity throughout the power system from generation to distribution companies and administering power market rules. Nigeria's transmission network consists of over 150 substations with a total (theoretical) transformation capacity of approximately 7,500 MW and 20,000 km of transmission lines. The system is disrupted by frequent system collapses and outages.

In May 2010, the MPR Minister announced the implementation of a new gas-to-power price framework to encourage more gas production for electricity generation. Under the approved price framework, gas prices (for gas-to-power projects) progressively increased from US$0.60 cents per MMBtu to US$1.00 per MMBtu in 2011; US$1.50 per MMBtu in 2012 and US$2.00 per MMBtu in 2014.

In addition, the Nigerian government has taken a number of steps to support the development of Independent Power Producers. In August 2011, a single buyer, Nigerian Bulk Electricity Trading ("NBET"), was established to buy electricity from the Independent Power Producers through Power Purchase Agreements and to sell it to the distribution companies. NBET, which became operational in early 2012, has a mandate to carry out contract management and bulk trading on behalf of the distribution companies until the industry stabilises, including in terms of demand and pricing.

Other measures taken by the Nigerian government to support development of the power sector include:

1. in August 2010, the creation by the Central Bank of Nigeria ("CBN") of a NGN 300 billion (approximately US$2 billion) Power and Aviation Sector Intervention Fund for investment in debentures to be issued by the Bank of Industry to finance power and aviation projects;
2. in March 2011, the disbursement by the CBN of NGN 198 billion (approximately US$1.3 billion) of funds to the Bank of Industry for onward disbursement as discounted loans to the power and aviation sectors;
3. in June 2012, the introduction of a new electricity tariff for the period from 2012 to 2017 with a view to encouraging potential investors who were concerned with the return on their investment under the former tariff regime to invest in the power sector; and
4. in 2012 introducing new regulations to enable state and local governments, private investors and suppliers and communities to generate and distribute electricity for their exclusive consumption using existing electricity distribution networks or to invest in generating electricity for transportation through electricity distribution networks in areas without access to the grid or distribution network or areas with poorly serviced distribution networks.

On 22 March 2017, Nigeria's federal government approved a Power Sector Recovery Plan in consultation with the World Bank Group. This comprised a NGN 701 billion payment assurance guarantee for the power sector, to be provided by the CBN as part of measures to tackle liquidity issues in the Nigerian power sector and to restore financial viability in the electricity market in its transitional phase and post-privatisation. This payment assurance programme was for an initial period of two years, but it was extended into 2020.

### 5.4 **Petroleum Investment Act 2021 impact on domestic gas market**

With the recent promulgation of the PIA, the Nigerian Midstream and Downstream Petroleum Regulatory Authority has now been empowered to determine a domestic base price for the purpose of determining the price for the power sector, commercial sector and gas based industries which are categorised as strategic sectors under the PIA. Notably, under the PIA, the price of marketable natural gas applicable to the power sector shall be the domestic base price at the marketable natural gas delivery point, while the price of marketable natural gas applicable to the commercial sector shall be the domestic base price at the marketable natural gas delivery point plus US$0.50 per MMBtu. Although gas distributors are permitted by the PIA to directly negotiate the supply and pricing of their natural gas, the PIA provides that the price of the gas distributors for their marketable natural gas shall not exceed that of the commercial sector. For gas based industries, the PIA has now set the floor price at US$0.90 per MMBtu, with the ceiling price being the domestic base price applicable for any particular year.

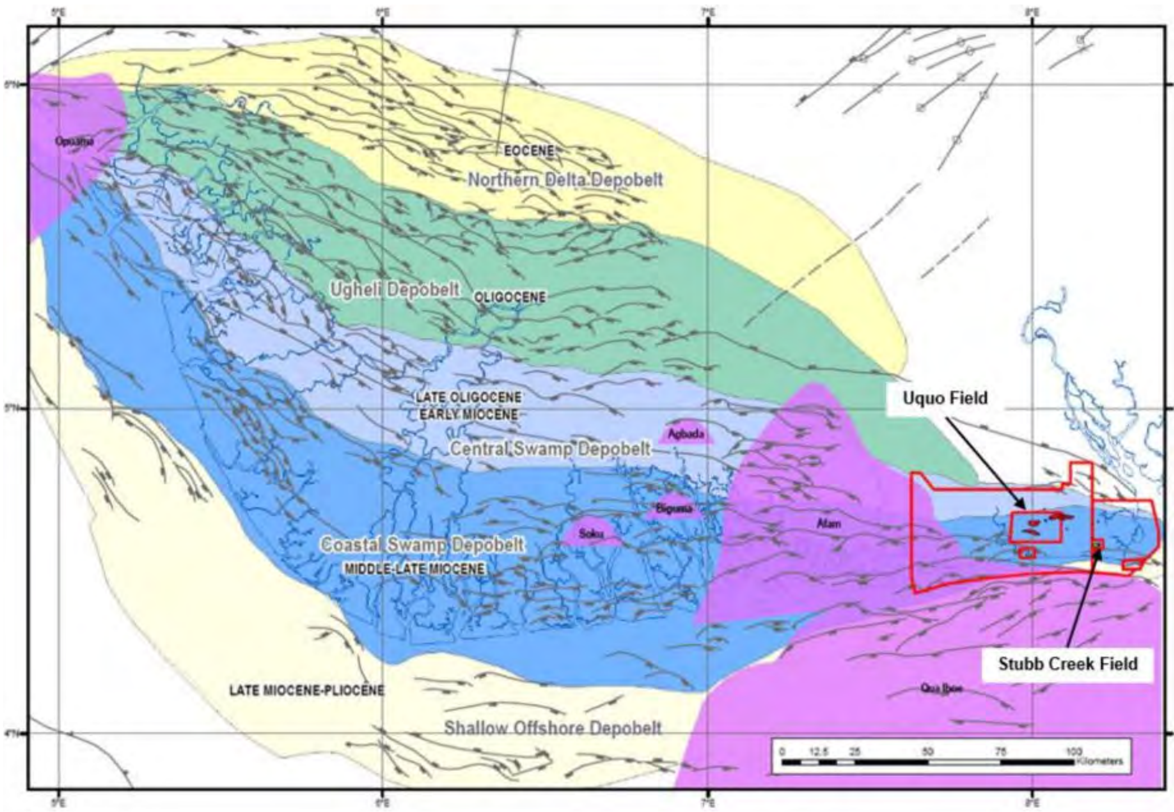
The Nigerian Midstream and Downstream Petroleum Regulatory Authority shall continue to determine the price of gas for these strategic sectors if, in its opinion, the control of the price of gas is required in this strategic sector as part of the Federal government's ongoing process to achieve full free market conditions. However, the Authority will not be required to control the prices where the entire domestic gas demand requirement under the PIA is covered by contract between the gas supplier and the user. In addition, the prices stipulated under the PIA shall not apply where the domestic market for natural gas is characterised by market based contracting for natural gas between willing buyers and sellers, based on the criteria stipulated by the Authority in consultation with relevant stakeholders in the industry.

## 6. NIGERIAN ASSETS

### 6.1 Introduction

The Nigerian Assets comprise the Uquo and Stubb Creek Marginal Fields and associated processing and transportation infrastructure owned by Accugas which are located onshore in the southern part of the country, in the South East of the prolific petroleum province of the Niger Delta, as shown in Figure 29 below.

*Figure 29, Niger Delta – Regional Setting*




*Source: 2021 Nigeria CPR*

***Upstream***

The Niger Delta Basin is a highly prolific, mature petroleum province, extending from the onshore delta onto the marine shelf and slope (Figure 29). Late Jurassic to Early Cretaceous rifting controlled the initial development of the delta and its main depocenter, while the Tertiary aged sedimentary pile has been prograding south-westwards since Eocene times (approximately 55 Mybp). The Tertiary age Niger Delta now covers an area of approximately 75,000 km$^2$, and has a sedimentary thickness of up to 12 km.

The Uquo and Stubb Creek fields are located in the South Eastern part of the onshore delta, which is dominated by normal faults trending northwest to southeast and down-thrown to the southwest towards the basin depocenter (Figure 29). Traps are present in a variety of combinations of rollover structures with different faulting styles.

The principal petroleum bearing section in the Niger Delta Basin is the Miocene age Agbada Formation, which contains multiple hydrocarbon bearing sand units, interbedded with extensive mudstones which form seals to the reservoir units. Reservoir sands are generally quite thick (of the order of 10 to 50 m) with excellent reservoir quality and with good lateral continuity. The interbedded mudstones are also thick and form good seals against faults. Sufficient burial of the pro-delta, marine shales of the underlying Akata Formation has allowed maturation for oil and gas generation, and these provide prolific source rocks to the area providing light, paraffinic crude.

### 6.2 **Licence Interests**

Savannah holds an indirect 80 per cent. interest in gas development and production in the Uquo Field through its 80 per cent. ownership in Uquo HoldCo. The remaining 20 per cent. interest is held indirectly by AIIM. Savannah does not have an equity interest in any current or future oil production at the Uquo Field, other than liquids associated with the production and processing of the gas.

Savannah also holds an indirect 51 per cent. operated interest in the Stubb Creek Field, through its 100 per cent. economic ownership of Universal, an indigenous Nigerian E&P company.

*Figure 30, Savannah's current licence interests*

| | *Operator* | *Savannah's Interest* | *Status* | *Licence Expiry Date* | *Licence Area* |
|---|---|---|---|---|---|
| Uquo Gas | SEUGL | 80 per cent. | Production | 2035 | 171 $km^2$ |
| Stubb Creek | Universal | 51 per cent. | Production | 2026 | 42 $km^2$ |

Both of the Uquo Field and Stubb Creek Field are currently in production. Oil and condensate from both the Uquo Field and Stubb Creek Field is exported through QIT which lies a short distance to the south of the Uquo Field, as shown in Figure 31. A number of large industrial gas consumers are located in this part of the Delta, including power stations at Ibom, Calabar and in the Port-Harcourt area and a cement plant at Calabar; these are connected to the Uquo Field via Accugas Limited's gas pipeline network.

*Figure 31, Map of Nigerian Assets, South East Niger Delta*


*Source: Company materials*

6.3 **Reserves and Resources**

Gross field and net attributable oil and gas reserves in the two upstream assets, as determined by CGG in the Nigeria CPR, are shown in Figure 32 below. Attributable volumes are calculated from an economic model, incorporating all the elements of the fiscal terms applicable to the fields. The combined assets amount to 3.6 MMstb of oil and condensate and 453.9 Bscf of gas in net attributable 2P Reserves, as of 1 October 2021. The small volume of liquids at Uquo (0.5 MMstb net 2P reserves) are condensates produced in conjunction with gas. Savannah has no rights to any separate oil development or production in the Uquo Field.

*Figure 32, Nigerian Assets, Reserves (as at 1 October 2021)*

| | *Gross on Licence* | | | *Net Attributable* | | | *Operator* |
|---|---|---|---|---|---|---|---|
| | *1P* | *2P* | *3P* | *1P* | *2P* | *3P* | |
| **Oil and Condensate Reserves** | | | | | | | |
| Uquo | 0.4 | 0.6 | 0.8 | 0.4 | 0.5 | 0.6 | SEUGL |
| Stubb Creek | 6.0 | 13.4 | 23.2 | 1.3 | 3.1 | 5.8 | Universal |
| **Total (MMstb)** | **6.4** | **14.0** | **24.0** | **1.7** | **3.6** | **6.4** | |
| **Gas Reserves** | | | | | | | |
| **Total (Bscf)** | **402.6** | **567.3** | **682.4** | **322.1** | **453.9** | **545.9** | |

*Source: Adapted from the 2021 Nigeria CPR*

Contingent Resources, as determined by CGG in the Nigeria CPR, are summarised in Figure 33 below. Additional gas at the Uquo Field, and the large undeveloped gas resource at the Stubb Creek Field, are considered by CGG to have a high probability of future commercial development (>75 per cent.) and 359.9 Bscf of gas is attributable to Savannah in the 2C, "Best Estimate", case.

*Figure 33, Nigerian Assets, Contingent Resources*

| | *Gross on Licence* | | | *Net Attributable* | | | *Chance of Development* | *Operator* |
|---|---|---|---|---|---|---|---|---|
| | *1C* | *2C* | *3C* | *1C* | *2C* | *3C* | | |
| **Gas (Bscf)** | | | | | | | | |
| Uquo | 66.6 | 82.8 | 101.1 | 53.3 | 66.2 | 80.9 | >75 per cent. | SEUGL |
| Stubb Creek | 364.9 | 515.3 | 680.3 | 208.0 | 293.7 | 387.8 | >75 per cent. | Universal |
| **Total (Bscf)** | **431.5** | **598.1** | **781.4** | **261.3** | **359.9** | **468.7** | | |

*Source: Adapted from the 2021 Nigeria CPR*

## 6.4 **Economic Evaluation**

The NPV (at 10 per cent. discount rate) of discounted cashflows derived from the exploitation of Reserves as at 1 October 2021 is shown in Figure 34 below. The values stated are net to Savannah's interest after deduction of capex, opex, taxes and royalties (but before debt service). Gas from the Uquo Field is sold to the Accugas Midstream Business under the Upstream GSA at a nominal price of US$1.41/Mscf in 2021, escalating thereafter to US$1.83/Mscf by 2025 and US$2.55/Mscf by 2030. For the purposes of the economic evaluation, oil prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively, have been assumed. Beyond 2024, the price is escalated at 2 per cent. per year. All other relevant assumptions, including price forecasts, are provided in the attached 2021 Nigeria CPR.

*Figure 34, NPV10 for Reserves net to Savannah from its Nigerian Assets (as at 1 October 2021)*

| | | *NPV10 (US$MM) of Reserves net to Savannah* | |
|---|---|---|---|
| | *1P* | *2P* | *3P* |
| Uquo | 239.1 | 329.1 | 421.7 |
| Stubb Creek | 34.2 | 69.5 | 82.7 |
| **Total** | **273.2** | **398.6** | **504.4** |

*Source: Adapted from the 2021 Nigeria CPR*

## 6.5 **Uquo Marginal Field**

The Uquo Field was designated as "Marginal" at a time when the primary E&P objective in the Niger Delta was oil, but it has actually proved to be a significant gas field, with some associated oil production. It is located onshore in OML 13 within Akwa Ibom State, South East Niger Delta, approximately10 km from QIT. The Uquo Field is contained within a licence area which now encompasses both the field itself and a number of undeveloped Discoveries and Prospects, which provide significant upside potential.

The Uquo Field was discovered by Shell in 1958, who identified oil and gas in a number of discrete sands in the Miocene Agbada Formation at Uquo-1, at depths between 6,800 ft (2,100 m) and 8,000 ft (2,400 m). Appraisal drilling in the 1970s encountered mainly gas, although one well was subsequently completed as an oil producer. The Uquo Field was originally awarded to Frontier in the 2003 Marginal Field round. Eleven wells have been drilled to date on the field, which have proven four separate structures with 20 hydrocarbon bearing reservoirs (15 gas, 4 oil and 1 potential oil), all of which lie within the Early Miocene Agbada Formation. The licence area is covered by a high quality 3D seismic survey, acquired in 2006-2007 and re-processed in 2020.

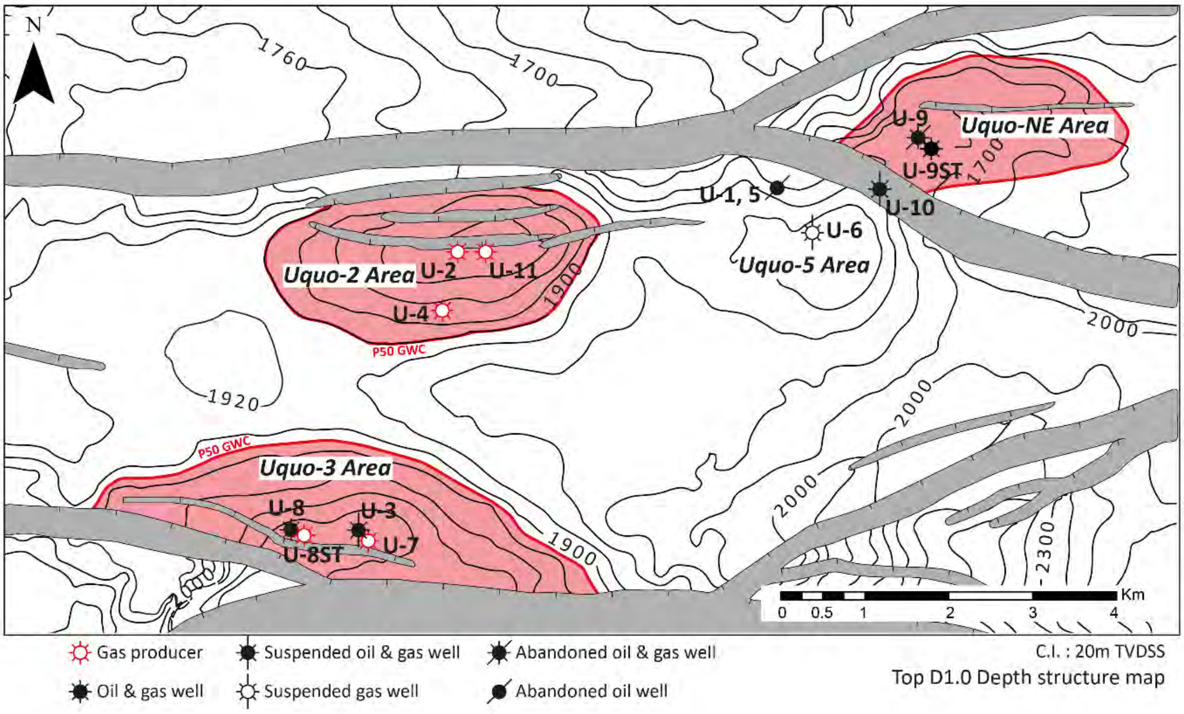
Under the Uquo JOA, which was amended to reflect the terms of the FOL Transaction on an ongoing basis with effect from 31 August 2018, SEUGL and Frontier have separated the oil and gas operations at the Uquo Field such that:

- SEUGL has 100 per cent. of the economic benefit of, shall retain all gas produced and gross proceeds from (including associated natural gas produced from the oil production), shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the Uquo Gas Project; and

- Frontier has 100 per cent economic benefit of, shall retain all crude produced and gross proceeds from, shall pay all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the oil production from the Uquo Field.

Uquo has primarily been developed as a gas field, with four wells (Uquo-2, -4, -7 and -8/8ST) completed as gas producers in the D1.0 and D2.0 reservoirs, and just one well (Uquo-3) completed as an oil producer in the slightly deeper D5.0 reservoir. An exploration/appraisal well, Uquo-9/9ST, was drilled in 2014 on an upthrown fault block to the north east, and discovered gas in Agbada C6.0 and D1.0 and D1.5 sands, as well as oil in the deeper D1.6 and D7.0 sands. In 2021, the Uquo-11 well was drilled as a gas producer in the D1.0 and D1.3/D1.4 reservoirs.

*Figure 35, Uquo Field Depth Structure*




*Source: 2021 Nigeria CPR*

The gas and oil accumulations proven at the Uquo Field lie in four distinct areas, corresponding to structural highs within the overall down-to-south fault complex, with varying gas/water and oil/water contacts within the different Agbada Formation sands (see Figure 36).

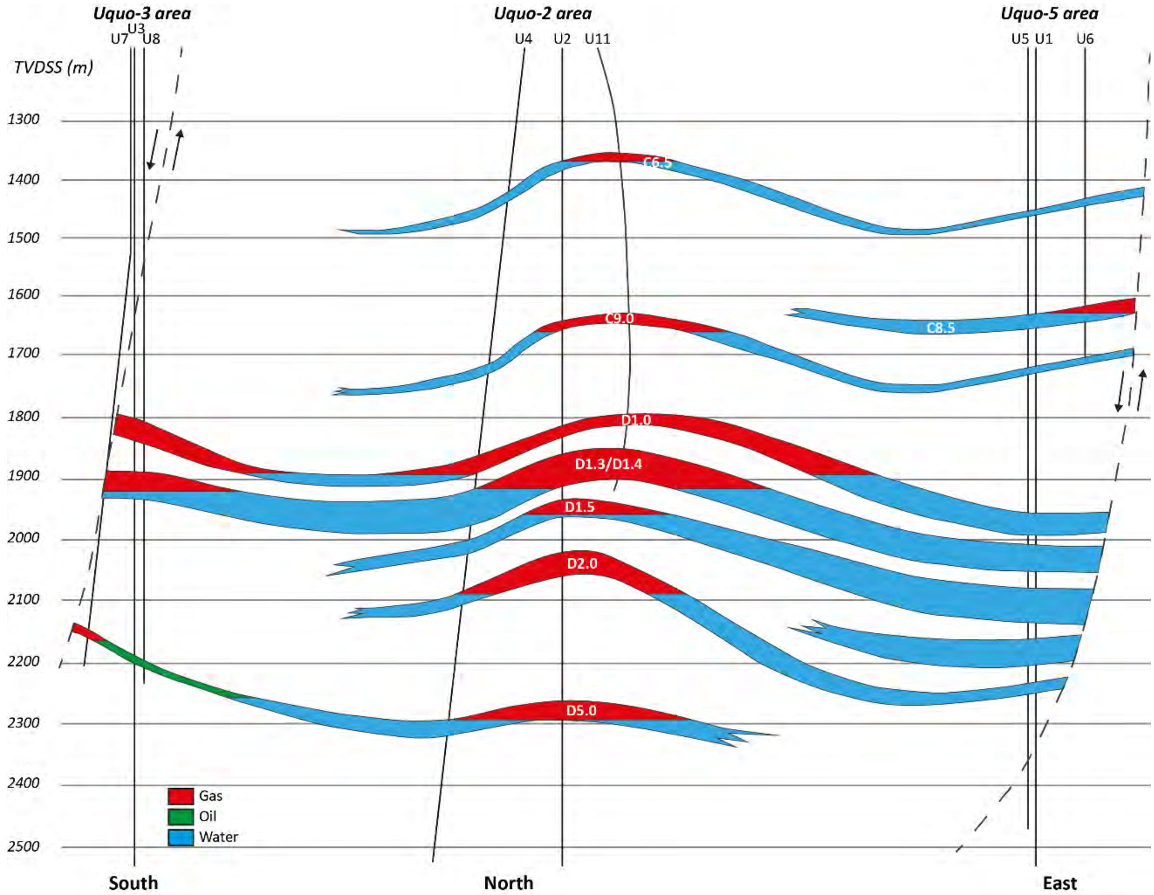
- *Uquo-2 area.* This dip closed rollover has gas proven in five of the Agbada D sands, with GIIP of approximately 449 Bscf (Best Estimate), at depths between 4450 ft (1,360 m) and 7,550 ft (2,300 m). There are two wells on production (Uquo-2 and Uquo-4) from the D2.0 and D1.0 sands respectively. A third well (Uquo-11) has recently been completed in the D1.0 and D1.3/D1.4 sands. Upside exists in uncompleted D sands and in the overlying Agbada C section, where an additional approximately 49 Bscf GIIP is identified in the C6.5 & C9.0 sands.

- *Uquo-3 area.* This is a dip and fault-bounded footwall accumulation, with gas in Agbada D1.0 and D1.3/D1.4 sands between approximately 5,900 ft (1,800 m) and 6,100 ft (1,900 m) and oil/gas in the deeper D5 below approximately 6,900 ft (2,100 m). The Best Estimate GIIP is approximately 356 Bscf (mainly in D1.0). Two gas wells are currently producing from the D1.0 sand (Uquo-7 and -8ST). Upside potential exists in associated extensions to the west.

- *Uquo-5 area.* This is a small dip-closed rollover in the hanging wall of an east-west fault, which was tested in the original discovery well and its Uquo-5 twin. There is thought to be some up-dip exploration potential in the C and D sands.

- *Uquo NE area.* This is a large upthrown fault block to the north east, with fault and dip closure. Oil and gas were discovered in the Uquo-9/9ST well. The Best Estimate GIIP on the licence is 230 Bscf (in the Agbada C6.0 at around 4,200 ft (1,300 m), and D1 sands).

*Figure 36, Uquo Field Depth Structure*




*Source: 2021 Nigeria CPR*

The gas sands at the Uquo Field are estimated to have a total GIIP in excess of 950 Bscf (Best Case), and full development is thought to require seven wells; four existing wells, three new wells (including the recently completed Uquo-11 well) and one work-over. Based on these assumptions, an independent assessment estimates around 567 Bscf could be recovered in the Proved plus Probable case, of which about 454 Bscf are attributable to Savannah's interest.

2020 gas production from the four producing wells averaged 103 MMscfpd with peak production of 177 MMscfpd and cumulative production of 212 Bscf of gas (to 30 September 2021) since first gas in Q4 2013.

Gas volumes within known gas sands which are not currently planned for completion and development are classified as Contingent Resources.

*Figure 37, Uquo Field – Gas Reserves and Contingent Resources (as at 1 October 2021)*

| | *Gross on Licence* | | | *Net Attributable* | | |
|---|---|---|---|---|---|---|
| Gas (Bscf) | 1P/1C | 2P/2C | 3P/3C | 1P/1C | 2P/2C | 3P/3C |
| Reserves | 402.6 | 567.3 | 682.4 | 322.1 | 453.9 | 545.9 |
| Contingent Resources | 66.6 | 82.8 | 101.1 | 53.3 | 66.2 | 80.9 |

*Source: Adapted from the 2021 Nigeria CPR*

Gas produced from the Uquo Field is processed through the Uquo CPF, which is owned by Accugas Limited. A detailed description of the assets held by Accugas Limited are contained in paragraph 6.7 of this Part 5.

Liquids from the Uquo Field are transported via a 4-inch, 8 km pipeline to the FUN Manifold facilities, before being sold-on to ExxonMobil. Current liquids handling capacity at the Uquo CPF is approximately 2,000 bopd.

**Exploration Prospects**

A number of un-drilled structural closures and un-evaluated sands have been identified in the immediate area of the Uquo Field and have been classified as notional "Exploration Prospects" (see Figure 38). Given the multiple reservoir horizons identified in this prolific area the exploration risks are thought to be moderate, with Chance of Success assessed at over 50 per cent. in some cases, with subsurface work planned on the newly reprocess seismic data to further de-risk these prospects. Together they provide a significant potential upside for the field, with over 700 Bscf of un-risked potential GIIP.

*Figure 38, Uquo Field – Exploration prospects*

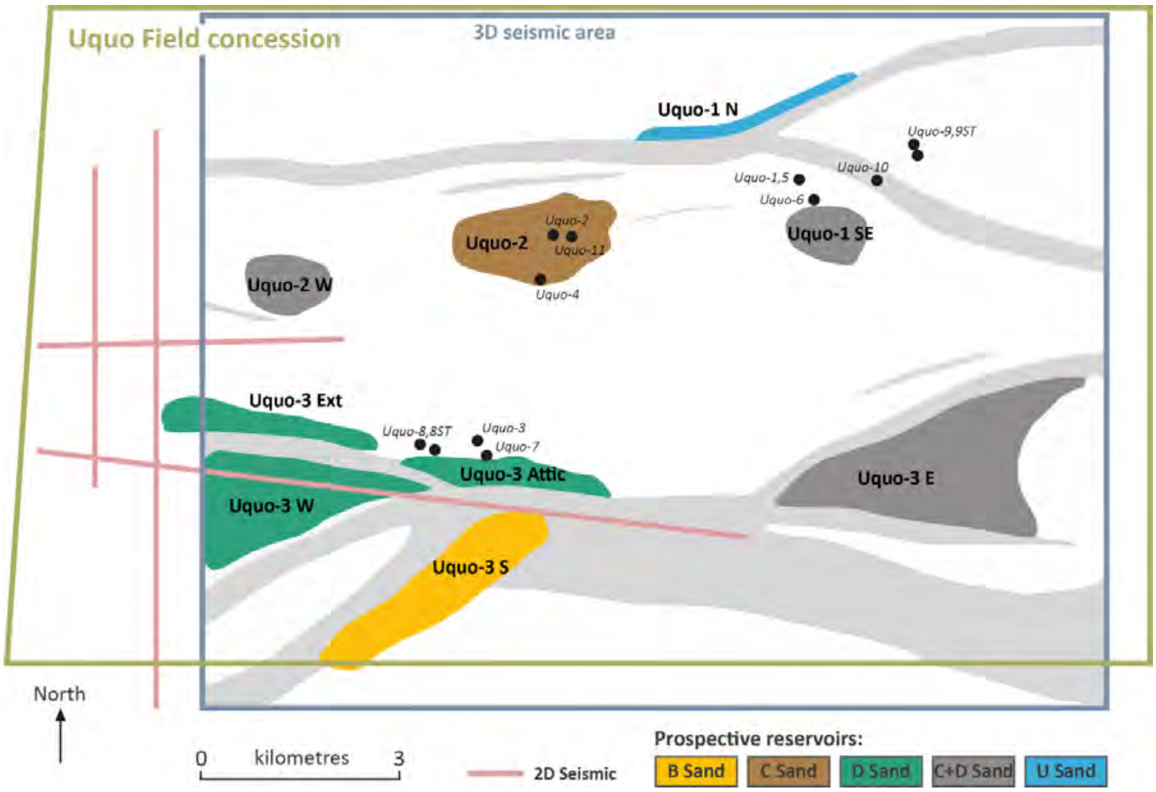
| *Prospect* | *Low* | *Gross GIIP (Bscf) Best* | *High* | *Chance of Success[1]* |
|---|---|---|---|---|
| Uquo 1SE | 55.7 | 84.8 | 139.9 | 0.50 |
| Uquo 2 | 5.5 | 15.4 | 39.0 | 0.73 |
| Uquo 2W | 71.3 | 88.4 | 103.7 | 0.57 |
| Uquo 3E Licence | 151.5 | 221.7 | 335.7 | 0.35 |
| Uquo 3S Licence | 114.8 | 154.3 | 200.1 | 0.66 |
| Uquo 3W Licence | 72.5 | 115.2 | 204.1 | 0.18 |
| Uquo 3 Extension | 10.2 | 15.1 | 22.6 | 0.14 |
| Uquo 3 Attic | 13.3 | 23.4 | 42.6 | 0.17 |
| Uquo 1N | 6.1 | 14.7 | 35.2 | 0.18 |
| **Total Licence [2]** | **500.9** | **733.0** | **1,122.9** | |

1 "Chance of Success" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. A High Chance of Success indicates a high chance of discovering hydrocarbons in sufficient quantity for them to be tested to surface.

2 Arithmetic sum

*Source: Adapted from the 2021 Nigeria CPR*

*Figure 39, Uquo Marginal Field Area – Exploration Prospects*




*Source: 2021 Nigeria CPR*

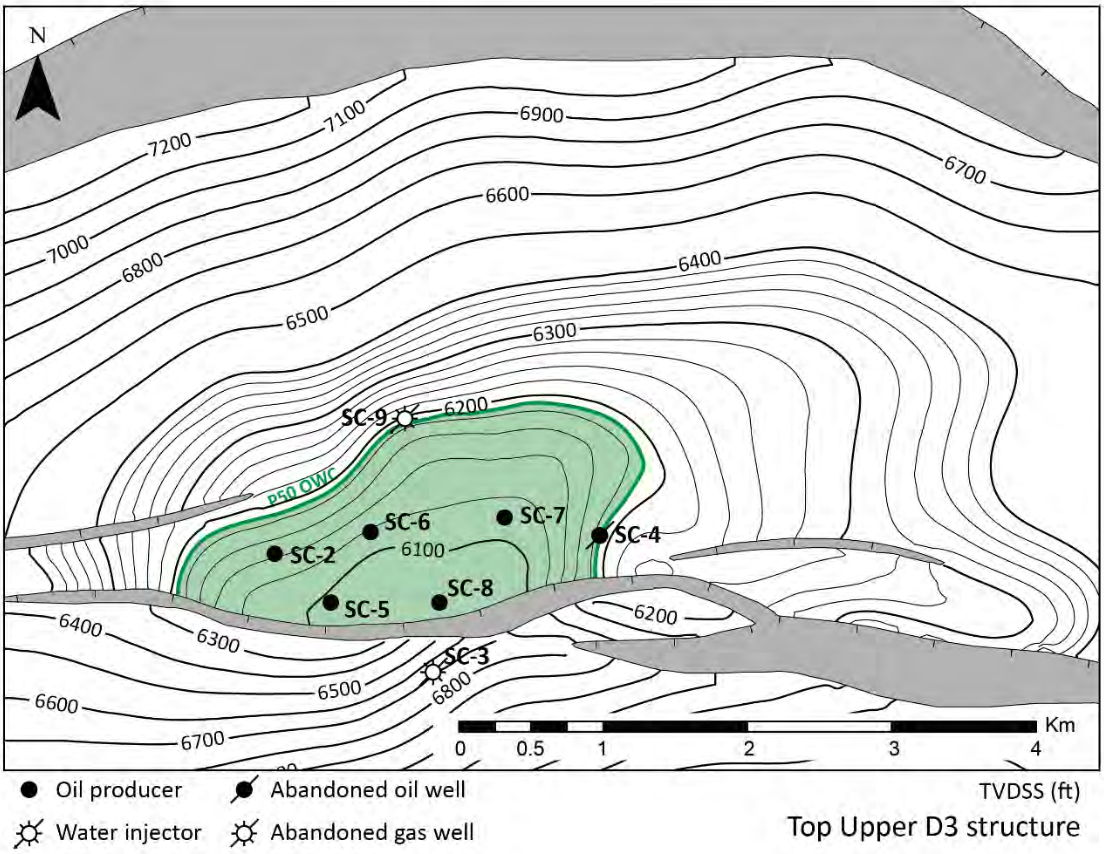
### 6.6 **Stubb Creek Marginal Field**

The Stubb Creek Field lies within the area of OPL 276, formerly OML 14, near the mouth of the Cross River and approximately 20 km east of the Uquo Field. Savannah holds an indirect 51 per cent. operated interest in the Stubb Creek Field through its 100 per cent. economic ownership of the field operator, Universal. The remaining 49 per cent. interest is held by Sinopec.

Discovered by Shell in 1971, Stubb Creek was awarded to Universal as a Marginal field in 2003. The Field was brought into commercial production in 2015 using the Stubb Creek EPF, which is capable of processing oil at a gross rate of around 3,000 bopd. Oil is exported via the FUN Manifold to QIT.

Oil and gas accumulations at the Stubb Creek Field are found in a series of sands of the Miocene Agbada Formation, located in a broadly east-west oriented rollover anticline structure in the downthrown hanging wall of a prominent east-west fault. A total of nine wells have been drilled in the field: four exploration and appraisal wells were drilled by Shell between 1971 and 1983; and five development wells drilled, tested and completed ready for production by the current operator Universal between 2007 and 2009. The field is covered by a 3D seismic survey acquired in 2005/06 by Universal. Data quality is excellent, allowing accurate structural mapping, and identification of amplitude anomalies related to hydrocarbon distribution.

*Figure 40, Stubb Creek Field outline – D3 depth structure*



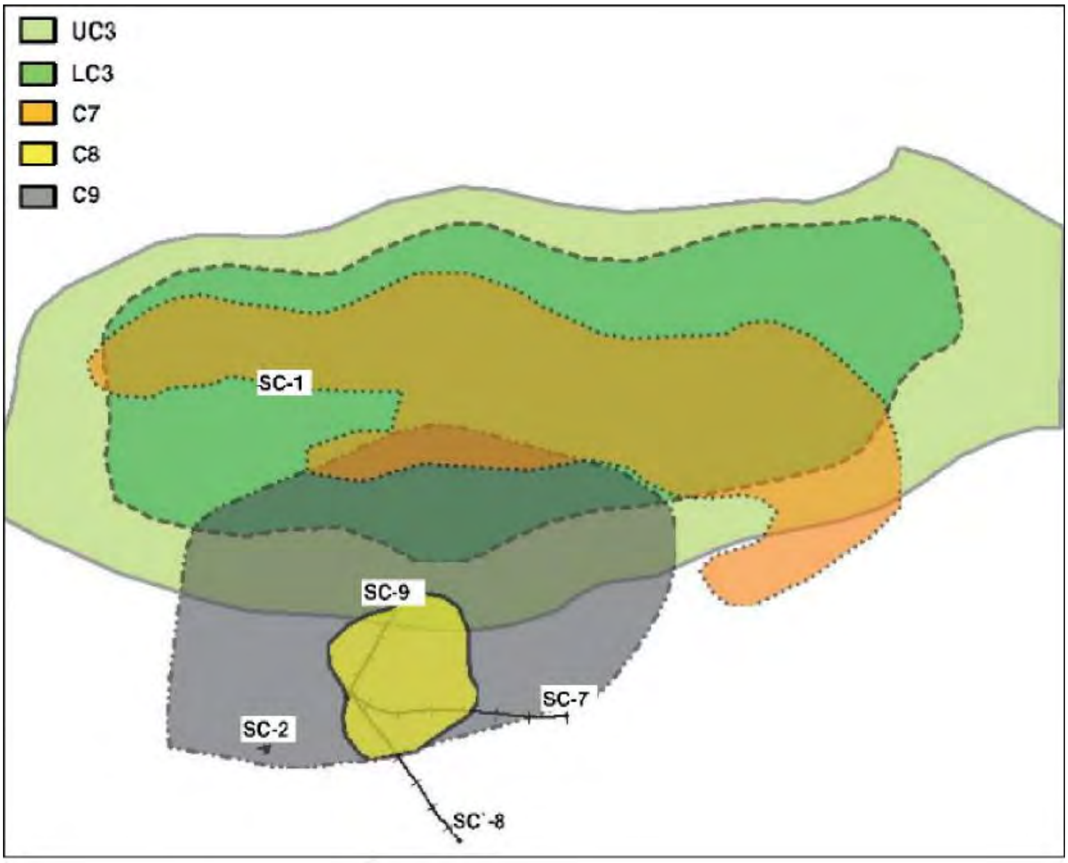

*Source: 2021 Nigeria CPR*

The focus of appraisal and development to date at Stubb Creek Field has been the oil, located in the deeper sands on the south side of the field. Production started in February 2015 and 5.4 MMstb have been produced to date (30 September 2021). However, in recent years attention has also turned to the large but un-appraised gas resources in the shallower section to provide gas to Accugas:

- **D Sands**. The deeper D sand section of the Agbada formation forms a three-way dip and fault bounded closure adjacent to a complex series of east-west normal faults on the south side of the field area (as is illustrated in Figure 40). Oil is found in the Upper D3 sands, at depths below 6,050 ft (1,800 m). A thin oil rim (12 ft) also occurs at the base of the deepest overlying C9 gas sand at around 4,700 ft (1,400 m), but only the Upper D3 sand is thought to be commercially viable for oil development. This unit has excellent reservoir properties and is estimated to contain STOIIP of 38.9 MMstb (Best Estimate). The C9 oil rim is estimated to contain 32.6 MMstb STOIIP (Best Estimate), but it is not included in any recoverable reserve estimates.

- **C Sands**. The Agbada C gas sands occur at depths of 3,600 ft (1,100 m) to 5,000 ft (1,500 m), shallower than the oil accumulations in the D sands. Gas occurs in the Upper and Lower C3, C7, C8 and C9 sands (see Figure 41). The majority of the GIIP – 466 Bscf (Best Estimate) – is located in the C3 sands, of which the shallowest, Upper C3, is the largest. These gas accumulations are only penetrated by a single well, the SC-1, although the gas volumes are quite clearly defined by their seismic amplitude signature on 3D seismic data. An additional 150 Bscf GIIP is estimated in the C9 sand, overlying the thin oil rim; this has been penetrated by four wells in the oil development area, and the accumulation is also well defined on 3D seismic.

*Figure 41, Stubb Creek Field – C sand gas resource outline*




*Source: 2021 Nigeria CPR*

Oil Reserves have been assigned only to the Upper D3 sand (Figure 42). These have been developed with five wells (SC-2, -5, -6, -7 and -8), of which three are currently on production at a combined rate of around 2.5 Kbopd (year to date 30 September 2021), with cumulative production to date of 5.4 MMstb. The SC-2 and -5 wells are currently shut-in, but are ready to go on stream once planned de-bottlenecking of facilities allows production to increase to approximately 5 Kbopd. The SC-9 well, on the northern down-dip edge of the accumulation, has been completed as a water injector. These wells, together with the addition of another injector, should be sufficient to fully develop the Upper D3 oil pool with about a 50 per cent. recovery factor. Gross remaining 2P reserves are 13.4 MMstb, of which 3.1 MMstb are attributable to Savannah's interest. There are no oil Contingent Resources recognised.

*Figure 42, Stubb Creek Field – Oil Reserves (as at 1 October 2021)*

| | *Gross on Licence* | | | *Net Attributable* | | |
|---|---|---|---|---|---|---|
| Oil (MMstb) | 1P | 2P | 3P | 1P | 2P | 3P |
| Reserves | 6.0 | 13.4 | 23.2 | 1.3 | 3.1 | 5.8 |

*Source: Adapted from the 2021 Nigeria CPR*

There are no gas reserves currently assigned to the Stubb Creek Field, as the main gas accumulations have not been flow tested or appraised and there is no approved field development plan at this stage. These are, however, high-quality gas reservoirs: a recovery factor of around 80 per cent. is anticipated, with high individual well productivity, and over 500 Bscf (Best Estimate case) have been classified as Contingent Resources, of which 293.7 Bscf are attributable to Savannah's interest.

*Figure 43, Stubb Creek Field – Gas Contingent Resources (as at 1 October 2021)*

| | *Gross on Licence* | | | *Net Attributable* | | |
|---|---|---|---|---|---|---|
| Gas (Bscf) | 1C | 2C | 3C | 1C | 2C | 3C |
| Contingent Resources | 364.9 | 515.3 | 680.3 | 208.0 | 293.7 | 387.8 |

*Source: Adapted from the Nigeria CPR*

It is anticipated that the existing Stubb Creek EPF will be debottlenecked in 2023, to increase oil production capacity to around 5 Kbopd. The total capital investment anticipated for this project, involving bringing two existing wells into production and drilling a water disposal well, is US$28 million.

Development of the contingent gas resources at the Stubb Creek Field is anticipated to begin in 2032 with up to three new gas wells drilled over a five year period at an estimated gross cost of US$54 million in the 2C case. Production would be tied back to the Uquo CPF via a new 31 km pipeline, allowing gas to be sold to the Accugas Midstream Business, supplementing the gas produced from the Uquo Field.

### 6.7 **Accugas Midstream Business**

Savannah holds an indirect 80 per cent. interest in Accugas Limited, the midstream business which focuses on the marketing, processing, distribution and sale of gas to the Nigerian market. Currently, Accugas supplies gas to power stations and industrial customers in South East Nigeria, in addition to which Savannah expects additional high value incremental demand from regional industrial customers and is in discussions with a number of customers in this regard.

The Accugas Midstream Business comprises:

- 200 MMscfpd gas processing capacity at the Uquo CPF;
- approximately 260 km network of gas pipelines; and
- approximately 600 MMscfpd gas distribution capacity.

The Uquo CPF, which was designed and built by respected industry contractor, Petrofac, consists of two identical gas processing trains, each with a nameplate capacity to process up to 100 MMscfpd.

Accugas buys gas from its sole current supplier, SEUGL, under an upstream GSA at a price of US$1.41/Mscf for 2021 on an unindexed basis, and sells this gas to its current customers at a weighted average nominal price of US$3.94/Mscf for 2021.

First commercial gas delivery from the Uquo CPF began in January 2014 to the 190 MW Ibom Power station. At present, Accugas has three long-term downstream GSAs in place, the largest of which is with the 560 MW Calabar NIPP power station. Together with its contract with the 190 MW Ibom Power station, Accugas supplies gas to fuel around ten per cent. of Nigeria's power generation capacity. The key terms of Accugas's GSAs are summarised in Figure 44. In addition, Accugas Limited has more recently signed two Interruptible GSAs with FIPL and Mulak for gas deliveries up to a maximum daily nominated quantity of 35 MMscfpd and 2.5 MMscfpd, respectively. FIPL Afam power plant has a current power generation capacity of 180MW.

#### ***Gas Sales Agreements***

There are three long-term downstream GSAs in place delivering as at 1 October 2021[1]

*Figure 44, Accugas Summary of Key Gas Sales Agreements*

| | *Calabar NIPP* | *Lafarge* | *Ibom Power* |
|---|---|---|---|
| *Description* | *Nigerian State Power Plant* | *Lafarge Cement Plant* | *Nigerian State Power Plant* |
| Contract End | Sept 2037 | Jan 2037 | Dec 2023 |
| Daily Contract Quantity ("DCQ") | 131.0 MMscfpd | 24.2 MMscfpd | 19.7MMscfpd |
| Take-or-Pay | 80 per cent. | 80 per cent. | 80 per cent. |

1 Deliveries to FIPL commenced 30 October 2021

Accugas's historic focus has primarily been on high volume, but lower price power station customers, which sell their electricity into the regulated Nigerian distribution network. These customers underpinned the contracted forward gas sales which were required to justify the initial capital investment into Accugas's business infrastructure. Going forward, Accugas's business development opportunities are expected to be focused on lower volume high-value industrial customers. These "last-mile" customers are typically reliant on diesel fuel solutions, creating a significant pricing arbitrage for Accugas to exploit. Accugas's facilities connect to three principal industrial activity hubs, areas surrounding Calabar, Port Harcourt and Aba.

The Company announced on 31 January 2020 that Accugas had entered into a new interruptible gas sales agreement ("IGSA") with FIPL in relation to the provision of gas to the FIPL Afam power plant ("FIPL Afam"). FIPL is an affiliate company of Sahara Group, a leading international energy and infrastructure conglomerate with operations in over 38 countries across Africa, the Middle East, Europe and Asia.

FIPL Afam has a current power generation capacity of 180MW. The FIPL IGSA facilitates the supply of gas (produced by Uquo, with a maximum daily nominated quantity of 35 MMscfpd or approximately 5.8 Kboepd) by Accugas to FIPL Afam in order to augment its existing gas supply on an interruptible basis for an initial term of one year, with the ability to extend upon mutual agreement. Deliveries to FIPL under this contract commenced on 30 October 2021.

The Company announced on 5 February 2021 that Accugas had entered into a new gas sales agreement with Mulak Energy Limited, a member of the Mansour Group, the leading Egyptian multinational conglomerate with operations in more than 100 countries and annual revenues exceeding US$7.5 billion. The agreement facilitates the supply of gas for an initial two-year period on an interruptible basis (the "Interruptible Gas Delivery Period") and the subsequent five years on a firm contract basis (the "Firm Delivery Period"). During the Interruptible Gas Delivery Period, Mulak is able to nominate a maximum daily quantity of up to 2.5 MMscfpd. Volumes in the Firm Delivery Period will be agreed by the parties before the end of the Interruptible Gas Delivery Period and may be increased prior to the start of each year by agreement between the parties.

The agreement for the supply of gas to Mulak's Compressed Natural Gas ("CNG") Nigerian project represents Savannah's first Gas-to-CNG sales agreement. Mulak initially plans to distribute CNG to its industrial customers in Rivers State, with the CNG to be substituted for diesel in generators supplied by the Mantrac Group (also a member of the Mansour Group and one of the world's largest dealers in Caterpillar machinery, power systems and equipment). Savannah's gas offers an opportunity for Mulak to convert Mantrac's existing 400MW of diesel-fuelled generators to CNG-fuelled generators, expected to provide Mantrac customers with up to a 40 per cent. saving in energy costs and a 30 per cent. reduction in their carbon footprint. Sales under the GSA are expected to commence in 2022 and, following the initial two-year period, Mulak has indicated that it is seeking to expand its CNG sales on a pan-Nigeria basis to Mantrac customers.

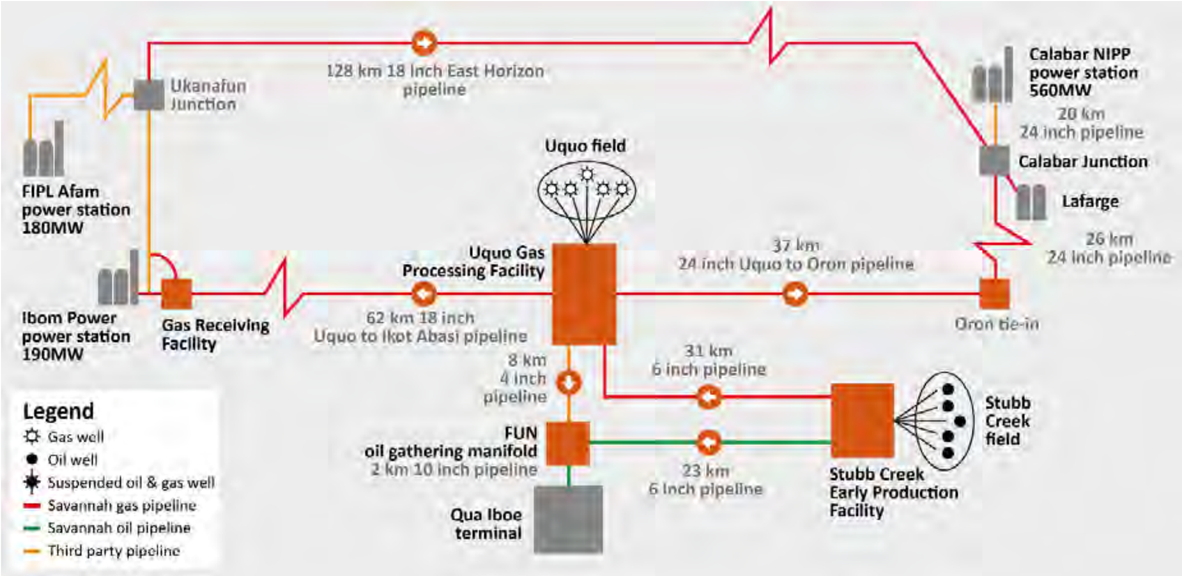
Accugas Limited continues to make good progress in relation to the negotiation of contracts to supply gas to several other potential new customers, expected to diversify customer-mix and sources of revenue.

***Infrastructure***

The key gas pipelines in the Accugas Limited network include (but are not limited to):

- Uquo to Ikot Abasi (62 km, 18-inch) – connects Uquo to the Ibom power station, constructed in 2010 – 2011
- Uquo to Oron (37 km, 24-inch) – connects Uquo to Oron, constructed in 2013-2014
- Oron to Creek Town (26 km, 24-inch) – connects Oron to Creek Town (the delivery point for the Calabar GSA), construction completed in 2016
- East Horizon gas pipeline (128 km, 18-inch) – acquired in Q1 2014 and delivering gas to Lafarge since 2012

*Figure 45, Accugas Midstream Business Infrastructure*




*Source: 2021 Nigeria CPR*

***Uquo Gas Processing Facility***

The Uquo CPF processes gas from the Uquo Field, and a network of pipelines links the processing facility to existing customers. Commercial production from the Uquo Field commenced in 2014. In addition to processing non-associated gas from the Uquo Field and future non-associated gas from the Stubb Creek Field, the Uquo CPF has the potential to provide a processing outlet for associated gas from other nearby Marginal fields; Qua Iboe (operated by Network Exploration and Production Company Nigeria Limited) and the Stubb Creek Field (operated by Universal). The associated gas from these fields can be delivered to the Uquo CPF by gas pipelines and eliminate gas flaring from crude oil operations.

Associated gas from the Stubb Creek field is currently being routed to the Uquo CPF.

***Valuation***

The base case NPV, at 10 per cent. discount rate, for the Accugas Midstream Business (and pre any debt charges or repayments) has been assessed to be $694.0 million, of which $555.2 million is net to Savannah's 80 per cent. interest. The valuation reflects the 2P and 2C forecasted delivery volumes defined in the 2021 Nigeria CPR, supplied from the Uquo Field and later by gas development at the Stubb Creek Field.

For the purposes of the economic evaluation performed by CGG in the Nigeria CPR, it is assumed that Accugas Limited sells the processed gas to five buyers, at an average nominal price of US$3.94/Mscf in 2021 indexing annually thereafter to US$5.04/Mscf by 2025 and US$5.52/Mscf by 2030.

# PART 6

# NIGER COUNTRY OVERVIEW AND ASSETS

## 1. Nigerien Country Overview

### 1.1 Introduction

Niger is a large country in West Africa covering an area of 1.3 million $km^2$, landlocked between Nigeria and Benin to the south, Burkina Faso and Mali to the west, Algeria and Libya to the north and Chad to the east. Approximately 80 per cent. of Niger's land area lies in the Sahara Desert. Niger was previously a French colony and gained independence in 1960. It has a population of over 25 million people and substantial natural mineral resources, yet it remains one of the most underdeveloped countries in the world. The World Bank estimates Niger to have an average GDP per capita of US$565. Niger is a constitutional democracy with a fast-growing economy and western-facing government.

### 1.2 Political environment overview

Since 1999, Niger has had a relatively stable and democratic government. After a short-lived military coup d'etat in 2010, a new constitution was established, leading to political stability and a significant increase in foreign direct investment.

The most recent presidential elections were held on 21 February 2021, which led to the election of President Mohamed Bazoum, leader of the Nigerien Party for Democracy and Socialism (PNDS-Tarayya), a centre-left leaning social democratic party founded in 1990, for a five-year mandate. President Mohamed Bazoum is focused on ensuring increased security[29] and developing the country's relatively nascent energy sector[30].

### 1.3 Economic environment overview

Niger's population grew 3.8 per cent. in 2020, a trend which is expected to continue over the coming years. Foreign direct investment, which has mainly been directed towards the country's natural resources sector, has increased substantially since the mid-2000s and, as a result, the Nigerien economy is expected to grow strongly in the medium term with the IMF estimating GDP growth of 5.6 per cent. in 2021, with further acceleration in 2022 and double-digit growth in 2023. This growth is expected to be primarily driven by increased output in the uranium mining industry, the country's agriculture sector and the continued development of the oil and gas industry.

Niger is set to become an oil exporting nation in 2022/23 following the expected completion of the Niger-Benin Export pipeline and oil revenues are expected to represent approximately 24 per cent. of GDP by 2025. There has been significant international investment in the industry from CNPC in consortium with OPIC, and from Sonatrach, the Algerian national oil company, as well as from Savannah.

In April 2014, Niger adopted its most recent investment code which lays out the general principles governing the reception and protection of foreign investment, as well as the incentives available for approved projects. The code allows for negotiated tax breaks provided by the Ministry of Commerce on a case-by-case basis. Most investors benefit from special tax treatment and tariff protection for varying periods depending on the level and location of investment. The investment code guarantees equal treatment of investors regardless of nationality and offers incentives for sectors the government deems key to economic development.

## 2. Overview of the Niger Oil and Gas Industry

Exploration activities in the Agadem Rift Basin of Niger have been ongoing since the 1970s. Between 1974 and 2004, five discoveries were made from a total of 25 exploration wells, all of which were drilled based on 2D seismic backed geological models. Companies active at that time included Elf Petroleum Nigeria Limited, Texaco, Conoco, Sun Oil, Esso and PETRONAS. In 2008, CNPC acquired the exploration rights to the Agadem License Area through paying a US$300 million signature bonus to acquire the five existing discoveries and the exploration rights to the area for eight years. Since acquiring its PSCs in 2008, CNPC has made 110 discoveries from 137 exploration wells (a success rate of approximately 80 per cent.) and has established a 2P reserve base of approximately 1 Bnbbls. CNPC thus demonstrated the pro-business environment and ease of ability to operate in Niger, given the magnitude of the work programme pursued in a relatively short period of time, which included: (i) drilling more than 200 exploration, appraisal and development wells; (ii) acquiring over 18,000 km of 2D seismic and 13,000 $km^2$ of 3D seismic; and (iii) building a 463 km pipeline and the 20 Kbopd Zinder refinery, achieving first oil for the country in 2011 with the commencement of production from the Sokor and Goumeri fields.

In early 2013, CNPC completed the sale of 20 per cent. of the licence area to OPIC. In July 2013, the first period of exploration of the Agadem licence area by CNPC ended, and approximately 50 per cent. of the acreage was returned to the public domain under the terms of CNPC's PSC with the government of Niger.

Sonatrach, the Algerian national oil company, is also active in oil development in Niger and its affiliate Sonatrach International Petroleum Exploration and Production, has a PSC over the Kafra licence area which is located in the north of Niger on the Algerian border. Following the acquisition of approximately 1,700 km 2D seismic, its first exploration well, Kafra-1, was drilled and reported as a significant discovery in April 2018. Kafra-1 was flow tested at a rate of approximately 1.5 Kbopd.

In July 2014, Savannah signed a PSC with the Government of Niger for the R1/R2 license area, followed by the signature of the R3/R4 PSC in July 2015, resulting in Savannah having approximately 50 per cent. of the Agadem Rift Basin under licence. The two PSCs are now being amalgamated into one single PSC called R1234 and this was approved by the Council of Ministers on 16 December 2021.

### 2.1 **Niger-Benin Export Pipeline**

Niger's domestic oil consumption is relatively low (currently approximately 12 Kbopd), meaning a significant proportion of existing production is exported, largely by truck and road to northern Nigeria. The majority of oil expected to be produced from future developments is intended to be exported, including from CNPC's Agadem PSC Grande Exclusive Exploitation Area (the next major phase of development on the Agadem PSC).

In September 2019, a Transportation Convention was signed between CNPC and the Republic of Niger in relation to a crude oil export pipeline from the ARB to the Atlantic coast in Benin (the "Niger-Benin Export Pipeline"). The Niger-Benin Export Pipeline is planned to run for approximately 2,000 km from the ARB in Niger to Port Seme on the Atlantic coast in Benin and is CNPC's largest ever cross-border crude oil pipeline investment.

The Transportation Convention sets out the contractual terms under which the Niger-Benin Export Pipeline will be constructed and operated. It follows the signature in August 2019 of the Niger-Benin Pipeline Construction and Operation Agreement between CNPC and the Republic of Benin, as well as the upstream approval granted by the Republic of Niger to CNPC in relation to the Agadem PSC Grande Exclusive Exploitation Area, the production from which is expected to be exported from Niger using the Niger-Benin Export Pipeline.

CNPC has confirmed that the Niger-Benin Export Pipeline construction is expected to be completed in 2023. Under the terms of the Savannah PSC, the Petroleum Code of Niger and its Implementing Decree, Savannah is entitled to access the Niger-Benin Export Pipeline and Savannah expects there to be spare capacity within the pipeline to enable the monetisation of further discoveries on the Savannah PSC.

### 2.2 **Niger oil service industry**

Niger has an active and efficient oil service industry present and established in-country. Great Wall Drilling Company Limited ("GWDC"), a large integrated petroleum engineering service provider (operating in 33 countries worldwide with 439 rigs), has operated in Niger for over 11 years and has drilled over 200 wells in the ARB. GWDC is a subsidiary of CNPC. It currently has eight drilling rigs which are active in the ARB, and four workover rigs which are used for completion and well testing. GWDC has an excellent HSE record in Niger, with no serious accidents in its time operating in-country and over 13 million man-hours worked without any LTI.

BGP Inc. CNPC ("BGP"), one of the world's leading geophysical service companies and one of the world's largest land seismic companies (65 land crews operating globally), has also operated in Niger for over 11 years. Since coming to Niger, BGP has acquired over 18,000 km of 2D seismic and over 13,000 $km^2$ of 3D seismic. BGP is also a subsidiary of CNPC.

Both GWDC and BGP have large logistics bases located in the ARB and are also joined by multiple local contractors who offer services including civil works, camp construction, desert transportation and logistics.

### 2.3 **Niger's National Legislative Framework**

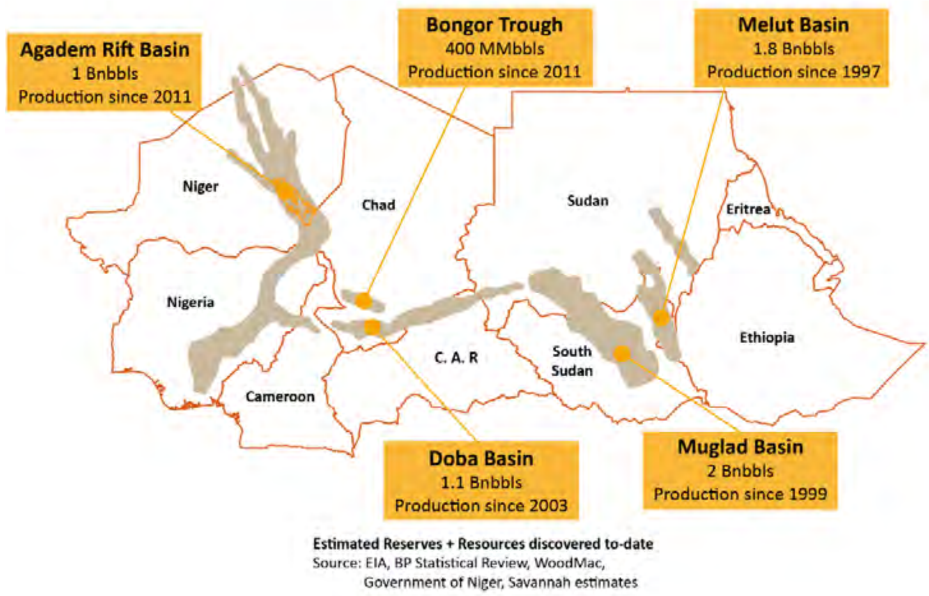
Refer to Appendix B of this document for an overview of Niger's National Legislative Framework.

## 3. NIGERIEN ASSETS

The Company's Nigerien assets comprise the R1234 PSC on which the Company conducted a highly successful exploration programme resulting in the drilling of five oil discoveries within the R3 East area in 2018.

The R1234 PSC is located in the highly prospective Agadem Rift Basin in South East Niger. The ARB is comparable in scale to the North Sea rift system, and forms part of the Central African Rift System. The Central African Rift System consists of a series of highly oil prolific Cretaceous and Tertiary rifts throughout Niger, Chad, Sudan, South Sudan and also Nigeria, with over 6 Bnbbls of oil discovered to date. Topography in the ARB is relatively flat, with no significant mobile sand dunes. The R1234 PSC is located approximately 200 km away from the nearest major population centres.

*Figure 46, Central African Rift System – Regional Discoveries*




*Source: 2021 Niger CPR*

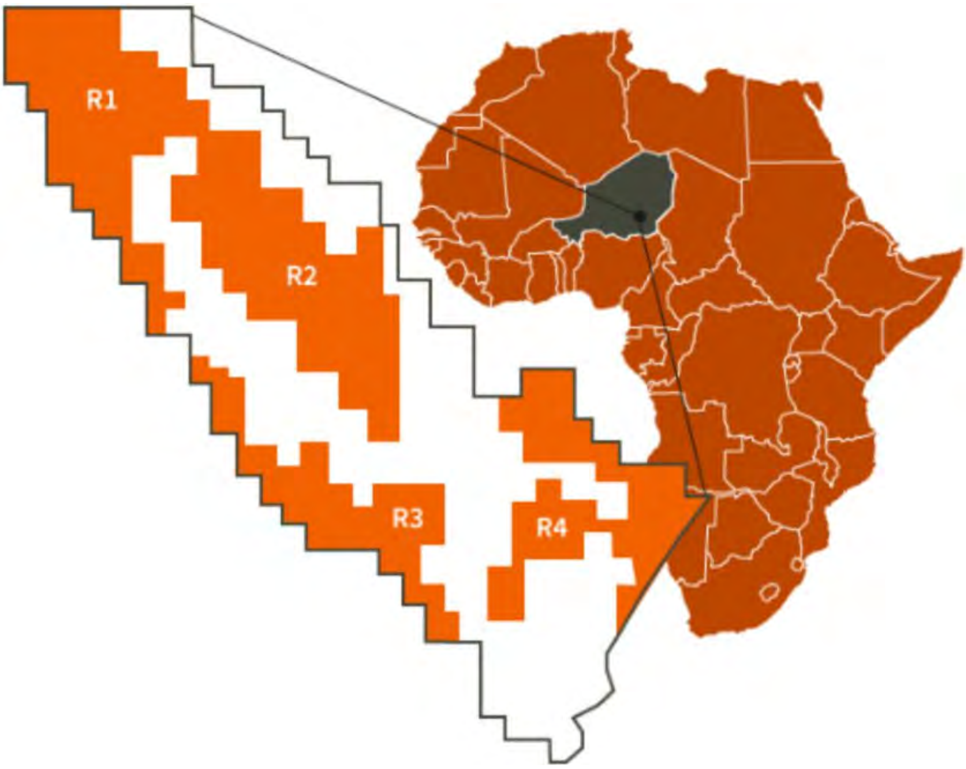
The R1234 PSC represents approximately 50 per cent. of the ARB, and of the original Agadem PSC Area which was compulsorily relinquished by CNPC in July 2013 and subsequently acquired by Savannah over the course of 2014 and 2015.

CNPC's involvement in Agadem has been transformational for the upstream industry in Niger, markedly increasing the success rate in the area, with 110 discoveries from 137 exploration wells, establishing 2P reserves of approximately 1 Bnbbls through the application of 3D seismic technology coupled with an efficient and effective operating model. Following the construction of a 20 Kbopd refinery at Zinder and a 463 km pipeline linking the refinery to Agadem, first oil from Agadem was established in 2011, only three years after licence acquisition.

### 3.1 **Licence Interest**

The new R1234 PSC covers an area of approximately 13,655 km$^2$. and the R3 area has been the initial focus of the Company's exploration efforts with an 806 km$^2$ 3D seismic survey acquired and processed in 2016/2017 and five successful exploration wells drilled in 2018.

*Figure 47, Location of the Savannah PSC*




*Source: 2021 Niger CPR*

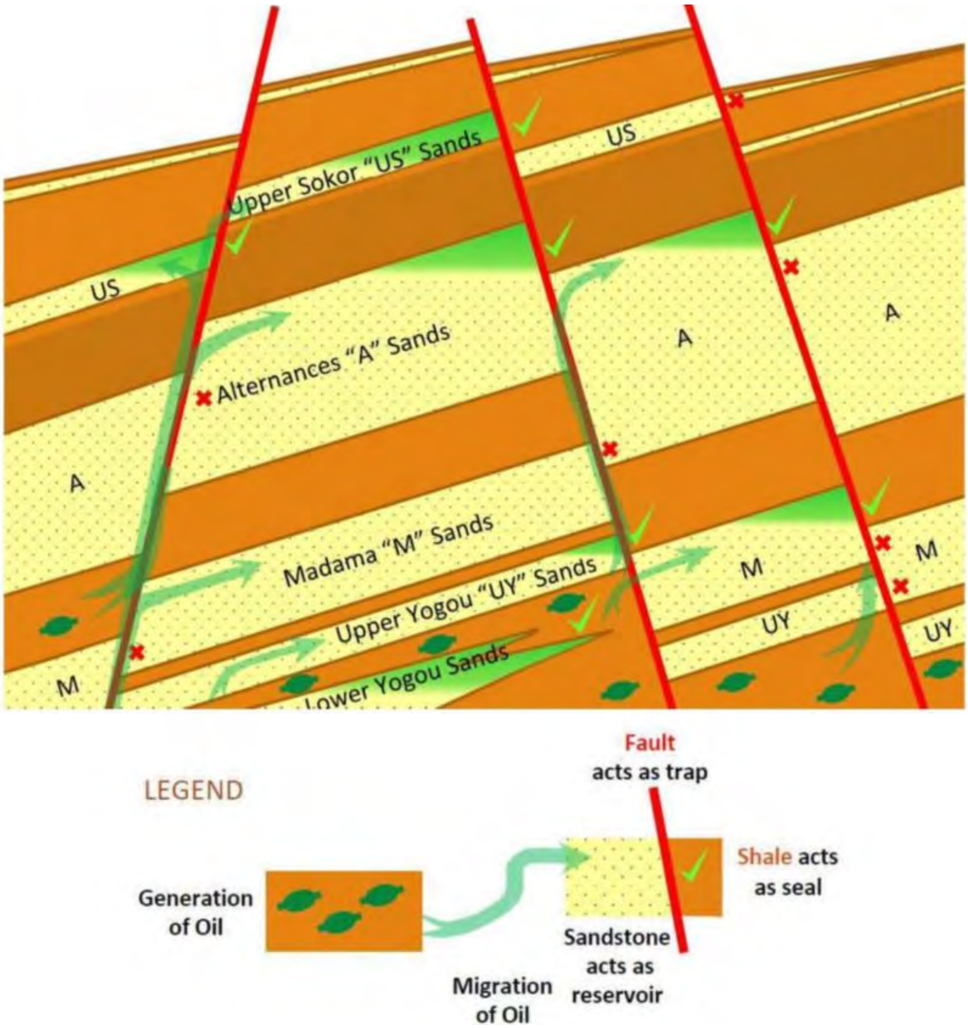
### 3.2 **Petroleum Geology of the Agadem Rift Basin**

The ARB sedimentary fill comprises up to 5 km of sands and shales, of Late Cretaceous to Tertiary age. These were deposited into the deepening rift from surrounding uplifted highlands, via a series of large rivers draining a predominantly arid hinterland, and with occasional marine incursions from the south. The deepest, Cretaceous section is currently "mature" for oil and gas and is thought to be the source of hydrocarbons trapped in the over-lying Eocene and younger section, mainly in traps formed by the rift faulting, which brings sealing shale lithologies against sandstone reservoir rocks, as shown in Figure 48 below.

Savannah recognises oil potential in a number of sequences within the ARB:

- *Upper Sokor Formation:* Oil has been recovered from at least 6 wells in the ARB from this shallow section, at depths less than 1,600 meters, and other shows are reported. Although this is shallow for a conventional oil exploration target, there are no signs of biodegradation reported, and sands here may be a viable secondary target.
- *Sokor Alternances Formation:* This has been the principal focus of exploration in the ARB to date; all of the Savannah discoveries are from within this sequence, as are a high proportion of the discoveries made by CNPC.
- *Madama Formation:* This unit, underlying the Sokor Alternances, has a distinctive seismic character seen across the ARB. It is not currently viewed as an exploration target, and many of the exploration wells are terminated within the Madama.
- *Upper Yogou Formation:* This Upper Cretaceous unit is thought to be the principal oil source in the ARB. It is mature for oil in the central part of the rift. Good porosity sandstones occur, and the unit is a viable exploration target on the Savannah acreage, with prospective resources recognised by CGG underlying the Eocene discoveries and prospects. Some larger, deep structures occur which are not reflected in the Eocene and may form interesting exploration targets. Some encouraging test results are reported from CNPC wells.
- *Lower Yogou & Donga Formations:* Various exploration ideas are being investigated for this deep and also potentially gas-mature part of the section, although no prospects have been identified to date.

*Figure 48, Cartoon section across the ARB, showing main hydrocarbon plays*




Source: 2017 Niger CPR

3.3 **Resources**

***Contingent Resources***

Each of the five wells drilled by Savannah in 2018 can be classified as 'Discoveries' under the Petroleum Resource Management System 2018 definitions, and for which Contingent Resource volumes can be estimated, as determined by CGG in the Niger CPR. These amount to over 33 MMstb net attributable to Savannah in the 2C, mid case.

*Figure 49, Contingent Resource estimates of Savannah's discoveries in the R3 portion of the R1234PSC*

| | Gross on Licence | | | Net Attributable | | | Chance of Development | Operator |
|---|---|---|---|---|---|---|---|---|
| *Discovery* | *1C* | *2C* | *3C* | *1C* | *2C* | *3C* | | |
| Amdigh | 7.2 | 18.4 | 83.9 | 6.8 | 17.5 | 79.7 | High | Savannah |
| Eridal | 4.3 | 6.2 | 8.5 | 4.0 | 5.9 | 8.1 | High | Savannah |
| Bushiya | 3.3 | 6.2 | 12.9 | 3.2 | 5.9 | 12.3 | High | Savannah |
| Kunama | 1.8 | 4.2 | 9.3 | 1.8 | 4.0 | 8.8 | High | Savannah |
| **Total MMstb** | **16.7** | **35.0** | **114.6** | **15.8** | **33.3** | **109.1** | | |
| Zomo | 0.0 | 0.2 | 0.0 | | 0.2 | | Medium | Savannah |

*Source: Adapted from the 2021 Niger CPR*

*Note:*

Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

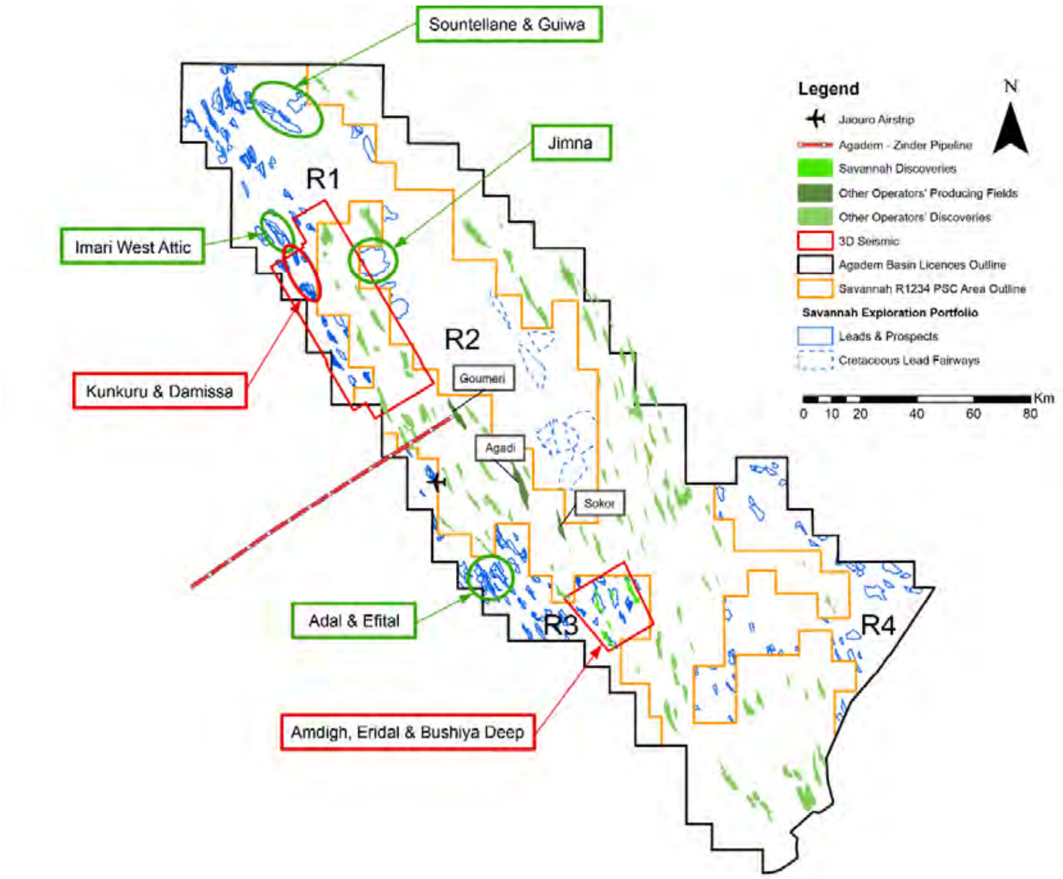
Four of these discoveries are assessed by CGG as having a high probability of commercial development, allowing relatively near-term future conversion of these volumes to Reserves under PRMS guidelines. Evaluation of the Zomo discovery is preliminary, pending further seismic evaluation, and the indicative resources shown are excluded from the total.

***Prospective Resources***

CGG recognises a total of eleven exploration Prospects and Leads, for which Prospective Resource estimations have been made (Figures 51 and 52). Five of these are located on the R3 area, with an aggregate gross Best Estimate Resource potential of approximately 90 MMstb (Figure 51) and assessed Chance of Success of 25 per cent. to 75 per cent. Three of these are deep exploration targets in the Cretaceous Yogou formation below the shallower discoveries at Bushiya, Amdigh and Eridal. Two further undrilled Leads are identified on the western edge of the R3 area, with prospectivity in the Sokor as well as the deeper Yogou formation.

A further six undrilled exploration prospects and leads have been assessed by CGG in the R1/R2 area. These all have exploration potential throughout the section and have a larger aggregate gross resource potential of 270 MMstb (Best Estimate – Figure 52). Two of these features, Kunkuru and Damissa, are covered by 3D seismic and are thought to have a high chance of exploration success (>75 per cent.). The other four features are also large (30 – 80 MMstb) but are currently regarded as medium or high risk (most <25 per cent. chance of exploration success).

*Figure 50, Map showing Prospects and Leads assessed by CGG*




*Source: 2021 Niger CPR*

*Figure 51, Prospective Resources estimates, R3 portion of the R1234 PSC*

| *Prospect/Lead* | *Gross on Licence* | | | *Net Attributable* | | | *Chance of Success* | *Operator* |
|---|---|---|---|---|---|---|---|---|
| | *Low* | *Best* | *High* | *Low* | *Best* | *High* | | |
| Bushiya Deep | 1.8 | 7.6 | 22.5 | 1.7 | 7.3 | 21.3 | Medium | Savannah |
| Amdigh Deep | 2.6 | 10.9 | 32.7 | 2.4 | 10.4 | 31.0 | Medium | Savannah |
| Eridal Deep | 1.7 | 6.9 | 20.0 | 1.6 | 6.6 | 19.0 | Medium | Savannah |
| Adal Lead | 3.2 | 20.6 | 72.6 | 3.0 | 19.6 | 69.0 | Medium | Savannah |
| Efital Lead | 8.7 | 44.0 | 130.0 | 8.3 | 41.8 | 123.5 | Medium | Savannah |
| **Total MMstb** | **18.0** | **90.0** | **277.8** | **17.0** | **85.7** | **263.8** | | |

*Source: Adapted from the 2021 Niger CPR*

*Note:*

Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

*Figure 52, Prospective Resources estimates, R1/R2 portion of the R1234 PSC*

| | *Gross on Licence* | | | *Net Attributable* | | | *Chance of Success* | *Operator* |
|---|---|---|---|---|---|---|---|---|
| *Prospect/Lead* | *Low* | *Best* | *High* | *Low* | *Best* | *High* | | |
| Damissa | 13.2 | 66.9 | 188.1 | 12.5 | 63.6 | 178.7 | High | Savannah |
| Kunkuru | 1.9 | 10.4 | 31.3 | 1.8 | 9.9 | 29.8 | High | Savannah |
| Sountellane | 9.4 | 35.8 | 108.2 | 8.9 | 34.0 | 102.8 | Medium | Savannah |
| Imari W Attic | 8.8 | 45.4 | 149.5 | 8.3 | 43.1 | 142.0 | Low | Savannah |
| Guiwa | 6.5 | 30.0 | 89.8 | 6.2 | 28.5 | 85.3 | Low | Savannah |
| Jimna | 17.2 | 81.5 | 254.8 | 16.3 | 77.4 | 242.0 | Low | Savannah |
| **Total MMstb** | **57.0** | **270.0** | **821.7** | **54.0** | **256.5** | **780.6** | | |

*Source: Adapted from the 2021 Niger CPR*

*Note:*

Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

***Yet-to-Find***

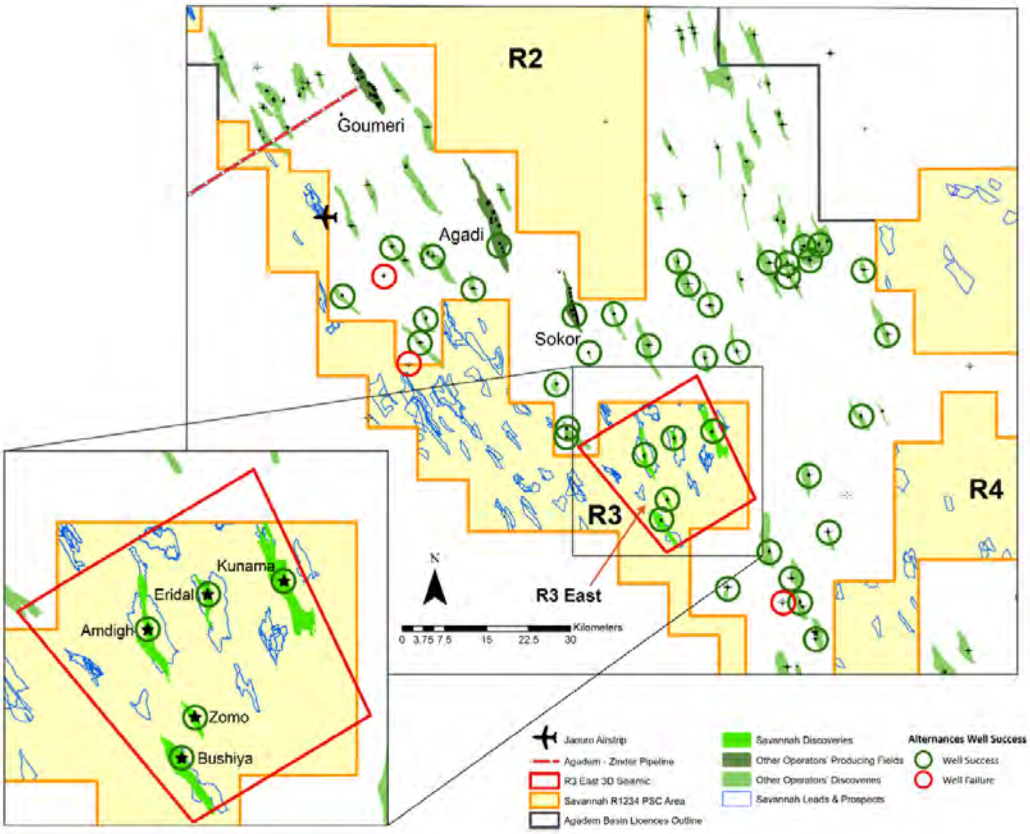
CGG have also undertaken a geological Yet-to-Find analysis, covering all exploration plays across the Savannah acreage, which suggests that on a Best Estimate, risked basis around 2.7 Bnbbls of oil resources could be anticipated.

### 3.4 **Oil Discoveries**

Savannah drilled a total of five exploration wells during the 2018 drilling campaign, resulting in five oil discoveries – an exploration success rate of 100 per cent. – although one of these (Zomo) is very small and has no attributable Resources. The wells were all drilled within the R3 East area of the R1234 PSC and are all covered by the R3 East 3D seismic survey acquired by Savannah in 2016 and 2017. All the discoveries have been made in sandstone reservoirs of the Sokor Alternances formation and have tested oil from the uppermost E1 sequence. In some cases, additional oil zones have been recognised in deeper sequences (E2, E3 and E5).

CGG note that the petrophysical analysis of many of the reservoir sands identified in these discoveries is problematic due to the lack of reliable formation water salinity data. Many of the discovery sands show electrical resistivities which would suggest a high-water saturation – although a combination of mud gas shows while drilling, Repeat Formation Tester pressure profiles and direct RFT samples show these to be oil bearing. This analysis will be further refined in the future as more data is obtained.

*Figure 53, Oil Discoveries – R3 East Area*

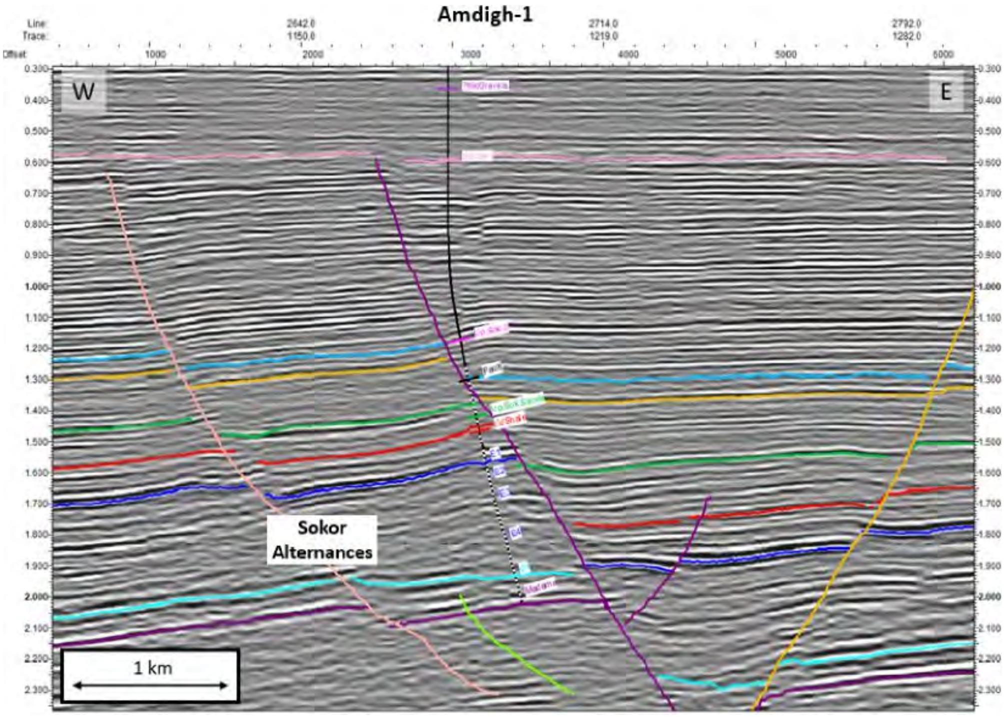



*Source: 2021 Niger CPR*

***Amdigh Discovery***

The Amdigh-1 well was drilled to 2,469 m on a narrow closure mapped along the crest of a tilted fault block (Figure 54). It is the largest of the Savannah discoveries in Niger to date and with by far the largest upside potential. The well encountered hydrocarbons in three separate sequences (E1, E2 and E3) of the Sokor Alternances formation. The presence of oil (27.5° API) in the E1 and E2 was confirmed by recovery of oil samples and by the interpretation of RFT pressure data.

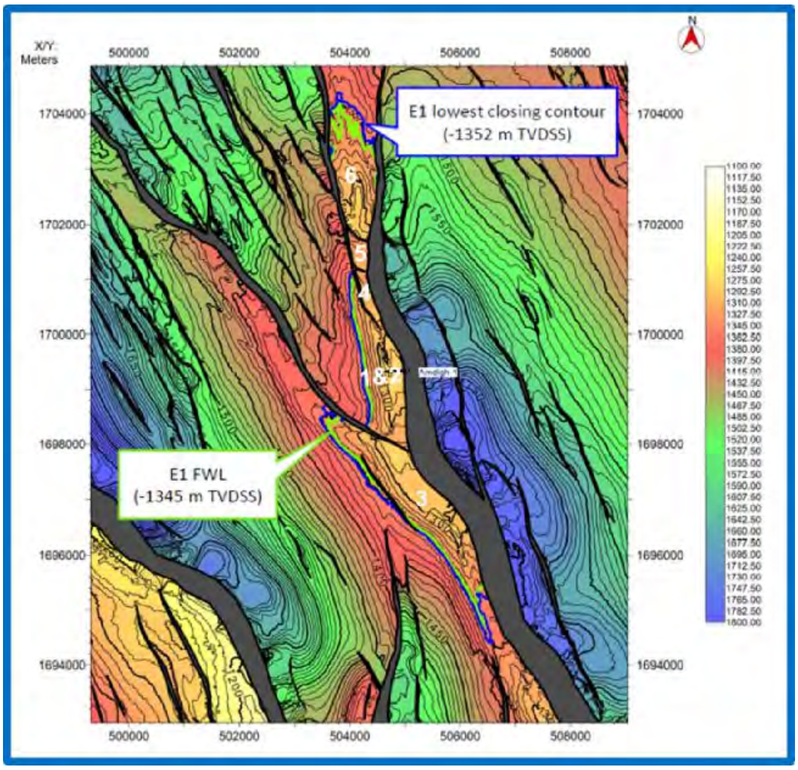
*Figure 54, Amdigh-1 Discovery – PSTM seismic section*




*Source: 2021 Niger CPR*

The discovery appears to be segmented by a series of cross-cutting faults (as shown in Figure 54), although the drilled central and southern segments are thought to be in pressure communication. The northern extension, however, may be isolated, and CGG have chosen to include this area in only the Upside volumetrics. The range of estimated STOIIP is therefore very wide, from 31 MMstb (P90) to over 250 MMstb (P10), with a P50 mid case of 66 MMstb. Recovery factors in these reservoirs are estimated to be in the range 23 per cent. to 33 per cent., giving a gross 2C Resources of around 18.4 MMstb, of which 17.5 MMstb is attributable to Savannah under the terms of the R1234 PSC.

*Figure 55, Amdigh Discovery – Top Sokor Alternances, E1 depth structure*




*Source: 2021 Niger CPR*

***Zomo Discovery***

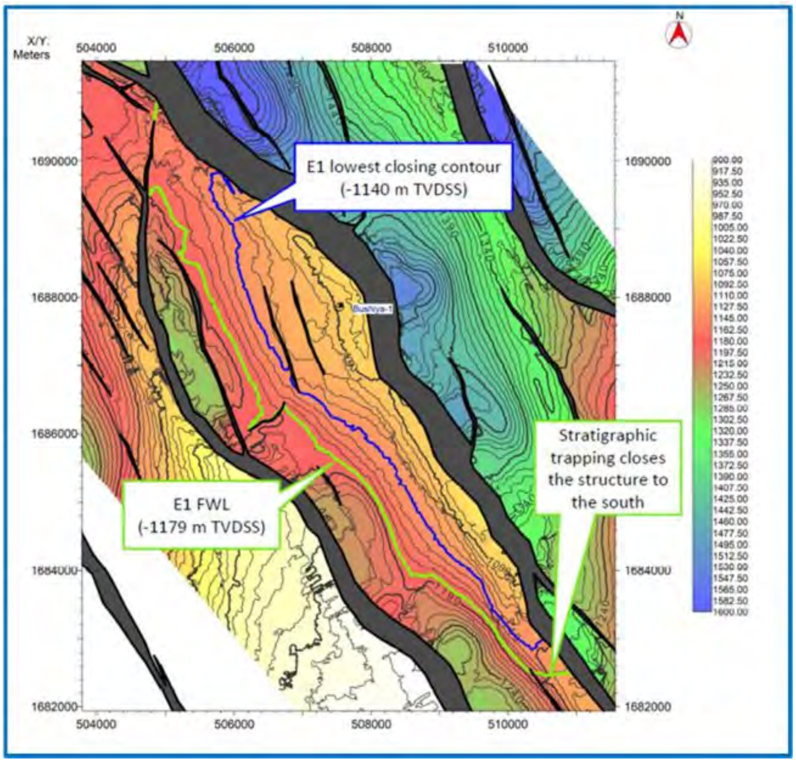
The Zomo-1 well was drilled to 2,499 m depth about 8 km South East of the Amdigh-1 discovery, along the same structural trend, as a potential appraisal of the Amdigh discovery. Oil was again found in the E1 sequence, but at 23.7° API it is somewhat heavier than at Amdigh-1. RFT pressure analysis demonstrates that the Zomo and Amdigh oil columns are actually separate, with Zomo restricted to a very small accumulation at the crest of a small separate closure. Estimated STOIIP is less than 1 MMstb and no recoverable Resources are currently assigned.

***Bushiya Discovery***

The Bushiya-1 well was drilled to 2,200 m on a closure mapped along the relatively un-faulted crest of a tilted fault block (Figure 56). The well encountered hydrocarbons at the top of the Sokor Alternances formation in sequences E1 and E3 (total net pay of 10 m). The E1 column was proven by recovery via RFT of a 24.2°API oil sample, in line with the Amdigh-1 oil analysis from the same interval. The E3 oil column was interpreted from the RFT pressure data.

The estimated STOIIP for Bushiya is smaller than Amdigh, with around 22 MMstb in the P50 case, of which around 6.2 MMstb are recoverable (28 per cent.), with 5.9 MMstb net to Savannah.

*Figure 56, Bushiya Discovery– Top Sokor Alternances, E1 depth structure*



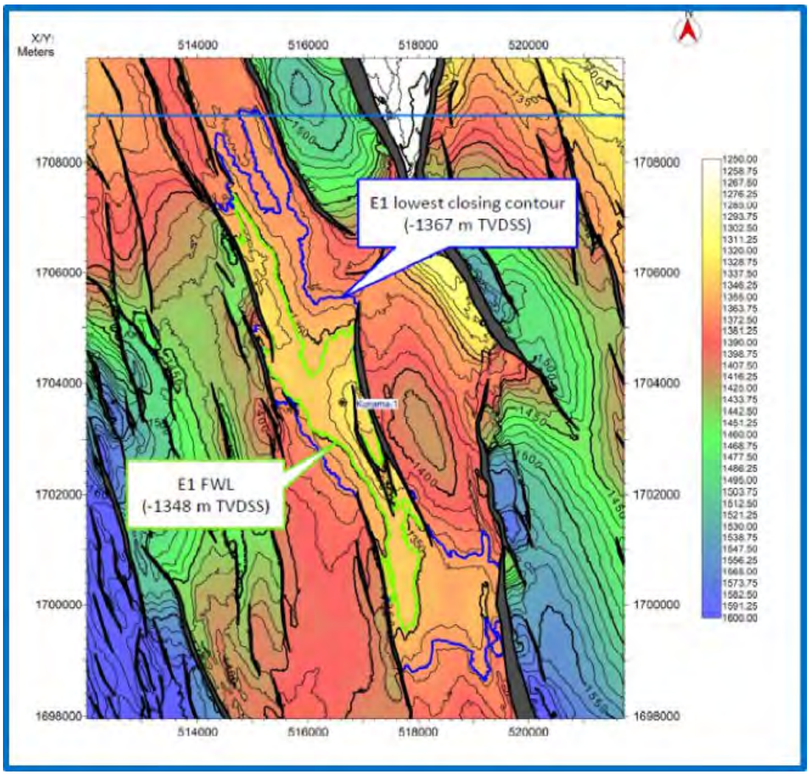

*Source: 2021 Niger CPR*

***Kunama Discovery***

The Kunama-1 well was drilled to 2,460 m on the relatively flat crest of a slightly tilted fault block (Figure 57). It is the most "basinal" of the discoveries, lying about 13 km North East of Amdigh. Oil was encountered in the E1 sequence at the top of the Sokor Alternances, proven by RFT recovery of a 28° API oil sample. An additional sample (24.6° API) was recovered from the E5 sequence.

The estimated mid case STOIIP is 15 MMstb of which around 4.2 MMstb are recoverable (28 per cent.), with 4.0 MMstb net to Savannah.

*Figure 57, Kunama Discovery– Top Sokor Alternances, E1 depth structure*



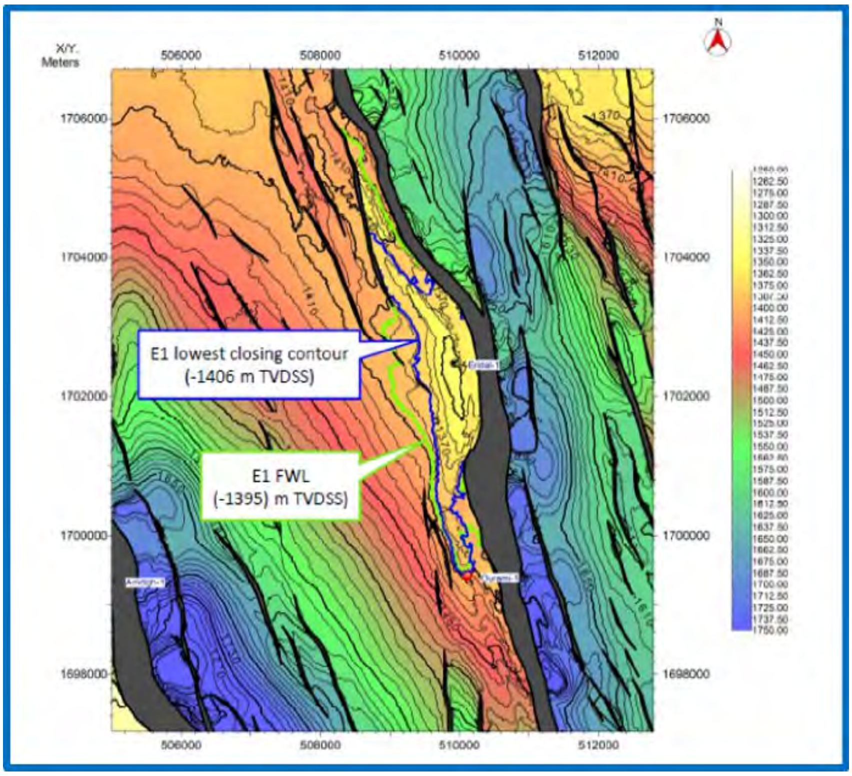

*Source: 2021 Niger CPR*

***Eridal Discovery***

The Eridal-1 discovery was drilled to 2,542 m on the crest of a tilted fault block (Figure 58), lying between Amdigh and Kunama. A dry hole, Ourami-1, was drilled by CNPC on the structure about 3 km to the south, but lies outside the currently mapped closure. The Eridal-1 well, about 50 m up-dip, encountered oil in the E1 sequence proven by RFT recovery of a 33° API oil sample.

The estimated mid case STOIIP is around 22 MMstb of which 6.2 MMstb are recoverable (28 per cent.), with 5.9 MMstb net to Savannah.

*Figure 58, Eridal Discovery – Top Sokor Alternances, E1 depth structure*




*Source: 2021 Niger CPR*

### 3.5 **Early Production Scheme ("EPS")**

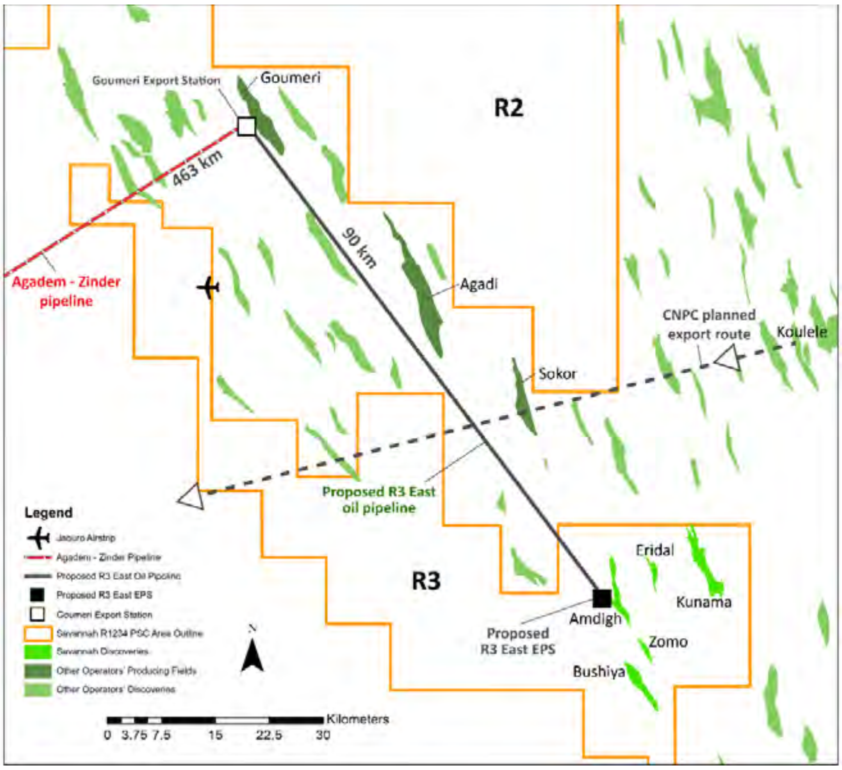
Following its successful 2018 exploration drilling campaign, the Company has focused on commercialising the discoveries through an EPS which would accommodate the well-testing operation and seamlessly continue to produce oil into the existing local infrastructure. This would see oil produced from the discovery wells in the R3 East area produced for sale into the Société de Raffinage de Zinder refinery. The refinery is connected to the ARB via the 463 km Agadem-Zinder pipeline.

In August 2018, Savannah signed an agreement with the Republic of Niger in relation to the EPS. This agreement sets out how the Niger Government and Savannah intend to work together, and how Savannah will be supported by the Niger Government, in order to deliver first production from the EPS.

Savannah has prepared a development scenario for the discoveries drilled in the R3 East area, where the four main discoveries have around 35 MMstb Gross Contingent Resources (2C). The facilities will be based around the largest discovery, Amdigh:

- *Phase 1:* Early Production: following production testing of the discovery wells, raw crude will be processed using an Early Production Facility (EPF). Processed crude would then be exported via a planned approximately 90 km pipeline between the EPF and the Goumeri Export Station (GES). The crude would then be piped to the Zinder refinery using the existing 463 km Agadem-Zinder pipeline. The expected production of approximately 1.5 Kbopd, is scheduled after the completion of well testing.
- *Phase 2:* Ramp-Up & Further Development: after phase 1, further wells will be drilled to ramp up the production to 5 Kbopd and will continue to be processed by the Zinder refinery. Following the ramp up, there will be further drilling and intra field pipelines constructed. This will create a gathering system to enable all discoveries (Amdigh, Eridal, Bushiya and Kunama) to be fully developed and tied into the EPF, along with a simple water treatment facility.

*Figure 59, R3 East Development Plan – Phase 1 and 2*




*Source: 2021 Niger CPR*

***Route to market***

On 15 September 2019, CNPC and the Republic of Niger entered into a Transportation Convention in relation to the planned Niger-Benin crude oil export pipeline. The Niger-Benin Export Pipeline is expected to run for approximately 2,000 km from the ARB in Niger to Port Seme on the Atlantic coast in Benin. Under the terms of Savannah's PSC, the Petroleum Code of Niger and its Implementing Decree, Savannah is entitled to access such third-party infrastructure that guarantee the owner a 12.5 per cent. return. Importantly, the Niger-Benin Export Pipeline provides Savannah with a significant additional potential route to market, alongside the existing Société de Raffinage de Zinder refinery.

# PART 7A

## ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF THE EXXON TARGET COMPANIES

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30 December 2021

The Directors
Savannah Energy PLC
40 Bank Street
London E14 5NR

The Directors
Strand Hanson Limited
26 Mount Row
London W1K 3SQ

Dear Sirs and Madams,

**Introduction**

We report on the audited combined historical financial information of Esso Exploration and Production Chad Inc ("EEPCI") and Esso Pipeline Investments Limited ("EPIL") (together, the "Exxon Target Companies") for the three years ended 31 December 2018, 31 December 2019 and 31 December 2020 (the "Exxon Target Companies' Financial Information"), set out in Part 7B "*Historical Financial Information of the Exxon Target Companies*" of Savannah Energy PLC's (the "Company") AIM admission document dated 30 December 2021 (the "Admission Document").

**Opinion on financial information**

In our opinion, the Exxon Target Companies' Financial Information gives, for the purposes of the Admission Document, a true and fair view of the state of affairs of the Exxon Target Companies as at the dates stated, and of the results, financial position, cash flows and changes in equity for the years then ended, in accordance with International Financial Reporting Standards adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union ("IFRS").

**Responsibilities**

The directors of the Company (the "Directors") are responsible for preparing the Exxon Target Companies' Financial Information in accordance with IFRS.

It is our responsibility to form an opinion on the Exxon Target Companies' Financial Information and to report our opinion to you.

**Basis of Preparation**

The Exxon Target Companies' Financial Information has been prepared for inclusion in the Admission Document on the basis of the accounting policies set out in note 2 to the Exxon Target Companies' Financial Information. This report is required by Paragraph (a) of Schedule Two to the AIM Rules for Companies and is given for the purposes of complying with that paragraph and for no other purpose.

**Basis of opinion**

We conducted our work in accordance with Standards of Investment Reporting issued by the Financial Reporting Council in the United Kingdom (the "FRC"). We are independent of the Exxon Target Companies in accordance with relevant ethical requirements. In the United Kingdom, this is the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the Exxon Target Companies' Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the Exxon Target Companies' circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Exxon Target Companies' Financial Information is free from material misstatement, whether caused by fraud or other irregularity or error.

**Conclusions relating to going concern**

We have not identified a material uncertainty related to events or conditions that, individually or collectively, may cast doubt on the ability of the Exxon Target Companies to continue as a going concern for a period of at least 12 months from the date of this report. We therefore conclude that the Directors' use of the going concern basis of accounting in the preparation of the Exxon Target Companies' Financial Information is appropriate.

**Declaration**

For the purposes of Paragraph (a) of Schedule Two of the AIM Rules for Companies, we are responsible for this report as part of the Admission Document and we declare, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import. This declaration is included in the Admission Document in compliance with Schedule Two of the AIM Rules for Companies.

Yours faithfully,

**Crowe U.K. LLP**
*Chartered Accountants*

## PART 7B

## HISTORICAL FINANCIAL INFORMATION OF THE EXXON TARGET COMPANIES

**Combined Statement of Comprehensive Income**
for the years ended 31 December

| | Note | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|---|
| Revenue | 6 | 133,468 | 241,636 | 320,401 |
| Cost of sales | 7 | (181,055) | (196,037) | (216,084) |
| **Gross (loss)/profit** | | (47,587) | 45,599 | 104,317 |
| Administrative and other operating expenses | 8 | (65,726) | (11,480) | (40,536) |
| Impairment | 13 | (471,693) | – | – |
| **Operating (loss)/profit** | | (585,006) | 34,119 | 63,781 |
| Finance income | 9 | 511 | 3,141 | 2,498 |
| Finance costs | 10 | (20,900) | (21,426) | (28,017) |
| Share of profit/(loss) from associates | 12 | 3,999 | 4,102 | (6,125) |
| **(Loss)/profit before tax** | | (601,396) | 19,936 | 32,137 |
| Current tax expense | 11 | – | (49,031) | (88,112) |
| Deferred tax credit | 11 | 360,092 | 35,291 | 50,210 |
| Tax credit/(expense) | | 360,092 | (13,740) | (37,902) |
| **(Loss)/profit after tax and total comprehensive (loss)/profit** | | **(241,304)** | **6,196** | **(5,765)** |

**Combined Statement of Financial Position**
as at 31 December

| | Note | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|---|
| **Assets** | | | | |
| **Non-current assets** | | | | |
| Property, plant and equipment | 13 | 200,242 | 737,864 | 796,123 |
| Investment in associates | 12 | 273,254 | 295,086 | 310,819 |
| Intangible assets | 14 | 2,103 | 2,528 | 3,096 |
| Deferred tax assets | 11 | 333,950 | 30,906 | 35,417 |
| Other non-current assets | | 135 | 137 | 43 |
| **Total non-current assets** | | **809,684** | **1,066,521** | **1,145,498** |
| **Current assets** | | | | |
| Inventory | 15 | 85,844 | 87,769 | 85,530 |
| Trade and other receivables | 16 | 185,743 | 170,053 | 147,500 |
| Cash at bank | 17 | 474 | 489 | 496 |
| **Total current assets** | | **272,061** | **258,311** | **233,526** |
| **Total assets** | | **1,081,745** | **1,324,832** | **1,379,024** |
| **Equity and Liabilities** | | | | |
| **Capital and Reserves** | | | | |
| Share capital | | 602,403 | 602,403 | 602,403 |
| Retained earnings | | (253,935) | (12,631) | (18,827) |
| **Total equity** | | **348,468** | **589,772** | **583,576** |
| **Non-current liabilities** | | | | |
| Deferred tax liabilities | 11 | 290,951 | 348,000 | 387,802 |
| Other payables | 18 | 314,124 | 284,158 | 302,918 |
| Decommissioning provisions | 19 | 104,011 | 56,818 | 54,586 |
| **Total non-current liabilities** | | **709,086** | **688,976** | **745,306** |
| **Current liabilities** | | | | |
| Trade and other payables | 18 | 24,191 | 46,084 | 50,142 |
| **Total current liabilities** | | **24,191** | **46,084** | **50,142** |
| **Total liabilities** | | **733,277** | **735,060** | **795,448** |
| **Total equity and liabilities** | | **1,081,745** | **1,324,832** | **1,379,024** |

**Combined Statement of Cash Flows**

for the years ended 31 December

| | Note | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|---|
| **Cash flows from operating activities**: | | | | |
| (Loss)/profit before tax | | (601,396) | 19,936 | 32,137 |
| Adjustments for: | | | | |
| Share of (profit)/loss from associates | | (3,999) | (4,102) | 6,125 |
| Depletion, depreciation and amortisation | | 114,851 | 97,819 | 121,133 |
| Impairment | | 471,693 | – | – |
| Inventories written-off | | 7,200 | 2,600 | 9,500 |
| Finance cost | | 20,632 | 19,774 | 23,774 |
| Taxation rebate/(payment) | | 15,484 | (49,844) | (116,002) |
| Operating cash flows before movements in working capital | | 24,465 | 86,183 | 76,667 |
| Net change in working capital | | (69,865) | (9,789) | (21,322) |
| **Net cash (used in)/generated from operating activities** | | (45,400) | 76,394 | 55,345 |
| **Cash flows from investing activities:** | | | | |
| Payments for property, plant and equipment | | (16,526) | (38,838) | (24,291) |
| Dividend received | | 25,831 | 19,835 | 18,764 |
| **Net cash provided by/(used in) investing activities** | | 9,305 | (19,003) | (5,527) |
| **Cash flows from financing activities**: | | | | |
| Interest paid on related party loan | | (17,038) | (17,542) | (20,403) |
| Repayment of related party loan | | – | (39,856) | (30,599) |
| Proceeds from related party loan | | 53,118 | – | – |
| **Net cash provided by/(used in) by financing activities** | | 36,080 | (57,398) | (51,002) |
| **Net decrease in cash and cash equivalents** | | (15) | (7) | (1,184) |
| **Cash and cash equivalents at beginning of year** | | 489 | 496 | 1,680 |
| **Cash and cash equivalents at end of year** | 17 | **474** | **489** | **496** |

**Combined Statement of Changes in Equity**

for the years ended 31 December

| | *Share Capital US$'000* | *Retained Earnings US$'000* | *Total Equity US$'000* |
|---|---|---|---|
| **Balance at 1 January 2018** | 602,403 | (13,062) | 589,341 |
| Loss for the year | – | (5,765) | (5,765) |
| **Total comprehensive loss for the year** | – | (5,765) | (5,765) |
| **Balance at 31 December 2018** | 602,403 | (18,827) | 583,576 |
| Loss for the year | – | 6,196 | 6,196 |
| **Total comprehensive loss for the year** | – | 6,196 | 6,196 |
| **Balance at 31 December 2019** | 602,403 | (12,631) | 589,772 |
| Loss for the year | – | (241,304) | (241,304) |
| **Total comprehensive loss for the year** | – | 241,304 | 241,304 |
| **Balance at 31 December 2020** | **602,403** | **(253,935)** | **348,468** |

## Notes to the Exxon Target Companies' Financial Information

### 1. General information

The Exxon Target Companies' Financial Information combines the audited historical financial information of both EEPCI and EPIL, collectively the "Exxon Target Companies".

EEPCI is a wholly owned subsidiary of Exxon Mobil Corporation. EEPCI holds a 40 per cent. interest in a joint arrangement – the Doba Oil Field Development Area ("Doba OFDA", "OFDA" or "Doba Oil Project") in Chad. EEPCI also acts as operator to the Doba Oil Project. EPIL is held by ExxonMobil International Holdings Inc. and Esso Exploration Holdings Inc. EPIL holds 41.06 per cent. and 40.19 per cent. interest in COTCo and TOTCo, respectively.

### 2. Basis of preparation

The Exxon Target Companies' Financial Information has been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets at the time of initial recognition.

***Statement of Compliance***

The Exxon Target Companies' Financial Information has been prepared on a basis that combines the results, assets, liabilities and cashflows of all entities making up the Exxon Target Companies, even though such entities did not historically form a legal group and therefore does not comply with the requirements of IFRS 10. The disclosure requirements of IFRS 7, IAS 7 paragraphs 44(a) to 44(e) and IAS 33 have also not been complied with. These have not been complied with due to the limited and immaterial value in which they offer the users of this document.

The Exxon Target Companies' Financial Information has been prepared in accordance with the requirements of the AIM Rules for Companies and in accordance with this basis of preparation. The basis of preparation describes how the Exxon Target Companies' Financial Information has been prepared in accordance with International Accounting Standards as adopted by the United Kingdom ("UK-adopted IAS") except as described below.

In preparing the Exxon Target Companies' Financial Information, certain accounting conventions commonly used for the preparation of historical financial information for inclusion in investment circulars as described in the Annexure to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements of historical financial information) issued by the Financial Reporting Council have been applied. The application of these conventions results in a material departure from IFRS as adopted by the UK: the Exxon Target Companies' Financial Information does not constitute a set of general-purpose financial statements under paragraph 2 of IAS 1 and consequently there is no explicit and unreserved statement of compliance with IFRS as contemplated by paragraph 16 of IAS 1.

In all other respects, IFRS as adopted by the UK has been applied. The significant accounting policies adopted in the preparation of the Historical Financial Information are set out in note 3. The policies have been consistently applied to all periods presented, unless otherwise stated.

***Basis of combination***

*Subsidiaries*

The combined Exxon Target Companies' Financial Information combine the financial statements of EEPCI and EPIL.

*Transactions eliminated upon consolidation*

Material intra-group transactions, balances, income and expenses are eliminated in full on combination.

## 3. Significant accounting policies

***Foreign currency translation***

Transactions entered into in a currency other than the functional currency are translated into the functional currency using the spot exchange rates prevailing at the dates of the transactions. At each reporting date, the monetary assets and liabilities of the Exxon Target Companies that are not in the functional currency of that entity are translated into the functional currency at exchange rates prevailing at the reporting date. The resulting exchange differences are recognised in the Statement of Comprehensive Income.

*Functional and presentation currency*

US Dollar is the functional currency of each entity of the Exxon Target Companies, due to it being the currency of the primary economic environment in which the Exxon Target Companies operate, based on the following facts:

- oil revenues are priced and invoiced in US Dollars;
- most of the expenses of the entities of the Exxon Target Companies are denominated in US Dollars; and
- the majority of funds raised from financing activities (debt or equity instruments) are generated in US Dollars.

***Revenue recognition***

The Exxon Target Companies are principally engaged in the exploration, development and production of crude oil. The Exxon Target Companies have generally concluded that it is the principal in its revenue arrangements, as it typically controls the goods or services before transferring them to the customer.

*Sales of crude oil*

Revenue from sales of crude oil is recognised at the point in time when control of the asset is transferred to the customer, generally on delivery of the processed crude oil at the delivery point. The normal credit term is 30 days upon delivery.

*Consideration payable to a customer*

The payment of the costs, claims, demands, liabilities and/or expenses suffered or incurred by the buyer under the oil contract (if any) has been recognised as a reduction of the transaction prices and, therefore, of revenue since the payment to the customer is not in exchange for distinct goods that the customers transfer to the Exxon Target Companies.

***Contract balances***

*Contract assets*

A contract asset is the right to consideration in exchange for goods or services transferred to the customer. If the Exxon Target Companies perform by transferring goods or services to a customer before the customer pays consideration or before payment is due, or not invoiced at the reporting date, a contract asset is recognised for the earned consideration that remains conditional.

*Trade receivables*

A receivable represents the Exxon Target Companies right to an amount of consideration that is unconditional (i.e. only the passage of time is required before payment of the consideration is due). Refer to accounting policies of financial assets under financial instruments – initial recognition and subsequent measurement.

***Oil and gas assets***

Expenditure on the construction, installation or completion of facilities such as process plant and the drilling of development wells is capitalised within oil and gas assets. When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or expensed in the period in which they are incurred, except for costs which qualify for capitalisation relating to producing asset additions, improvements or new developments. Development and producing assets are carried at cost less accumulated depreciation, depletion and accumulated impairment losses.

***Infrastructure assets and other property, plant and equipment***

Infrastructure assets and other property, plant and equipment are stated at cost less accumulated depreciation and any accumulated impairment losses. Cost includes expenditure that is directly attributable to the acquisition of the items.

***Depletion, depreciation and amortisation***

Depletion, depreciation and amortisation are provided at rates calculated to write each asset down to its estimated residual value over its expected useful life as follows:

| | *Years* |
|---|---|
| **Oil and gas assets** | |
| Production and development costs | Unit[1] |
| Geological and geophysical costs, production drilling costs and development drilling costs | Unit[1] |
| **Infrastructure assets** | |
| Pipeline and facilities | 5 – 20 |
| Equipment | 5 – 7 |
| **Other assets** | |
| Computers | 5 |
| Motor vehicles | 5 |
| Furniture and fixtures | 5 |
| **Intangible assets** | |
| Software | 5 – 20 |

1 Dependent on a unit-of-production using reserves.

Oil and gas assets are depleted on a unit-of-production basis over the total Proved Reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

***Investments in associates***

Associates are entities which the Exxon Target Companies have significant influence including representation on the Directors, but not control or joint control, over the financial and operating policies of the investee company.

Investments in associates are accounted for using the equity method, with the Exxon Target Companies' share of net assets being recognised on the Statement of Financial Position, being adjusted for changes in the Exxon Target Companies' share of net assets of the associates. The Statement of Comprehensive Income reflects the Exxon Target Companies' share of results of operations in the associates. The Exxon Target Companies also assess the investment for impairment and, if the carrying amount is greater than the expected recoverable amount, an impairment is recognised in the Statement of Comprehensive Income.

***Segmental analysis***

The Exxon Target Companies are primarily organised into one geographical operating segment, refer to note 5.

***Impairment***

*Property, plant and equipment*

At each reporting date, the Exxon Target Companies review the carrying amounts of its property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any).

The recoverable amount is the higher of fair value less costs to sell and value-in-use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than the carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in the Statement of Comprehensive Income.

Non-financial assets which have suffered an impairment are reviewed for possible reversal of the impairment at each reporting date. Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (cash-generating unit) in prior periods. A reversal of an impairment loss is recognised immediately in the Statement of Comprehensive Income.

***Financial assets***

*Other receivables*

Other receivables are measured at amortised cost using the effective interest method less any impairment.

*Impairment of financial assets*

The Exxon Target Companies recognise an allowance for expected credit loss ("ECL") for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Exxon Target Companies expect to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms (if any). ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit loss that results from default events that are possible within the next twelve months (a twelve-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit loss expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For most trade receivables, the Exxon Target Companies are required to follow a simplified approach in calculating ECLs if no significant financing component exists. Therefore, the Exxon Target Companies do not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date.

***Joint arrangements***

A joint arrangement is an arrangement over which two or more parties have joint control. Joint control exists when the Exxon Target Companies do not have the power, directly or indirectly, to solely govern the financial and operating policies of an entity. In assessing control, potential voting rights which are currently exercisable are taken into account. The Exxon Target Companies engage in oil exploration, development, production and distribution through unincorporated joint ventures or jointly controlled entities. The Exxon Target Companies account for their share of assets, liabilities, revenues and expenses of unincorporated joint arrangements as joint operations.

Interest in jointly controlled entities is accounted for using the equity method. Under the equity method, the investment is initially recognised at cost. The carrying amount of the investment is adjusted to recognise changes in the Exxon Target Companies' share of net assets of the venture since the acquisition date. The aggregated Statement of Comprehensive Income reflects the Exxon Target Companies' share of results of operations in the ventures.

***Financial liabilities and equity***

Debt and equity instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangement.

*Financial liabilities at FVTPL*

Financial liabilities are classified as at FVTPL when the financial liability is: (i) contingent consideration that may be paid by an acquirer as part of a business combination; (ii) held for trading; or (iii) designated as at FVTPL.

Financial liabilities at FVTPL are stated at fair value, with any gains or losses arising on remeasurement recognised in profit or loss. The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in the fair value adjustment line item in the statement of comprehensive income.

*Financial liabilities at amortised cost*

After initial recognition at fair value, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate ("EIR") method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process. Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in profit or loss.

*Equity instruments*

Equity instruments issued by the Exxon Target Companies are recorded at the fair value of the proceeds received or the fair value price at the date of issue, net of direct issue costs, which are recorded to share capital (nominal value) and share premium.

*Trade payables*

Trade payables are measured initially at fair value and subsequently measured at amortised cost.

***Taxation***

*Current tax*

The tax currently payable is based on assessable taxable income generated for the year. Taxable profit differs from profit as reported in the statement of comprehensive income because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The Exxon Target Companies' liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

*Deferred tax*

Deferred tax is recognised on differences between the carrying amounts of assets and liabilities in the Exxon Target Companies' Financial Information and the corresponding tax basis used in the computation of taxable profit and is accounted for using the statement of financial position liability method.

Deferred tax liabilities are generally recognised for all taxable temporary differences, and deferred tax assets are generally recognised for all deductible temporary differences to the extent that it is probable that taxable profits will be available against which those deductible temporary differences can be utilised.

Such assets and liabilities are not recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint ventures, except where the Exxon Target Companies is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered. Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realised, based on tax rates (and tax laws) that have been enacted or substantively enacted by the reporting date. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Exxon Target Companies expect, at the reporting date, to recover or to settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Exxon Target Companies intend to settle their current tax assets and liabilities on a net basis.

*Current and deferred tax for the year*

Current and deferred tax are recognised as an expense or income in profit or loss, except when they relate to items credited or debited directly to equity or other comprehensive income, in which case the tax is also recognised directly in equity or other comprehensive income, as appropriate.

***Inventories***

Inventories of oil and gas assets are stated at the lower of cost and net realisable values. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

Costs of crude oil includes costs of bringing the inventories to their present location and condition and is determined on a weighted average basis.

Lifting of offtake arrangements for crude oil produced in joint operations is such that it is not practicable for each participant to receive or sell its precise share of the overall production during the period. At each reporting date, the extent of underlift is recognised as an asset at the lower of the cost and net realisable value, while overlift is recognised as a liability. The net movement in underlift and overlift is recognised in the Statement of Comprehensive Income within Cost of sales.

***Cash at bank***

Cash at bank in the Statement of Financial Position comprises cash and cash equivalents, such as cash at banks and at hand and short-term deposits with an original maturity of three months or less. For the purpose of the Statement of Cash Flows, cash and cash equivalents consist of cash and cash equivalents as defined.

***Provisions***

*General*

Provisions are recognised when the Exxon Target Companies have a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are measured at the Exxon Target Companies' best estimate of the expenditure required to settle the obligation at the reporting date, considering the risks and uncertainties of the obligation, and are discounted to present value where the effect is material. Where discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost in the Statement of Comprehensive Income.

Provisions are not recognised for future operating losses. Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Where the Exxon Target Companies expect some or all of a provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset, but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the statement of profit or loss and other comprehensive income net of any reimbursement.

*Decommissioning liability*

The Exxon Target Companies recognise an initial decommissioning liability and an asset in Property, plant and equipment, if they have a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. The obligation generally arises when the asset is installed, or the ground/environment is disturbed at the location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related assets to the extent that it was incurred by the development/construction of the asset. Any decommissioning obligations that arise through the production of inventory are expensed as incurred. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to Property, plant and equipment.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to the Statement of Comprehensive Income. If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Exxon Target Companies consider whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the revised oil and gas asset net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense.

Over time, the discounted liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in the Statement of Profit or Loss and Other Comprehensive Income as a finance cost.

***Capital***

The capital structure of the Exxon Target Companies consists of equity attributable to the owners of EEPCI and EPIL, comprising issued capital and retained earnings.

*Share capital*

Share capital comprises issued capital in respect of issued and paid-up shares, at their par value.

***Retained earnings***

Retained earnings comprises the accumulated or deficit of earnings retained by the Exxon Target Companies.

The Exxon Target Companies' objective when managing capital is to maintain adequate financial flexibility to preserve their ability to meet financial obligations, both current and long-term, and to maintain an optimal capital structure to reduce the cost of capital. The capital structure of the Exxon Target Companies is managed and adjusted to reflect changes in economic conditions.

***Employee benefits***

*Defined contribution plan*

The retirement savings plan is a voluntary plan. The Exxon Target Companies and their employees respectively contribute up to 15 per cent. of the employees' base salary. Employees' contributions to the scheme are funded through payroll deductions while the Exxon Target Companies' contributions are charged to the Statement of Comprehensive Income in the year to which the contributions relate. Funds are bearing interest at 3.5 per cent. per year, which is the minimum return for insurance contracts under the CIMA (Conference Interafricaine des Marches d'Assurance) code. Savings are available at the definitive retirement date, but employees can request the withdrawal of part or the whole of their retirement savings plan as per the 2021 Collective Labour Agreement in certain permitted circumstances.

If an employee leaves either of the Exxon Target Companies within five years of commencing employment, the Exxon Target Companies' contribution is vested as follows:

- 4 years – 80 per cent.;
- 3 years – 60 per cent.;
- 2 years – 40 per cent.;

- 1 year – 20 per cent.; and
- Less than 1 year – 0 per cent.

The contribution is vested at 100 per cent. for employees having at least five years of service.

## 4. Critical accounting judgements and key sources of estimation uncertainty

In the application of the Exxon Target Companies' accounting policies, which are described above, judgements, estimates and assumptions are required to be made, about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of revision and future periods if the revision affects both current and future periods.

### *Key sources of estimation uncertainty*

*Income and deferred taxes*

Judgement is required to determine which types of arrangements are a tax on income in contrast to an operating cost. Judgement is also required in determining whether deferred income tax assets are recognised in the Statement of Financial Position. Deferred income tax assets, including those arising from un-utilised tax losses, require management to assess the likelihood that the entities within the Exxon Target Companies will generate sufficient taxable earnings in future periods, in order to utilise recognised deferred income tax assets.

The deferred tax assets presented in the Exxon Target Companies' Financial Information are based on estimated future taxable profits of the Exxon Target Companies. These estimates of future taxable income are based on projected cash flows from operations (which are impacted by production and sales volumes, oil prices, reserves, operating costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Exxon Target Companies to realise the net deferred income tax assets recorded at the reporting date could be impacted.

*Fair value measurement*

From time-to-time the Exxon Target Companies are required to determine the fair values of both financial and non-financial assets and liabilities, e.g. when the entity acquires a business, or where an entity measures the recoverable amount of an asset or cash-generating unit. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. The Exxon Target Companies use valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

*Fair value hierarchy*

Where the fair value of financial assets and financial liabilities recorded in the Statement of Financial Position cannot be derived from active markets, their fair value is determined using valuation techniques including the discounted cash flow model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgement is required in establishing fair values. The judgements include considerations of inputs such as liquidity risk, credit risk and volatility. The fair value of cash and cash equivalents, accounts receivable and accounts payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At each reporting period, the fair value of these balances approximated their carrying value due to their short-term to maturity.

*Decommissioning liabilities*

The Exxon Target Companies have decommissioning obligations in respect of their oil assets. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation.

The extent to which a provision is recognised requires management to make judgements on the legal and constructive obligations at the date of decommissioning, estimates of the restoration costs, timing of work, long-term inflation and discount rates to be applied. As a result, there could be significant adjustments to the provisions established which would affect future financial results. Changes to expected timing of cash outflows can materially change the decommissioning liability.

*Recoverability of oil assets*

Management is required to assess the Exxon Target Companies' oil assets for indicators of impairment. Management considers the Exxon Target Companies' latest development plans and business strategies and applies judgement in determining the appropriate cash-generating units for the purpose of applying the annual impairment assessment. Management compares the carrying value of these assets to the estimated net present value of the underlying oil and gas reserves and related future cash flows that could be generated from these reserves based upon estimates of future revenues, development costs and operating costs and applying a suitable post-tax discount rate. The reserve estimates are management's best estimates, taking into consideration independent evaluations of the proved and probable reserves attributable to the Exxon Target Companies' economic interests, using industry standard definitions and measurement techniques. Further details on the recoverability of oil assets are disclosed in note 13.

## 5. Segmental reporting

The Exxon Target Companies comply with IFRS 8: Operating Segments which requires operating segments to be identified on the basis of internal reports about the components of the Exxon Target Companies that are regularly reviewed by the Exxon Target Companies' management to allocate resources to the segments and to assess their performance.

The operations of the Exxon Target Companies comprise of oil production and transportation and related activities in Chad and Cameron.

## 6. Revenue

Set out below is the disaggregation of the Exxon Target Companies revenue from contracts with customers:

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Crude Oil sales | 133,468 | 241,636 | 320,401 |
| | **133,468** | **241,636** | **320,401** |

The Exxon Target Companies sell oil under sales and purchase agreements with various customers and revenue is recognised at a point in time, when the oil has been delivered to the customer, based on terms included within the sales contract.

All revenue is earned from the sale of crude oil.

## 7. Cost of sales

| | Audited Year ended 31 December 2020 US$'000 | Audited Year ended 31 December 2019 US$'000 | Audited Year ended 31 December 2018 US$'000 |
|---|---|---|---|
| Depreciation and depletion – oil and gas assets (note 13) | 113,737 | 96,212 | 120,214 |
| Royalties and similar fees | 3,984 | 5,041 | 26,140 |
| Facility operation and maintenance costs | 63,334 | 94,784 | 69,730 |
| | **181,055** | **196,037** | **216,084** |

Until May 2018, royalties on crude oil sales were paid-in-cash. Thereafter, royalties were paid-in-kind with production oil barrels.

## 8. Administrative and other operating expenses

| | Audited Year ended 31 December 2020 US$'000 | Audited Year ended 31 December 2019 US$'000 | Audited Year ended 31 December 2018 US$'000 |
|---|---|---|---|
| Net staff costs | 35,514 | 29,199 | 28,030 |
| Employee Benefits | 4,985 | 3,748 | 2,055 |
| Other expenses | 63,719 | 54,795 | 69,013 |
| Depletion and depreciation- other assets (note 13) | 434 | 736 | 562 |
| Capitalised expenses | (5,384) | (40,119) | (25,141) |
| Joint venture cutbacks to other joint operating partners | (62,467) | (71,712) | (68,207) |
| Administrative expenses | 28,925 | 34,833 | 34,224 |
| | **65,726** | **11,480** | **40,536** |

## 9. Finance income

| | Audited Year ended 31 December 2020 US$'000 | Audited Year ended 31 December 2019 US$'000 | Audited Year ended 31 December 2018 US$'000 |
|---|---|---|---|
| Bank deposit interest income | 6 | 2 | 18 |
| Related party interest income | 505 | 3,139 | 2,480 |
| | **511** | **3,141** | **2,498** |

## 10. Finance Costs

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Unwinding of decommissioning discount | 3,594 | 2,232 | 3,371 |
| Interest on related party loan | 17,038 | 17,542 | 20,403 |
| Other finance costs | 226 | 1,608 | 4,206 |
| Bank charges | 42 | 44 | 37 |
| | **20,900** | **21,426** | **28,017** |

## 11. Taxation

(a) ***Income tax***

The tax (credit)/expense recognised in the Statement of Comprehensive Income for the Exxon Target Companies are:

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Current tax | | | |
| – Current year | – | 49,031 | 88,112 |
| Deferred tax | | | |
| – Current year | (360,092) | (35,291) | (50,210) |
| **Total tax (credit)/expense for the year** | **(360,092)** | **13,740** | **37,902** |

Corporation tax is calculated at the applicable tax rate based on the estimated taxable profit/(loss) for the year. There was no current tax liability for the year ended 31 December 2020 as the Exxon Target Companies made an assessed loss. The current tax liabilities for the year ended 31 December 2019 and 31 December 2018 were US$4.0 million and US$4.8 million respectively.

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| The (credit)/expense for the year can be reconciled per the Statement of Comprehensive Income as follows: | | | |
| (Loss)/profit on ordinary activities before taxes | (601,396) | 19,936 | 32,137 |
| (Loss)/profit before taxation multiplied by the tax rate of 60.0% (2019: 60.0%, 2018: 60.0%) | (360,838) | 11,962 | 19,282 |
| Tax effects of: | | | |
| Expenses disallowed for taxation purposes | 341,354 | 47,052 | 122,683 |
| Other Chad corporate taxes | – | (9,983) | (53,853) |
| Tax losses carried forward | 19,484 | – | – |
| **Tax charge for the year** | **–** | **49,031** | **88,112** |

(b) ***Deferred tax***

The following are the major deferred tax asset/(liabilities) recognised by the Exxon Target Companies and movements thereon during the years under review.

| | *Property, plant and equipment US$'000* | *Other Provisions US$'000* | *Tax losses US$'000* | *Total US$'000* |
|---|---|---|---|---|
| Balance at 1 January 2018 | (438,527) | 35,932 | – | (402,595) |
| Credit/(expense) to Statement of Comprehensive Income | 50,725 | (515) | – | 50,210 |
| Balance at 31 December 2018 | (387,802) | 35,417 | – | (352,385) |
| Credit/(expense) to Statement of Comprehensive Income | 39,802 | (4,511) | – | 35,291 |
| Balance at 31 December 2019 | (348,000) | 30,906 | – | (317,094) |
| Credit/(expense) to Statement of Comprehensive Income | 57,049 | 283,559 | 19,484 | 360,092 |
| **Balance at 31 December 2020** | **(290,951)** | **314,465** | **19,484** | **42,998** |

Certain deferred tax assets and liabilities have been offset. The following is the analysis of the net deferred tax balances for financial reporting purposes:

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Deferred tax assets | 333,950 | 30,906 | 35,417 |
| Deferred tax liabilities | (290,951) | (348,000) | (387,802) |
| | **42,999** | **(317,094)** | **(352,385)** |

## 12. Investment in associate

| *Companies* | *2020, 2019 & 2018 Equity %* | *Country of incorporation* | *Principal activities* |
|---|---|---|---|
| TOTCo | 40.19% | Republic of Chad | Pipeline operation |
| COTCo | 41.06% | Republic of Cameroon | Pipeline operation |

The following tables summarise the information of the Exxon Target Companies significant associates, as adjusted for any differences in accounting policies:

***COTCo***

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Current assets | 184,927 | 171,026 | 134,068 |
| Non-current assets | 524,519 | 591,763 | 657,120 |
| Current Liabilities | 21,768 | 23,164 | 21,742 |
| Non-current liabilities | 65,839 | 67,340 | 62,858 |
| Equity | 621,839 | 672,285 | 706,588 |
| Share in equity | 41.06% | 41.06% | 41.06% |
| **Carrying amount of the investment** | **255,308** | **276,020** | **290,104** |

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Revenue | 163,101 | 171,461 | 149,198 |
| Operating expenses | (151,269) | (160,584) | (163,280) |
| Profit/(loss) before tax | 11,832 | 10,877 | (14,082) |
| Income tax expenses | (1,683) | (1,006) | 532 |
| Profit/(loss) for the year | 10,149 | 9,871 | (13,550) |
| Share in equity | 41.06% | 41.06% | 41.06% |
| **Share of profit/(loss)** | **4,167** | **4,052** | **(5,563)** |

***TOTCo***

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Current assets | 18,665 | 22,282 | 20,921 |
| Non-current assets | 66,885 | 74,958 | 83,288 |
| Current Liabilities | 6,240 | 13,077 | 13,329 |
| Non-current liabilities | 35,941 | 38,006 | 40,621 |
| Equity | 43,369 | 46,157 | 50,259 |
| Share in equity | 40.19% | 40.19% | 40.19% |
| **Carrying amount of the investment** | **17,429** | **18,549** | **20,198** |

| | Audited<br>Year ended<br>31 December<br>2020<br>US$'000 | Audited<br>Year ended<br>31 December<br>2019<br>US$'000 | Audited<br>Year ended<br>31 December<br>2018<br>US$'000 |
|---|---|---|---|
| Revenue | 19,958 | 20,374 | 19,312 |
| Operating expenses | (20,669) | (20,063) | (21,403) |
| (Loss)/profit before tax | (711) | 311 | (2,091) |
| Income tax expenses | 292 | (187) | 693 |
| (Loss)/profit for the year | (419) | 124 | (1,398) |
| Share in equity | 40.19% | 40.19% | 40.19% |
| **Share of (loss)/profit** | **(168)** | **50** | **(562)** |

| | Audited<br>As at<br>31 December<br>2020<br>US$'000 | Audited<br>As at<br>31 December<br>2019<br>US$'000 | Audited<br>As at<br>31 December<br>2018<br>US$'000 |
|---|---|---|---|
| Carrying amount of investment in associates | 272,737 | 294,569 | 310,302 |
| Goodwill | 517 | 517 | 517 |
| **Net carrying amount of investment in associates** | 273,254 | 295,086 | 310,819 |
| **Share of profit/(loss) from associate** | **3,999** | **4,102** | **(6,125)** |

| | US$'000 |
|---|---|
| Balance at 1 January 2018 (audited) | 335,708 |
| Share of net loss | (6,125) |
| Dividends received | (18,764) |
| Balance at 31 December 2018 (audited) | 310,819 |
| Share of net profit | 4,102 |
| Dividends received | (19,835) |
| Balance at 31 December 2019 (audited) | 295,086 |
| Share of net profit | 3,999 |
| Dividends received | (25,831) |
| **Balance at 31 December 2020 (audited)** | **273,254** |

## 13. Property, plant and equipment

| | Oil and gas assets US$'000 | Infra-structure assets US$'000 | Other assets US$'000 | Total US$'000 |
|---|---|---|---|---|
| **Cost** | | | | |
| Balance at 1 January 2018 | 2,997,064 | 24,060 | 29,355 | 3,050,479 |
| Additions | 21,124 | 229 | 332 | 21,685 |
| Disposals | (4) | (424) | (342) | (770) |
| Balance at 31 December 2018 (audited) | 3,018,184 | 23,865 | 29,345 | 3,071,394 |
| Additions | 37,659 | 856 | 226 | 38,741 |
| Disposals | (40) | (12) | (1,494) | (1,546) |
| Balance at 31 December 2019 (audited) | 3,055,803 | 24,709 | 28,077 | 3,108,589 |
| Additions | 4,117 | 430 | 696 | 5,243 |
| Disposals | – | (574) | (26) | (600) |
| Decommissioning remeasurement adjustment | 43,599 | – | – | 43,599 |
| **Balance at 31 December 2020 (audited)** | **3,103,519** | **24,565** | **28,747** | **3,156,831** |

| | Oil and gas assets US$'000 | Infra-structure assets US$'000 | Other assets US$'000 | Total US$'000 |
|---|---|---|---|---|
| **Accumulated depreciation** | | | | |
| Balance at 1 January 2018 | (2,110,817) | (16,903) | (26,775) | (2,154,495) |
| Depletion | (119,835) | (379) | (562) | (120,776) |
| Balance at 31 December 2018 (audited) | (2,230,652) | (17,282) | (27,337) | (2,275,271) |
| Depletion | (95,566) | (646) | (736) | (96,948) |
| Disposals | – | – | 1,494 | 1,494 |
| Balance at 31 December 2019 (audited) | (2,326,218) | (17,928) | (26,579) | (2,370,725) |
| Depletion | (113,040) | (697) | (434) | (114,171) |
| Impairment | (471,693) | – | – | (471,693) |
| **Balance at 31 December 2020 (audited)** | **(2,910,951)** | **(18,625)** | **(27,013)** | **(2,956,589)** |
| **Net book value** | | | | |
| **31 December 2018 (audited)** | **787,532** | **6,583** | **2,008** | **796,123** |
| **31 December 2019 (audited)** | **729,585** | **6,781** | **1,498** | **737,864** |
| **31 December 2020 (audited)** | **192,568** | **5,940** | **1,734** | **200,242** |

Oil and gas assets principally comprise the well and field development costs relating to Moundouli, Miandoum, Maikeri, Bolobo, Kome and Nya and Timbre in Chad. The Infrastructure assets principally comprise the Chadian midstream assets associated with the Exxon Target Companies' network of transportation pipelines, and processing facilities. Other assets typically include vehicles, office equipment and building improvements.

During 2020, the Exxon Target Companies undertook a more detailed technical assessment of the decommissioning provision cost estimates using an independent contractor. The associated decommissioning asset has been adjusted to reflect the new cost estimates. The new asset value will be depreciated over the remaining life of the respective assets.

The recoverable amount for impaired cash-generating unit was US$199.3 million was determined from the value-in-use calculations using cash flow projections. The project cash flows were discounted using a discount rate of 10.00 per cent.

The principal driver of the impairments and impairment reversal has been the projected oil price based on a range of long-term assumptions and management expectations of market developments including the following:

- Shorter of economic life or remaining unexpired concession period;
- Projected crude oil prices;
- Future capital and operating expenditures to be spent on the projects and their corresponding incremental reserves potentially to be recovered; and
- Current and forecasted market conditions.

The estimated future cash flows are reviewed at each reporting date, while the discount rate is reviewed annually based on the above factors and changes will eventually affect profit or loss through impairment charges or reversal of impairment.

### 14. Intangible Assets

| | *US$000* |
|---|---|
| **Cost** | |
| Balance at 1 January 2018 | 6,129 |
| Additions | 2,968 |
| Balance at 31 December 2018 (audited) | 9,097 |
| Additions | 303 |
| Balance at 31 December 2019 (audited) | 9,400 |
| Additions | 84 |
| Reclassification of assets | 171 |
| **Balance at 31 December 2020 (audited)** | **9,655** |
| **Accumulated depreciation** | |
| Balance at 1 January 2018 | (5,644) |
| Amortisation charge | (357) |
| Balance at 31 December 2018 (audited) | (6,001) |
| Amortisation charge | (871) |
| Balance at 31 December 2019 (audited) | (6,872) |
| Amortisation charge | (680) |
| **Balance at 31 December 2020 (audited)** | **(7,552)** |
| **Net book value** | |
| **Balance at 31 December 2018 (audited)** | **3,096** |
| **Balance at 31 December 2019 (audited)** | **2,528** |
| **Balance at 31 December 2020 (audited)** | **2,103** |

Intangible assets consist of software costs capitalised and amortised over their useful life.

### 15. Inventory

| | *Audited 2020 US$'000* | *Audited 2019 US$'000* | *Audited 2018 US$'000* |
|---|---|---|---|
| Spare parts | 73,217 | 83,356 | 85,530 |
| Crude Oil | 12,627 | 4,413 | – |
| | **85,844** | **87,769** | **85,530** |

During the year, the amount of inventories recognised as an expense in Cost of sales of the Exxon Target Companies was US$7.2 million (2019: US$2.6 million, 2018: US$9.5 million).

### 16. Trade and other receivables

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Trade receivables | 25,169 | 19,519 | 5,535 |
| Receivables from a joint arrangement | 19,800 | – | 18,000 |
| Other receivables | 3,718 | 7,131 | 15,248 |
| VAT receivables | 100 | 100 | – |
| Prepayments | 4,004 | 4,615 | 4,091 |
| Related party receivables | 132,952 | 138,688 | 104,626 |
| | **185,743** | **170,053** | **147,500** |

### 17. Cash at bank

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Petty Cash | 474 | 489 | 496 |
| | **474** | **489** | **496** |

The carrying amount of cash at bank approximates their fair value.

### 18. Trade and other payables

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| **Current trade and other payables** | | | |
| Trade payables | 4,599 | 10,427 | 7,665 |
| Accruals | 9,935 | 19,898 | 18,891 |
| VAT and Withholding tax payables | 2,944 | 4,394 | 625 |
| Current tax liability | – | 4,000 | 4,803 |
| Crude oil overlift | 2,425 | 4,439 | 9,362 |
| Notes payables | 1,517 | 1,077 | 4,313 |
| Other payables | 2,771 | 1,849 | 4,483 |
| | 24,191 | 46,084 | 50,142 |
| **Non-current other payables** | | | |
| Employee benefits | 65,517 | 57,121 | 50,670 |
| Related party loan payables | 248,607 | 227,037 | 252,248 |
| | 314,124 | 284,158 | 302,918 |
| | **338,315** | **330,242** | **353,060** |

## 19. Decommissioning provisions

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Decommissioning provision | 104,011 | 56,818 | 54,586 |
| | **104,011** | **56,818** | **54,586** |

Provision for decommissioning of oil and gas properties and other property, plant and equipment is recognised when there is an obligation to abandon a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. The Exxon Target Companies provide for the present value of estimated future decommissioning costs for certain of its oil and gas properties in Chad. These costs are updated annually based upon a review of both inflation and discount rates. Periodically, the Exxon Target Companies will undertake a more detailed technical assessment by both internal and external specialists as appropriate. The amounts shown are expected to crystallise in 2039.

The provision recognised is the present value of the obligations of the estimated future costs determined in accordance with current conditions and requirements.

A corresponding asset of an amount equivalent to the provision is also created. This asset is depreciated in accordance with the policy set out in note 3.

Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal events actually occur are uncertain. Because actual timing and net cash outflows can differ from estimates due to changes in laws, regulations, public expectations, technology, prices and conditions, the carrying amounts of provisions, together with the interest rate used in discounting the cash flows and inflation rate, are regularly reviewed and adjusted to take account of such changes.

| *Decommissioning provision* | *Audited 2020 US$'000* | *Audited 2019 US$'000* | *Audited 2018 US$'000* |
|---|---|---|---|
| As at 1 January | 56,818 | 54,586 | 51,215 |
| Adjustment due to change in assumptions (note 13) | 43,599 | – | – |
| Unwinding of decommissioning provision discount (note 10) | 3,594 | 2,232 | 3,371 |
| **As at 31 December** | **104,011** | **56,818** | **54,586** |

During the year ended 31 December 2020, the Exxon Target Companies undertook a detailed technical assessment of the decommissioning provision cost estimates. The assessments had a significant impact on the provision amount and hence an adjustment in the accounts for the financial year, ended 31 December 2020 was done.

## PART 7C

## UNAUDITED INTERIM FINANCIAL INFORMATION OF THE EXXON TARGET COMPANIES

### Combined Statement of Comprehensive Income

| | Note | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|---|
| Revenue | 1 | 122,110 | 54,986 |
| Cost of sales | 2 | (159,491) | (86,248) |
| **Gross loss** | | (37,381) | (31,262) |
| Administrative and other operating expenses | 3 | (20,227) | (17,780) |
| Impairment reversal | 6 | 267,109 | – |
| **Operating profit/(loss)** | | 209,501 | (49,042) |
| Finance income | | 165 | 581 |
| Finance costs | 4 | (11,783) | (10,407) |
| Share of profit in associates | 7 | 3,630 | 3,273 |
| **Profit/(loss) before tax** | | 201,513 | (55,595) |
| Current tax (expense)/credit | 5 | (29,383) | 11,118 |
| Deferred tax (expense)/credit | 5 | (94,153) | 21,296 |
| Tax (expense)/credit | 5 | (123,536) | 32,414 |
| **Profit/(loss) after tax and total comprehensive profit/(loss)** | | **77,977** | **(23,181)** |

**Combined Statement of Financial Position**

| | Note | *Unaudited 30 June 2021 US$'000* | *Audited 31 December 2020 US$'000* |
|---|---|---|---|
| **Assets** | | | |
| **Non-current assets** | | | |
| Property, plant and equipment | 6 | 330,252 | 200,242 |
| Investment in associates | 7 | 247,756 | 273,254 |
| Intangible Assets | | 1,766 | 2,103 |
| Deferred tax assets | | 148,208 | 333,950 |
| Other non-current assets | | 106 | 135 |
| **Total non-current assets** | | **728,088** | **809,684** |
| **Current assets** | | | |
| Inventory | 8 | 89,587 | 85,844 |
| Trade and other receivables | 9 | 301,089 | 185,743 |
| Cash at bank | 10 | 467 | 474 |
| **Total current assets** | | **391,143** | **272,061** |
| **Total assets** | | **1,119,231** | **1,081,745** |
| **Equity and Liabilities** | | | |
| **Capital and Reserves** | | | |
| Share capital | | 602,403 | 602,403 |
| Retained earnings | | (175,958) | (253,935) |
| **Total equity** | | **426,445** | **348,468** |
| **Non-current liabilities** | | | |
| Deferred tax liabilities | | 237,963 | 290,951 |
| Other payables | 11 | 337,014 | 314,124 |
| Decommissioning provisions | | 106,922 | 104,011 |
| **Total non-current liabilities** | | **681,899** | **709,086** |
| **Current liabilities** | | | |
| Trade and other payables | 11 | 10,887 | 24,191 |
| **Total current liabilities** | | **10,887** | **24,191** |
| **Total liabilities** | | **692,786** | **733,277** |
| **Total equity and liabilities** | | **1,119,231** | **1,081,745** |

**Combined Statement of Cash Flows**

| | Note | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|---|
| **Cash flows from operating activities**: | | | |
| Profit/(loss) before tax | | 201,513 | (55,595) |
| Adjustments for: | | | |
| Share of profit from associates | | (3,630) | (3,273) |
| Depletion, depreciation and amortisation | | 135,454 | 55,990 |
| Impairment reversal | | (267,109) | – |
| Finance cost | | 11,783 | 10,407 |
| Taxation rebate | | – | 7,117 |
| Operating cash flows before movements in working capital | | 78,011 | 14,646 |
| Net change in working capital | | (120,035) | 3,076 |
| **Net cash (used in)/generated from operating activities** | | (42,024) | 17,722 |
| **Cash flows from investing activities:** | | | |
| Payments for property, plant and equipment | | – | (10,465) |
| Dividend received | | 29,128 | – |
| **Net cash provided by/(used in) investing activities** | | 29,128 | (10,465) |
| **Cash flows from financing activities**: | | | |
| Interest paid on related party loan | | (7,878) | (7,835) |
| Proceeds from related party loan | | 20,767 | – |
| **Net cash provided by/(used in) financing activities** | | 12,889 | (7,835) |
| **Net decrease in cash and cash equivalents** | | (7) | (578) |
| **Cash and cash equivalents at beginning of period** | | 474 | 489 |
| **Cash and cash equivalents at end of period** | 10 | **467** | **(89)** |

**Combined Statement of Changes in Equity**

| | *Share Capital US$'000* | *Retained earnings US$'000* | *Total Equity US$'000* |
|---|---|---|---|
| **Balance at 1 January 2021 (audited)** | 602,403 | (253,935) | 348,468 |
| Profit for the period | – | 77,977 | 77,977 |
| **Total comprehensive loss for the period** | – | 77,977 | 77,977 |
| **Balance at 30 June 2021 (unaudited)** | **602,403** | **(175,958)** | **426,445** |

| | *Share Capital US$'000* | *Retained earnings US$'000* | *Total Equity US$'000* |
|---|---|---|---|
| **Balance at 1 January 2020 (audited)** | 602,403 | (12,631) | 589,772 |
| Loss for the period | – | (23,181) | (23,181) |
| **Total comprehensive loss for the period** | – | (23,181) | (23,181) |
| **Balance at 30 June 2020 (unaudited)** | **602,403** | **(35,812)** | **566,591** |

## Notes to the Exxon Target Companies' Interim Financial Information

### 1. Revenue

Set out below is the disaggregation of the Exxon Target Companies' revenue from contracts with customers:

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Crude Oil sales | 122,110 | 54,986 |
| | **122,110** | **54,986** |

All revenue is earned from the sale of crude oil.

### 2. Cost of sales

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Depletion and depreciation – oil and gas, and infrastructure assets | 134,903 | 55,420 |
| Royalties and similar fees | 1,041 | 1,901 |
| Facility operation and maintenance costs | 23,547 | 28,927 |
| | **159,491** | **86,248** |

### 3. Administrative and other operating expenses

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Net staff costs | 15,762 | 14,588 |
| Other expenses | 24,907 | 26,847 |
| Depreciation and amortisation | 551 | 570 |
| Capitalised expenses | (1,854) | (10,764) |
| JV Cutbacks to joint operation partners | (30,534) | (30,162) |
| Administrative expenses | 11,395 | 16,701 |
| | **20,227** | **17,780** |

## 4. Finance Cost

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Unwinding of decommissioning discount | 3,111 | 1,747 |
| Interest on related party loan | 7,878 | 7,835 |
| Other finance costs | 780 | 800 |
| Bank charges | 14 | 25 |
| | **11,783** | **10,407** |

## 5. Taxation

The tax credit recognised in the Statement of Comprehensive Income for the Exxon Target Companies is:

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Current tax | (29,383) | 11,118 |
| Deferred tax | (94,153) | 21,296 |
| | **(123,536)** | **32,414** |

## 6. Property, plant and equipment

| | *Oil and gas assets US$'000* | *Infrastructure assets US$'000* | *Other assets US$'000* | *Total US$'000* |
|---|---|---|---|---|
| **Cost** | | | | |
| Balance at 1 January 2020 (audited) | 3,055,803 | 24,709 | 28,077 | 3,108,589 |
| Additions | 4,117 | 430 | 696 | 5,243 |
| Disposals | – | (574) | (26) | (600) |
| Decommissioning remeasurement adjustment | 43,599 | – | – | 43,599 |
| Balance at 31 December 2020 (audited) | 3,103,519 | 24,565 | 28,747 | 3,156,831 |
| Additions | – | 52 | 16 | 68 |
| Disposals | (2,049) | – | – | (2,049) |
| Reclassification of assets | (2) | (111) | 113 | – |
| **Balance at 30 June 2021 (unaudited)** | **3,101,468** | **24,506** | **28,876** | **3,154,850** |
| **Accumulated depreciation** | | | | |
| Balance at 1 January 2020 (audited) | (2,326,218) | (17,928) | (26,579) | (2,370,725) |
| Depletion and depreciation | (113,040) | (697) | (434) | (114,171) |
| Impairment | (471,693) | – | – | (471,693) |
| Balance at 31 December 2020 (audited) | (2,910,951) | (18,625) | (27,013) | (2,956,589) |
| Depletion and depreciation | (134,392) | (511) | (215) | (135,118) |
| Impairment reversal | 267,109 | – | – | 267,109 |
| **Balance at 30 June 2021 (unaudited)** | **(2,778,234)** | **(19,136)** | **(27,228)** | **(2,824,598)** |
| **Net book value** | | | | |
| **31 December 2020 (audited)** | **192,568** | **5,940** | **1,734** | **200,242** |
| **30 June 2021 (unaudited)** | **323,234** | **5,370** | **1,648** | **330,252** |

## 7. Investment in associates

| | *US$'000* |
|---|---|
| Balance at 1 January 2020 (audited) | 295,086 |
| Share of net profit | 3,999 |
| Dividends received | (25,831) |
| Balance at 31 December 2020 (audited) | 273,254 |
| Share of net profit | 3,630 |
| Dividends received | (29,128) |
| **Balance at 30 June 2021 (unaudited)** | **247,756** |

## 8. Inventory

| | Unaudited 30 June 2021 US$'000 | Audited 31 December 2020 US$'000 |
|---|---|---|
| Spare parts | 73,342 | 73,217 |
| Crude oil | 16,245 | 12,627 |
| | **89,587** | **85,844** |

## 9. Trade and other receivables

| | Unaudited 30 June 2021 US$'000 | Audited 31 December 2020 US$'000 |
|---|---|---|
| Trade receivables | 2,620 | 25,169 |
| Receivables from a joint arrangement | 17,800 | 19,800 |
| Other receivables | 60,924 | 3,718 |
| VAT receivables | 75 | 100 |
| Intercompany receivable | 216,406 | 132,952 |
| Prepayments | 3,264 | 4,004 |
| | **301,089** | **185,743** |

## 10. Cash at bank

| | Unaudited 30 June 2021 US$'000 Unaudited | Audited 31 December 2020 US$'000 Audited |
|---|---|---|
| Cash and cash equivalents | 467 | 474 |
| | **467** | **474** |

## 11. Trade and other payables

| | Unaudited 30 June 2021 US$'000 | Audited 31 December 2020 US$'000 |
|---|---|---|
| **Current trade and other payables** | | |
| Trade payables | 4,628 | 4,599 |
| Accruals | 1,294 | 9,935 |
| VAT and Withholding tax payables | 1,166 | 2,944 |
| Crude oil overlift | 3,663 | 2,425 |
| Notes payable | – | 1,517 |
| Other payables | 136 | 2,771 |
| | 10,887 | 24,191 |
| **Non-current other payables** | | |
| Employee benefits | 67,640 | 65,516 |
| Related party loan payables | 269,374 | 248,608 |
| | 337,014 | 314,124 |
| | **347,901** | **338,315** |

PART 7D

# ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF THE PETRONAS TARGET COMPANIES

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30 December 2021

The Directors
Savannah Energy PLC
40 Bank Street
London E14 5NR

The Directors
Strand Hanson Limited
26 Mount Row
London W1K 3SQ

Dear Sirs and Madams,

## Introduction

We report on the audited consolidated historical financial information of PETRONAS Carigali Chad Exploration & Production Inc., PETRONAS Carigali (Chad EP) Inc., Doba Pipeline Investments Inc. and PETRONAS Chad Marketing Inc. (together, the "PETRONAS Target Companies") for the three years ended 31 December 2018, 31 December 2019 and 31 December 2020 (the "PETRONAS Target Companies' Financial Information"), set out in Part 7E "*Historical Financial Information of the PETRONAS Target Companies*" of Savannah Energy PLC's (the "Company") AIM admission document dated 30 December 2021 (the "Admission Document").

## Opinion on financial information

In our opinion, the PETRONAS Target Companies' Financial Information gives, for the purposes of the Admission Document, a true and fair view of the state of affairs of the PETRONAS Target Companies as at the dates stated, and of the results, financial position, cash flows and changes in equity for the years then ended, in accordance with International Financial Reporting Standards adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union ("IFRS").

## Responsibilities

The directors of the Company (the "Directors") are responsible for preparing the PETRONAS Target Companies' Financial Information in accordance with IFRS.

It is our responsibility to form an opinion on the PETRONAS Target Companies' Financial Information and to report our opinion to you.

**Basis of Preparation**

The PETRONAS Target Companies' Financial Information has been prepared for inclusion in the Admission Document on the basis of the accounting policies set out in note 2 to the PETRONAS Target Companies' Financial Information. This report is required by Paragraph (a) of Schedule Two to the AIM Rules for Companies and is given for the purposes of complying with that paragraph and for no other purpose.

**Basis of opinion**

We conducted our work in accordance with Standards of Investment Reporting issued by the Financial Reporting Council in the United Kingdom (the "FRC"). We are independent of the PETRONAS Target Companies in accordance with relevant ethical requirements. In the United Kingdom, this is the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the PETRONAS Target Companies' Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the PETRONAS Target Companies' circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the PETRONAS Target Companies' Financial Information is free from material misstatement, whether caused by fraud or other irregularity or error.

**Conclusions relating to going concern**

We have not identified a material uncertainty related to events or conditions that, individually or collectively, may cast doubt on the ability of the PETRONAS Target Companies to continue as a going concern for a period of at least 12 months from the date of this report. We therefore conclude that the Directors' use of the going concern basis of accounting in the preparation of the PETRONAS Target Companies' Financial Information is appropriate.

**Declaration**

For the purposes of Paragraph (a) of Schedule Two of the AIM Rules for Companies, we are responsible for this report as part of the Admission Document and we declare, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import. This declaration is included in the Admission Document in compliance with Schedule Two of the AIM Rules for Companies.

Yours faithfully,

**Crowe U.K. LLP**
*Chartered Accountants*

## PART 7E

## HISTORICAL FINANCIAL INFORMATION OF THE PETRONAS TARGET COMPANIES

**Consolidated Statement of Comprehensive Income**

| | Note | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|---|
| Revenue | 6 | 170,656 | 234,201 | 321,495 |
| Cost of sales | 7 | (153,211) | (143,235) | (171,148) |
| **Gross profit** | | 17,445 | 90,966 | 150,347 |
| Administrative and other operating expenses | 8 | (1,718) | (1,678) | (3,912) |
| (Impairment)/impairment reversal | 12 | (547,007) | (190,444) | 530,643 |
| **Operating (loss)/profit** | | (531,280) | (101,156) | 677,078 |
| Finance costs | 9 | (1,702) | (3,091) | (7,140) |
| Share of profit/(loss) associates | 11 | 3,512 | 2,976 | (4,480) |
| **(Loss)/profit before tax** | | (529,470) | (101,271) | 665,458 |
| Current tax expense | 10 | (27,831) | (45,219) | (92,088) |
| Deferred tax credit/(expense) | 10 | 279,443 | 131,457 | (300,258) |
| Tax credit/(expense) | 10 | 251,612 | 86,238 | (392,346) |
| **(Loss)/profit after tax and total comprehensive (loss)/profit** | | **(277,858)** | **(15,033)** | **273,112** |

**Consolidated Statement of Financial Position**

| | Note | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|---|
| **Assets** | | | | |
| **Non-current assets** | | | | |
| Investment in associates | 11 | 149,324 | 200,419 | 193,775 |
| Property, plant and equipment | 12 | 162,897 | 635,549 | 859,189 |
| Deferred tax assets | 10 | 28,382 | – | – |
| **Total non-current assets** | | **340,603** | **835,968** | **1,052,964** |
| **Current assets** | | | | |
| Inventory | 13 | – | 8,869 | 15,469 |
| Trade and other receivables | 14 | 74,328 | 39,086 | 35,938 |
| Cash at bank | 15 | 14,247 | 35,620 | 29,182 |
| **Total current assets** | | **88,575** | **83,575** | **80,589** |
| **Total assets** | | 429,178 | 919,543 | 1,133,553 |
| **Equity and liabilities** | | | | |
| **Capital and reserves** | | | | |
| Share capital | 16 | – | – | – |
| Retained earnings | | 224,942 | 527,800 | 612,833 |
| **Total equity** | | **224,942** | **527,800** | **612,833** |
| **Non-current liabilities** | | | | |
| Deferred tax liabilities | 10 | 495 | 251,556 | 383,013 |
| Decommissioning provisions | 18 | 194,135 | 138,977 | 136,360 |
| **Total non-current liabilities** | | **194,630** | **390,533** | **519,373** |
| **Current liabilities** | | | | |
| Trade and other payables | 17 | 6,780 | 1,210 | 1,347 |
| Tax liabilities | | 2,826 | – | – |
| **Total current liabilities** | | **9,606** | **1,210** | **1,347** |
| **Total liabilities** | | **204,236** | **391,743** | **520,720** |
| **Total equity and liabilities** | | **429,178** | **919,543** | **1,133,553** |

**Consolidated Statement of Cash Flows**

| | Note | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|---|
| **Cash flows from operating activities:** | | | | |
| (Loss)/profit before tax | | (529,470) | (101,271) | 665,458 |
| Adjustments for: | | | | |
| Share of (profit)/loss from associates | | (3,512) | (2,976) | 4,480 |
| Depletion | | 44,375 | 53,926 | 23,377 |
| Net impairment/(reversal) on property, plant and equipment | | 533,210 | 190,444 | (530,643) |
| Inventories written-off | | 13,797 | – | – |
| Finance cost | | 1,702 | 3,091 | 7,140 |
| Taxation paid | | (23,261) | (41,908) | (113,875) |
| Operating cash flows before movements in working capital | | 36,841 | 101,306 | 55,937 |
| Net change in working capital | | (35,735) | 2,906 | 33,393 |
| **Net cash generated from operating activities** | | 1,106 | 104,212 | 89,330 |
| **Cash flows from investing activities:** | | | | |
| Payments for property, plant and equipment | | (16,233) | (42,199) | (20,361) |
| Dividend received | | 18,754 | 14,425 | 13,660 |
| **Net cash provided by/(used in) investing activities** | | 2,521 | (27,774) | (6,701) |
| **Cash flows from financing activities:** | | | | |
| Dividends paid | | (25,000) | (70,000) | (11,841) |
| Interest paid on shareholder's loan | | – | – | (4,880) |
| Repayment of shareholder's loan | | – | – | (80,000) |
| **Net cash used in by financing activities** | | (25,000) | (70,000) | (96,721) |
| **Net (decrease)/increase in cash and cash equivalents** | | (21,373) | 6,438 | (14,092) |
| **Cash and cash equivalents at beginning of year** | | 35,620 | 29,182 | 43,274 |
| **Cash and cash equivalents at end of year** | 15 | **14,247** | **35,620** | **29,182** |

**Consolidated Statement of Changes in Equity**

| | *Share capital US$'000* | *Retained earnings US$'000* | *Total US$'000* |
|---|---|---|---|
| Balance at 1 January 2018 | – | 351,562 | 351,562 |
| Profit for the year | – | 273,112 | 273,112 |
| **Total comprehensive profit for the year** | – | 273,112 | 273,112 |
| **Transactions with shareholders:** | | | |
| Dividend paid | – | (11,841) | (11,841) |
| **Balance at 31 December 2018 (audited)** | – | 612,833 | 612,833 |
| Loss for the year | – | (15,033) | (15,033) |
| **Total comprehensive loss for the year** | – | (15,033) | (15,033) |
| **Transactions with shareholders:** | | | |
| Dividend paid | – | (70,000) | (70,000) |
| **Balance at 31 December 2019 (audited)** | – | 527,800 | 527,800 |
| Loss for the year | – | (277,858) | (277,858) |
| **Total comprehensive loss for the year** | – | (277,858) | (277,858) |
| **Transactions with shareholders:** | | | |
| Dividend paid | – | (25,000) | (25,000) |
| **Balance at 31 December 2020 (audited)** | **–** | **224,942** | **224,942** |

**Notes to the PETRONAS Target Companies' Financial Information**

## 1. General information

The PETRONAS Target Companies' Historical Financial Information consolidates PCCEPI and its three wholly owned subsidiaries (collectively the "PETRONAS Target Companies"):

- PC Chad, which holds a 35 per cent. participating interest in the Doba Oil Field Development Area;
- Doba Pipeline, which holds a 29.77 per cent. shareholding interest in COTCo and a 30.16 per cent. shareholding interest in TOTCo, each of which own and operate certain sections of the Chad-Cameroon Pipeline: and
- PC Marketing, which markets PC Chad's offtake volumes from the Doba Oil Field Development Area.

## 2. Basis of preparation

The PETRONAS Target Companies' Financial Information has been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets at the time of initial recognition.

### *Statement of Compliance*

The PETRONAS Target Companies constitute a separate legal group. As a result, the consolidated PETRONAS Target Companies' Financial Information for the three years ended 31 December 2018, 31 December 2019 and 31 December 2020 has been prepared on a basis that consolidates the results, assets and liabilities and cashflows of the four entities comprising the PETRONAS Target Companies.

The PETRONAS Target Companies' Financial Information has been prepared in accordance with the requirements of the AIM Rules for Companies and in accordance with this basis of preparation. The basis of preparation describes how the PETRONAS Target Companies' Financial Information has been prepared in accordance with International Financial Reporting Standards as adopted by the United Kingdom ("UK-adopted IFRS") except as described below. The PETRONAS Target Companies' Financial Information has also been prepared in accordance with the relevant requirements of and Malaysian Financial Reporting Standards ("MFRS").

In preparing the PETRONAS Target Companies' Financial Information, certain accounting conventions commonly used for the preparation of historical financial information for inclusion in investment circulars as described in the Annexure to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements of historical financial information) issued by the Financial Reporting Council have been applied. The application of these conventions results in a material departure from IFRS as adopted by the UK: the PETRONAS Target Companies' Financial Information does not constitute a set of general-purpose financial statements under paragraph 2 of IAS 1 and consequently there is no explicit and unreserved statement of compliance with IFRS as contemplated by paragraph 16 of IAS 1.

In all other respects, IFRS as adopted by the UK has been applied. The significant accounting policies adopted in the preparation of the PETRONAS Target Companies' Financial Information are set out in note 3. The policies have been consistently applied to all periods presented, unless otherwise stated.

### *Basis of consolidation*

*Subsidiaries*

The consolidated PETRONAS Target Companies' Financial Information incorporate the financial information of the PCCEPI and its subsidiaries.

Control is achieved when the PETRONAS Target Companies are exposed, or have rights, to variable returns from their involvement with the investee and have the ability to affect those returns through their power over the investee. Specifically, PCCEPI controls an investee if, and only if, the PCCEPI has:

- power over the investee (i.e. existing rights that give it the current ability to direct the relevant activities of the investee);
- exposure, or rights, to variable returns from its involvement with the investee; and
- the ability to use its power over the investee to affect its returns.

Generally, there is a presumption that a majority of voting rights result in control. To support this presumption and when PCCEPI has less than a majority of the voting or similar rights of an investee, PCCEPI considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- the contractual arrangement with the other vote holders of the investee;
- rights arising from other contractual arrangements; and
- PCCEPI voting rights and potential voting rights.

PCCEPI re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when PCCEPI obtains control over the subsidiary and are included in the consolidated financial information from the date PCCEPI gains control until the date PCCEPI ceases to control the subsidiary.

See note 1 for the companies that have been consolidated within the PETRONAS Target Companies Financial Information.

*Transactions eliminated upon consolidation*

Where necessary, adjustments are made to the financial information of subsidiaries to bring their accounting policies into line with those used by other members of the PETRONAS Target Companies. All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

**3. Significant accounting policies**

***Foreign currency translation***

*Transactions and balances*

Transactions entered into in a currency other than the functional currency are translated into the functional currency using the spot exchange rates prevailing at the dates of the transactions. At each reporting date, the monetary assets and liabilities of the PETRONAS Target Companies' entities that are not in the functional currency of that entity are translated into the functional currency at exchange rates prevailing at the reporting date. The resulting exchange differences are recognised in the Statement of Comprehensive Income.

*Functional and presentation currency*

US Dollar is the functional currency of each entity of the PETRONAS Target Companies due to it being the currency of the primary economic environment in which the PETRONAS Target Companies operate, based on the following facts:

- oil reserves are priced and invoiced in US Dollars;
- most of the expenses of the entities of the PETRONAS Target Companies are denominated in US Dollars; and
- the majority of funds raised from financing activities (debt or equity instruments) are generated in US Dollars.

***Revenue recognition***

The PETRONAS Target Companies are principally engaged in the exploration, development and production of crude oil. The PETRONAS Target Companies have generally concluded that they are the principal in their revenue arrangements, as they typically control the goods or services before transferring them to the customer.

*Sales of crude oil*

Revenue from sales of crude oil is recognised at the point in time when control of the asset is transferred to the customer, generally on delivery of the processed crude at the delivery point. The normal credit term is 30 days upon delivery.

*Consideration payable to a customer*

The payment of the costs, claims, demands, liabilities and/or expenses suffered or incurred by the buyer under the gas contract (if any) has been recognised as a reduction of the transaction prices and, therefore, of revenue since the payment to the customer is not in exchange for distinct goods that the customers transfer to the PETRONAS Target Companies.

***Contract balances***

*Contract assets*

A contract asset is the right to consideration in exchange for goods or services transferred to the customer. If the PETRONAS Target Companies perform by transferring goods or services to a customer before the customer pays consideration, or before payment is due, or not invoiced at the reporting date, a contract asset is recognised for the earned consideration that remains conditional.

*Trade receivables*

A receivable represents the PETRONAS Target Companies' right to an amount of consideration that is unconditional (i.e. only the passage of time is required before payment of the consideration is due). Refer to accounting policies of financial assets under financial instruments – initial recognition and subsequent measurement.

*Contract liabilities*

A contract liability is the obligation to transfer goods or services to a customer for which the PETRONAS Target Companies have received consideration (or an amount of consideration is due) from the customer. If a customer pays consideration before the PETRONAS Target Companies transfer goods or services to the customer, a contract liability is recognised when the payment is made, or the payment is due (whichever is earlier). Contract liabilities are recognised as revenue when the PETRONAS Target Companies perform under the contract.

***Oil and gas assets***

Expenditure on the construction, installation or completion of facilities such as process plant and the drilling of development wells is capitalised within oil and gas assets. When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or expensed in the period in which they are incurred, except for costs which qualify for capitalisation relating to producing asset additions, improvements or new developments. Development and producing assets are carried at cost less accumulated depreciation, depletion and accumulated impairment losses.

Projects-in-progress are stated at cost less accumulated impairment losses and are not depreciated.

***Depletion and depreciation***

Depletion and depreciation is provided at rates calculated to write each asset down to its estimated residual value over its expected useful life as follows:

| | *Years* |
|---|---|
| **Oil and gas assets** | |
| Producing oil and gas properties | Unit[1] |
| Development costs | Unit[2] |

[1] Dependent on a unit-of-production using Proved Reserves.

[2] Dependent on a total proved developed reserves basis.

Oil and gas assets are depleted on a unit-of-production basis over the total Proved Reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

***Investments in associates***

Associates are entities which the PETRONAS Target Companies have significant influence, including representation on the Board of Directors, but not control or joint control, over the financial and operating policies of the investee company.

Investments in associates are accounted for using the equity method, with the PETRONAS Target Companies' share of net assets being recognised on the Statement of Financial Position, being adjusted for changes in the PETRONAS Target Companies' share of net assets of the associates. The Statement of Comprehensive Income reflects the PETRONAS Target Companies' share of results of operations in the associates. The PETRONAS Target Companies also assesses the investment for impairment and if the carrying amount is greater than the expected recoverable amount, an impairment is recognised in the Statement of Comprehensive Income.

***Segmental analysis***

The PETRONAS Target Companies are primarily organised into one geographical operating segment, refer to note 5.

***Impairment***

*Property, plant and equipment*

At each reporting date, the PETRONAS Target Companies review the carrying amounts of their property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any).

The recoverable amount is the higher of fair value less costs to sell and value-in-use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than the carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in the Statement of Comprehensive Income.

Non-financial assets which have suffered an impairment are reviewed for possible reversal of the impairment at each reporting date. Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (cash-generating unit) in prior periods. A reversal of an impairment loss is recognised immediately in the Statement of Comprehensive Income.

***Financial assets***

*Other receivables*

Other receivables are measured at amortised cost using the effective interest method, less any impairment.

*Impairment of financial assets*

The PETRONAS Target Companies recognise an allowance for expected credit loss ("ECL") for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the PETRONAS Target Companies expect to receive, discounted at an approximation of the original effective interest rate.

The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms (if any). ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit loss that results from default events that are possible within the next twelve months (a twelve-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit loss expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For most trade receivables, the PETRONAS Target Companies are required to follow a simplified approach in calculating ECLs if no significant financing component exists. Therefore, the PETRONAS Target Companies do not track changes in credit risk, but instead recognise a loss allowance based on lifetime ECLs at each reporting date.

***Joint arrangements***

A joint arrangement is an arrangement over which two or more parties have joint control. Joint control exists when the PETRONAS Target Companies do not have the power, directly or indirectly, to solely govern the financial and operating policies of an entity. In assessing control, potential voting rights which are currently exercisable are taken into account. The PETRONAS Target Companies are engaged in oil exploration, development, production and distribution through unincorporated joint ventures or jointly controlled entities. The PETRONAS Target Companies account for their share of assets, liabilities, revenues and expenses of unincorporated joint arrangements as joint operations.

Interest in jointly controlled entities is accounted for using the equity method. Under the equity method, the investment is initially recognised at cost. The carrying amount of the investment is adjusted to recognise changes in the PETRONAS Target Companies' share of net assets of the venture since the acquisition date. The aggregated Statement of Comprehensive Income reflects the PETRONAS Target Companies' share of results of operations in the ventures.

***Financial liabilities and equity***

Debt and equity instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangement.

*Financial liabilities at FVTPL*

Financial liabilities are classified as at FVTPL when the financial liability is: (i) contingent consideration that may be paid by an acquirer as part of a business combination; (ii) held for trading; or (iii) designated as at FVTPL.

Financial liabilities at FVTPL are stated at fair value, with any gains or losses arising on remeasurement recognised in profit or loss. The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in the fair value adjustment line item in the statement of comprehensive income.

*Financial liabilities at amortised cost*

After initial recognition at fair value, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate ("EIR") method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process. Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in profit or loss.

*Equity instruments*

Equity instruments issued by the PETRONAS Target Companies are recorded at the fair value of the proceeds received or the fair value price at the date of issue, net of direct issue costs, which are recorded to share capital (nominal value) and share premium.

*Trade payables*

Trade payables are measured at fair value and subsequently measured at amortised cost.

***Taxation***

*Current tax*

The tax currently payable is based on assessable taxable income generated for the year. Taxable profit differs from profit as reported in the Statement of Comprehensive Income because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The PETRONAS Target Companies' liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

*Deferred tax*

Deferred tax is recognised on differences between the carrying amounts of assets and liabilities in the PETRONAS Target Companies' Financial Information and the corresponding tax basis used in the computation of taxable profit and is accounted for using the statement of financial position liability method.

Deferred tax liabilities are generally recognised for all taxable temporary differences, and deferred tax assets are generally recognised for all deductible temporary differences to the extent that it is probable that taxable profits will be available against which those deductible temporary differences can be utilised.

Such assets and liabilities are not recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint ventures, except where the PETRONAS Target Companies are able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered. Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realised, based on tax rates (and tax laws) that have been enacted or substantively enacted by the statement of financial position date. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the PETRONAS Target Companies expect, at the reporting date, to recover or to settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the PETRONAS Target Companies intend to settle its current tax assets and liabilities on a net basis.

*Current and deferred tax for the year*

Current and deferred tax are recognised as an expense or income in profit or loss, except when they relate to items credited or debited directly to equity or other comprehensive income, in which case the tax is also recognised directly in equity or other comprehensive income, as appropriate.

***Inventories***

Inventories of oil and gas assets are stated at the lower of cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

Costs of crude oil includes costs of bringing the inventories to their present location and condition and is determined on a weighted average basis.

Lifting of offtake arrangements for crude oil produced in joint operations is such that it is not practicable for each participant to receive or sell its precise share of the overall production during the period. At each reporting date, the extent of underlift is recognised as an asset at the lower of the cost and net realisable value, while overlift is recognised as a liability. The net movement in underlift and overlift is recognised in the Statement of Comprehensive Income within Cost of sales.

***Cash at bank***

Cash at bank in the Statement of Financial Position comprise cash and cash equivalents, such as cash at banks and at hand and short-term deposits with an original maturity of three months or less. For the purpose of the Statement of Cash Flows, cash and cash equivalents consist of cash and cash equivalents as defined.

***Provisions***

*General*

Provisions are recognised when the PETRONAS Target Companies have a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are measured at the PETRONAS Target Companies' best estimate of the expenditure required to settle the obligation at the reporting date, considering the risks and uncertainties of the obligation, and are discounted to present value where the effect is material. Where discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost in the Statement of Comprehensive Income.

Provisions are not recognised for future operating losses. Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Where the PETRONAS Target Companies expect some or all of a provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset, but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the Statement of Profit or Loss and Other Comprehensive Income net of any reimbursement.

*Decommissioning liability*

The PETRONAS Target Companies recognise an initial decommissioning liability and an asset in Property, plant and equipment, if it has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. The obligation generally arises when the asset is installed, or the ground/environment is disturbed at the location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related assets to the extent that it was incurred by the development/construction of the asset. Any decommissioning obligations that arise through the production of inventory are expensed as incurred. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to Property, plant and equipment.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to the Statement of Comprehensive Income. If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the PETRONAS Target Companies consider whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the revised oil and gas asset net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense.

Over time, the discounted liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in the Profit or Loss and Other Comprehensive Income as a finance cost.

***Capital***

The capital structure of the PETRONAS Target Companies consist of equity attributable to the owners of PCCEPI, comprising issued capital and retained earnings.

*Share capital*
Share capital comprises issued capital in respect of issued and paid-up shares, at their par value.

*Retained earnings*
Retained earnings comprises the accumulated or deficit of earnings retained by the PETRONAS Target Companies.

The PETRONAS Target Companies' objective when managing capital is to maintain adequate financial flexibility to preserve its ability to meet financial obligations, both current and long term, and to maintain an optimal capital structure to reduce the cost of capital. The capital structure of the PETRONAS Target Companies is managed and adjusted to reflect changes in economic conditions.

## 4. Critical accounting judgements and key sources of estimation uncertainty

In the application of the PETRONAS Target Companies' accounting policies, which are described above, judgements, estimates and assumptions are required to be made, about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of revision and future periods if the revision affects both current and future periods.

### *Key sources of estimation uncertainty*

*Income and deferred taxes*
Judgement is required to determine which types of arrangements are a tax on income in contrast to an operating cost. Judgement is also required in determining whether deferred income tax assets are recognised in the statement of financial position. Deferred income tax assets, including those arising from un-utilised tax losses, require management to assess the likelihood that the entities within the PETRONAS Target Companies will generate sufficient taxable earnings in future periods, in order to utilise recognised deferred income tax assets.

The deferred tax assets presented in the combined financial information are based on estimated future taxable profits of the PETRONAS Target Companies. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil prices, reserves, operating costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the PETRONAS Target Companies to realise the net deferred income tax assets recorded at the reporting date could be impacted.

*Fair value measurement*
From time-to-time the PETRONAS Target Companies are required to determine the fair values of both financial and non-financial assets and liabilities, e.g. when the entity acquires a business, or where an entity measures the recoverable amount of an asset or cash-generating unit. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. The PETRONAS Target Companies use valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

*Fair value hierarchy*

Where the fair value of financial assets and financial liabilities recorded in the Statement of Financial Position cannot be derived from active markets, their fair value is determined using valuation techniques including the discounted cash flow model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgement is required in establishing fair values. The judgements include considerations of inputs such as liquidity risk, credit risk and volatility. The fair value of cash and cash equivalents, accounts receivable and accounts payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At each reporting period presented, the fair value of these balances approximated their carrying value due to their short term to maturity.

*Decommissioning liabilities*

The PETRONAS Target Companies have decommissioning obligations in respect of their oil assets. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation.

The extent to which a provision is recognised requires management to make judgements on the legal and constructive obligations at the date of decommissioning, estimates of the restoration costs, timing of work, long-term inflation and discount rates to be applied. As a result, there could be significant adjustments to the provisions established which would affect future financial results. Changes to expected timing of cash outflows can materially change the decommissioning liability.

*Recoverability of oil assets*

Management is required to assess the PETRONAS Target Companies' oil assets for indicators of impairment. Management considers the PETRONAS Target Companies' latest development plans and business strategies and applies judgement in determining the appropriate cash-generating units for the purpose of applying the annual impairment assessment. Management compares the carrying value of these assets to the estimated net present value of the underlying oil and gas reserves and related future cash flows that could be generated from these reserves based upon estimates of future revenues, development costs and operating costs and applying a suitable post-tax discount rate. The reserve estimates are management's best estimates, taking into consideration independent evaluations of the proved and probable reserves attributable to the PETRONAS Target Companies' economic interests using industry standard definitions and measurement techniques. Further details on the recoverability of oil assets are disclosed in note 12.

## 5. Segmental reporting

The PETRONAS Target Companies comply with IFRS 8: Operating Segments which requires operating segments to be identified on the basis of internal reports about the components of the PETRONAS Target Companies that are regularly reviewed by the PETRONAS Target Companies' management to allocate resources to the segments and to assess their performance.

The operations of the PETRONAS Target Companies comprise one class of business, being oil production and transportation and related activities in Chad and Cameroon.

## 6. Revenue

Set out below is the disaggregation of the PETRONAS Target Companies' revenue from contracts with customers:

| | *Audited year ended 31 December 2020 US$'000* | *Audited year ended 31 December 2019 US$'000* | *Audited year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Oil sales | 170,656 | 234,201 | 321,495 |
| | **170,656** | **234,201** | **321,495** |

The PETRONAS Target Companies sell oil under sales and purchase agreements with various customers and revenue is recognised at a point in time, when the oil has been delivered to the customer, based on terms included within the sales contract.

All revenue is earned from the sale of crude oil and the primary geographical market where the crude oil is sold is the United Kingdom. There are no variable elements in consideration, obligation for returns or refunds nor warrant in the provision of goods by the PETRONAS Target Companies.

## 7. Cost of sales

| | *Audited year ended 31 December 2020 US$'000* | *Audited year ended 31 December 2019 US$'000* | *Audited year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Depreciation and depletion – oil and gas assets (note 12) | 44,375 | 53,926 | 23,377 |
| Facility operation and maintenance costs | 83,310 | 61,772 | 91,850 |
| Royalties | – | – | 31,667 |
| Pipeline tariffs | 12,763 | 14,032 | 17,957 |
| Export duties | 4,370 | 5,184 | 6,297 |
| Other | 8,393 | 8,321 | – |
| | **153,211** | **143,235** | **171,148** |

Until May 2018 royalties on crude oil sales were paid in cash. Thereafter, royalties were paid-in-kind with production oil barrels.

## 8. Administrative and other operating expenses

| | *Audited year ended 31 December 2020 US$'000* | *Audited year ended 31 December 2019 US$'000* | *Audited year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Selling and marketing expenses | 339 | 339 | 839 |
| General and administrative expenses | 1,154 | 1,193 | 3,018 |
| Other | 225 | 146 | 55 |
| | **1,718** | **1,678** | **3,912** |

## 9. Finance costs

| | Audited year ended 31 December 2020 US$'000 | Audited year ended 31 December 2019 US$'000 | Audited year ended 31 December 2018 US$'000 |
|---|---|---|---|
| Unwinding of decommissioning provision | 1,702 | 3,090 | 4,072 |
| Interest on related party loan | – | – | 3,068 |
| Other finance costs | – | 1 | – |
| | **1,702** | **3,091** | **7,140** |

## 10. Taxation

(a) ***Income tax***

The tax (credit)/expense recognised in the Statement of Comprehensive Income for the PETRONAS Target Companies is:

| | Audited year ended 31 December 2020 US$'000 | Audited year ended 31 December 2019 US$'000 | Audited year ended 31 December 2018 US$'000 |
|---|---|---|---|
| Current tax | | | |
| – Current year | 30,014 | 54,277 | 96,345 |
| – Adjustments in respect of prior years | (2,183) | (9,058) | (4,257) |
| | 27,831 | 45,219 | 92,088 |
| Deferred tax | | | |
| – Current year | (282,883) | (138,937) | 291,730 |
| – Adjustments in respect of prior years | 3,440 | 7,480 | 8,528 |
| | (279,443) | (131,457) | 300,258 |
| **Total tax (credit)/expense for the year** | **(251,612)** | **(86,238)** | **392,346** |

| | Audited year ended 31 December 2020 US$'000 | Audited year ended 31 December 2019 US$'000 | Audited year ended 31 December 2018 US$'000 |
|---|---|---|---|
| The (credit)/expense for the year can be reconciled per the Statement of Comprehensive Income as follows: | | | |
| (Loss)/profit on ordinary activities before taxes | (529,470) | (101,271) | 665,458 |
| (Loss)/profit before taxation multiplied by the tax rate of 60.0 per cent. (2019: 60.0 per cent., 2018: 60.0 per cent.) | (317,682) | (60,763) | 399,275 |
| Tax effects of: | | | |
| Non-deductible expenses, net of non-assessable income | 25,107 | (12,071) | 9,717 |
| Over provision of income tax in prior year | (2,183) | (9,058) | (4,256) |
| Under provision of deferred tax in prior year | 3,440 | 7,480 | 8,528 |
| Effect of different tax rates between jurisdictions | 39,706 | (11,826) | (20,918) |
| **Tax (credit)/charge for the year** | **(251,612)** | **(86,238)** | **392,346** |

(b) ***Deferred tax***

The following are the major deferred tax assets/(liabilities) recognised by the PETRONAS Target Companies and movements thereon during the years under review.

| | *Property, plant and equipment US$'000* | *Total US$'000* |
|---|---|---|
| Balance at 1 January 2018 | (82,755) | (82,755) |
| Expense to Statement of Comprehensive Income | (300,258) | (300,258) |
| Balance at 31 December 2018 (audited) | (383,013) | (383,013) |
| Credit to Statement of Comprehensive Income | 131,457 | 131,457 |
| Balance at 31 December 2019 (audited) | (251,556) | (251,556) |
| Credit to Statement of Comprehensive Income | 279,443 | 279,443 |
| **Balance at 31 December 2020 (audited)** | **27,887** | **27,887** |

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Deferred tax assets | 28,382 | – | – |
| Deferred tax liabilities | (495) | (251,556) | (383,013) |
| **Net deferred assets/(liabilities)** | **27,887** | **(251,556)** | **(383,013)** |

## 11. Investment in associates

| *Companies* | *2020, 2019 & 2018 Equity %* | *Country of incorporation* | *Principal activities* |
|---|---|---|---|
| TOTCo | 30.16 | Republic of Chad | Pipeline operation |
| COTCo | 29.77 | Republic of Cameroon | Pipeline operation |

The following tables summarise the information of the PETRONAS Target Companies significant associates, as adjusted for any differences in accounting policies:

**COTCo**

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Current assets | 185,927 | 171,026 | 134,068 |
| Non-current assets | 524,519 | 591,763 | 657,120 |
| Current Liabilities | 20,696 | 23,164 | 21,742 |
| Non-current liabilities | 65,839 | 67,340 | 62,858 |
| Equity | 623,911 | 672,285 | 706,588 |
| Share in equity | 29.77% | 29.77% | 29.77% |
| **Carrying amount of the investment** | **185,738** | **200,139** | **210,351** |

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Revenue | 164,101 | 171,461 | 149,198 |
| Operating expenses | (150,196) | (160,584) | (163,362) |
| Profit/(loss) before tax | 13,905 | 10,877 | (14,164) |
| Income tax expenses | (1,683) | (1,006) | 532 |
| Profit/(loss) for the year | 12,222 | 9,871 | (13,632) |
| Share in equity | 29.77% | 29.77% | 29.77% |
| **Share of profit/(loss)** | **3,638** | **2,939** | **(4,058)** |

**TOTCo**

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Current assets | 18,665 | 22,282 | 20,921 |
| Non-current assets | 66,885 | 74,958 | 83,288 |
| Current Liabilities | 6,240 | 13,077 | 13,329 |
| Non-current liabilities | 35,941 | 38,006 | 40,621 |
| Equity | 43,369 | 46,157 | 50,259 |
| Share in equity | 30.16% | 30.16% | 30.16% |
| **Carrying amount of the investment** | **13,080** | **13,921** | **15,158** |

| | *Audited Year ended 31 December 2020 US$'000* | *Audited Year ended 31 December 2019 US$'000* | *Audited Year ended 31 December 2018 US$'000* |
|---|---|---|---|
| Revenue | 19,958 | 20,374 | 19,312 |
| Operating expenses | (20,669) | (20,063) | (21,403) |
| (Loss)/profit before tax | (711) | 311 | (2,091) |
| Income tax expenses | 292 | (187) | 693 |
| (Loss)/profit for the year | (419) | 124 | (1,398) |
| Share in equity | 30.16% | 30.16% | 30.16% |
| **Share of (loss)/profit** | **(126)** | **37** | **(422)** |

| | Audited As at 31 December 2020 US$'000 | Audited As at 31 December 2019 US$'000 | Audited As at 31 December 2018 US$'000 |
|---|---|---|---|
| Carrying amount of investment in associates | 198,818 | 214,060 | 225,509 |
| Accumulated impairment losses | (49,494) | (13,641) | (31,734) |
| **Net carrying amount of investment in associates** | 149,324 | 200,419 | 193,775 |
| **Share of profit/(loss) from associate** | **3,512** | **2,976** | **(4,480)** |

| | US$'000 |
|---|---|
| Balance at 1 January 2018 | 211,915 |
| Share of net loss | (4,480) |
| Dividends received | (13,660) |
| Balance at 31 December 2018 (audited) | 193,775 |
| Share of net profit | 2,976 |
| Impairment reversal of associate | 18,093 |
| Dividends received | (14,425) |
| Balance at 31 December 2019 (audited) | 200,419 |
| Share of net profit | 3,512 |
| Impairment of associate | (35,853) |
| Dividends received | (18,754) |
| **Balance at 31 December 2020 (audited)** | **149,324** |

## 12. Property, plant and equipment

| | *Oil and gas assets US$'000* | *Projects in progress US$'000* | *Total US$'000* |
|---|---|---|---|
| **Cost** | | | |
| Balance at 1 January 2018 | 2,750,307 | 2,371 | 2,752,678 |
| Additions | – | 20,360 | 20,360 |
| Decommissioning remeasurement adjustment (note 18) | (12,515) | – | (12,515) |
| Transfers from projects in progress | 427 | (427) | – |
| Balance at 31 December 2018 (audited) | 2,738,219 | 22,304 | 2,760,523 |
| Additions | – | 42,200 | 42,200 |
| Disposals | (3,927) | – | (3,927) |
| Decommissioning remeasurement adjustment (note 18) | 550 | – | 550 |
| Transfers from projects in progress | 17,079 | (17,079) | – |
| Balance at 31 December 2019 (audited) | 2,751,921 | 47,425 | 2,799,346 |
| Additions | – | 16,233 | 16,233 |
| Disposals | (610) | – | (610) |
| Decommissioning remeasurement adjustment (note 18) | 53,457 | – | 53,457 |
| Transfers from projects in progress | 22,690 | (22,690) | – |
| **Balance at 31 December 2020 (audited)** | **2,827,458** | **40,968** | **2,868,426** |
| **Accumulated depreciation** | | | |
| Balance at 1 January 2018 | (2,408,600) | – | (2,408,600) |
| Depletion | (23,377) | – | (23,377) |
| Impairment reversal | 530,643 | – | 530,643 |
| Balance at 31 December 2018 (audited) | (1,901,334) | – | (1,901,334) |
| Depletion | (53,926) | – | (53,926) |
| Impairment | (208,537) | – | (208,537) |
| Balance at 31 December 2019 (audited) | (2,163,797) | – | (2,163,797) |
| Depletion | (44,375) | – | (44,375) |
| Impairment | (491,449) | (5,908) | (497,357) |
| **Balance at 31 December 2020 (audited)** | **(2,699,621)** | **(5,908)** | **(2,705,529)** |
| **Net book value** | | | |
| **31 December 2018 (audited)** | **836,885** | **22,304** | **859,189** |
| **31 December 2019 (audited)** | **588,124** | **47,425** | **635,549** |
| **31 December 2020 (audited)** | **127,837** | **35,060** | **162,897** |

### Impairment

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Impairment/(reversal) of oil and gas assets | 491,449 | 208,537 | (530,643) |
| Impairment of projects in progress | 5,908 | – | – |
| Impairment/(reversal) of investment in associates (note 11) | 35,853 | (18,093) | – |
| Inventory write-down | 13,797 | – | – |
| | **547,007** | **190,444** | **(530,643)** |

The PETRONAS Target Companies' recoverable amount for impaired cash-generating unit was US$130.0 million (2019: US$569.9 million, 2018: US$789.0 million) was determined from the value-in-use calculations using cash flow projections. The project cash flows were discounted using a discount rate of 9.28 per cent. and 10.47 per cent. for Cameroon and Chad respectively (2019: 9.59 per cent. and 10.73 per cent., 2018: 8 per cent. and 8 per cent.); the different rates reflect the different operational risks within each country.

The principal driver of the impairments and impairment reversal has been the projected oil price. The PETRONAS Target Companies use a range of long-term assumptions based on past performance and management expectations of market development including the following:

- Shorter of economic life or remaining unexpired concession period;
- Projected crude oil prices;
- Future capital and operating expenditures to be spent on the projects which meet the PETRONAS Target Companies' investment criteria and their corresponding incremental reserves potentially to be recovered; and
- Current and forecasted market conditions.

The estimated future cash flows are reviewed at each reporting date, while the discount rate is reviewed annually based on the above factors and changes will eventually affect profit or loss through impairment charges or reversal of impairment.

## 13. Inventory

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| | – | 8,869 | 15,469 |
| | **–** | **8,869** | **15,469** |

During the year, the amount of inventories recognised as an expense in Cost of sales of the PETRONAS Target Companies was US$13.8 million (2019: US$6.6 million, 2018: US$0.2 million).

## 14. Trade and other receivables

| | *Audited As at 31 December 2020 US$'000* | *Audited As at 31 December 2019 US$'000* | *Audited As at 31 December 2018 US$'000* |
|---|---|---|---|
| Trade receivables | 47,882 | – | – |
| Amount due from joint operation partner | 26,446 | 37,940 | 35,381 |
| Tax receivable | – | 1,136 | 520 |
| Amount due from related parties | – | 10 | 13 |
| Amount due from associates | – | – | 24 |
| | **74,328** | **39,086** | **35,938** |

## 15. Cash at bank

| | Audited As at 31 December 2020 US$'000 | Audited As at 31 December 2019 US$'000 | Audited As at 31 December 2018 US$'000 |
|---|---|---|---|
| Cash and cash equivalents | 14,247 | 35,620 | 29,182 |
| | **14,247** | **35,620** | **29,182** |

Included in cash at bank of the PETRONAS Target Companies, are interest-bearing balances amounting to US$14.2 million (2019: US$35.6 million, 2018: US$29.2 million).

## 16. Capital and reserves

| | Audited As at 31 December 2020 No. of shares | Audited As at 31 December 2020 Amount US'$ | Audited As at 31 December 2019 No. of shares | Audited As at 31 December 2019 Amount US'$ | Audited As at 31 December 2018 No. of shares | Audited As at 31 December 2018 Amount US'$ |
|---|---|---|---|---|---|---|
| **Ordinary shares** | **2** | **2** | **2** | **2** | **2** | **2** |

The holders of ordinary shares are entitled to receive dividends as declared from time-to-time and are entitled to one vote per share at meetings of PCCEPI.

## 17. Trade and other payables

| | Audited As at 31 December 2020 US$'000 | Audited As at 31 December 2019 US$'000 | Audited As at 31 December 2018 US$'000 |
|---|---|---|---|
| Trade payables | 2,095 | 1,072 | 1,303 |
| Crude oil overlift | 4,492 | – | – |
| Amounts owed to penultimate holding company | 193 | 46 | 32 |
| Amounts owed to related companies | – | 81 | 10 |
| Other payables | – | 11 | 2 |
| | **6,780** | **1,210** | **1,347** |

## 18. Decommissioning provisions

| | Audited As at 31 December 2020 US$'000 | Audited As at 31 December 2019 US$'000 | Audited As at 31 December 2018 US$'000 |
|---|---|---|---|
| Decommissioning provision | 194,135 | 138,977 | 136,360 |
| | **194,135** | **138,977** | **136,360** |

Provision for decommissioning of oil and gas properties and other property, plant and equipment is recognised when there is an obligation to abandon a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reasonable estimate of that liability can be made.

The provision recognised is the present value of the PETRONAS Target Companies' obligations of the estimated future costs determined in accordance with current conditions and requirements.

A corresponding asset of an amount equivalent to the provision is also created. This asset is depreciated in accordance with the policy set out in note 3. The increase in the present value of the provision for the expected costs due to the passage of time is included within finance costs.

Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal events actually occur are uncertain. As actual timing and net cash outflows can differ from estimates due to changes in laws, regulations, public expectations, technology, prices and conditions, the carrying amounts of provisions, together with the interest rate used in discounting the cash flows and inflation rate, are regularly reviewed and adjusted to take account of such changes. The interest rate and inflation rate used to determine the obligation as at 31 December 2020 was at 0.88 per cent. (2019: 2.14 per cent., 2018: 2.91 per cent.) and 1.30 per cent. (2019: 1.80 per cent., 2018: 2.50 per cent.) respectively. Changes in the expected future costs are reflected in both the provision and the asset.

| *Decommissioning provision* | *Audited 2020 US$'000* | *Audited 2019 US$'000* | *Audited 2018 US$'000* |
|---|---|---|---|
| As at 1 January | 138,977 | 136,360 | 145,442 |
| Provided during the year | 53,456 | 550 | (12,515) |
| Provision utilised | – | (1,023) | (639) |
| Unwinding of decommissioning provision discount (note 9) | 1,702 | 3,090 | 4,072 |
| **As at 31 December** | **194,135** | **138,977** | **136,360** |

## PART 7F

## UNAUDITED INTERIM FINANCIAL INFORMATION OF THE PETRONAS TARGET COMPANIES

**Consolidated Statement of Comprehensive Income**

| | Note | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|---|
| Revenue | 1 | 132,002 | 80,295 |
| Cost of sales | 2 | (72,983) | (87,050) |
| **Gross profit/(loss)** | | 59,019 | (6,755) |
| Administrative and other operating expenses | 3 | (1,184) | (1,350) |
| Impairment | 3 | (3,638) | (464,854) |
| **Operating profit/(loss)** | | 54,197 | (472,959) |
| Finance income | | 26 | 97 |
| Share of profit in associates | 6 | 2,652 | 2,959 |
| Foreign translation loss | | (2) | (2) |
| **Profit/(Loss) before tax** | | 56,873 | (469,905) |
| Current tax expense | 4 | (131) | (6,544) |
| Deferred tax (expenses)/credit | 4 | (2,447) | 294,057 |
| Tax (expense)/credit | 4 | (2,578) | 287,513 |
| **Net profit/(loss) after tax and total comprehensive profit/(loss)** | | **54,295** | **(182,392)** |

## Consolidated Statement of Financial Position

| | Note | *Unaudited 30 June 2021 US$'000* | *Audited 31 December 2020 US$'000* |
|---|---|---|---|
| **Assets** | | | |
| **Non-current assets** | | | |
| Investment in associates | 6 | 131,057 | 149,324 |
| Property, plant and equipment | 5 | 142,202 | 162,897 |
| Deferred tax assets | | 25,935 | 28,382 |
| **Total non-current assets** | | **299,194** | **340,603** |
| **Current assets** | | | |
| Trade and other receivables | 7 | 124,390 | 74,328 |
| Cash at bank | 8 | 33,570 | 14,247 |
| **Total current assets** | | **157,960** | **88,575** |
| **Total assets** | | **457,154** | **429,178** |
| **Equity and liabilities** | | | |
| **Capital and reserves** | | | |
| Share capital | | – | – |
| Retained earnings | | 239,237 | 224,942 |
| **Total equity** | | **239,237** | **224,942** |
| **Non-current liabilities** | | | |
| Deferred tax liabilities | | 495 | 495 |
| Decommissioning provisions | 10 | 194,135 | 194,135 |
| **Total non-current liabilities** | | **194,630** | **194,630** |
| **Current liabilities** | | | |
| Trade and other payables | 9 | 23,287 | 6,780 |
| Tax liabilities | | – | 2,826 |
| **Total current liabilities** | | **23,287** | **9,606** |
| **Total liabilities** | | **217,917** | **204,236** |
| **Total equity and liabilities** | | **457,154** | **429,178** |

**Condensed consolidated Statement of Cash Flows**

| | Note | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|---|
| **Cash flows from operating activities:** | | | |
| Profit/(loss) before tax | | 56,873 | (469,905) |
| Adjustments for: | | | |
| Depletion | | 15,648 | 35,383 |
| Impairment loss | | 3,638 | 464,854 |
| Share of profit from associates | 6 | (2,652) | (2,959) |
| Unrealised foreign exchange gain | | (2) | – |
| Operating cash flows before movements in working capital | | 73,505 | 27,373 |
| Change in working capital | | (36,510) | (2,131) |
| **Net cash generated from operating activities** | | 36,995 | 25,242 |
| **Cash flows from investing activities:** | | | |
| Dividends received | | 20,919 | – |
| Proceeds from property, plant and equipment | | 1,409 | – |
| **Net cash provided by investing activities** | | 22,328 | – |
| **Cash flows from financing activities:** | | | |
| Dividends paid to shareholders | | (40,000) | – |
| **Net cash used in financing activities** | | (40,000) | – |
| **Net increase in cash and cash equivalents** | | 19,323 | 25,242 |
| **Cash and cash equivalents at beginning of period** | | 14,247 | 35,620 |
| **Cash and cash equivalents at end of period** | 8 | **33,570** | **60,862** |

**Condensed Consolidated Statement of Changes in Equity**

| | *Share capital US$'000* | *Retained earnings US$'000* | *Total equity US$'000* |
|---|---|---|---|
| **Balance at 1 January 2021 (audited)** | – | 224,942 | 224,942 |
| Profit for the period | – | 54,295 | 54,295 |
| **Total comprehensive profit for the period** | – | 54,295 | 54,295 |
| **Transactions with shareholders:** | | | |
| Dividend paid | – | (40,000) | (40,000) |
| **Balance at 30 June 2021 (unaudited)** | **–** | **239,237** | **239,237** |

| | *Share capital US$'000* | *Retained earnings US$'000* | *Total equity US$'000* |
|---|---|---|---|
| **Balance at 1 January 2020 (audited)** | – | 527,794 | 527,794 |
| Loss for the period | – | (182,392) | (182,392) |
| **Total comprehensive loss for the period** | **–** | **(182,392)** | **(182,392)** |
| **Balance at 30 June 2020 (unaudited)** | **–** | **345,402** | **345,402** |

**Notes to the PETRONAS Target Companies' Interim Financial Information**

## 1. Revenue

Set out below is the disaggregation of the PETRONAS Target Companies' revenue from contracts with customers:

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Crude oil sales | 132,002 | 80,295 |
| | **132,002** | **80,295** |

All revenue is earned from the sale of crude oil.

## 2. Cost of sales

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Depreciation and depletion – oil and gas assets | 15,648 | 35,383 |
| Facility operation and maintenance costs | 51,431 | 42,933 |
| Export duties | – | 2,726 |
| Pipeline tariff | 5,904 | 6,008 |
| | **72,983** | **87,050** |

## 3. Operating profit/(loss)

Operating profit/(loss) has been arrived at after charging:

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Impairment losses- Property, plant and equipment | 3,638 | 465,463 |
| Impairment losses write back – receivable | – | (609) |
| Administrative and other operating expenses | 1,184 | 1,350 |
| | **4,822** | **466,204** |

## 4. Taxation

The tax (expense)/credit for the PETRONAS Target Companies is:

| | *Unaudited Six months ended 30 June 2021 US$'000* | *Unaudited Six months ended 30 June 2020 US$'000* |
|---|---|---|
| Current tax | (131) | (6,544) |
| Deferred tax (charge)/credit | (2,447) | 294,057 |
| | **(2,578)** | **287,513** |

## 5. Property, plant and equipment

| | *Oil and gas assets US$'000* | *Projects in progress US$'000* | *Total US$'000* |
|---|---|---|---|
| **Cost** | | | |
| Balance at 1 January 2020 (audited) | 2,751,921 | 47,425 | 2,799,346 |
| Additions | – | 16,233 | 16,233 |
| Disposal | (610) | – | (610) |
| Decommissioning remeasurement adjustment[1] | 53,457 | – | 53,457 |
| Transfer from Projects in progress | 22,690 | (22,690) | – |
| Balance at 31 December 2020 (audited) | 2,827,458 | 40,968 | 2,868,426 |
| Disposals | (1,409) | – | (1,409) |
| Transfers from projects in progress | 30,712 | (30,712) | – |
| **Balance at 30 June 2021 (unaudited)** | **2,856,761** | **10,256** | **2,867,017** |
| **Accumulated depreciation** | | | |
| Balance at 1 January 2020 (audited) | (2,163,797) | – | (2,163,797) |
| Depletion | (44,375) | – | (44,375) |
| Impairment | (491,449) | (5,908) | (497,357) |
| Balance at 31 December 2020 (audited) | (2,699,621) | (5,908) | (2,705,529) |
| Depletion | (15,648) | – | (15,648) |
| Impairment | (3,638) | – | (3,638) |
| **Balance at 30 June 2021 (unaudited)** | **(2,718,907)** | **(5,908)** | **(2,724,815)** |
| **Net book value** | | | |
| **31 December 2020 (audited)** | **127,837** | **35,060** | **162,897** |
| **30 June 2021 (unaudited)** | **137,854** | **4,348** | **142,202** |

1. Includes revision to future cost of decommissioning of oil and gas properties amounting to US$53.5 million.

***Impairment***

| | Unaudited As at 30 June 2021 US$'000 | Unaudited As at 30 June 2020 US$'000 |
|---|---|---|
| Impairment of oil and gas assets | 3,638 | 464,854 |
| | **3,638** | **464,854** |

The PETRONAS Target Companies' recoverable amount for impaired cash-generating units were determined from the value in use calculations, using cash flow projections, which use a range of long-term assumptions including prices, volumes, margins and costs based on past performance and management's expectations of market development.

## 6. Investment in associates

| | US$'000 |
|---|---|
| Balance at 1 January 2020 (audited) | 200,419 |
| Share of net profit | 3,512 |
| Dividends received | (18,754) |
| Impairment | (35,853) |
| Balance at 31 December 2020 (audited) | 149,324 |
| Share of net profit | 2,652 |
| Dividends received | (20,919) |
| **Balance at 30 June 2021 (unaudited)** | **131,057** |

## 7. Trade and other receivables

| | Unaudited 30 June 2021 US$'000 | Audited 31 December 2020 US$'000 |
|---|---|---|
| Trade receivables | 68,280 | 47,882 |
| Receivables from a joint operation partner | 50,460 | 26,446 |
| Tax recoverable | 5,650 | – |
| | **124,390** | **74,328** |

## 8. Cash at bank

| | Unaudited 30 June 2021 US$'000 | Audited 31 December 2020 US$'000 |
|---|---|---|
| Cash and cash equivalents | 33,570 | 14,247 |
| | **33,570** | **14,247** |

## 9. Trade and other payables

| | *Unaudited 30 June 2021 US$'000* | *Audited 31 December 2020 US$'000* |
|---|---|---|
| Other payables | 867 | 2,095 |
| Amount due to holding company | 30 | – |
| Amount due to penultimate holding company | 322 | 193 |
| Crude oil overlift | 22,068 | 4,492 |
| | **23,287** | **6,780** |

## PART 7G

## HISTORICAL FINANCIAL INFORMATION ON THE EXISTING GROUP

In accordance with Rule 28 of the AIM Rules, this document does not contain historical financial information on the Existing Group, which would otherwise be required under Section 18 of Annex 1 of the AIM Rules.

This information is available on the Company's website, as follows:

| *Financial Information* | *Hyperlink* |
| --- | --- |
| Savannah's audited results for the year ended 31 December 2018 | https://wp-savannah-2020.s3.eu-west-2.amazonaws.com/media/2020/05/26155507/SVP_AR18_web-bookmarked-1.pdf |
| Savannah's audited results for the year ended 31 December 2019 | https://wp-savannah-2020.s3.eu-west-2.amazonaws.com/media/2020/10/26100057/SVE_AR19_1-1.pdf |
| Savannah's audited results for the year ended 31 December 2020 | https://wp-savannah-2020.s3.eu-west-2.amazonaws.com/media/2021/06/07175510/Savannah-Energy-PLC-Annual-Report-and-Accounts-2020.pdf |
| Savannah's interim results for the Six months ended 30 June 2021 | https://wp-savannah-2020.s3.eu-west-2.amazonaws.com/media/2021/09/30071011/H1-2021-Results-Release_FINAL.pdf |

Shareholders or other recipients of this document may request a hard copy of the above information incorporated by reference from the Company at its registered office, 40 Bank Street, London E14 5NR, or by telephoning +44 (0) 20 3817 9844. Such copy will be provided to the requester within 7 days. A hard copy of the information incorporated by reference will not be sent to Shareholders or other recipients of this document unless requested.

## PART 8A

## ACCOUNTANT'S REPORT ON THE UNAUDITED PRO FORMA STATEMENT OF NET ASSETS OF THE ENLARGED GROUP

Crowe U.K. LLP
*Chartered Accountants*
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DX: 0014 London Chancery Lane
www.crowe.co.uk

30 December 2021

The Directors
Savannah Energy PLC
40 Bank Street
London E14 5NR

The Directors
Strand Hanson Limited
26 Mount Row
London W1K 3SQ

Dear Sirs and Madams,

We report on the unaudited pro forma statement of net assets as at 30 June 2021 of Savannah Energy PLC (the "Company") (the "Pro Forma Financial Information") set out in Part 8B "*Unaudited Pro Forma Statement of Net Assets of the Enlarged Group"* of the Company's AIM admission document dated 30 December 2021 (the "Admission Document").

**Opinion**

In our opinion:

- the Pro Forma Financial Information has been properly compiled on the basis stated; and
- such basis is consistent with the accounting policies of the Company.

**Responsibilities**

It is the responsibility of the directors of the Company (the "Directors") to prepare the Pro Forma Financial Information.

It is our responsibility to form an opinion as to the proper compilation of the Pro Forma Financial Information and to report that opinion to you.

In providing this opinion, we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

**Basis of preparation**

The Pro Forma Financial Information has been prepared on the basis described, for illustrative purposes only, to provide information about how:

- the acquisitions of Esso Exploration and Production Chad Inc and Esso Pipeline Investments Limited (together, the "Exxon Target Companies");
- the acquisitions of PETRONAS Carigali Chad Exploration & Production Inc., PETRONAS Carigali (Chad EP) Inc., Doba Pipeline Investments Inc. and PETRONAS Chad Marketing Inc. (together, the "PETRONAS Target Companies");
- the receipt of the Debt Financing;
- the Company's entry into the Junior Loan Facility;
- the placing; and
- settlement of the placing and re-admission costs

might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the unaudited consolidated interim financial information for the six-month period ended 30 June 2021.

**Basis of Opinion**

We conducted our work in accordance with Standards of Investment Reporting issued by the Financial Reporting Council in the United Kingdom (the "FRC"). We are independent of the Company in accordance with relevant ethical requirements. In the United Kingdom this is the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro Forma Financial Information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

**Declaration**

For the purposes of Item 1.2 of Annex 1 to the AIM Rules for Companies, we are responsible for this report as part of the Admission Document and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import. This declaration is included in the Admission Document in compliance with Schedule Two of the AIM Rules for Companies.

Yours faithfully,

**Crowe U.K. LLP**
*Chartered Accountants*

# PART 8B

# UNAUDITED PRO FORMA STATEMENT OF NET ASSETS OF THE ENLARGED GROUP

## Section A: Introduction

The unaudited Pro Forma Financial Information set out below has been prepared to illustrate the effects of the Exxon Acquisition, the PETRONAS Acquisition, the Placing, the Subscription, the Junior Loan Facility, the receipt of the Debt Financing and settlement of the associated costs on the net assets of the Existing Group as if the Exxon Acquisition, the PETRONAS Acquisition, the Placing, the Subscription, the receipt of the Junior Loan Facility and the receipt of the Debt Financing and settlement of the associated costs had taken place on 30 June 2021. The unaudited Pro Forma Financial Information has been prepared on the basis of, and should be read in conjunction with, the notes set out below.

The unaudited Pro Forma Statement of Net Assets has been prepared for illustrative purposes only and illustrates the impact of the Exxon Acquisition, the PETRONAS Acquisition, the Placing, the Subscription, the receipt of the Junior Loan Facility, the receipt of Debt Financing and settlement of the associated costs as if they had been undertaken on 30 June 2021. As a result, the hypothetical financial position included in the unaudited Pro Forma Financial Information may differ from the Enlarged Group's actual financial position.

The unaudited Pro Forma Financial Information of the Enlarged Group is based on:

- the unaudited, consolidated interim financial information of the Existing Group for the six months ended 30 June 2021, incorporated by reference in Part 7G "Historical Financial Information of the Existing Group" of this document;
- the unaudited Exxon Target Companies' Interim Financial Information, included in Part 7C "Unaudited Interim Financial Information of the Exxon Target Companies" of this document; and
- the unaudited PETRONAS Target Companies' Interim Financial Information, included in Part 7F "Unaudited Interim Financial Information of the PETRONAS Target Companies" of this document.

The unaudited Pro Forma Financial Information has been prepared in a manner consistent with the accounting policies adopted by the Company in preparing the unaudited consolidated interim financial information of the Existing Group for the six months ended 30 June 2021, in accordance with Annex 20 of the Prospectus Regulation and on the basis set out in the notes below.

## Section B: Unaudited Pro Forma Statement of Net Assets of the Enlarged Group

| | | *Exxon* | *PETRONAS* | | | | |
|---|---|---|---|---|---|---|---|
| | *Existing* | *Target* | *Target* | | | | *Pro* |
| | *Group* | *Companies* | *Companies* | | *Adjustments* | | *forma* |
| | *Note 1* | *Note 2* | *Note 3* | *Note 4* | *Note 5* | *Note 6* | |
| **Assets** | *US$000* | *US$000* | *US$000* | *US$000* | *US$000* | *US$000* | *US$000* |
| **Non-current assets** | | | | | | | |
| Property, plant and equipment | 604,104 | 330,252 | 142,202 | 142,096 | – | 552,092 | 1,770,746 |
| Exploration and evaluation assets | 160,135 | – | – | – | – | – | 160,135 |
| Intangible assets | – | 1,766 | – | – | – | – | 1,766 |
| Investment in associates | – | 247,756 | 131,057 | – | – | (378,813) | – |
| Deferred tax assets | 190,093 | 148,208 | 25,935 | (85,257) | – | – | 278,979 |
| Right-of-use assets | 5,074 | – | – | – | – | – | 5,074 |
| Restricted cash | 1,635 | – | – | – | – | – | 1,635 |
| Other non-current assets | 864 | 106 | – | – | – | 1,404 | 2,374 |
| **Total non-current assets** | **961,905** | **728,088** | **299,194** | **56,839** | **–** | **174,683** | **2,220,709** |
| **Current assets** | | | | | | | |
| Inventories | 3,605 | 89,587 | – | – | – | 41,477 | 134,669 |
| Trade and other receivables | 138,670 | 301,089 | 124,390 | – | (216,406) | 47,396 | 395,139 |
| Cash at bank | 134,050 | 467 | 33,570 | 45,000 | – | 91,393 | 304,480 |
| **Total current assets** | **276,325** | **391,143** | **157,960** | **45,000** | **(216,406)** | **180,266** | **834,288** |
| **Total assets** | **1,238,230** | **1,119,231** | **457,154** | **101,839** | **(216,406)** | **354,949** | **3,054,997** |
| **Liabilities** | | | | | | | |
| **Non-current liabilities** | | | | | | | |
| Other payables | 4,884 | 337,014 | – | – | (269,374) | 44,125 | 116,649 |
| Borrowings | 405,433 | – | – | 332,000 | – | – | 737,433 |
| Lease liabilities | 6,352 | – | – | – | – | – | 6,352 |
| Provisions | 108,342 | 106,922 | 194,135 | – | – | – | 409,399 |
| Contract liabilities | 201,970 | – | – | – | – | – | 201,970 |
| Deferred tax liabilities | – | 237,963 | 495 | – | – | 50,965 | 289,423 |
| **Total non-current liabilities** | **726,981** | **681,899** | **194,630** | **332,000** | **(269,374)** | **95,090** | **1,761,226** |
| **Current liabilities** | | | | | | | |
| Trade and other payables | 104,063 | 10,887 | 23,287 | – | – | 33,281 | 171,518 |
| Borrowings | 99,689 | – | – | – | – | – | 99,689 |
| Interest payable | 66,498 | – | – | – | – | – | 66,498 |
| Tax liabilities | 3,640 | – | – | – | – | (1,555) | 2,085 |
| Lease liabilities | 1,424 | – | – | – | – | – | 1,424 |
| Contract liabilities | 8,828 | – | – | – | – | – | 8,828 |
| **Total current liabilities** | **284,142** | **10,887** | **23,287** | **–** | **–** | **31,726** | **350,042** |
| **Total liabilities** | **1,011,123** | **692,786** | **217,917** | **332,000** | **(269,374)** | **126,816** | **2,111,268** |
| **Net assets** | **227,107** | **426,445** | **239,237** | **(230,161)** | **52,968** | **228,133** | **943,729** |

*Notes:*

1. The net assets of the Existing Group as at 30 June 2021 have been extracted without adjustment from the Unaudited Interim Consolidated Statement of Financial Position set out in Savannah's unaudited interim financial information for the six months ended 30 June 2021, incorporated by reference in Part 7G "Historical Annual Financial Information of the Existing Group" of this document.

2. The net assets of the Exxon Target Companies as at 30 June 2021 have been extracted without material adjustment from the Statement of Financial Position, set out in the Exxon Target Companies' Interim Financial Information included in Part 7C of this document.

3. The net assets of the PETRONAS Target Companies as at 30 June 2021 have been extracted without material adjustment from the Statements of Financial Position, set out in the PETRONAS Target Companies' Interim Financial Information included in Part 7F of this Admission Document.

4. The adjustment reflects the purchase consideration for the acquisition of the PETRONAS Target Companies and the Exxon Target Companies, together with the receipt of the Junior Loan Facility and the receipt of the Debt Financing and settlement of the associated transaction expenses.

| | *US$000* |
|---|---|
| **Consideration and fees** | |
| Exxon Acquisition and the PETRONAS Acquisition considerations and costs | 650,000 |
| Other costs associated with the Placing, Subscription and Re-Admission | 23,000 |
| Exxon Acquisition and PETRONAS Acquisition related adjustments at Completion | (321,000) |
| | **352,000** |
| **Funding sources** | |
| Initial amount drawn under the Debt Financing | 300,000 |
| Initial amount drawn under the Junior Loan Facility | 32,000 |
| Placing and Subscription proceeds | 65,000 |
| | **397,000** |
| Net increase in cash at Completion | **45,000** |

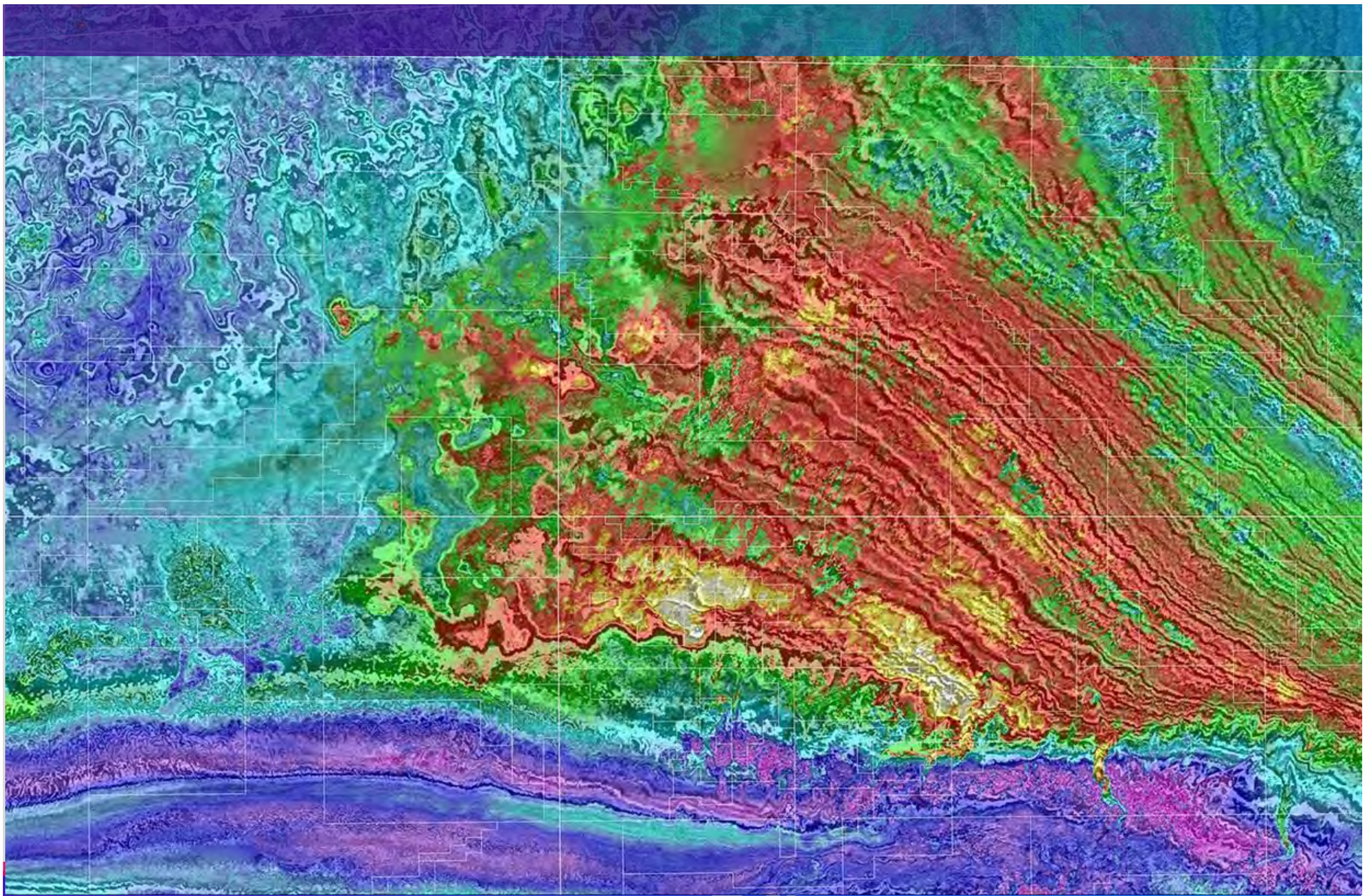
For the purposes of this Pro Forma Information, no adjustment has been made to the separate assets and liabilities of the Exxon Target Companies or the PETRONAS Target Companies, including the purchase consideration paid, with the exception of property, plant and equipment and associated deferred tax assets. These have been adjusted to align the carrying values of the Exxon Target Companies and the PETRONAS Target Companies to approximate values as at 30 June 2021. The net assets of the Exxon Target Companies and the PETRONAS Target Companies and the fair value of the purchase consideration will be subject to fair value assessment as at the date of Completion as required by IFRS 3 (Revised). The Pro Forma Information does not, therefore, include any calculation of goodwill or negative goodwill associated with the Exxon Acquisition or the PETRONAS Acquisition.

5. The adjustments in Note 5 reflect the eliminations of: (i) under the terms of the Exxon SPA, amounts owed by/due to the Exxon Target Companies as at 30 June 2021 to other members of the ExxonMobil group that are not being acquired under the terms of the Exxon SPA; and (ii) under the terms of the PETRONAS SPA, amounts owed by/due to the PETRONAS Target Companies as at 30 June 2021 to other members of PETRONAS group that are not being acquired under the terms of the PETRONAS SPA.

6. The PETRONAS Target Companies and the Exxon Target Companies hold investments in TOTCo and COTCo with significant influence and therefore these investments have been recognised under the equity accounting method as 'Investment in associates'. On completion of both the Exxon Acquisition and the PETRONAS Acquisition, the Existing Group will have indirect controlling interests in TOTCo and COTCo and these entities will be consolidated into the Statement of Financial Position of the Enlarged Group. Therefore, the "Investments in associates" will be eliminated and the underlying separable assets and liabilities of TOTCo and COTCo will be consolidated. The unaudited net assets of TOTCo and COTCo as at 30 June 2021 have been provided by management of the Exxon Target Companies and the PETRONAS Target Companies.

# PART 9

# COMPETENT PERSON'S REPORT FOR THE CHAD/CAMEROON ASSETS



# COMPETENT PERSONS REPORT

## Doba Oil Project and Chad/Cameroon Pipeline

For
Savannah Energy PLC
Strand Hanson Limited
finnCap Ltd
Panmure Gordon (UK) Limited



cgg.com

SEE THINGS DIFFERENTLY

# DISCLAIMER AND CONDITIONS OF USAGE

**Professional Qualifications**

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

**Data and Valuation Basis**

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. The capital and operating costs have been combined with production forecasts based on the Reserves or Resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cashflow technique. In estimating the future cashflows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Savannah Energy PLC in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warranty to Savannah Energy PLC's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserves; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Energy PLC.

CGG affirms that from 1st October 2021 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix B** of the CPR.

**Conditions of Usage**

This report was compiled using existing data during the period 1st February 2021 to 13th October 2021. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Savannah Energy PLC for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on Savannah Energy PLC's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The copyright of this CPR document remains the property of CGG. It has been provided to Savannah Energy PLC, Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited for the purpose of Savannah's re-admission to trading on AIM, its inclusion in the related AIM Admission Document and disclosure on the Savannah's website in accordance with the AIM Rules and specifically to the AIM Note for Mining, Oil & Gas Companies (these together being the "Purpose"). CGG agrees to disclose the enclosed CPR to Savannah Energy PLC, Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited for the Purpose. The recipient should also note that this document is being provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by CGG. Notwithstanding these general conditions, CGG additionally agrees to the publication of the CPR document, in full, on the Savannah Energy PLC's website in accordance with the AIM rules.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

| CGG Services (UK) Limited Reference No: BP510 | | | | |
|---|---|---|---|---|
| **Rev** | **Date** | **Originator** | **Checked & Approved** | **Issue Purpose** |
| 01 | 17th December 2021 | AKS/TU/PW | AW | Final Report |

| **Date** | **Originator** | **Checked & Approved** |
|---|---|---|
| Signed: | AKS/TU/PW |  |

| Prepared for: | | Prepared By: |
|---|---|---|
| Savannah Energy PLC<br>40 Bank Street<br>London<br>E14 5NR<br><br>finnCap Ltd<br>One Bartholomew Close<br>London<br>EC1A 7BL | Strand Hanson Limited<br>26 Mount Row<br>London<br>W1K 3SQ<br><br>Panmure Gordon (UK) Limited<br>One New Change<br>London<br>EC4M 9AF | Andrew Webb<br>CGG Services (UK) Limited<br>Crompton Way, Manor Royal Estate<br>Crawley, West Sussex RH10 9QN<br>United Kingdom |

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**FIGURES**

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# 1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited, CGG Services (UK) Limited (CGG) has prepared a Competent Persons Report (CPR) on the acquisition of 100 per cent of ExxonMobil's (Exxon) and 100 per cent of Petronas (E&P) Overseas Ventures SDN. BHD.'s (Petronas) interest in the Doba Oil Project and Chad-Cameroon Export Transportation System (ETS).

The effective date for the evaluation is 1st October 2021.

## 1.1 Licence Interests

The assets and interests under consideration are summarised below:

Acquisition from Exxon of a:

(a) 100% equity interest in Esso Exploration and Production Chad Inc. (EEPCI) which holds:
   i. 40% operated interest in the Doba Oil Field Development Area (Doba OFDA, or Doba Oil Project) in Chad; and

(b) 100% equity interest in Esso Pipeline Investments Limited (EPIL) which holds:
   i. 40.19% interest in the Tchad Oil Transportation Company (TOTCo, or Chad Pipeline Company); and
   ii. 41.06% interest in the Cameroon Oil Transportation Company (COTCo, or Cameroon Pipeline Company).

Acquisition from Petronas of a:

(c) 100% equity interest in Petronas Carigali Chad Exploration & Production Inc. (PCCEPI) which holds:
   i. 35% interest in the Doba Oil Project;
   ii. 30.16% interest in the Chad Pipeline Company; and
   iii. 29.77% interest in the Cameroon Pipeline Company.

The Doba Oil Project is owned by the Doba consortium comprised of EEPCI as Operator (40%), PCCEPI (35%), and SHT Petroleum Chad Company Limited (25%), an affiliate of the Chad National Oil Company, Société des Hydrocarbures du Tchad.

## 1.2 Asset Details

The Upstream assets under review are comprised of seven oil fields in the Doba Basin of Southern Chad (Kome, Miandoum, Bolobo, Moundouli, Maikeri, Nya and Timbre) and includes associated surface facilities, all of which constitute the Doba Oil Project. A summary of the field discovery and first production dates are shown in **Table 1-1.**

| Field | Miandoum | Kome | Bolobo | Nya | Moundouli | Maikeri | Timbre |
|---|---|---|---|---|---|---|---|
| Year of discovery | 1975 | 1975 | 1989 | 2002 | 2001 | 2005 | 2005 |
| Production Start-up | Jul-03 | Feb-04 | Aug-04 | Jun-05 | Mar-06 | Jul-07 | Sep-09 |

Table 1-1 Field Discovery and First Production Dates

Two gathering and pre-processing stations were initially installed at Miandoum and Kome, with Bolobo tied-back to Kome. Processing and power generation is centralised at Kome in a Central Treating Facility (CTF) before crude is exported through the Chad-Cameroon Export Transportation System (ETS).

The ETS is a crude oil export pipeline, 1,081 kilometres long, between Chad and Cameroon with name plate capacity of 250,000 bopd. It also includes an offshore moored Floating Storage and Offloading vessel (FSO) and terminal infrastructure located near the Port of Kribi, on the coast of Cameroon. The ETS is used to export all crude from the Doba Oil Project as well as crude from other Operators (i.e. Glencore, China National Petroleum Corporation - CNPC, Overseas Petroleum and Investment Corporation – OPIC). OPIC is a subsidiary of Taiwan's national oil company, CPC.

## 1.3 Reserves and Resources

A summary of the Reserves associated with the Doba fields, on both a gross and net attributable basis are shown in **Table 1-2**. Production is assumed to cease at the earlier of the economic limit or the expiry of the Concessions in September 2050. On a Gross Proved & Probable basis, 120.4 MMstb out of 138.4 MMstb (i.e. c. 85%) are Proved Developed Reserves from a No Further Investment case, highlighting the robustness of the Reserves base.

| Reserves (MMstb) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net Attributable | | | Operator |
| | Proved | Proved & Probable | Proved, Probable & Possible | Proved | Proved & Probable | Proved, Probable & Possible | |
| Moundouli, Nya | 7.9 | 13.6 | 22.2 | 5.9 | 10.2 | 16.7 | EEPCI |
| Maikeri, Timbre | 3.3 | 4.9 | 5.3 | 2.5 | 3.7 | 4.0 | EEPCI |
| Miandoum, Bolobo, Kome | 89.4 | 119.9 | 160.1 | 67.0 | 89.9 | 120.1 | EEPCI |
| **Total** | **100.6** | **138.4** | **187.7** | **75.4** | **103.8** | **140.7** | |

*Notes*

1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied.*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Totals may not add up due to rounding*
5. *Net: the portion of the gross reserves attributable to Savannah before royalties, taxes and fuel consumed in operations*
6. *Full definitions of the Reserves categories can be found in Appendix B*

Table 1-2 Table of Reserves; Gross and Net Attributable to EEPCI and PCCEPI as at 1st October 2021

A summary of the Contingent Resources is shown in **Table 1-3** and demonstrates the potential upside these mature assets could offer. While the Contingent Resources are mostly based on further infill drilling, there would be opportunity for Savannah based on future technical work, to develop those resources by other means. This could come in the form of optimisation of water/polymer flooding and artificial lift, alternative well completion and intervention technologies, workover/recompletion of existing non-producing wells to improve oil recovery and even the application of further Enhanced Oil Recovery (EOR) techniques.

| Contingent Resources (MMstb) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net Attributable | | | Risk Factor | Operator |
| | 1C | 2C | 3C | 1C | 2C | 3C | | |
| Moundouli, Nya | 11.6 | 23.2 | 34.8 | 8.7 | 17.4 | 26.1 | medium | EEPCI |
| Maikeri, Timbre | 2.1 | 4.6 | 6.7 | 1.6 | 3.5 | 5.0 | medium | EEPCI |
| Miandoum, Bolobo, Kome | 48.0 | 82.4 | 117.4 | 36.0 | 61.8 | 88.1 | low | EEPCI |
| **Total** | **61.7** | **110.2** | **158.8** | **46.3** | **82.7** | **119.2** | | |

*Notes*

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
   *Risk factor: low = > 75%, medium = 25% - 75%, high = <25%*
5. *Total may not add up due to rounding*
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and fuel consumed in operations*
7. *Full definitions of the Contingent Resource categories can be found in Appendix B*

Table 1-3 Table of Contingent Resources; Gross and Net Attributable to EEPCI and PCCEPI as at 1st October 2021

## 1.4 Economic Evaluation

### 1.4.1 Doba Oil Project

The Net Present Values (NPV) of future cashflows derived from the exploitation of the Reserves are presented in **Table 1-4**. The values stated are net to EEPCI and PCCEPI's interest and after deduction of crude consumed in operations, Royalties and Taxes. The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. The NPVs do not include EEPCI and PCCEPI's outstanding liabilities/assets at the evaluation date, and do not necessarily relate to the actual dividend stream that may accrue to shareholders.

| NPV10 (US$MM) of Reserves Net to Savannah | | | |
|---|---|---|---|
| | Proved | Proved & Probable | Proved, Probable & Possible |
| Moundouli, Nya | 24.3 | 49.9 | 94.0 |
| Maikeri, Timbre | 12.1 | 18.5 | 23.9 |
| Miandoum, Bolobo, Kome | 313.4 | 416.4 | 578.0 |
| **Total*** | **349.7** | **484.8** | **695.9** |

** Total may not add up due to rounding*

Table 1-4 NPV10 (US$MM) of Reserves Net to Savannah as at 1st October 2021

NPV sensitivities relating to oil prices and costs have also been run on the base case. The results of this analysis are presented in **Table 1-5**.

| NPV10 (US$MM) Net to Savannah | | | |
|---|---|---|---|
| | **Proved** | **Proved & Probable** | **Proved, Probable & Possible** |
| Base case | 349.7 | 484.8 | 695.9 |
| Oil price – US$50/bbl | 121.7 | 214.3 | 355.4 |
| Oil price – US$60/bbl | 280.6 | 405.9 | 602.6 |
| Oil price – US$70/bbl | 439.2 | 603.3 | 857.7 |
| Oil price – US$80/bbl | 597.7 | 813.8 | 1,118.2 |
| Oil price – US$90/bbl | 756.2 | 1,024.3 | 1,345.1 |
| Oil price – US$100/bbl | 904.4 | 1,231.4 | 1,568.2 |
| Capex +25% | 340.2 | 476.6 | 685.2 |
| Capex -15% | 355.4 | 490.9 | 702.3 |
| Opex +25% | 211.3 | 326.7 | 518.3 |
| Opex -15% | 432.6 | 583.5 | 807.7 |

Table 1-5 NPV10 (US$MM) Sensitivities of Reserves Net to Savannah as at 1st October 2021

### 1.4.2 Chad-Cameroon Export Transportation System

Indicative Net Present Values (NPV) of estimated after-tax future cashflows accruing to Savannah's share of the Chad and Cameroon Pipeline companies have been calculated. Values have been estimated for a base and an upside case scenarios of the third party production throughput based on a Wood Mackenzie study* commissioned by Savannah. In each scenario, the Proved & Probable Doba Oil Project forecasted volumes have also been considered.

All cases account for c. 17,000bopd crude oil from CNPC being routed to the Djermaya Refinery, near N'Djamena, as well as crude consumed in operations. Indicative Net Present Values (NPV) of estimated after-tax future cashflows accruing to EPIL and PCCEPI's share of the Chad and Cameroon Pipeline Companies are tabulated in **Table 1-6**. There are no Reserves or Resources associated with EPIL and PCCEPI's share of the Chad and Cameroon Pipeline companies.

It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. NPVs do not include EPIL and PCCEPI's outstanding liabilities/assets at the evaluation date, and do not necessarily relate to the actual dividend stream that may accrue to shareholders.

| NPV10 (US$MM) Net to Savannah | | |
|---|---|---|
| | **Base** | **Upside** |
| Chad Pipeline Company | 18.9 | 19.3 |
| Cameroon Pipeline Company | 478.7 | 618.1 |
| **Total** | **497.6** | **637.3** |

Table 1-6 Indicative NPV10 (US$MM) of EPIL and PCCEPI's share of the Chad and Cameroon Pipeline Companies cashflows as at 1st October 2021

* *The data and information provided by Wood Mackenzie should not be interpreted as advice or relied on for any purpose. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for the use of this data and information*

# 2 INTRODUCTION

## 2.1 Overview

The assets under review are comprised of seven oil fields (namely Kome, Miandoum, Bolobo, Moundouli, Maikeri, Nya and Timbre presented in **Figure 2.1**) in the Doba Basin of Southern Chad, including associated surface facilities. These Upstream assets together constitute the Doba Oil Project.

Processed crude from the Doba Oil Project and other third-party fields is exported via the Chad-Cameroon Export Transportation System (ETS) which is composed of an export pipeline and an offshore moored Floating Storage & Offloading vessel (FSO) and terminal infrastructure. The pipeline linking Doba basin in Chad to the port of Kribi on the coast of Cameroon, has a diameter of 30" and a total length of 1,081km (178km in Chad and 903km in Cameroon), and a nameplate capacity of 250,000 bopd. The route of the pipeline as well as associated facilities are presented in **Figure 2.2**.

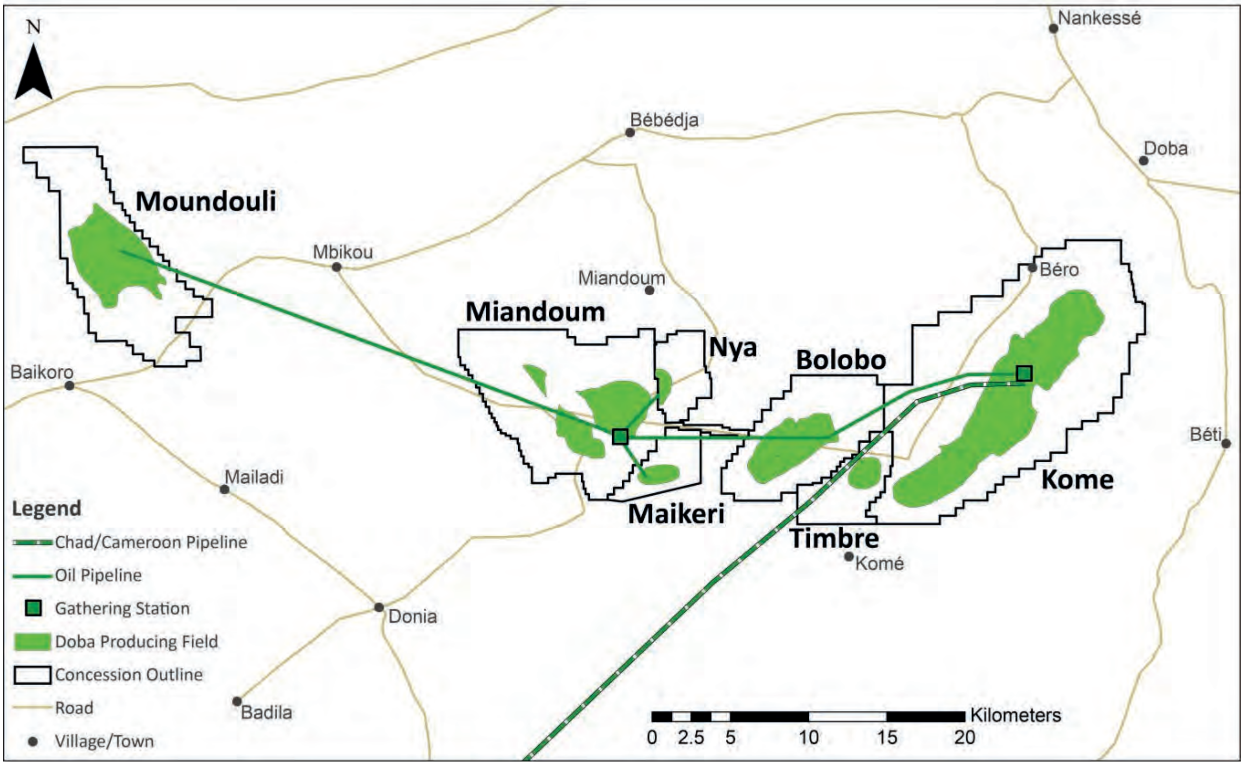



Figure 2.1 Location map showing the seven oil fields and associated main pipelines

*Source: Savannah Energy*

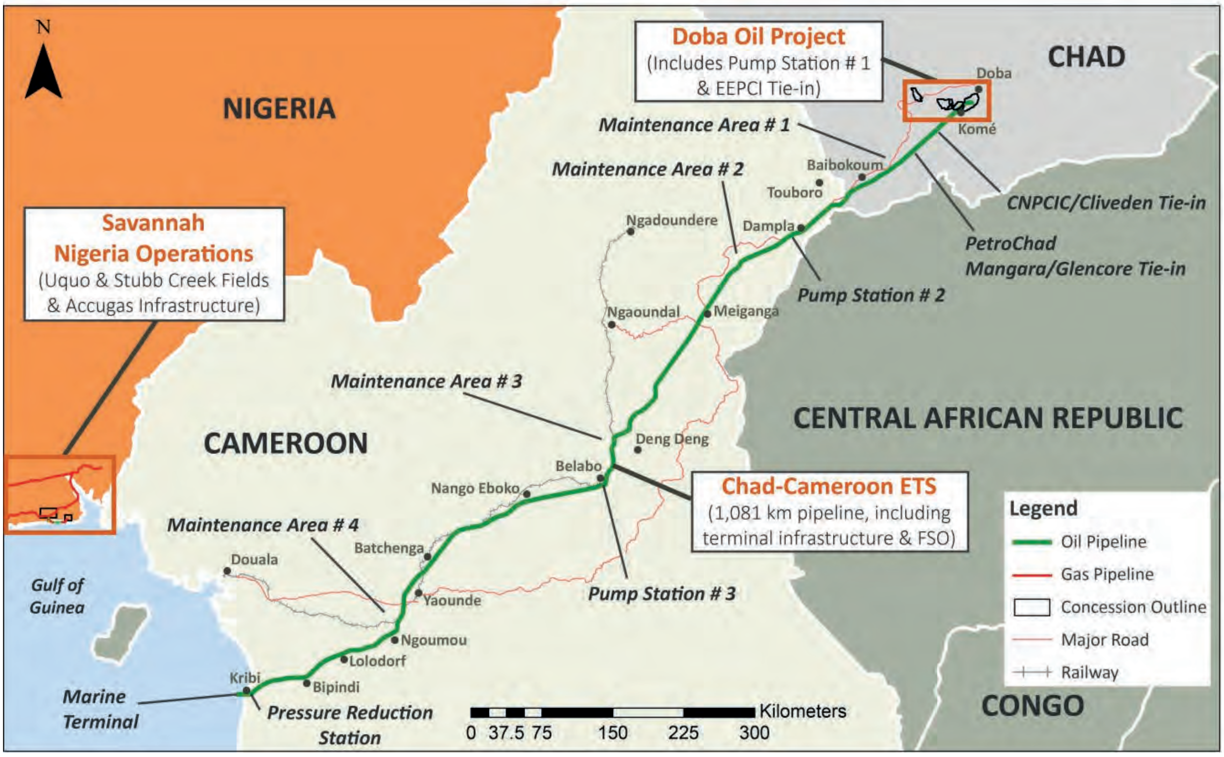



Figure 2.2 Overview map of the assets (development area, facilities and pipeline)

*Source: Savannah Energy*

The assets are as follows:

(i) 100% of the outstanding capital stock of Esso Exploration and Production Chad Inc. (EEPCI). EEPCI, with a 40% working interest, is the Operator of the oil fields in Southern Chad's established Doba Oil Project.

(ii) 100% of the outstanding capital stock of Esso Pipeline Investments Limited (EPIL). EPIL holds a 40.19% shareholding interest in Chad's 178-kilometre segment of the Chad-Cameroon Pipeline, through Tchad Oil Transportation Company (TOTCo), and a 41.06% shareholding interest in Cameroon's 903-kilometre segment of the Chad-Cameroon Pipeline and Kome Kribi 1 FSO through Cameroon Oil Transportation Company (COTCo).

(iii) 100% of the outstanding capital stock of Petronas Carigali Chad Exploration & Production Inc. (PCCEPI). PCCEPI holds a 35% operating interest in the Doba Oil Project, a 30.16% interest in TOTCo, and a 29.77% interest in COTCo.

## 2.2 Sources of Information

Data was provided to CGG for independent analysis by means of a Virtual Data Room (VDR), referred to herein as the Doba Oil Project VDR.

## 2.3 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment, and evaluation of hydrocarbon reserves.

Andrew Webb

Andrew Webb has supervised the preparation of this CPR. Andrew is the Manager of the Petroleum Reservoir & Economics Group at CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 20 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

Dr. Stefan Calvert

Dr Stefan Calvert is a Petrophysics Team Lead with 20+years of experience. Prior to joining CGG he consulted for two years with AkerBP in Oslo. Fourteen years were spent with Shell/BG based in the UK, Trinidad, Australia and India. He initially had four years working as a Research Petrophysicist for Reeves Wireline Technologies Ltd (now Weatherford). His interests include unconventional reservoirs, horizontal well log interpretation, rock physics, cased hole nuclear logging, carbonates and thin bed evaluation. Stefan holds a BSc Physics, a MSc Geophysics and a PhD Petrophysics from UK universities. He has also published papers with SPWLA, SPE and EAGE. Stefan is a member of SPWLA, SPE and IOP. Stefan jointly holds patents for cased hole density log hydrocarbon evaluation.

Philippa Park

Philippa Park is a development Manager/Subsurface Team Leader with 23 years' experience with three major international Oil and Gas Companies. Philippa has a degree in Engineering Science from Cambridge University and a Masters degree in Petroleum Engineering from Imperial College. Her first role was with ARCO where she worked on gas reservoir engineering, production engineering, well test analysis and also drilling and completion engineering including an extended reach drilling campaign on Arco's Trent and Tyne fields. She then joined Chevron and worked on the Alba infill drilling campaign after which she was production and operations team leader for Alba. At BG, she was subsurface team lead for Santos Basin super giant oil fields including Lula and Iracema. She worked on development planning including EOR screening and miscible WAG project planning. She has a broad-based E&P experience from all aspects of petroleum engineering, development planning, reservoir engineering, drilling & completions engineering and production operations.

Toni Uwaga

Toni Uwaga has a MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish Sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has written several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright gained a MA in Engineering from Cambridge University and a MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

## 2.4 Evaluation Methodology

In evaluating the hydrocarbon Reserves and Resources associated with the fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation. More detailed descriptions of the workflow and methodologies employed are provided in the relevant sections of this report.

CGG independently validated reservoir properties, Hydrocarbon Initially in Place, Reserves, production profiles and estimates of capital and operating costs provided by Savannah. The Reserves have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

The evaluation has been performed in accordance with:-

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)

- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

# 3 GEOLOGY AND GEOPHYSICS

A brief review of the geology of the area establishes some basic features of the oil reservoirs and principles controlling oil production.

## 3.1 Regional Geology

The oil reservoirs are in the Doba Basin and are part of the West and Central African Rift System (**Figure 3.1**).

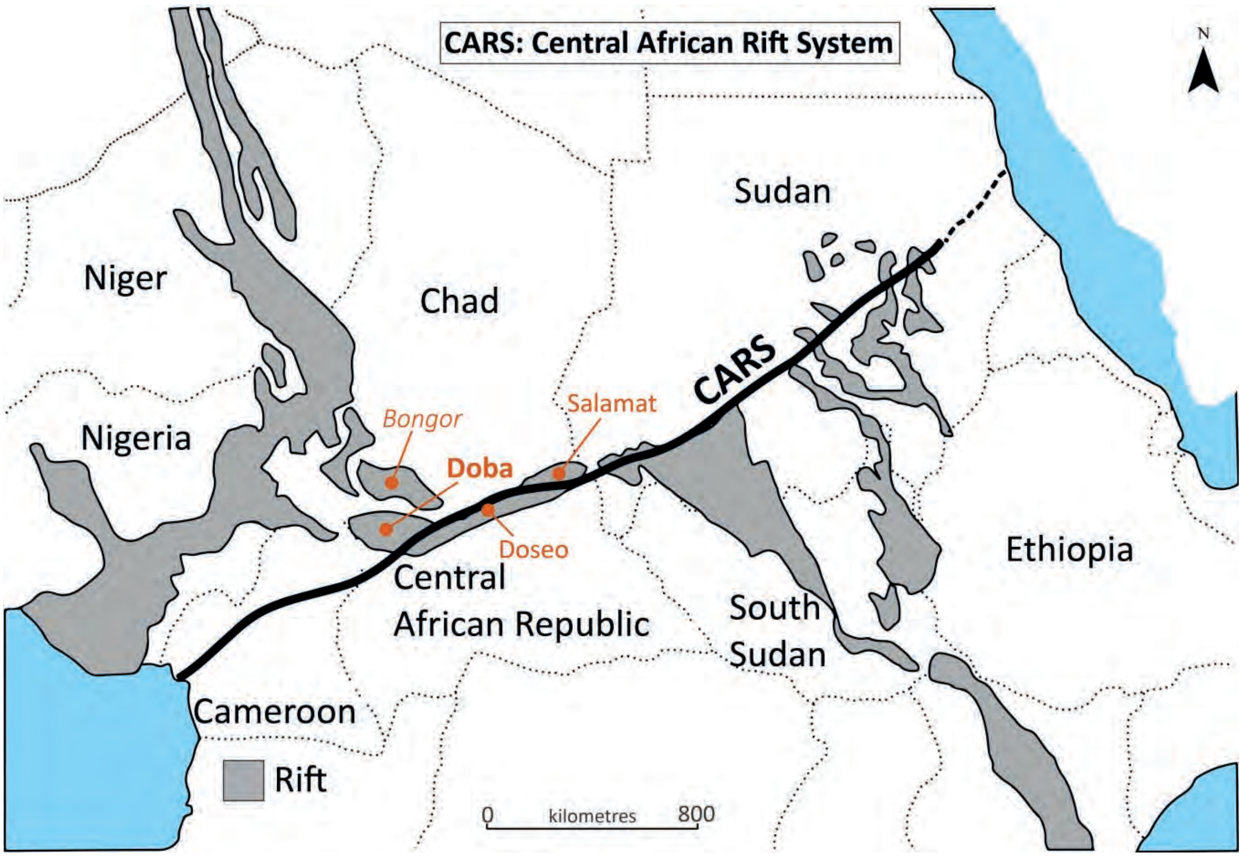



Figure 3.1 The Doba Basin set within the West and Central African rift systems

*Modified from: Public Domain, https://commons.wikimedia.org/w/index.php?curid=12828521*

Crustal movements associated with the opening of the Atlantic Ocean beginning about 130 million years ago caused the development of major fault zones across Niger and Chad. Movement along these fault lines generated extensional basins, such as the Doba Basin, into which sandy fluvial sediments were transported from surrounding uplands (**Figure 3.2**). At the centre of the Basin a large lake accumulated organic-rich shales that subsequently became the main source rocks for the Doba oil accumulations.

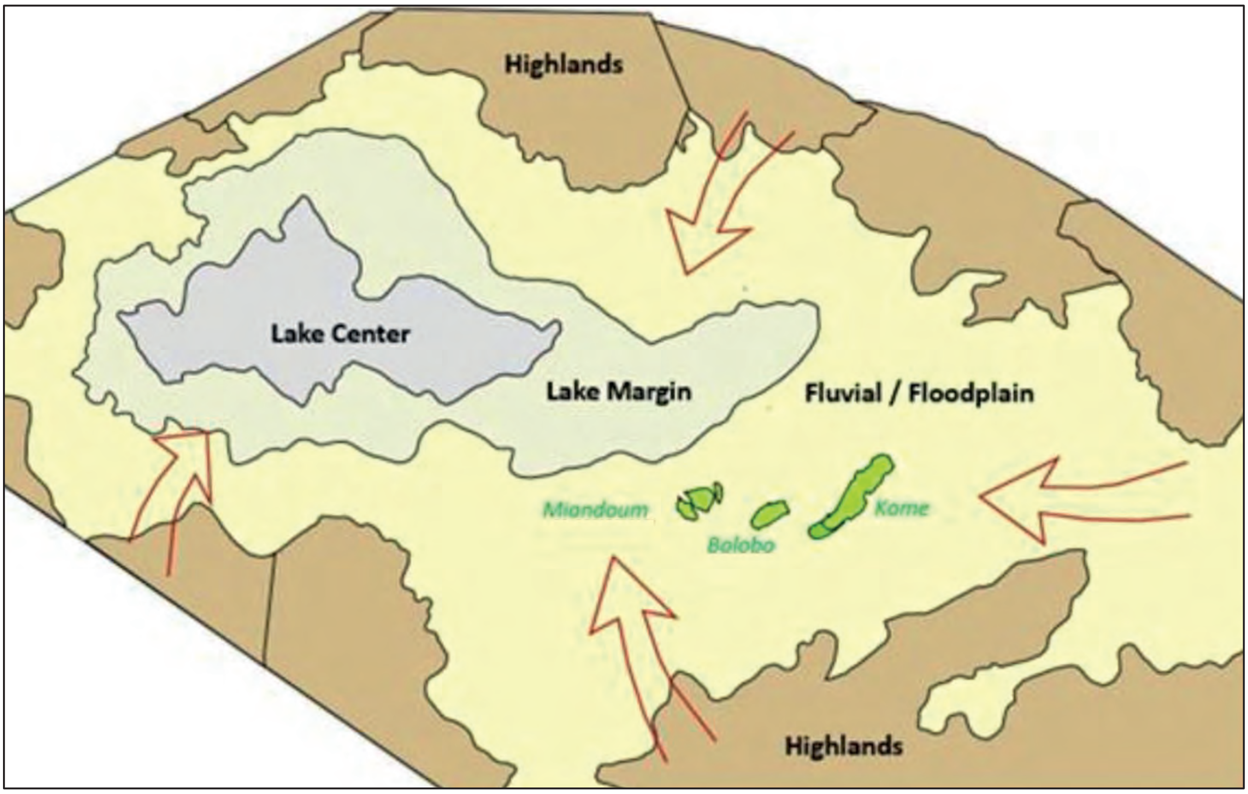


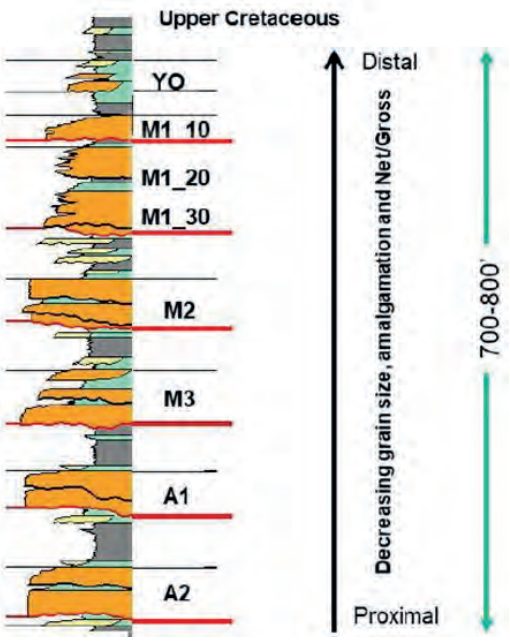

Figure 3.2 Palaeogeographic sketch showing the main sediment transport directions

Source: Doba Oil Project VDR

Considering **Figure 3.2**, the depositional assumptions contained within the current Operator's 3D geomodels are reasonable (see **Figure 3.3** and **Figure 3.5)** which show channel and channel-belt alignment that broadly follows the regional transport direction. The shortest route for water ingress from the aquifer is likely to be along the length of channel sandstones, either via basal channel lags or some other higher permeability layers.

## 3.2 Reservoir Geology

The Upper Cretaceous reservoir interval was deposited in a semi-arid braided fluvial environment. The different zones contain reservoirs which have the following character:




1)Isolated channel deposits encased in overbank fines with lacustrine mudstones.

2)Composite sheet sands formed in periods of low accommodation, during which amalgamation of channel sands occurred to create a more continuous deposit (this situation is typical of the M1 series reservoirs).

The Y0 and M1 reservoirs were formed by fluvial depositional systems but have different lateral continuity in the subsurface. The Y0 reservoirs are made up of discrete channel systems or individual channels that are encased in shale. The M1 reservoirs have a higher sand content generally; the M1-10, M1-20 and M1-30 zones show full continuity over the entire area of the Kome Field.

A series of crestal faults causes pressure isolation leading to different oil-water contacts in the different fault blocks.

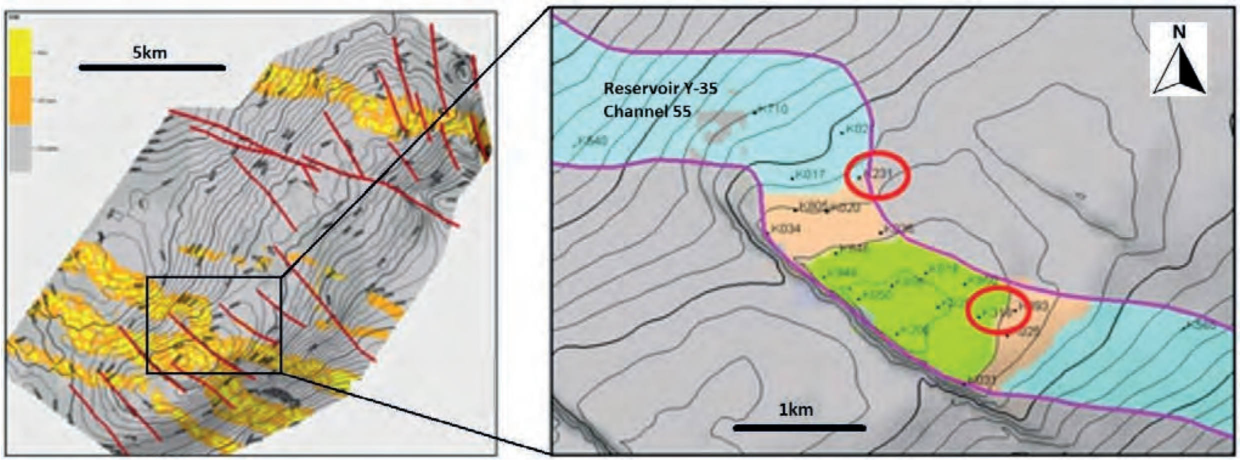



Figure 3.3 Y0 Reservoirs are thought to be isolated channels encased in shale (Kome Field)

Source: Doba Oil Project VDR

Further reservoirs can be found in the Lower Cretaceous at the Kome and Timbre fields. Those reservoirs were deposited in similar lacustrine and fluvio-deltaic environments with multiple sand & shale sequences charting lake contraction & expansion. To date, c. 98% of the cumulative oil production have been from the Upper Cretaceous reservoirs.

**Figure 3.3** shows how the Operator has modelled the fluvial channel sands in the Y0 reservoirs in the Kome Field. The modelled channels are heavily constrained by well data and do not appear to overestimate the sand volume in the Y0 reservoir interval. The same appears to be the case with the M-Series reservoirs, in which a discrete channel belt has been mapped from well data and then modelled (**Figure 3.5**). The Operator's mapping of sand extent appears very reasonable and is expected to be a good basis for the estimation of pore volume and STOIIP.

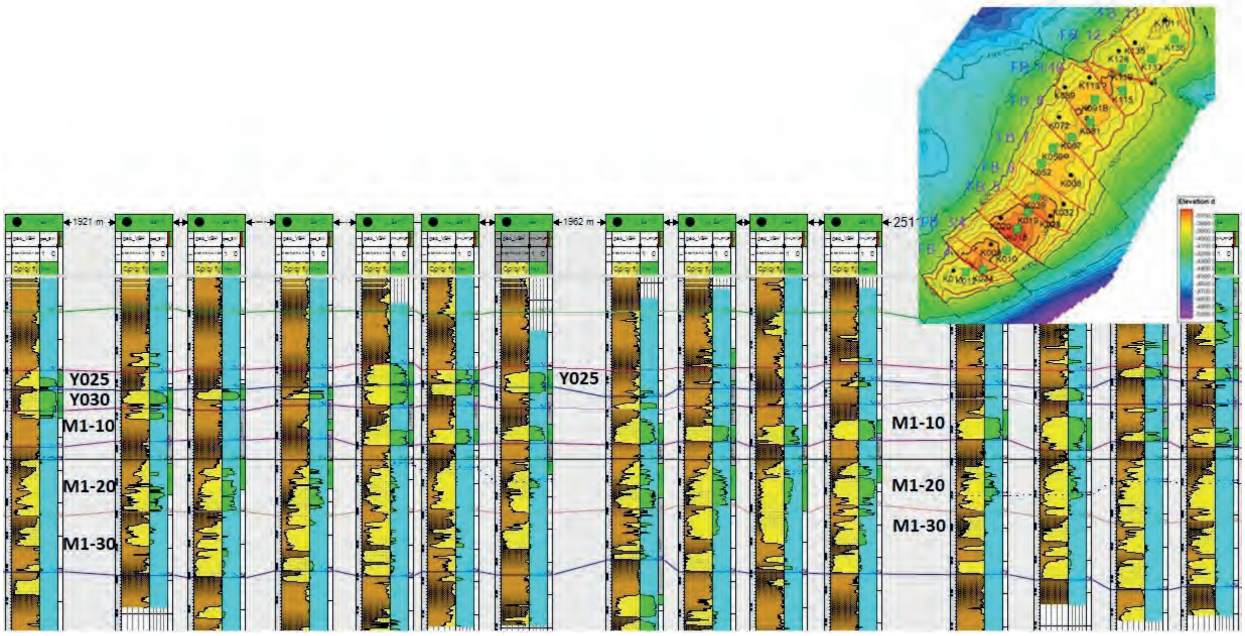



Figure 3.4 Well Section illustrating different lateral continuity of Y0 and M1 Reservoirs, Kome Field

*Source: Doba Oil Project VDR*

*Inset: Map at Top M1-20 showing line of section along crest of structure, indicated by green squares*

Within the laterally continuous, amalgamated, channel sands of the M1 series (**Figure 3.4**), shale barriers and 'baffles' representing the remains of floodplain sediments are common. These divide the reservoirs in a vertical sense within individual wellbores but are also likely to dip away from wells in unpredictable directions. These baffles have been identified and are acknowledged as significant reservoir heterogeneities that could:

- Channel water ingress
- Create barriers to connection between wells, and
- Influence sweep efficiency between wells.

The thin shale heterogeneities are not resolvable on seismic and their 3D orientation and lateral extent are difficult to discern or predict.

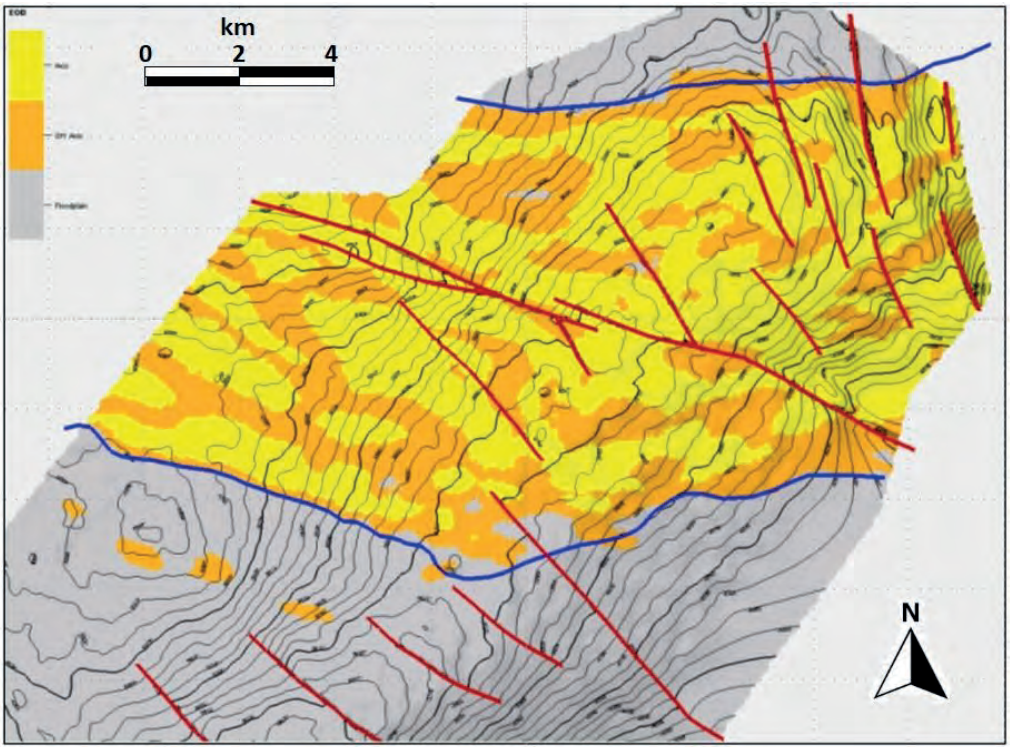



Figure 3.5 Mapped reservoir channel belt (Zone M1-10, Kome Field)

Source: Doba Oil Project VDR

## 3.3 Seismic Interpretation, Structure and Gross Rock Volume

The depth structure map and Gross Rock Volume (GRV) of a selection of major reservoir zones in Kome, Miandoum and Bolobo fields have been independently verified by mapping and 3D modelling. CGG is thereby able to verify that the current Operator's technical evaluation of oil-in-place appears reasonable. Furthermore, CGG has assessed stock-tank initial oil-in-place uncertainty which is now constrained to an extent by production decline analysis results and implied recovery factors. CGG's production forecasts and ultimate recovery factors are fully consistent with the estimated range of oil-in-place.

Overall, seismic data quality is relatively good, considering it is onshore and the abundant well penetrations give confidence to the overall GRV. Well-to-seismic ties have been checked and appear good. The structural interpretation has been reviewed and appears reliable; the faults identified and mapped by the current Operator have been verified as present and the overall pattern of faulting is entirely consistent with a strike-slip structural setting with fault splays branching off the main strike-slip zone.

After QC of the seismic horizon and fault picks, a velocity model was created from the extensive time and depth data available at the wells (see **Figure 3.6**, on which well markers in depth are plotted against time values from the seismic interpretation at well locations). This data delivers a good and straight relationship as defined in **Figure 3.6**.

An average velocity map was created for the conversion of the time map to the depth domain. Following this operation, the depth map was tied to the large number of closely spaced well tops. The result of the M1-20 map is shown in **Figure 3.7**.

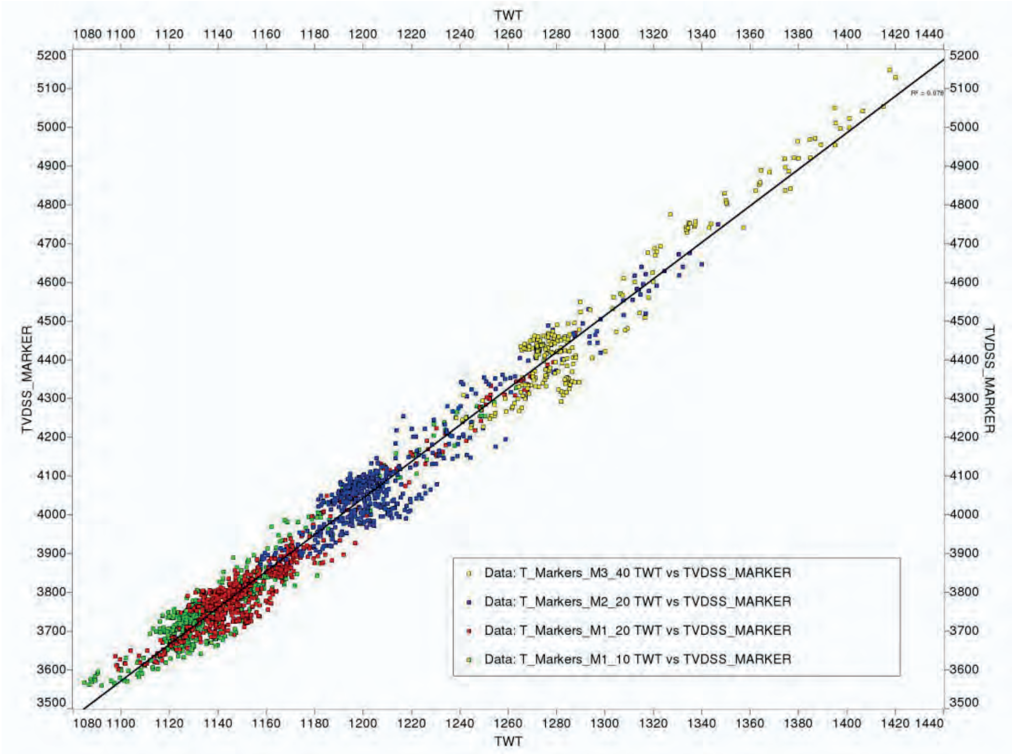



Figure 3.6 Time-depth plot for Kome Wells (TWT in ms and TVDSS in feet)

In the Kome Field, the M1-20 depth structure map was used as the basis for mapping deeper and shallower reservoir horizons. The high density of well tops over the structure means that there is a low uncertainty in reservoir depths within the oil zone. Areas of lower drilling density, for example down flank in the aquifer, have increased depth uncertainty however this has a low impact on calculated oil-in-place.

In a similar manner, time-depth relationships were established for Miandoum and Bolobo Field data. In the Bolobo Field, the data indicated slightly different correlations for reservoirs M1, M2 and M3.

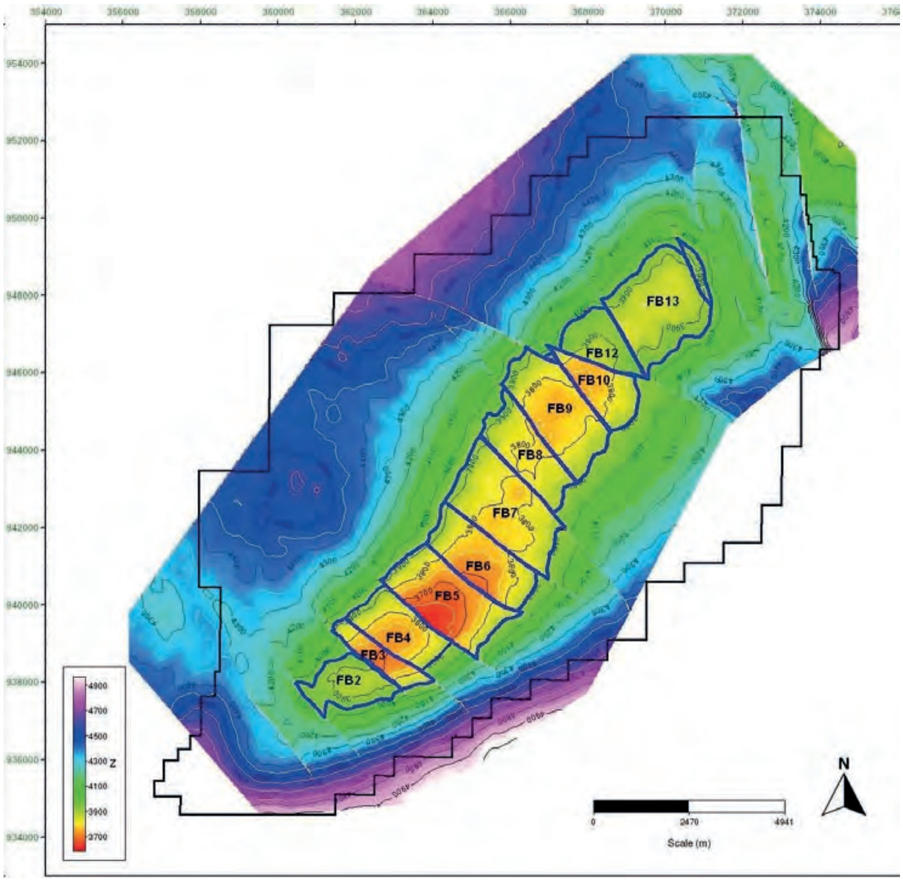



Figure 3.7 CGG's depth structure map at top of reservoir zone M1-20, Kome Field (contours in feet, TVDSS)

*Blue Polygons represent the Fault Blocks, incorporating the existing Oil-Water Contact and black outline corresponds to the Kome concession boundary*

The form and structure of the M1-20 depth map (**Figure 3.7**) is representative of all of the Upper Cretaceous reservoir zones. However, the Lower Cretaceous reservoirs appear to have a slightly different structure as illustrated in **Figure 3.8**. In the Lower Cretaceous, reservoir depths range between 8,700 to 11,000 feet (TVDSS).

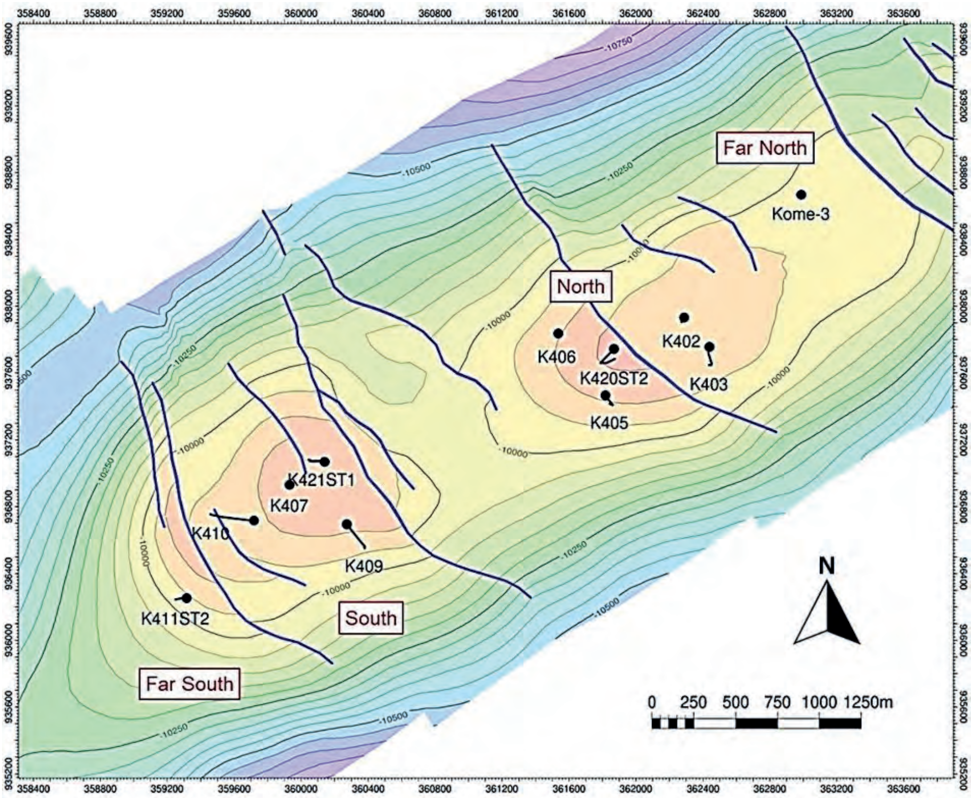



Figure 3.8 depth structure map at top of reservoir D-01, Lower Cretaceous, Kome Field

(contours in feet, TVDSS) – Source: Doba Oil Project VDR

CGG's independently derived depth-structure maps for Miandoum and Bolobo fields are shown in **Figure 3.9** and **Figure 3.10**.

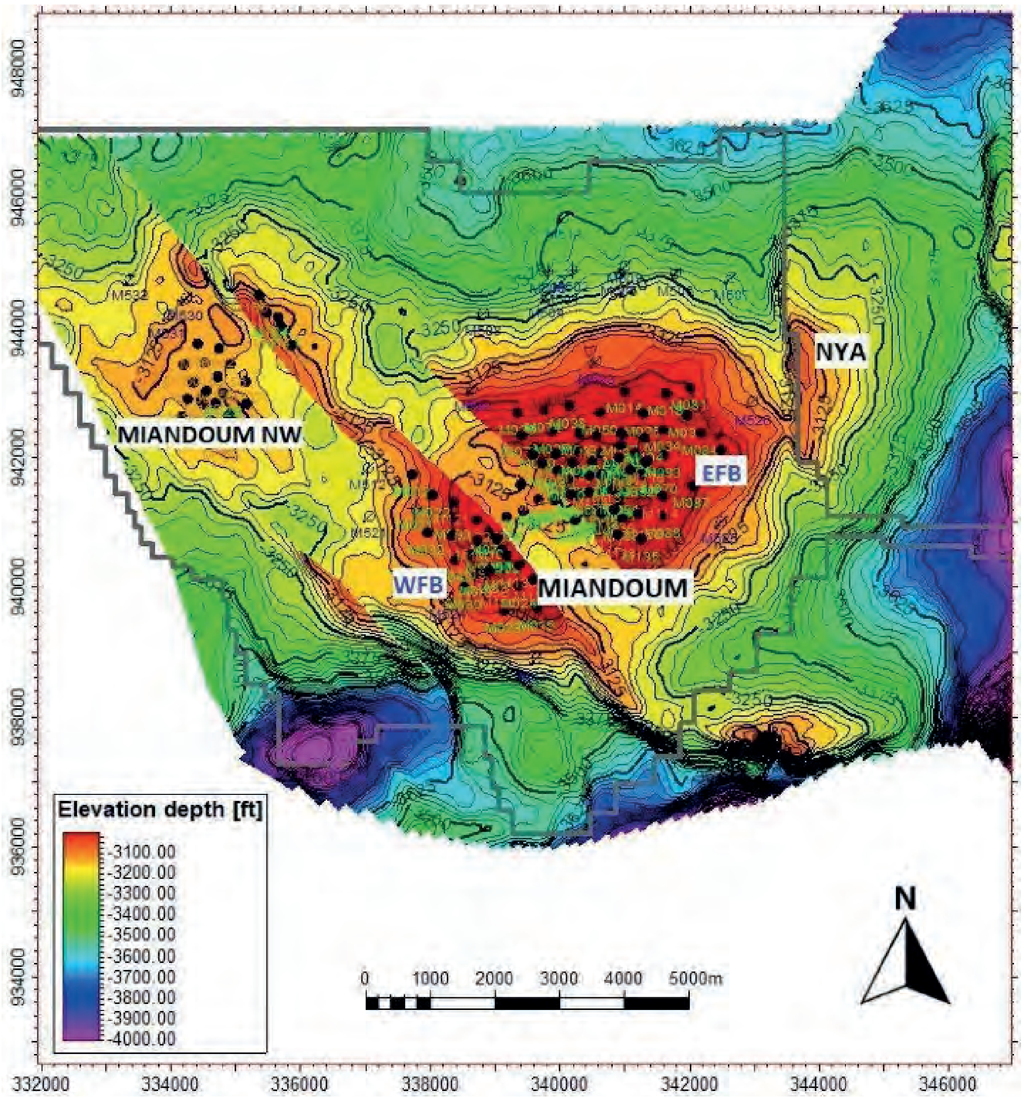



Figure 3.9 CGG depth structure map at top of reservoir M1-10, Upper Cretaceous, Miandoum Fields

(contours in feet, TVDSS)

*Grey outline corresponds to the Miandoum concession boundary*

*N.B., Miandoum Field consists of Western (WFB) and Eastern (EFB) Fault Blocks and Miandoum NW and Nya satellite structures*

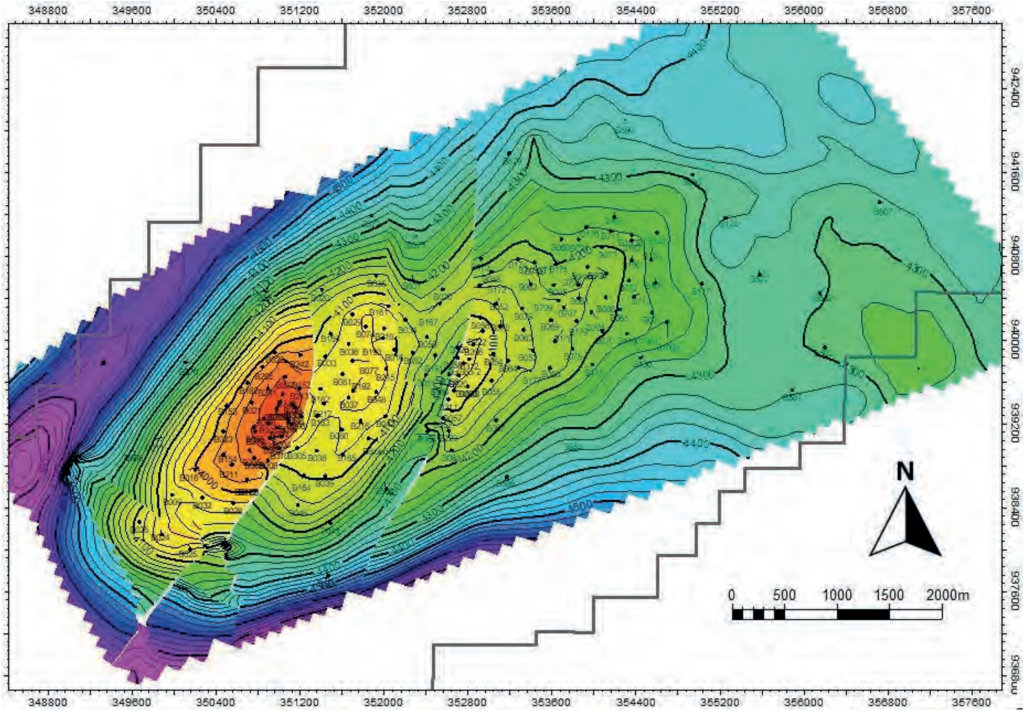


Figure 3.10 CGG depth structure map at top of reservoir M1-20, Upper Cretaceous, Bolobo Field

(contours in feet, TVDSS) - *Grey outline corresponds to the Bolobo concession boundary*

## 3.4 Reservoir Properties

CGG selected a number of key wells for the purposes of checking the Petrophysical reservoir properties assigned by the current Operator to the reservoirs under examination.

### 3.4.1 Methodology

The Petrophysical QC workflow is outlined in **Figure 3.11**. The Operator's approach to shale volume and porosity taken were simple, easily replicated and showed a good match to core calibration data. In respect to the water saturation and pay zone, CGG's method differs from the Operator's approach due to the challenges identified with the resistivity-based water saturation methods. The challenge is caused by the low salinity formation water (1,200-3,000ppm) that give rise to similar resistivity values in both oil and water bearing reservoirs. CGG used a capillary pressure, J-function, based water saturation estimation. The comparison of apparent water resistivity methods guided the pay zone selection.

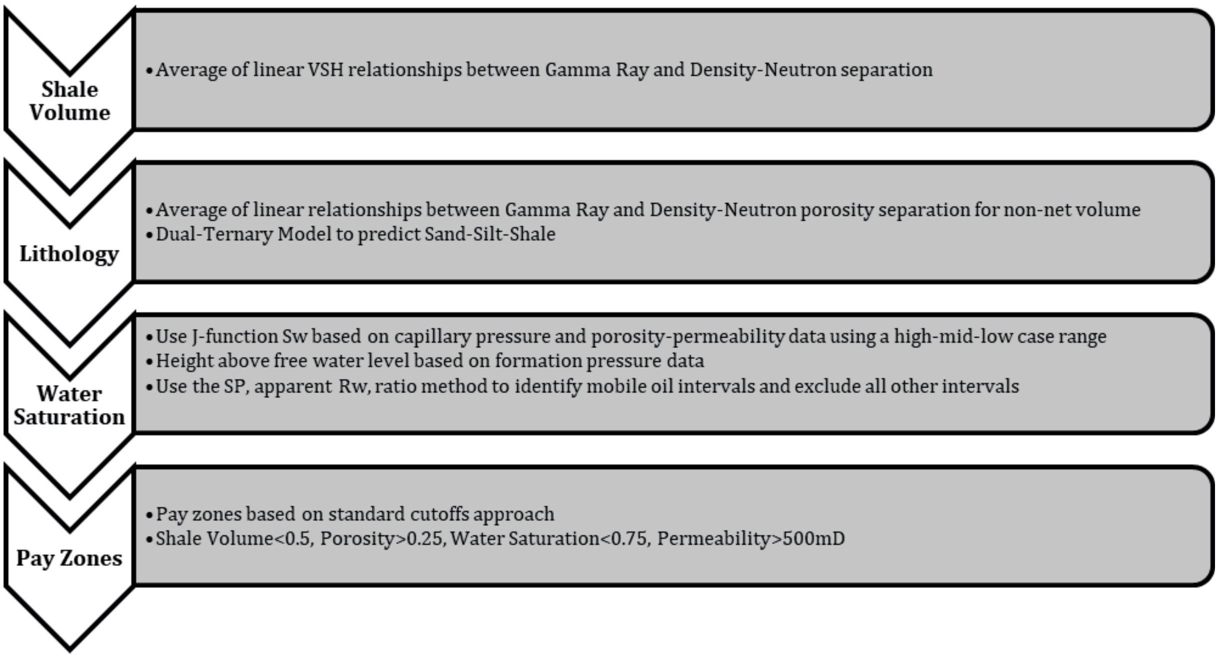



Figure 3.11 Petrophysical workflow

### 3.4.2 Shale Volume, Porosity and Lithology

The shale volume was derived from an average between linear gamma ray and density-neutron separation methods. The gamma ray logs were normalised from key wells and shale volume calculated linearly using GR. The shale volume from density-neutron separation via the crossplot method was also performed.

Total porosity was calculated using the standard linear method using the density log. The comparison of CGG with the current Operator's results are shown in **Figure 3.13** and **Figure 3.14**. The lithology divided the rock into two binary models of Sand-Silt (Vsh<0.5) and Silt-Shale (Vsh>0.5) (**Figure 3.12**).

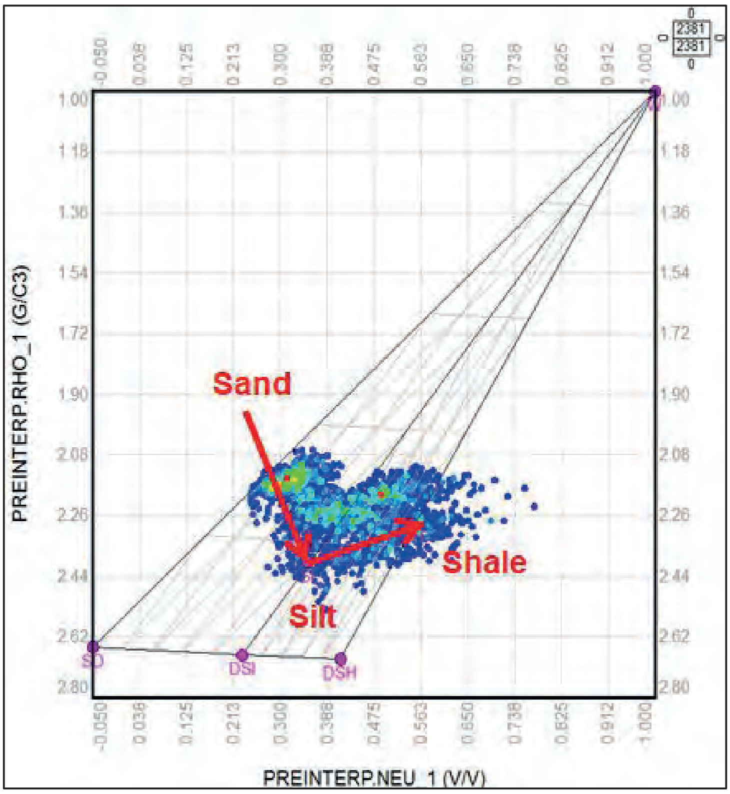



Figure 3.12 Density-neutron cross plot showing lithology division, for key well Kome-729

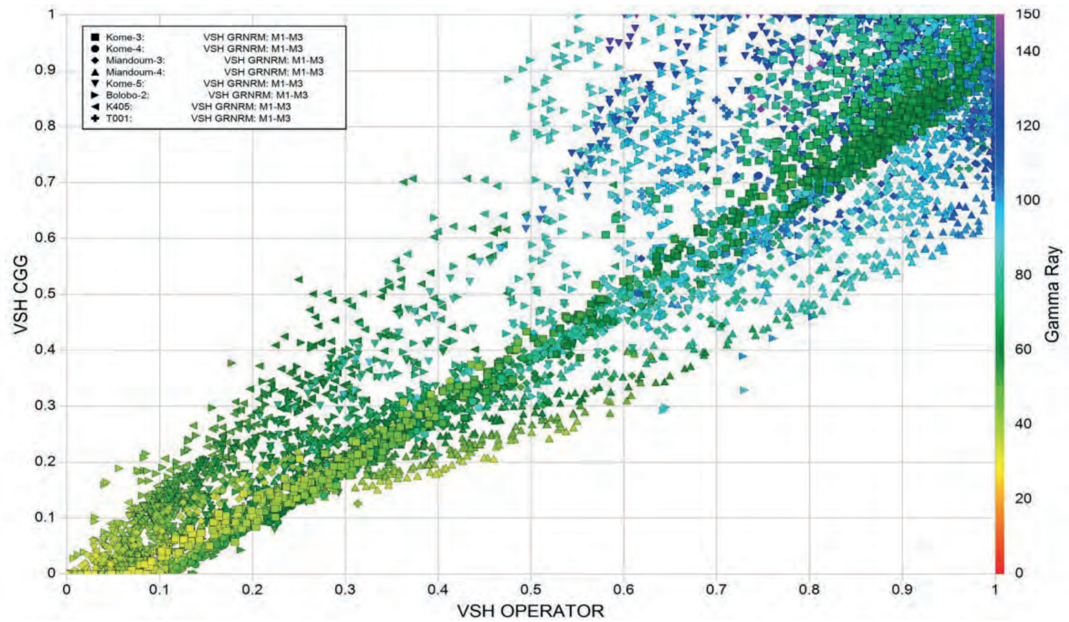



Figure 3.13 CGG / Operator's Shale Volume comparison plot, wells Kome-3,-4,-5,-405, Miandoum-3,-4, Timbre-1 and Bolobo-2 for M intervals

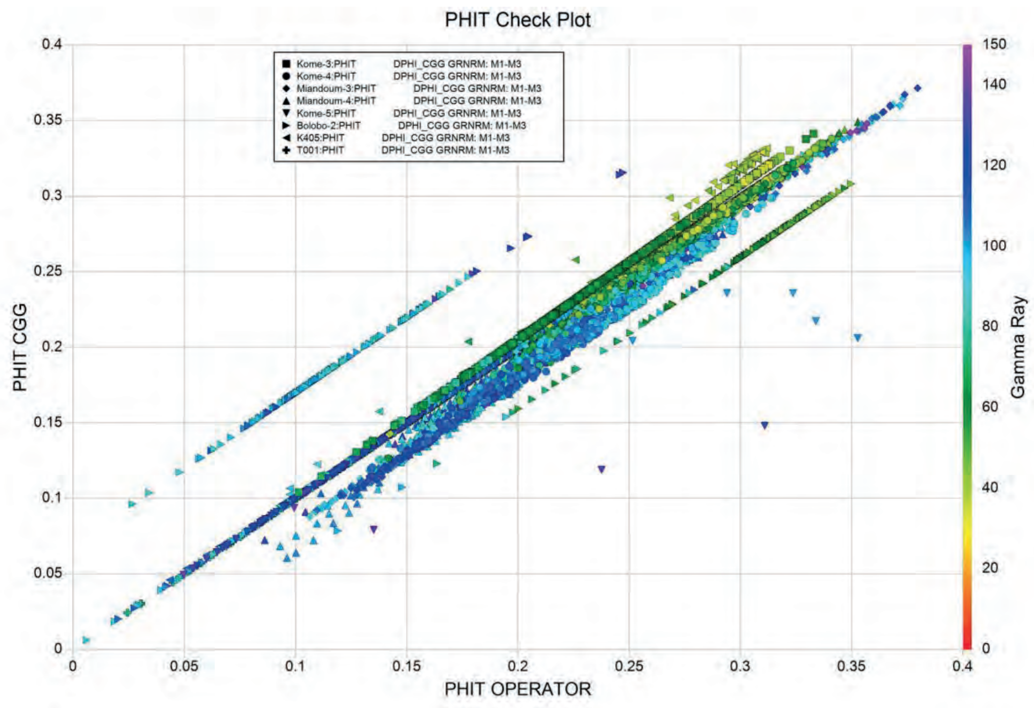



Figure 3.14 CGG / Operator's Porosity comparison plot, wells Kome-3,-4,-5,-405, Miandoum-3,-4, Timbre-1 and Bolobo-2 for M intervals

### 3.4.3 Water Saturation

The water saturation was calculated from the available capillary pressure data using the standard J function methodology. This is to avoid the issue of the low salinity formation water (1,200-3,000ppm) giving rise to the water and oil bearing formations having similar resistivity responses making a resistivity based water saturation approach ambiguous.

For the heavy viscous (~22ºAPI, ~80cP) oil to be mobile, a high porosity and permeability formation is needed. An additional simplification was that the free water level and oil water contact differences are considered to be negligible due to the high-quality reservoir (>500mD and 0.25v/v), which was supported by porous plate capillary pressure data.

Capillary pressure is a function of height above the free water level that is given from the extensive formation pressure data across the fields of interest. Free Water levels were derived on a reservoir by reservoir basis for key wells in Kome, Miandoum, Bolobo and Timbre, while other required parameters were calibrated and ground truthed to core capillary pressure measurements.

The pay zones are delineated based on the porosity-permeability and capillary pressure data. They indicate that the net pay cut-off is 500mD due to the high viscosity of the oil with the corresponding porosity cut-off being 0.25 v/v. This corresponds to gamma ray values of 75API or a shale volume cut-off of 0.5. A standard water saturation cut-off of 0.75 is applied and considered reasonable given the formation quality and application of polymer flood. A comparison of CGG and the current Operator's evaluation is provided in **Figure 3.15**

### 3.4.4 Conclusion

Independent petrophysical interpretation is able to reproduce the Operator's reservoir property estimation in selected key wells and suggests low levels of uncertainty in net-to-gross and porosity cut-offs with respect to core data. The water saturation and pay zone identification method was capillary pressure based due to the challenges that were identified with the resistivity-based water saturation methods. A comparison of apparent water resistivity methods was used to identify mobile oil intervals. This was combined with the free water levels known from formation pressure data to guide the pay zone identification.

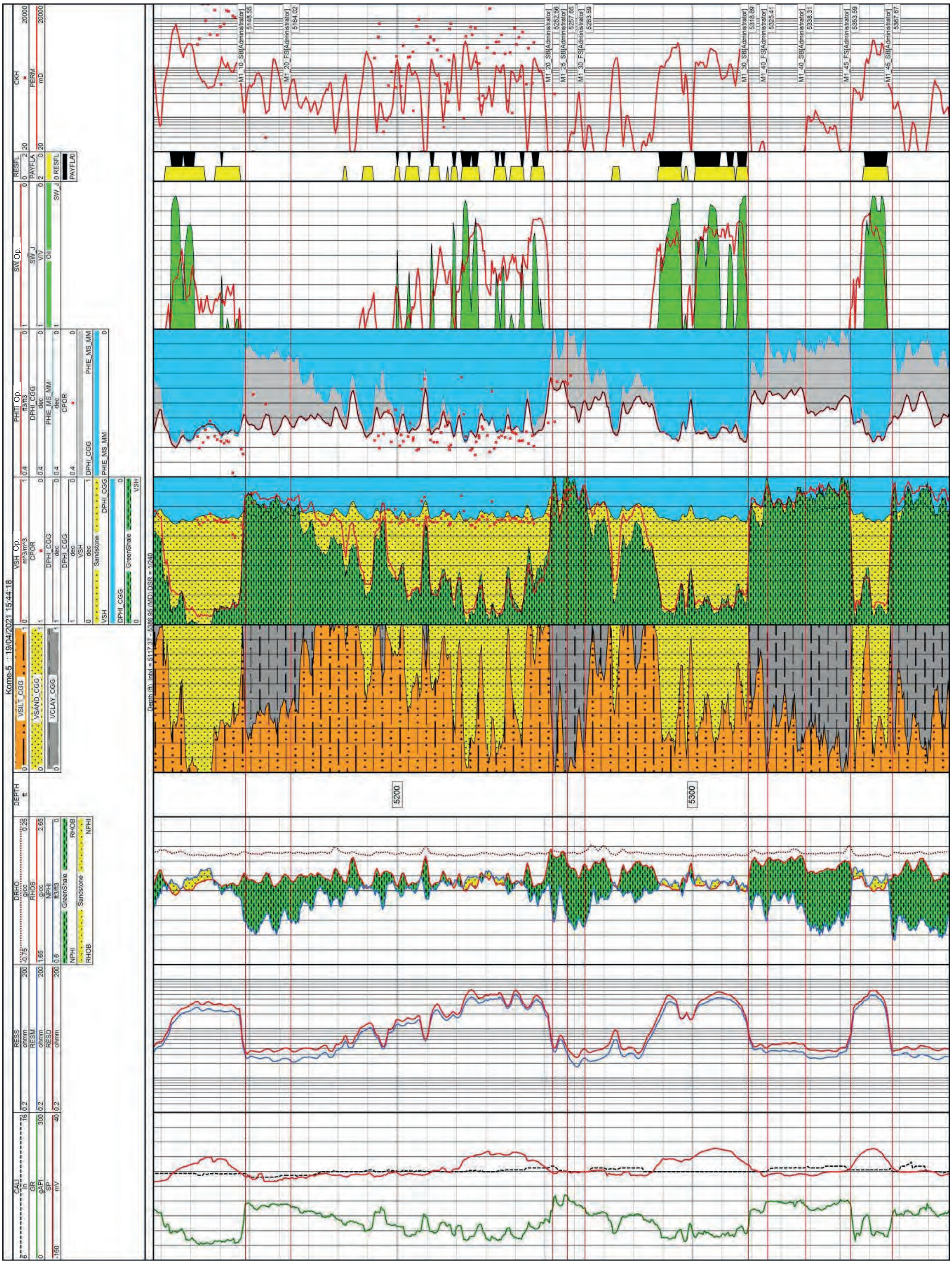


Figure 3.15 Key well comparing CGG and current Operator evaluations for well Kome-5

## 3.5 Stock Tank Oil-Initially-in-Place Validation

### 3.5.1 Methodology

The petrophysical QC of selected wells has demonstrated that net-to-gross and porosity provided by the current Operator are reliable, but that the water saturation is particularly uncertain due to the inability of the resistivity logs to distinguish oil from the fresh (low salinity) formation water. The current Operator has primarily used MDT data alongside depths such as oil-down-to and water-up-to, to define fairly reliable oil-water contacts. The estimated oil saturation above contact is the main uncertainty.

Defining a range of plausible water saturations above contact is key to assessing original-oil-in-place and implied recovery factor. Certain observations are important in this regard, and help to shape our approach to the assessment of STOIIP:

1. It is CGG's opinion that the oil originally migrated into the reservoir sands in the form of a lighter oil than is currently present. High oil saturations were achieved in high permeability and high porosity sands, and water saturation (Sw) likely reached irreducible with a minimum transition zone height.
2. Potential values of irreducible water saturation are suggested by capillary pressure (J-Function) data and may lie in the range 5% to 15% for the highest permeability sand and rising to 30 or 40% as permeability reduces and clay content increases. A range of initial oil saturations could therefore be 60% to 90%, dependent on sand quality.
3. Oil API was later decreased by in-situ bio-degradation, reducing oil mobility and ultimate recovery factor.
4. Production data from individual wells confirms that relatively clean oil with low water-cut is characteristic of early production, and this observation supports the idea that there is essentially no mobile water above contact.

For Kome, Miandoum and Bolobo fields, a 3D model has been constructed independently with depth maps tied to well tops at top and base of the main reservoir zones, plus oil-water contacts as verified by CGG. Gross Rock Volumes above oil-water contact are being considered fairly reliable due to the density of well penetrations. In densely drilled areas, there is a low uncertainty in depth structure maps and reservoir zone thickness maps.

CGG has performed this modelling work as a validation of the STOIIP in Kome Field M1, M2 and M3 series reservoirs and for Miandoum and Bolobo Y0 and M-series reservoirs. After verifying that the STOIIP stated by the current Operator for the volumetrically largest reservoirs is reasonable and based on sound technical work, CGG has assumed that the current Operator's STOIIP values for the lower volume reservoirs can also be considered reliable.

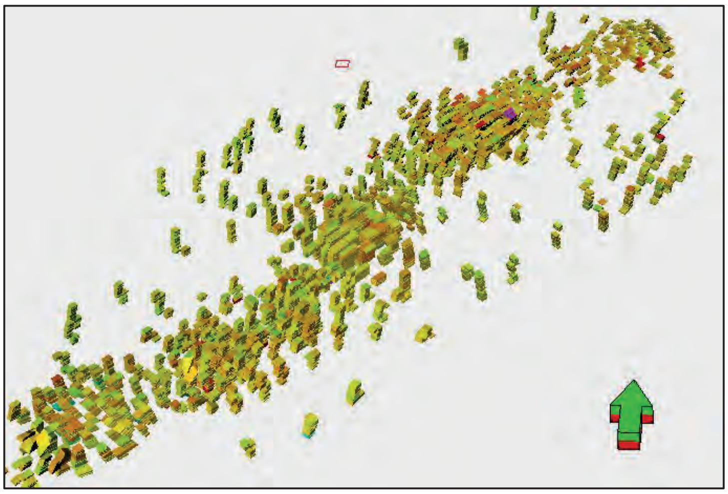


Figure 3.16 Upscaled cells for porosity, Kome Field. High data density in oil zone.

Following the creation of the 3D grid, net-to-gross and net-porosity well logs derived from available data were upscaled into the 3D grid (**Figure 3.16** illustrates the large density of wells). To avoid any bias, no property interpolation was performed. Layer thickness in these grids ranges from 1.5 feet to 4 feet, with an average of approximately 3 feet. This provides good vertical resolution and good reliability of the extracted reservoir property average values.

### 3.5.2 Uncertainties

CGG considers two primary uncertainties in the evaluation of oil-in-place: Gross Rock Volume (GRV) and water saturation. Reservoir depth control is excellent in most fields due to the close spacing of wells. The reservoir properties net-to-gross and porosity are considered relatively certain. For the purposes of this validation exercise, only GRV and water saturation are varied. Due to the close well spacing, GRV was varied by just +/-5% from the base case. However, based upon petrophysical analysis results, water saturation was varied by +/- 10 to 15% from the base case.

Base case values are derived, as described in earlier sections, by making use of the well log data upscaled into a 3D grid. Formation volume factors could only be obtained from available PVT data provided in the Kome field and are considered very reasonable considering the type of oil present and biodegradation.

### 3.5.3 Volumetrics: Kome, Bolobo, Miandoum and Nya Fields

CGG's evaluation of the volumes of oil-initially-in-place are given in **Table 3-1**.

| Field | Kome | Bolobo | Miandoum | Nya |
|---|---|---|---|---|
| Total (MMstb) | 2037 | 530 | 679 | 62 |

Table 3-1 Kome, Bolobo, Miandoum* and Nya Fields: Base case STOIIP results

*Note that the Miandoum volumes include the Miandoum North West structure volume (as described in **Figure 3.9**) in **Table 3-1** and all subsequent tables.

A separate evaluation of the Lower Cretaceous volumes and reservoir properties for Kome was carried out, concluding that the available maps and data, support the current Operator in-place values. CGG's independent assessment generated larger values than these, but data being relatively sparse, the current Operator's STOIIP of 81 MMstb has been carried.

### 3.5.4 Volumetrics: Moundouli, Maikeri and Timbre Fields

Having carried out a detailed assessment of volumetrics for Kome, Miandoum and Bolobo Fields, CGG has assessed the available STOIIP relating to the Moundouli, Maikeri and Timbre fields as being reasonable. The initial oil-in-place for these fields is as given in **Table 3-2**.

| Field | Moundouli | Maikeri | Timbre |
|---|---|---|---|
| Total (MMstb) | 331 | 75 | 44 |

Table 3-2 Moundouli, Maikeri and Timbre Fields: Base case STOIIP results

### 3.5.5 Definition of Low, Mid and High Case STOIIP

Independent petrophysical evaluation of key wells in Kome, Miandoum and Bolobo fields confirm that net-to-gross and porosity are relatively certain compared to water saturation. The range of porosity used in the calculations ranged from 27% to 31%. Due to the high density of wells, the GRV uncertainty is considered low. In heavily drilled fields with a long production history and which have produced more than two-thirds of the recoverable oil, the calculated STOIIP range must be consistent with the Decline Curve Analysis (DCA) results and the implied recovery factor.

CGG has assessed the STOIIP uncertainty primarily on the basis of varying calculated water saturation but also using a small GRV uncertainty (which may be understood as minor uncertainties in reservoir depth between the closely spaced wells and some uncertainty in the precise position of the oil-water contacts). The chosen uncertainty range for GRV is a 5%

subtraction or addition around the Mid Case GRV. Chosen uncertainty ranges for water saturation are +/- 15% for Kome field and +/- 10% for the Miandoum cluster and Bolobo. Although the average Sw is a variable, there are bounds imposed by what may be considered excessively optimistic initial oil saturations and by current and ultimate recovery factors implied. Range of STOIIP for the fields independently assessed by CGG are presented in **Table 3-3**. Uncertainty range for the remaining fields are presented in the next section.

Due to limited available data in the data package supplied, uncertainty ranges in the Lower Cretaceous (LK) STOIIP have not been computed.

| Field | STOIIP (MMstb) | | |
|---|---|---|---|
| | Low | Mid | High |
| Kome | 1638 | 2037 | 2451 |
| Bolobo | 453 | 530 | 612 |
| Miandoum | 586 | 679 | 777 |
| Nya | 53 | 62 | 71 |

Table 3-3 Kome, Bolobo, Miandoum and Nya Fields: STOIIP uncertainty range

Throughout the STOIIP validation and uncertainty analysis exercise, CGG has been mindful of the recovery factors indicated at end of field life.

### 3.5.6 Recovery Factor to 30th September 2021

The recovery factor, at full-field level and as at 30th September 2021, is given by cumulative oil production divided by the STOIIP. Given the range of STOIIP reported above, the range of recovery factors to 30th September 2021 is presented in **Table 3-4**.

| Field | STOIIP (MMstb) | | | Cum Prod** | Recovery Factors (frac.) to 30/09/21 | | |
|---|---|---|---|---|---|---|---|
| | Low | Mid | High | (MMstb) | Low | Mid | High |
| Kome* | 1719 | 2118 | 2532 | 307.9 | 0.18 | 0.15 | 0.12 |
| Miandoum | 586 | 679 | 777 | 136.1 | 0.23 | 0.20 | 0.18 |
| Bolobo | 453 | 530 | 612 | 117.4 | 0.26 | 0.22 | 0.19 |
| Moundouli | 283 | 331 | 382 | 31.3 | 0.11 | 0.09 | 0.08 |
| Maikeri | 64 | 75 | 87 | 19.1 | 0.30 | 0.25 | 0.22 |
| Nya | 53 | 62 | 71 | 13.5 | 0.25 | 0.22 | 0.19 |
| Timbre | 38 | 44 | 51 | 5.7 | 0.15 | 0.13 | 0.11 |
| **Total*** ** | **3196** | **3839** | **4512** | **631.0** | | | |

* Kome oil-initially-in-place including LK STOIIP
** Cumulative Production values as at 30th September 2021
*** Total may not add up due to rounding

Table 3-4 Field Recovery Factors indicated by the Low, Mid and High STOIIP Cases as at 30th September 2021

# 4 RESERVOIR ENGINEERING

## 4.1 Introduction

Reservoir Engineering activities carried out for the seven fields under review involved:

- Carrying out Decline Curve Analysis (DCA) to estimate Expected Ultimate Recovery (EUR) for the various fields on a No Further Investment basis.
- A review of the performance of the polymer flood in Kome and Miandoum fields with the aim of generating expected incremental recoveries as additional EURs to that estimated from the DCA analysis for the two fields, also on a No Further Investment basis.
- A review of the performance of the various wells drilled in the last drilling campaign, specifically in the period years between 2010 – 2015. The aim of this exercise is to generate Type Curves for the respective fields to be used in the estimation of Proved Undeveloped (PUD) recoverable volumes and production profile generation for planned future infill wells in the Doba fields.

By No Further Investment, it is assumed that similar operational activities (e.g. artificial lift repairs, polymer injection) will continue, as per current Operator program, but no additional wells will be drilled or re-completed.

## 4.2 Production History and Decline Curve Analysis

### 4.2.1 Production History

Historical production data for the various fields was provided on a monthly basis up to 30th September 2021. Oil production since inception is presented in **Figure 4.1** including a field by field breakdown. As at 30th September 2021, 631MMstb of oil has been produced from the Doba Oil Project. It should be noted that drilling activities stopped in 2015. Average gross production in 2020 was 33.7Kbopd with an average of c. 300 producers online. Most wells are on artificial lift with c. 90% on Electrical Submersible Pump (ESP) and c. 10% on Progressive Cavity Pump (PCP).

Crude oil tends to be heavier 17 to 27ºAPI with Gas Oil Ratio <100 scf/stb in the Upper Cretaceous reservoirs, while lighter crude (c. 40ºAPI and GOR > 1000 scf/stb) is produced from the Lower Cretaceous reservoirs.

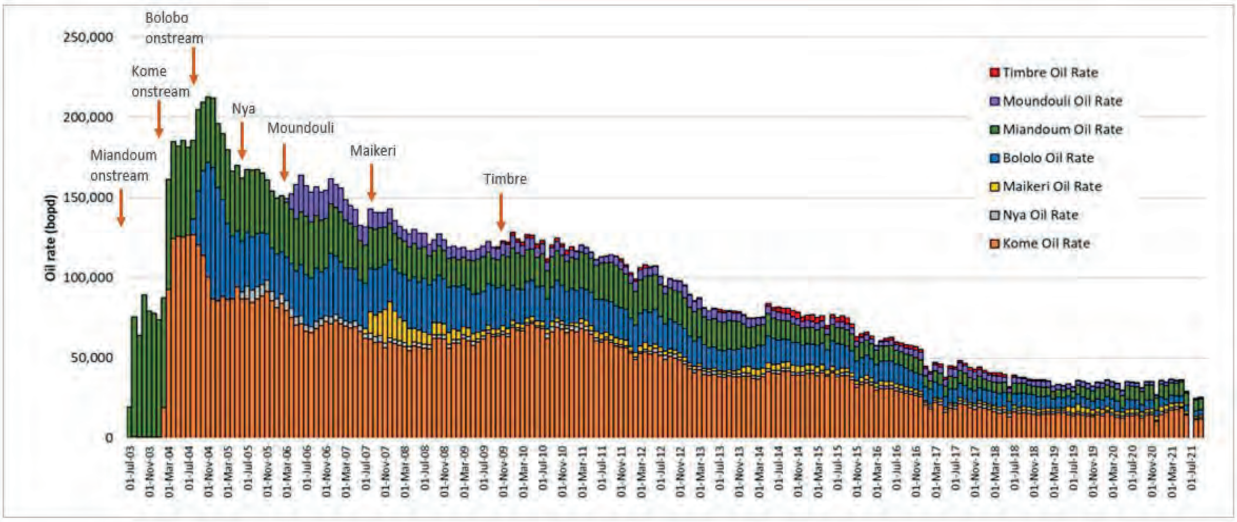



Figure 4.1 Historical production for the Doba Oil Project – Source: Savannah Energy

### 4.2.2 Decline Curve Analysis

The methodology adopted for the DCA carried out for the respective fields is as follows:

- Cartesian plot of oil rate versus cumulative oil and semi-log plot of produced Water-Oil Ratio (WOR) versus cumulative oil produced were generated and used in determining DCA based No Further Investment low and high EUR range. For the EUR analysis using the produced WOR versus cumulative oil semi-log plot, a WOR cut-off of 65bbl/bbl was adopted.
- Where possible different trends are picked from each of the oil rate versus cumulative oil and WOR versus cumulative oil plots. These different trends and respective EUR values, together with other relevant past and planned operational activities in the respective fields taken into consideration based on discussions with Savannah, formed the basis for assigning DCA based No Further Investment 1P, 2P and 3P EURs for the respective fields.

The results from both DCA methods are presented in **Appendix A**.

## 4.3 Technical Recoverable Volumes and Production Forecasts

### 4.3.1 DCA No Further Investment Technical Recoverable Volumes

#### 4.3.1.1 DCA No Further Investment Gross EUR Range

**Table 4-1** summarises the No Further Investment EUR range for the respective fields from the DCA analysis.

| Field | DCA No Further Investment EUR Range (MMstb) | |
|---|---|---|
| | Low | High |
| Bolobo | 124.0 | 132.0 |
| Kome | 340.0 | 400.0 |
| Maikeri | 21.0 | 24.5 |
| Miandoum | 150.0 | 190.0 |
| Moundouli | 34.0 | 50.0 |
| Nya | 15.0 | 18.0 |
| Timbre | 5.6 | 6.0 |

Table 4-1 DCA No Further Investment – Gross Technical EUR range

#### 4.3.1.2 DCA No Further Investment - Gross 1P, 2P, 3P EUR Estimates

**Table 4-2** summarises the No Further Investment 1P, 2P and 3P EUR estimates for the respective fields from the DCA analysis.

| Field | DCA No Further Investment EUR (MMstb) | | |
|---|---|---|---|
| | 1P | 2P | 3P |
| Bolobo | 127.0 | 128.0 | 132.0 |
| Kome | 350.0 | 375.0 | 400.0 |
| Maikeri | 23.5 | 24.3 | 24.5 |
| Miandoum | 165.0 | 170.1 | 190.0 |
| Moundouli | 38.8 | 41.4 | 50.0 |
| Nya | 16.0 | 17.0 | 18.0 |
| Timbre | 5.6 | 5.8 | 6.0 |
| **Total*** | **725.9** | **761.6** | **820.5** |

* Arithmetic sum

Table 4-2 DCA No Further Investment – Gross Technical 1P, 2P, 3P EUR

#### **4.3.1.3** DCA No Further Investment - Gross Technical Remaining Recoverable Volumes

**Table 4-3** summarises the No Further Investment - technical remaining recoverable volumes for the respective fields from the DCA analysis.

| Field | DCA No Further Investment Remaining Recoverable Volume (MMstb) | | |
|---|---|---|---|
| | 1P | 2P | 3P |
| Bolobo | 9.6 | 10.6 | 14.6 |
| Kome | 42.7 | 67.7 | 92.7 |
| Maikeri | 4.5 | 5.3 | 5.5 |
| Miandoum | 29.2 | 34.3 | 54.2 |
| Moundouli | 7.5 | 10.1 | 18.7 |
| Nya | 2.5 | 3.5 | 4.5 |
| Timbre | 0.0 | 0.1 | 0.3 |
| **Total*** | **95.9** | **131.5** | **190.4** |

* Arithmetic sum, Total may not add up due to rounding

Table 4-3 DCA No Further Investment - Gross technical remaining recoverable volumes

#### 4.3.1.4 DCA No Further Investment - Production Forecast

January to September 2021 actual production are incorporated at the start of the production forecast presented in this section for the various fields.

Decline Curve Analysis was carried out for the respective fields in order to determine the nominal decline rate, “a”, and decline exponent constant, “b”, based on Cartesian plots of oil rate versus time. Using the “a” and “b” values exponential, hyperbolic and harmonic oil rate versus time decline profiles were generated and inserted into the historical data plot thereby giving indication as to how the respective fields are declining over time. An example for the Kome field is presented in **Figure 4.2**. Hyperbolic decline was used for the 1P case, while Harmonic decline was used for the 2P and 3P cases.

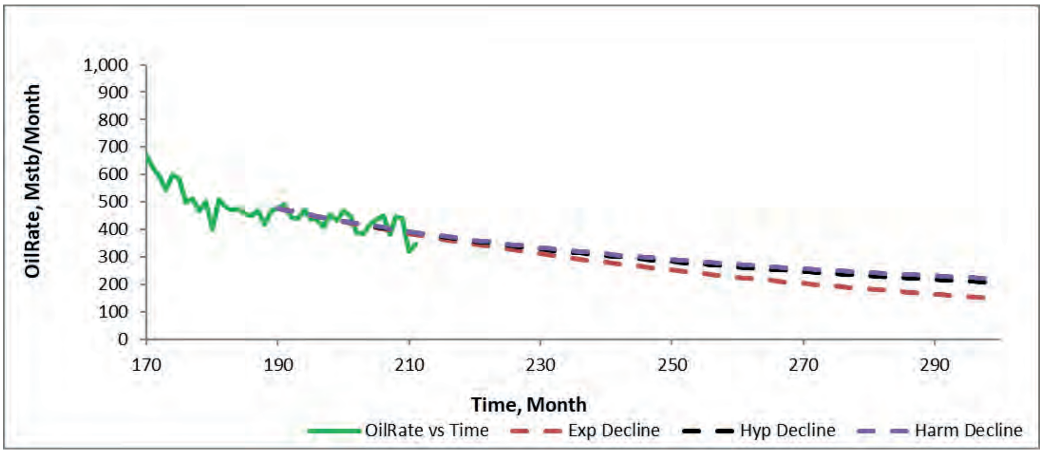



Figure 4.2 Kome field historical decline trend

#### 4.3.1.4.1 Kome Field

**Figure 4.3** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Kome field.

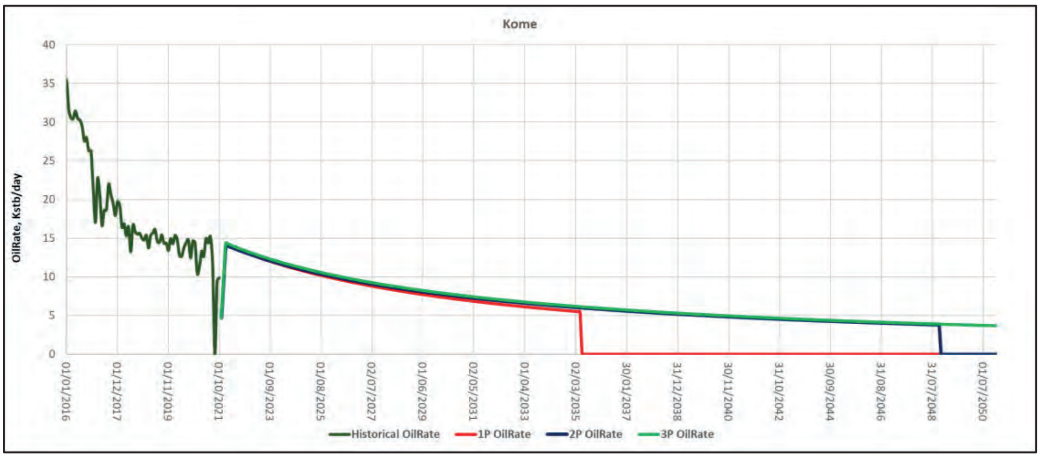



Figure 4.3 Kome field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

#### 4.3.1.4.2 Bolobo Field

**Figure 4.4** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Bolobo field.

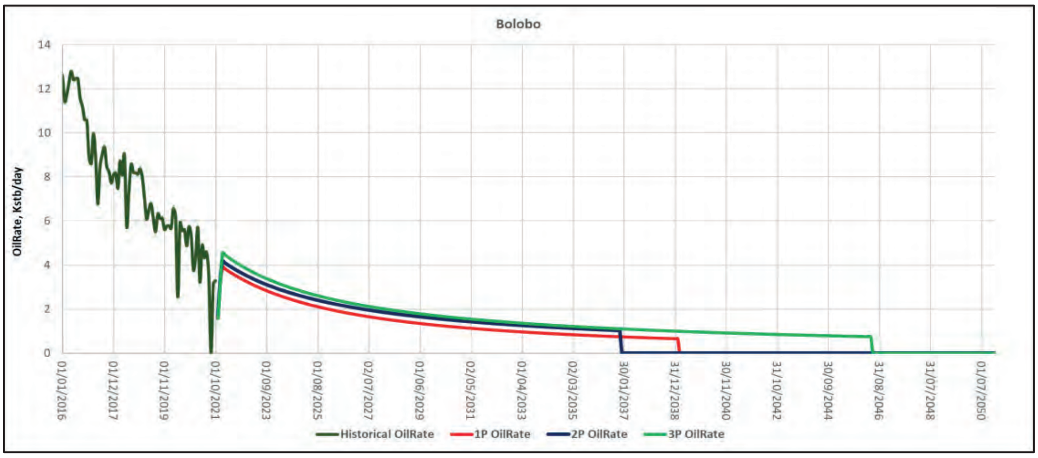



Figure 4.4 Bolobo field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

#### 4.3.1.4.3 Maikeri Field

**Figure 4.5** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Maikeri field.

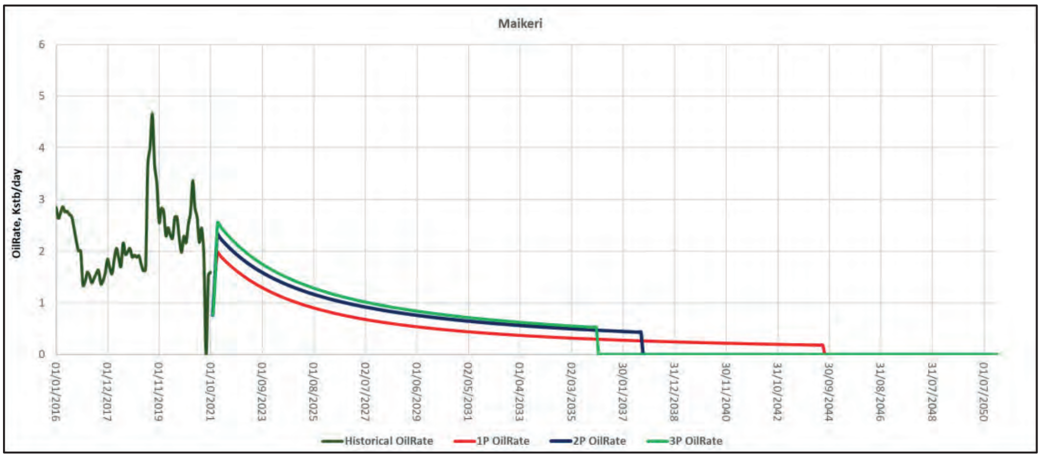



Figure 4.5 Maikeri field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

4.3.1.4.4 Miandoum Field

**Figure 4.6** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Miandoum field.

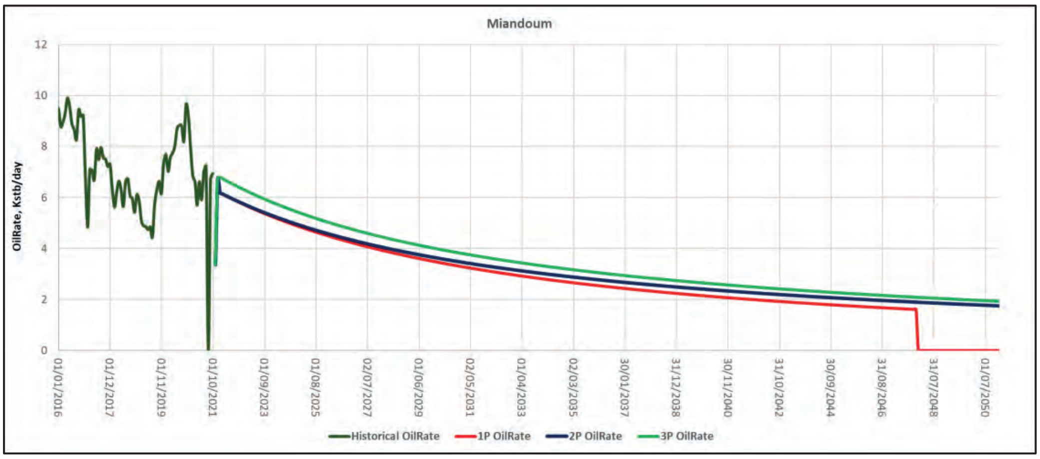



Figure 4.6 Miandoum field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

4.3.1.4.5 Moundouli Field

**Figure 4.7** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Moundouli field.

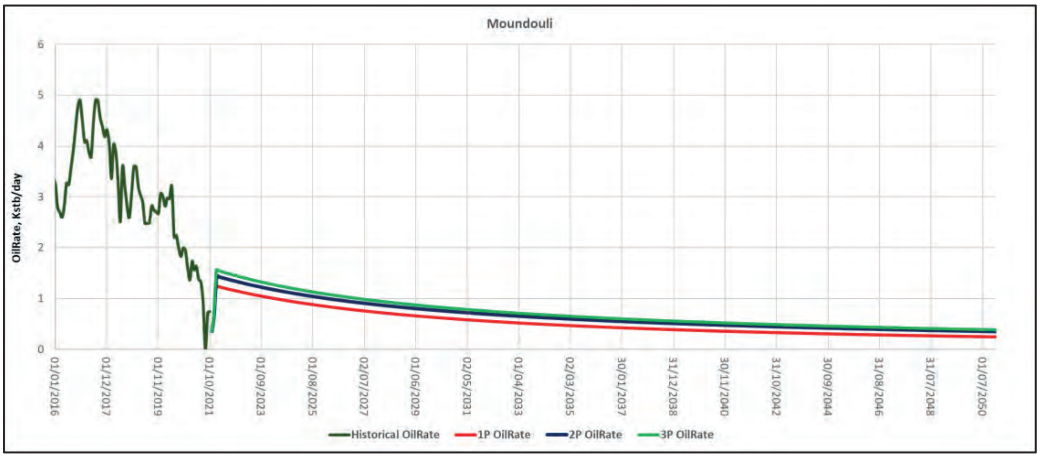



Figure 4.7 Moundouli field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

4.3.1.4.6 Nya Field

**Figure 4.8** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Nya field.

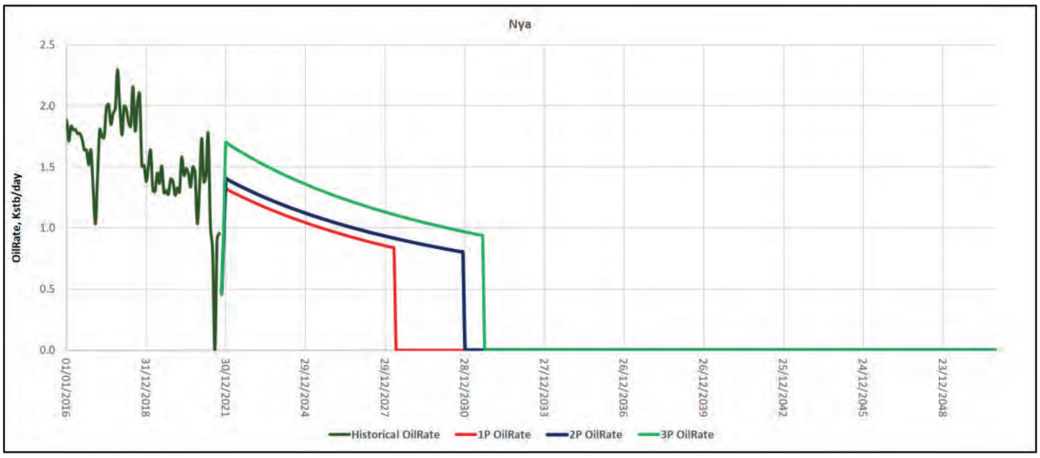



Figure 4.8 Nya field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

4.3.1.4.7 Timbre Field

**Figure 4.9** shows 1P, 2P and 3P Oil Rate versus Time production forecast (No Further Investment) respectively based on the DCA analysis carried out for the Timbre field. The 1P remaining recoverable volume is very small, therefore there are no Reserves forecasted in the 1P production profile.

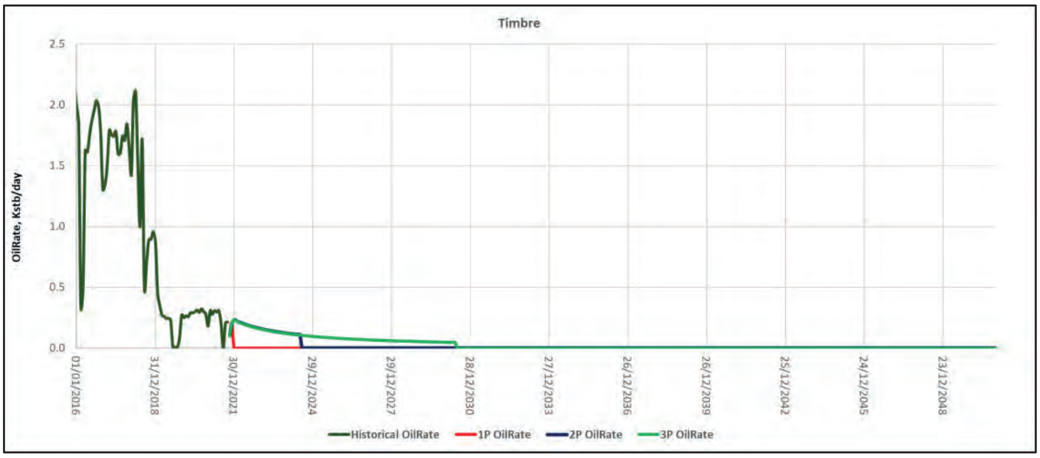



Figure 4.9 Timbre field 1P, 2P and 3P DCA No Further Investment Gross Oil Rate vs Time production forecast

### 4.3.2 Polymer Flooding

#### 4.3.2.1 Technical Recoverable Reserves and Forecast

Currently there are three polymer skids in operation; Skid 1 on Kome field, Skid 2 on Miandoum and Skid 3A on Kome (which came onstream at the end of 2020) - **Figure 4.12**. For these skids, the polymer flood has been implemented at a larger scale and the well spacing is greater than the initial pilot, conducted in 2015/2016 at Kome field. The reservoir complexity has also increased with injection into, and production from, multiple zones.

CGG has identified a range of recovery factors for full field polymer implementation based on a review of the available data. CGG would place a reasonable weight on the benefits characterised from full field simulation (although we have not reviewed any simulation models) at around 7-9%. The pilot study for the inner wells indicated an increased recovery of 12-18% for 0.5 pore volume injected. However, more recent Skid 1 and Skid 2 performances indicate recoveries on the low side of the range, closer to 12% (after 0.5 PV injected). The benefit of 0.5-1 PV injected and beyond is more uncertain, due to a more complex geological setting than in the Pilot area and there is a clear indication that benefits were limited after 1 PV was injected.

CGG has used the recovery factors as shown in the **Table 4-4** below as a best assessment of the range of recovery and to guide production performance forecasts.

| Low | Mid | High |
|---|---|---|
| 3-4% low side case | 7-9% simulation | 12% (Skid 1 & 2 performance) |

Table 4-4 CGG Range of Recovery Factors for Polymer Flood

The recovery factors have been calculated using the STOIIP and PV from the current Operator for the areas subject to polymer injection. Although CGG has verified STOIIP volumes for the fields overall, CGG has not verified the specific polymer flood polygon volumes as overall volumes were in good agreement.

To estimate future performance, CGG has used production performance from the two skids available to provide a guide for incremental oil uplift, initially resulting from the injection of polymer. These initial uplifts are in the order of 1-3 Kstb/d. A small plateau rate has been included in the profiles. By inspection of the pilot inner producer response, such a plateau might be expected to continue for up to 0.3 PV injected, which translates to around 3 years. A plateau might be expected due to the reduced viscous fingering and improved sweep performance of the polymer. CGG has then used the same decline curve approach as used for the full field to decline these profiles over a period of 10-15 years, the time it would take to inject approximately 1 pore volume at current injection rates. This has led to a range of recoveries from around 3% up to 11% for Kome, which was broadly consistent with CGG view from review of the data (**Table 4-4**).

CGG has assumed a range in initial production rates for 1P, 2P and 3P cases which captures the uncertainty in establishing a clear baseline from which to measure polymer benefits. As the profiles have only assumed benefits from polymer injection up to ~1PV injected, the 3P profile is curtailed at a fairly high rate and does cause a step in the overall profile in 2035. Technical Remaining Reserves associated with polymer flooding are shown in **Table 4-5**. Those Reserves form part of the No Further Investment case in addition to the DCA No Further Investment Remaining Recoverable.

Profiles for the Proved & Probable cases are presented in **Figure 4.10** and **Figure 4.11** for the Kome and Miandoum fields.

| Remaining Reserves (MMstb) | | | | Recovery Factor *(from start prod)* | | |
|---|---|---|---|---|---|---|
| **Skid** | **1P** | **2P** | **3P** | **1P** | **2P** | **3P** |
| # 1 | 2.8 | 5.0 | 10.4 | 3% | 6% | 11% |
| # 2 | 4.1 | 7.2 | 10.9 | 3% | 5% | 8% |
| # 3A | 2.9 | 5.0 | 10.9 | 3% | 5% | 11% |
| **Total*** | **9.9** | **17.2** | **32.2** | | | |

* Total may not add up due to rounding

Table 4-5 Polymer Flood Predicted Gross Recoverable Reserves at October 1st 2021 and Recovery Factor

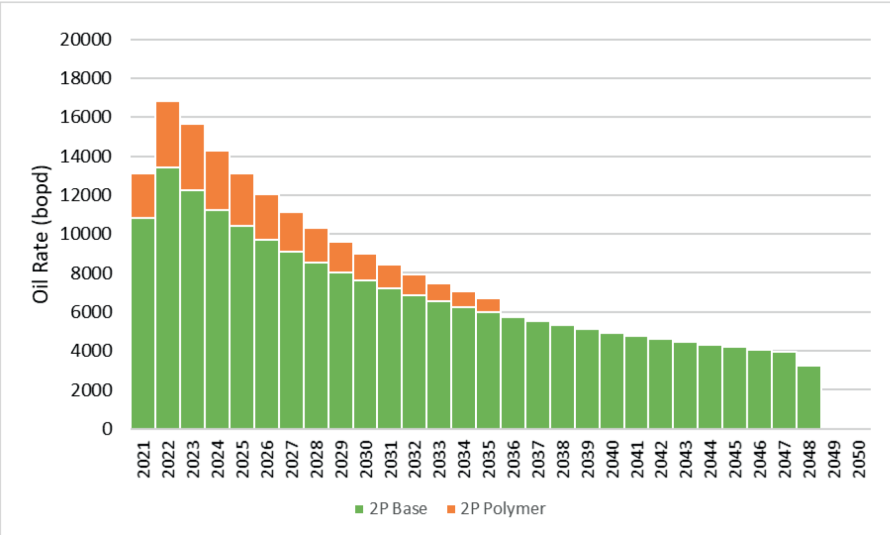



Figure 4.10 Kome Field – Base and Polymer Gross Proved & Probable forecast

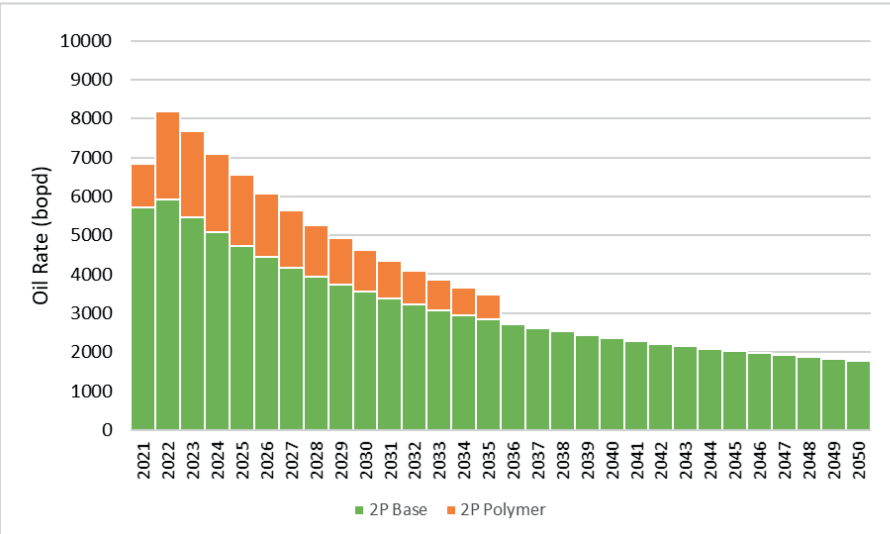



Figure 4.11 Miandoum Field – Base and Polymer Gross Proved & Probable forecast

#### 4.3.2.2 Contingent Resources Associated with Polymer Flooding

Further stages of polymer flooding are envisaged on the Doba fields. Stage 1 of the polymer development programme also includes skids 3B & 3C on Kome and Skid 4 on Bolobo beyond the current skids, see **Figure 4.12** below. Future stages beyond Stage 1, become increasingly uncertain, moving to areas of lower drilling density plus wedge and flank areas of the fields. CGG has considered that additional polymer skids beyond Skids 1, 2 and 3A should be classified as Contingent Resources.

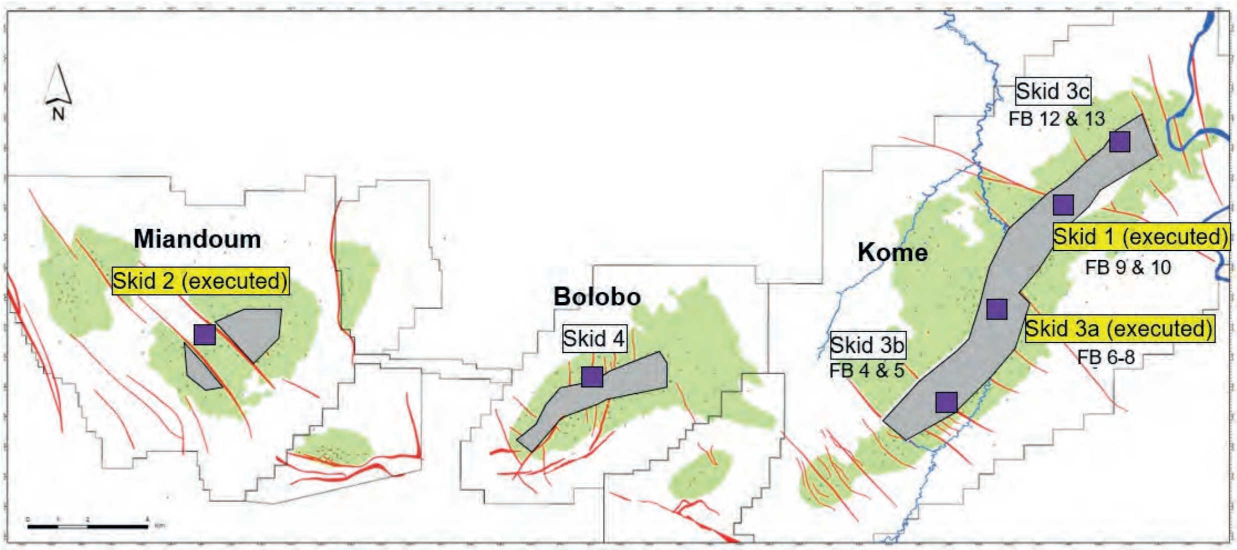



Figure 4.12 Polymer Flood Stage 1 Map

Source: Doba Oil Project VDR

Savannah has provided their view of Contingent Resources for the Polymer expansion programme which is shown in **Table 4-6**. Incremental recovery factors chosen are supported by CGG, being values up to the low end of the recovery identified in **Table 4-4** and consistent with the more challenging setting as discussed above.

| | 1C | 2C | 3C |
|---|---|---|---|
| Resources (MMstb) | 22.0 | 43.9 | 66.0 |
| Incremental Recovery Factor | 2% | 4% | 6% |

Table 4-6 Gross Contingent Resources Associated with Polymer Flood and Incremental Recovery Factors

The STOIIP used by Savannah was not based on all the areas included in the original Operator's plan, but on a sub-set of that plan resulting in a lower STOIIP. Overall CGG considers the Contingent Resources to be a good reflection of the potential uplift that might be realised with further polymer flooding expansion.

### 4.3.3 Proved Undeveloped Reserves from Planned Infill Wells

In order to understand and predict the performance of planned new wells, CGG reviewed the performance of the various wells drilled in the last drilling campaigns, specifically spanning the years 2010 – 2015. The aim of this exercise was to generate type curves for the respective fields that can be used in the estimation of technical recoverable volumes and production profile generation for planned future wells in the Doba fields.

For the Kome field, CGG looked at the initial production rates for wells drilled in the year 2014 & partly 2015. This time period is the most recent time when a drilling campaign was carried out in this field. During this period, 58 wells were brought into production between 1st January 2014 till 31st January 2015. The oil production rate from these new wells was plotted against normalised time axis where the time axis was converted into 'months into production' instead of actual time. This yielded an oil production trend for analysis. **Figure 4.13** shows this plot of oil production rate for Kome wells with respect to months into production. CGG then took average of the oil production rates for each normalised 'month into production' and this average oil production rate is shown as a solid **Green** line (labelled **Average**). A hyperbolic decline curve was fitted to this average production rate shown as a **Black** line (labelled **Fit**). The initial oil rate for this fit is 250 bopd (with monthly decline rate a=0.04 and b=0.3). **Figure 4.14** shows the 'average oil production rate' and hyperbolic curve fit in a separate plot for the Kome field. Similar analysis was done for Miandoum, Moundouli, Nya and Bolobo fields over a relevant period corresponding to the oil production rate data of most recently drilled wells. **Figure 4.15** shows the low, mid and high cases oil production profile for type wells in Kome, Miandoum, Moundouli and Nya fields. The infill programme is based on a one-rig programme drilling starting in January 2023, and each well taking an average of a month to be drilled. The drilling programme is outlined below:

- Moundouli drilling 18 wells from January 2023
- Kome drilling 60 wells from July 2024
- Miandoum drilling 9 wells from July 2029
- Nya drilling two wells from April 2030

In addition, there are further planned wells for the Bolobo field, but these are classified as Contingent Resources as they will be a long way out in time, based on a single rig schedule.

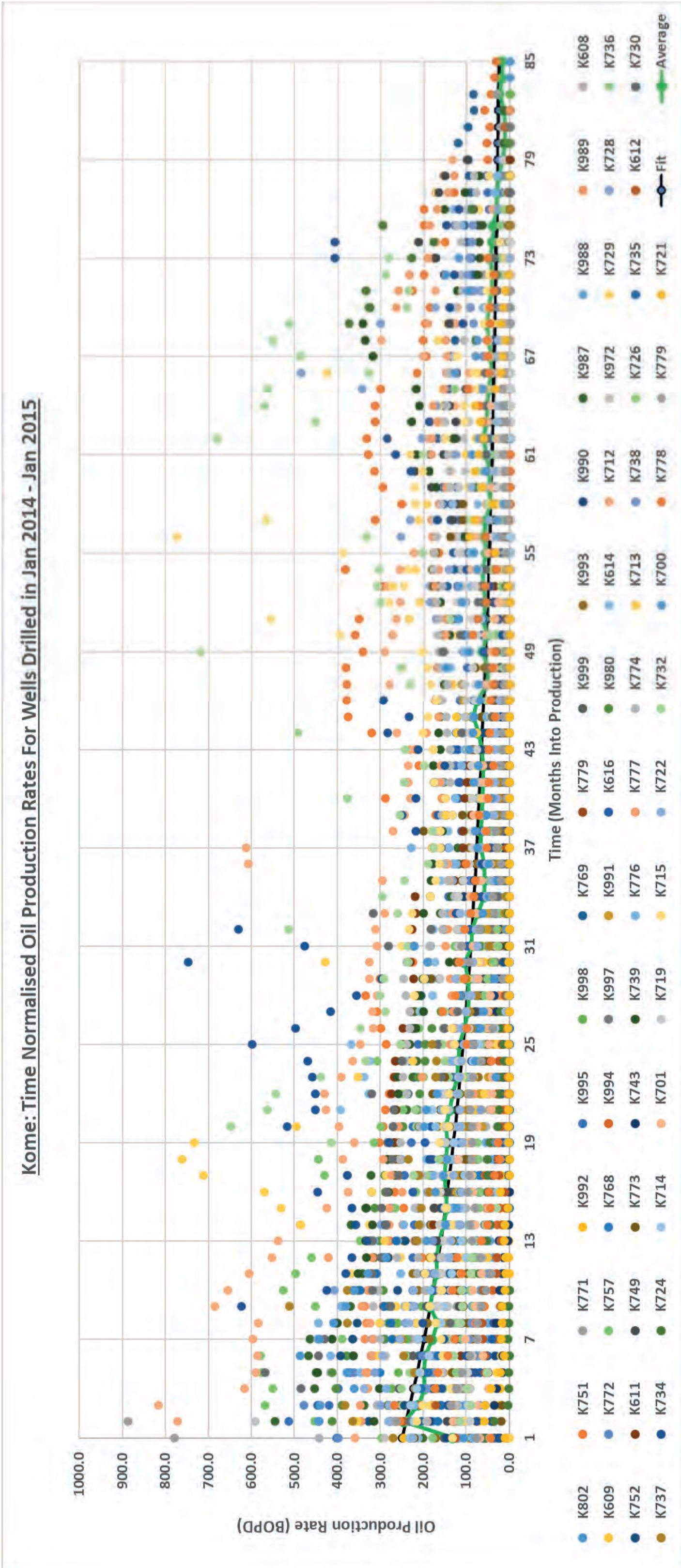



Figure 4.13 Time normalised oil production rates for wells drilled during Jan 2014 - Jan 2015 in Kome field

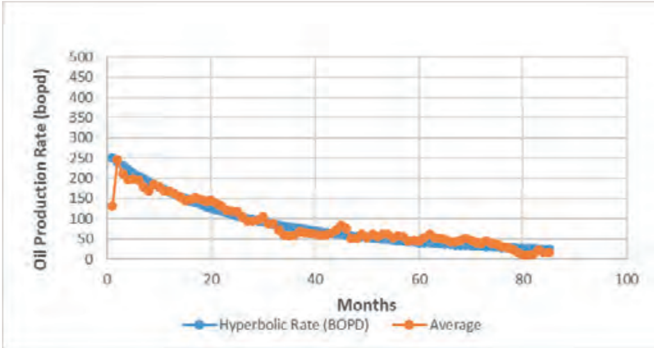



Figure 4.14 Average oil production rate fit for recent Kome wells

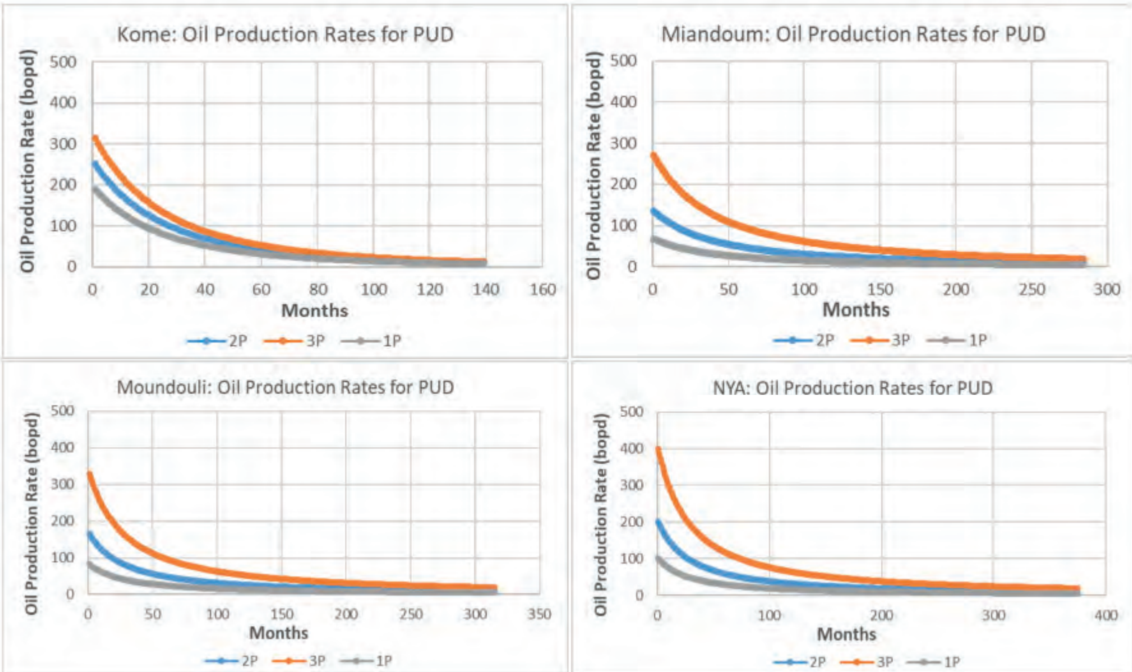



Figure 4.15: Low, mid and high case oil production profiles for type wells in Kome, Miandoum, Moundouli and Nya fields

Based on the expected well performance and the number of wells to be drilled the following recoverable volumes have been calculated, as shown in **Table 4-7**.

| Field | PUD Remaining Recoverable Volume | | |
|---|---|---|---|
| | 1P | 2P | 3P |
| Kome | 11.1 | 14.9 | 18.6 |
| Miandoum | 1.3 | 2.6 | 5.1 |
| Moundouli | 2.8 | 5.7 | 11.3 |
| Nya | 0.4 | 0.8 | 1.6 |
| **Total*** | **15.7** | **23.9** | **36.6** |

* Total may not add up due to rounding

Table 4-7 Gross Proved Undeveloped Reserves based on future drilling

### 4.3.4 Doba Oil Project Reserves Summary

**Table 4-8** is a summary of the Technical Recoverable volumes for the Doba Oil Project separated into Proved Developed Producing (PDP) and Proved Undeveloped (PUD). The PDP case requires no further investments and includes remaining recoverable volumes derived from the DCA (**Section 4.3.1.3**) and Polymer flooding (**Section 4.3.2.1**).

| Field | CumOil (MMstb) | 1P | 2P | 3P |
|---|---|---|---|---|
| | as at 30/09/2021 | No Further Investment Remaining Recoverable Volume (MMstb) | | |
| Bolobo | 117.4 | 9.6 | 10.6 | 14.6 |
| Kome | 307.9 | 48.4 | 77.6 | 113.9 |
| Maikeri | 19.1 | 4.4 | 5.2 | 5.4 |
| Miandoum | 136.1 | 33.4 | 41.6 | 65.1 |
| Moundouli | 31.3 | 7.5 | 10.1 | 18.7 |
| Nya | 13.5 | 2.5 | 3.5 | 4.5 |
| Timbre | 5.7 | 0.0 | 0.1 | 0.3 |
| **Doba Oil Project Total PDP*** | | **105.9** | **148.8** | **222.6** |
| | | **PUDs based on Further drilling** | | |
| Kome | | 11.1 | 14.9 | 18.6 |
| Miandoum | | 1.3 | 2.6 | 5.1 |
| Moundouli | | 2.8 | 5.7 | 11.3 |
| Nya | | 0.4 | 0.8 | 1.6 |
| **Doba Oil Project Total PUD*** | | **15.7** | **23.9** | **36.6** |
| **Doba Oil Project Total Technical Reserves*** | | **121.6** | **172.7** | **259.2** |

* Total may not add up due to rounding

Table 4-8 Summary of the Gross Technical Recoverable volumes for the Doba Oil Project

Also presented in **Figure 4.16** to **Figure 4.18,** are the profiles of the three cases (1P, 2P, 3P).

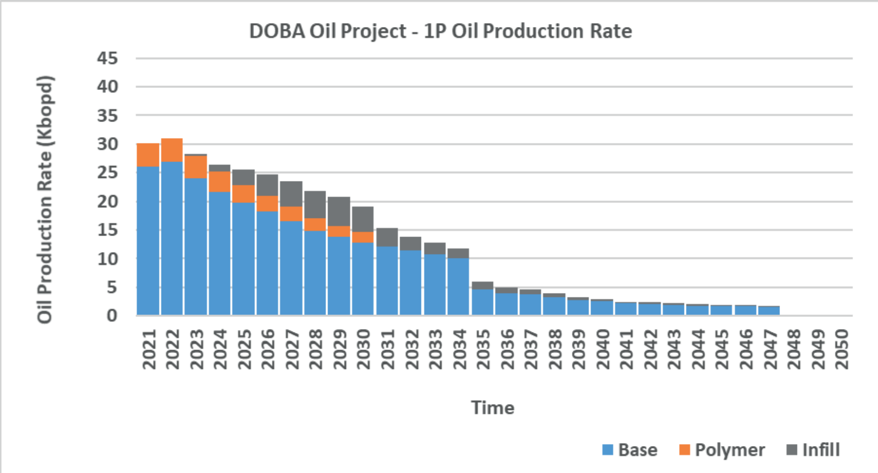



Figure 4.16 Doba Oil Project - 1P Gross Oil Production Rate

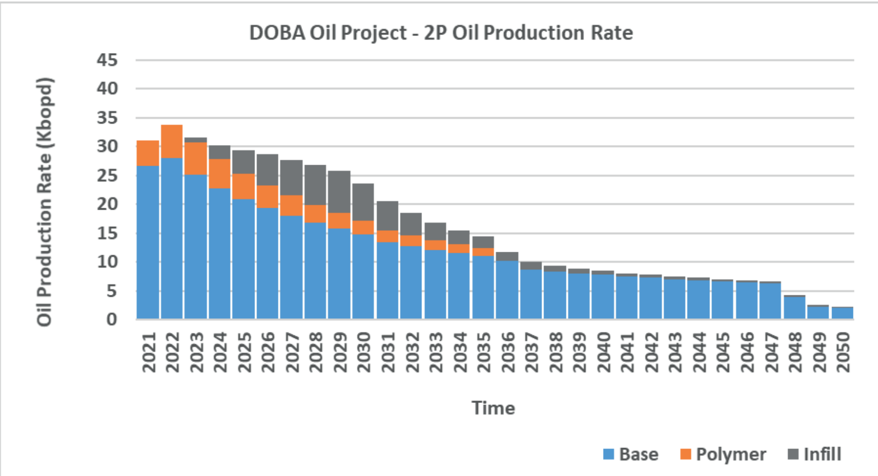



Figure 4.17 Doba Oil Project - 2P Gross Oil Production Rate

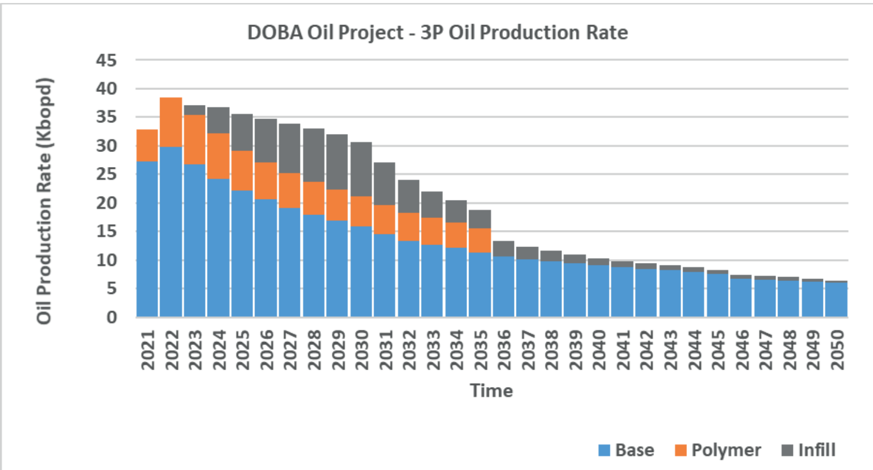



Figure 4.18 Doba Oil Project - 3P Gross Oil Production Rate

The 1P profile with the P2 and P3 increments is shown in **Figure 4.19** below.

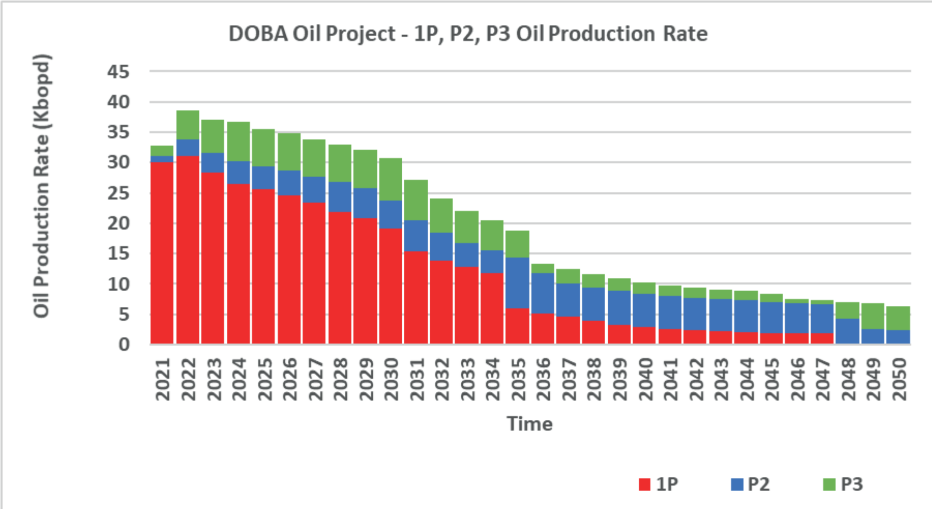



Figure 4.19 Doba Oil Project 1P, P2 and P3 Gross Oil Production Rate

The forecast technical recoverable volumes, initial oil-in-place and ultimate recovery factors should be reasonable, consistent and logical. Considering uncertainties embedded in the initial oil-in-place calculations and in production forecasting, the range of Ultimate Recovery Factors (URFs) indicated for the fields is provided in **Table 4-9**. The table includes volumes based on Decline Curve Analysis, production increments from operational and planned Skids 1, 2 and 3A as well as Proved Undeveloped Reserves associated with planned future drilling.

| Field | STOIIP (MMstb) | | | EUR (MMstb) | | | Recovery Factors (frac.) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Low | Mid | High | 1P | 2P | 3P | Low | Mid | High |
| Kome* | 1719 | 2118 | 2532 | 367.6 | 400.5 | 440.6 | 0.21 | 0.19 | 0.17 |
| Miandoum | 586 | 679 | 777 | 170.8 | 180.4 | 206.4 | 0.29 | 0.27 | 0.27 |
| Bolobo | 453 | 530 | 612 | 127.0 | 128.0 | 132.0 | 0.28 | 0.24 | 0.22 |
| Moundouli | 283 | 331 | 382 | 41.6 | 47.1 | 61.3 | 0.15 | 0.14 | 0.16 |
| Maikeri | 64 | 75 | 87 | 23.5 | 24.3 | 24.5 | 0.37 | 0.32 | 0.28 |
| Nya | 53 | 62 | 71 | 16.4 | 17.8 | 19.6 | 0.31 | 0.29 | 0.28 |
| Timbre | 38 | 44 | 51 | 5.7 | 5.8 | 6.0 | 0.15 | 0.13 | 0.12 |
| **Total**** | **3196** | **3839** | **4512** | **752.6** | **803.8** | **890.3** | | | |

* Kome oil-initially-in-place including LK STOIIP
** Total may not add up due to rounding

Table 4-9 Ultimate Recovery Factor based on STOIIP and EUR volumes

The Kome Field URF is low relative to many of the other fields. CGG is confident that the range of initial oil-in-place is reasonable. The reasons for this are:

1. Very high well density minimises depth uncertainty at top reservoir zones (unusually low GRV uncertainty)
2. Net-to-Gross and porosity are considered by CGG to show low uncertainty and the high volume of well data further reduces uncertainty (thus, the possible pore volume range is considered to be relatively narrow).
3. Water saturation is noted as a significant uncertainty within reasonable bounds, as defined by independent petrophysical analysis.
4. CGG's estimates of initial oil-in-place match those of current Operator (within 4% difference).

The comparatively low URF points to future potential of the fields. The large number of wells and perforated intervals, relatively inflexible gravel pack completions and lack of understanding of where fluids (both oil and water) are coming from may have led to incomplete sweep (high bypass) for the Kome reservoirs. The task of monitoring all of the wells and perforations is large; the current Operator stopped allocating production to reservoir zones when it became clear that they could not determine recovery on a zonal basis. Limited PLT data reviewed suggests that water ingress occurs via distinct, often quite thin, high permeability, reservoir layers that occur within the main sand packs. Inability to identify and shut off these perforations may be a cause of sustained high water cut and high bypass.

Comparing Kome to Miandoum field performance, where the major reservoir parameters are also quite well established, the Kome Field has three times the oil-in-place but only a little over twice the technical recovery. This observation strongly suggests that there is a significant opportunity at Kome, but the amount of technical work required to unlock it will be large. Additional risks will be present arising from uncertainty in the recovery (sweep) from individual reservoir zones.

Maikeri field ultimate recovery seems high at 28-37%. CGG considers that the data indicates that the oil-in-place estimation may be too small. Production to end of September 2021 clearly suggests the initial oil-in-place may be higher. The technically recoverable volumes for Maikeri, which are solely derived from DCA, are considered fairly reliable and so it is likely that the oil-in-place estimation may require upward revision.

The Moundouli and Timbre field's URF both look relatively low, possibly due to these fields being in mid-life. However, more detailed analysis of initial oil-in-place would be recommended in order to verify the reserves base and to update the development plan, if required.

In addition, it should be noted that production contribution from the Lower Cretaceous (with Higher GOR compare to oil from Upper Cretaceous reservoirs) has diminished in recent years. This could constitute an opportunity to "re-develop" the Lower Cretaceous in order to increase associated gas production that could replace current crude consumed in operations.

## 4.4 Contingent Resources

There are Contingent Resources which can be recovered from additional infill drilling and deployment of polymer skids. For Contingent Resources attributed to Polymer flooding, an increase of between 2% to 6% in recovery factor gives a reasonable expectation of potential uplift. The Contingent Resources estimated in **Table 4-6** are presented for each field in **Table 4-10**. Further infill drilling is assumed to increase recovery beyond that from the further deployment of polymer skids. Only fields which offer additional opportunities based on recovery factors have been considered.

| Field | 1C | | | 2C | | | 3C | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Polymer** | **Drilling** | **Total** | **Polymer** | **Drilling** | **Total** | **Polymer** | **Drilling** | **Total** |
| Miandoum | 1.7 | 0.0 | ***1.7*** | 3.4 | 0.0 | ***3.4*** | 5.2 | 0.0 | ***5.2*** |
| Kome | 10.0 | 19.3 | ***29.3*** | 19.9 | 30.0 | ***49.9*** | 29.9 | 40.6 | ***70.5*** |
| Bolobo | 6.2 | 10.8 | ***17.0*** | 12.5 | 16.6 | ***29.1*** | 18.7 | 23.0 | ***41.7*** |
| Nya | 0.0 | 0.0 | ***0.0*** | 0.0 | 0.0 | ***0.0*** | 0.0 | 0.0 | ***0.0*** |
| Moundouli | 3.3 | 8.3 | ***11.6*** | 6.6 | 16.6 | ***23.2*** | 9.9 | 24.9 | ***34.8*** |
| Maikeri | 0.8 | 0.0 | ***0.8*** | 1.5 | 0.0 | ***1.5*** | 2.3 | 0.0 | ***2.3*** |
| Timbre | 0.0 | 1.3 | ***1.3*** | 0.0 | 3.1 | ***3.1*** | 0.0 | 4.4 | ***4.4*** |
| **Total* (MMstb)** | **22.0** | **39.7** | **61.7** | **43.9** | **66.2** | **110.2** | **66.0** | **92.8** | **158.8** |

* Total may not add up due to rounding

Table 4-10 Doba Oil Project Gross Contingent Resources

# 5 FACILITIES AND COSTS

## 5.1 Facilities and Infrastructure Overview

There are two gathering and pre-processing stations installed at Miandoum and Kome, with Bolobo tied-back to Kome. Miandoum and Kome started production in July 2003 and February 2004 respectively, followed by Bolobo in August 2004. The processing and power generation is centralised at Kome in a Central Treating Facility (CTF) before crude is exported through the Chad-Cameroon Export Transportation System (ETS). Water injection was implemented early in the development, in 2004, for pressure support in the Y0 and M1 reservoirs.

There are four power generation turbines (4x 30MW) that have been converted, so that they can run on a mix of oil and gas which has improved availability and reduced the dependency on imported fuel. Currently, the Doba Oil Project Facilities are running with three turbines with the fourth on standby.

Between 2005 and 2007 the three satellite fields (Nya, Moundouli and Maikeri) were tied-back into the Doba Oil Project facilities, with all three being connected and pre-processed at the Miandoum Gathering Station (MGS). In 2009, Timbre was tied-back to the Kome Gathering Station (KGS). Below in **Figure 5.1** is a schematic of the Doba Oil Project Facilities.

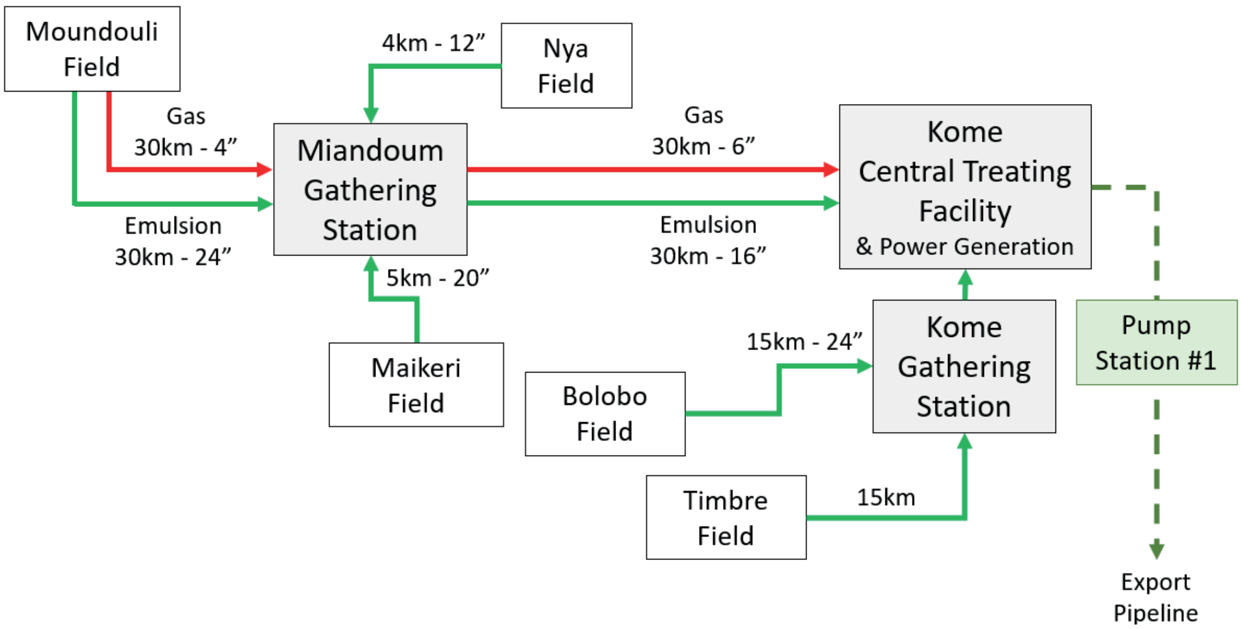



Figure 5.1 Schematic of the Doba Oil Project Facilities

Source: Savannah Energy

**Table 5-1** is a summary of the Kome Central treating facility.

| Facility | Design Capacity | Current |
|---|---|---|
| Oil | 250Kbopd | ~40Kbopd |
| Gas compression | 15MMcfpd | ~5 MMcfpd |
| Water injection | 950 Kbwpd | >750 Kbwpd (3 turbines) |
| | | >850 Kbwpd (4 turbines) |
| Power generation | 120 MW | ~85 MW (3 turbines) |
| | | ~110 MW (4 turbines) |
| Crude Storage | 250 Kbbl | 250 Kbbl |

Table 5-1 Kome Central treating facility

In **Figure 5.2**, an overview of the Kome facilities is presented. Those are the main facilities which comprise of a gathering station, treating plant, power plant and an export pump station (PS#1).

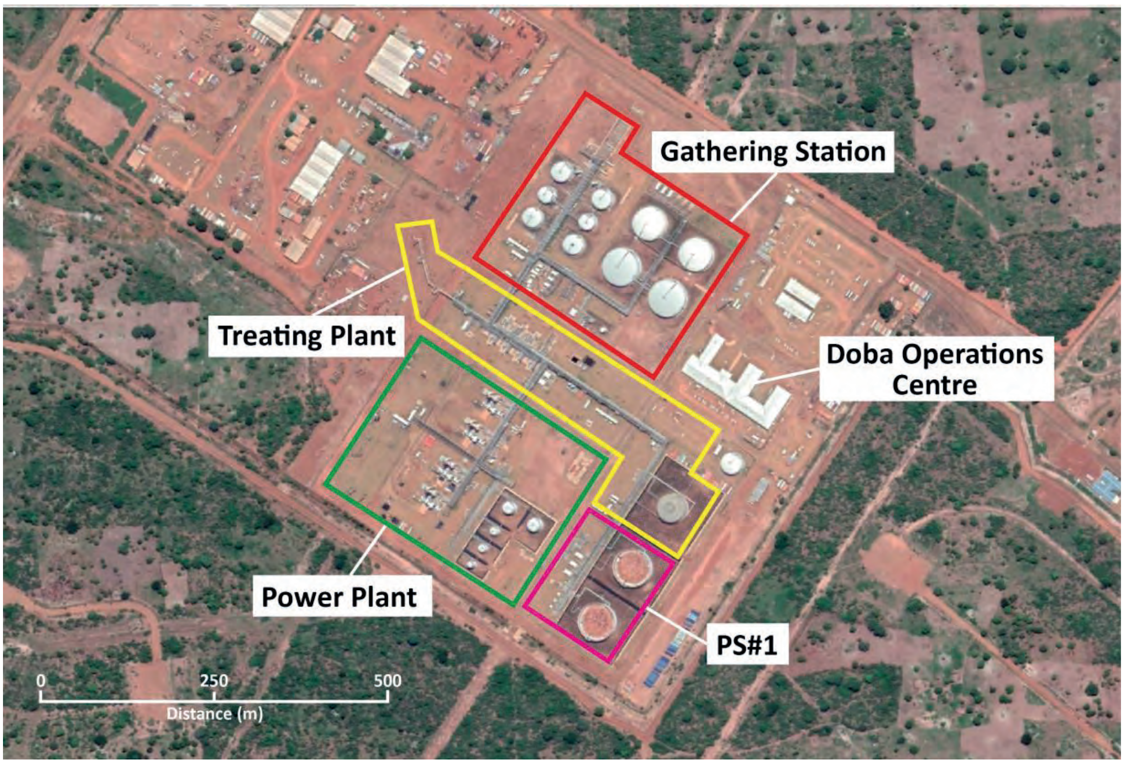



Figure 5.2 Kome Central treating facility Overview

Source: Savannah Energy

## 5.2 Chad-Cameroon Export Transportation System (ETS)

The ETS is a crude export system comprising of an export pipeline and an offshore moored (Floating Storage & Offloading) FSO vessel and terminal infrastructure. The pipeline linking Doba basin in Chad to the port of Kribi on the coast of Cameroon, has a diameter of 30" and a total length of 1,081km (178km in Chad and 903km in Cameroon), and a nameplate capacity of 250,000 bopd and it can transport relatively heavy crude. This pipeline is connected to the Doba oil fields and is the only pipeline connecting landlocked Chad to the Kome Kribi 1 FSO for international exports. The ETS is used to export all crude from the Doba Oil Project as well as crude from other Operators (i.e. Glencore, China National Petroleum Corporation - CNPC, OPIC). OPIC (Overseas Petroleum and Investment Corporation) is a subsidiary of Taiwan's national oil company, CPC.

Two separate JV companies, TOTCo and COTCo, own and operate the Chad-Cameroon ETS. The total capital cost of the project was approximately US$2.2 billion.

The pipeline includes three pumping stations and a small pressure reduction station, as well as four maintenance areas, and is equipped with a leak detection system. The first pumping station is located at the Kome facilities, and there is also a fiscal metering system at this location. This is the main historical entry to the ETS infrastructure. The second and third pumping stations are located in Cameroon, at KM 215 and KM 880. All three pumping stations employ oil-burning heaters that raise the crude oil temperature in order to reduce the crude viscosity and improve the flow through the pipeline. This is shown in **Figure 5.3**.

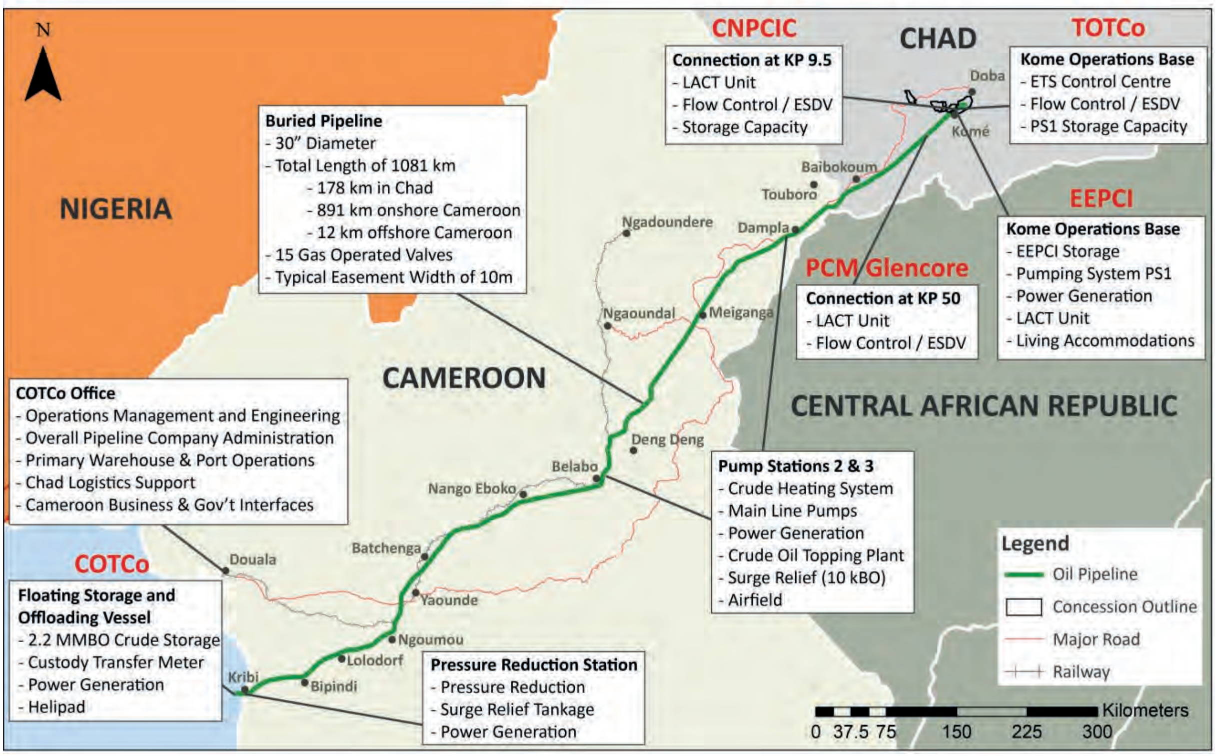



Figure 5.3 Chad-Cameroon ETS Map

Source: Savannah Energy

The Kome Kribi 1 is the offshore moored floating storage and offloading vessel. With its associated marine pipelines and related facilities, it is part of the ETS infrastructure. The FSO is a converted crude tanker with a nameplate storage capacity of 2.2 MMbbl. It is moored off Kribi Beach, and it is connected to a single-point mooring system. The FSO is able to accommodate tandem-berthed, 80,000-320,000 dwt export tankers. The custody transfer is located at the inlet flange to the FSO.

COTCo and TOTCo both charge shippers a tariff to transport their crude that covers the operating costs and recognition of the historical investment in the pipeline. Tariff differs for the original shippers (the Doba Consortium) and new shippers.

Figure 5.4 The Kome Kribi FSO

Source: Doba Oil Project VDR

## 5.3 Cost Review

CGG has reviewed the cost that have been assumed going forwards and used in the economics. Presented in this section is a discussion on the key assumptions made in arriving at estimates of future asset costs which are classified as:

- Capital expenditure (Capex),
- Operations expenditure (Opex) and
- Drilling expenditure (Drillex).

Having reviewed the cost forecasts, CGG feel that the values and projections used, are reasonable and in line with industry standards.

### 5.3.1 Capital expenditure (Capex)

There are no significant capital projects planned, hence Capex costs are a relatively modest US$8 MM per year in the short term, decreasing to US$5 MM per year. These are understood to cover Capex for general services and are derived from current Operator budget estimates.

### 5.3.2 Drilling expenditure (Drillex)

These figures represent the estimated cost of drilling infill wells needed for the development of the Proved Undeveloped Reserves (PUD), based on a drilling programme, which assumes:

- Purchase of one drilling rig at a cost of US$10 MM
- Each well to take an average of one month and cost US$2.5 MM
- Drilling starting in January 2023

### 5.3.3 Operations expenditure (Opex)

**Base Production Opex**

The Opex figure of US$107.3 MM for 2021 is from the Operator Work Programme and Budget (WP&B) for 2021 presented at the 2021 Operational Committee Meeting (OCM). Base Production Opex for the following years are based upon the 2021 figure but are reduced to take into consideration the reduction in oil production.

**Fuel Opex**

Fuel Opex is understood to cover the cost of buying-in fuel for use on the Doba Oil Project. Fuel Opex does not include provision for produced oil and gas that is used as fuel for power generation. This is handled separately, as a reduction in the amount of oil and gas available for sales.

These figures are based on a simple 5% of the 'Base Production Opex', which is derived from proportion for Fuel in the 2021 WP&B.

**Well Work Opex**

Well Work Opex covers the cost of maintaining wells and replacing the downhole pumps that are used to lift the produced fluids up the wellbore to the surface. The artificial lift technology used are of two types: Progressive Cavity Pump (PCP) and Electrical Submersible Pump (ESP). Both types of pump use significant quantities of electrical power and, since they are mechanical, are prone to wear and breakdown. Estimated Well Work Opex going forward are based on costs, current and forecasted by the current Operator in their WP&B and an analysis of historical well breakdowns and repairs.

The following assumptions have been used when calculating well work costs going forward:

- Failure ratio assuming a well pump fails on average every 5 years of operational life, ie. 20% of pumps will fail in any year. This is realistic when compared to the historical failure rate.
- Four wells each year are assumed uneconomic to repair and are therefore assumed to be taken out of service, thereby reducing the total number of active wells. As a quality check, the implied lifetime cumulative oil production volume per well has been calculated, to ensure that there are sufficient wells to provide the volumes that are assumed in the reservoir engineering calculations.
- For years 2022 to 2026, costs are based on the WP&B presented at the 2021 Operating Committee Meeting (OCM). Savannah has increased well work Opex by US$10 MM in the first 5 years to account for contingencies.
- The cost of well work beyond 2026 is based on a figure of US$23.6 MM as per WP&B for years 2024 & 2025. It is assumed that this well work cost represents the cost of repairing 60 wells.
- For the years 2026 to 2035, there are an assumed 60 well repairs per year, based on each well being repaired every 5 years for a population of c. 300 wells.

**Polymer Injection Project Opex**

The Opex cost for Polymer Injection Project represents the cost of operating the three existing polymer skids. The cost is entirely made up of the cost of buying the polymer with which the injection water is treated.

For estimating the Opex cost of polymer injection, the current effective injection rates have been assumed for each skid. It has also been assumed that initially a slug of polymer of approximately 50% of the pore volume would be injected. After this, polymer usage has been allowed to tail off injection water until approximately 90% of the pore volume has been injected. A polymer cost of US$0.72 per bbl of injection water is used. This is based on the 2021 WP&B and forecasted yearly Polymer Opex from current Operator.

# 6 ECONOMIC EVALUATION

## 6.1 Methodology

Reserves and Net Present Values (NPVs) have been calculated using Savannah's integrated Excel™ economic model of the Doba Oil Project and the Chad-Cameroon Export Transportation System (ETS, or Chad-Cameroon Pipeline System). The model has been reviewed by CGG and has also been subject to a detailed review by Ernst & Young.

## 6.2 General Assumptions

General assumptions used by CGG in the economic evaluation are tabulated below in **Table 6-1.**

| Parameter | Value |
|---|---|
| Discount Rate (Annual) | 10% |
| Discount Methodology | Mid-year |
| Cost Inflation | 2% per annum |
| Evaluation Date | 1st October 2021 |

Table 6-1 General assumptions

## 6.3 Equity Interests

The assets and interests under consideration are summarised below:

Acquisition from Exxon of a:

(a) 100% equity interest in Esso Exploration and Production Chad Inc. (EEPCI) which holds:

  i. 40% operated interest in the Doba Oil Field Development Area (Doba OFDA, or Doba Oil Project) in Chad; and

(b) 100% equity interest in Esso Pipeline Investments Limited (EPIL) which holds

  i. 40.19% interest in the Tchad Oil Transportation Company (TOTCo, or Chad Pipeline Company); and

  ii. 41.06% interest in the Cameroon Oil Transportation Company (COTCo, or Cameroon Pipeline Company).

Acquisition from Petronas

(c) 100% equity interest in Petronas Carigali Chad Exploration & Production Inc. (PCCEPI) which holds:

  i. 35% interest in the Doba Oil Project;

  ii. 30.16% interest in the Chad Pipeline Company; and

  iii. 29.77% interest in the Cameroon Pipeline Company.

## 6.4 Key Fiscal Terms

A summary of the key terms of the fiscal regimes applicable to the Doba Oil Project and the ETS as understood by CGG are presented in the following sections.

### 6.4.1 Doba Oil Project

The Doba Oil Project is subject to three similar royalty/tax fiscal regimes with different terms depending on location and date of concession award of the fields. The fields are covered by either the Republic of Chad 1988, Amended 1988 or 2004 Conventions.

The fiscal terms for the three groups of fields are summarised below in **Table 6-2:**

| Field | Convention | Income tax rate | Royalty Rate |
|---|---|---|---|
| Nya, Moundouli | 1988 | 50% flat | 12.5% |
| Maikeri, Timbre | 2004 | 50% - 65% depending on R-factor, cumulative production | 14.25% |
| Kome, Bolobo, Miandoum | 1988 | 40% - 65% depending on R-factor, oil price and cumulative production | 12.5% |

Table 6-2 Upstream Fiscal Terms by Field

In addition to the royalties and taxes, a statistical tax (Redevance Statistique) of 2% is paid on the value of crude exported from the fields, and is deductible against corporate income tax.

### 6.4.2 Chad-Cameroon Export Transportation System (ETS)

The Chad-Cameroon Export Transportation System (ETS) consists of the export pipeline and the offshore marine terminal, consisting of the FSO and the onshore facilities at Kribi. The Chadian section of the pipeline is operated by TOTCo, and the Cameroonian pipeline section and the marine terminal are operated by COTCo. TOTCo and COTCo are subject to Chadian and Cameroonian corporate taxes, respectively.

**TOTCo - Chad Pipeline Company**

All shippers pay TOTCo for their share of running costs, calculated on a per barrel throughput basis. Third party shippers also pay an additional transportation fee as well as an access levy to the Chadian government. TOTCo profits are subject to corporate income tax at 50%.

**COTCo - Cameroon Pipeline Company**

All shippers pay COTCo for their share of operating costs, calculated on a per barrel throughput basis, as well as a transit fee to the Cameroonian government. Third party shippers also pay an additional transportation fee to COTCo. COTCo profits are subject to corporate income tax at 5%.

## 6.5 Oil Price Assumption

It is assumed that all crude production from the Doba Oil Project is sold to international buyers on a FOB (Free On Board) basis at the marine terminal in Cameroon. Historically, it is understood that crude has sold within a +/- US$2/bbl to Brent, and it has therefore been assumed that the crude will sell at Brent going forwards.

The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

Sensitivity cases are also assumed at US$50/bbl, US$60/bbl, US$70/bbl, US$80/bbl, US$90/bbl and US$100/bbl. Those oil prices have been inflated at 2% per year from January 2022.

## 6.6 Results

### 6.6.1 Reserves Evaluation

A summary of the Reserves associated with the Doba fields, on both a gross and net attributable basis, are shown in **Table 6-3**. Production is assumed to cease at the earlier of the economic limit or the expiry of the Concessions in September 2050.

| Reserves (MMstb) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net Attributable | | | | | | Operator |
| | Proved | Proved & Probable | Proved, Probable & Possible | Proved | | Proved & Probable | | Proved, Probable & Possible | | |
| | | | | EEPCI | PCCEPI | EEPCI | PCCEPI | EEPCI | PCCEPI | |
| Moundouli, Nya | 7.9 | 13.6 | 22.2 | 3.2 | 2.8 | 5.4 | 4.8 | 8.9 | 7.8 | EEPCI |
| Maikeri, Timbre | 3.3 | 4.9 | 5.3 | 1.3 | 1.2 | 2.0 | 1.7 | 2.1 | 1.8 | EEPCI |
| Miandoum, Bolobo, Kome | 89.4 | 119.9 | 160.1 | 35.7 | 31.3 | 48.0 | 42.0 | 64.1 | 56.1 | EEPCI |
| **Total** | **100.6** | **138.4** | **187.7** | **40.2** | **35.2** | **55.4** | **48.4** | **75.1** | **65.7** | |

*Notes*

1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied.*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Total may not add up due to rounding*
5. *Net: the portion of the gross reserves attributable to Savannah before royalties, taxes and fuel consumed in operations*
6. *Full definitions of the Reserves categories can be found in Appendix B*

Table 6-3 Reserves; Gross and Net Attributable to EEPCI and PCCEPI as at 1st October 2021

### 6.6.2 Contingent Resources Evaluation

A summary of the Contingent Resources are shown in **Table 6-4** and demonstrates the potential upside of the assets.

| Contingent Resources (MMstb) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net Attributable | | | | | | Risk Factor | Operator |
| | 1C | 2C | 3C | 1C | | 2C | | 3C | | | |
| | | | | EEPCI | PCCEPI | EEPCI | PCCEPI | EEPCI | PCCEPI | | |
| Moundouli, Nya | 11.6 | 23.2 | 34.8 | 4.6 | 4.1 | 9.3 | 8.1 | 13.9 | 12.2 | medium | EEPCI |
| Maikeri, Timbre | 2.1 | 4.6 | 6.7 | 0.8 | 0.7 | 1.8 | 1.6 | 2.7 | 2.3 | medium | EEPCI |
| Miandoum, Bolobo, Kome | 48.0 | 82.4 | 117.4 | 19.2 | 16.8 | 33.0 | 28.8 | 47.0 | 41.1 | low | EEPCI |
| **Total** | **61.7** | **110.2** | **158.8** | **24.7** | **21.6** | **44.1** | **38.6** | **63.5** | **55.6** | | |

*Notes*

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
   *Risk factor: low = > 75%, medium = 25% - 75%, high = <25%*
5. *Total may not add up due to rounding*
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and fuel consumed in operations*
7. *Full definitions of the Contingent Resource categories can be found in Appendix B*

Table 6-4 Contingent Resources; Gross and Net Attributable to EEPCI and PCCEPI as at 1st October 2021

### 6.6.3 Economic Evaluation

#### 6.6.3.1 Doba Oil Project

The Net Present Values (NPV) of future cashflows derived from the exploitation of the Reserves are tabulated below in **Table 6-5**. The values stated are net to EEPCI and PCCEPI's interest after deduction of crude consumed in operations, royalties and taxes. The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. The NPVs include estimated brought forward tax balances, but do not include EEPCI and PCCEPI's other outstanding liabilities/assets at the evaluation date, and do not relate to the actual dividend stream that may accrue to shareholders.

| NPV10 (US$MM) of Reserves Net to Savannah | | | | | | |
|---|---|---|---|---|---|---|
| | Proved | | Proved & Probable | | Proved, Probable & Possible | |
| | EEPCI | PCCEPI | EEPCI | PCCEPI | EEPCI | PCCEPI |
| Moundouli, Nya | 12.5 | 11.7 | 25.9 | 24.0 | 49.2 | 44.8 |
| Maikeri, Timbre | 5.6 | 6.5 | 8.9 | 9.6 | 11.8 | 12.1 |
| Miandoum, Bolobo, Kome | 157.1 | 156.3 | 210.6 | 205.8 | 297.7 | 280.3 |
| **Total*** | **175.2** | **174.5** | **245.4** | **239.4** | **358.7** | **337.1** |

* Total may not add up due to rounding

Table 6-5 NPV10 (US$MM) of Reserves Net to Savannah as at 1st October 2021

NPV sensitivities relating to oil prices and costs have also been run on the base case. The results of this analysis are tabulated below in **Table 6-6**.

| NPV10 (US$MM) of Reserves Net to Savannah | | | | | | |
|---|---|---|---|---|---|---|
| | Proved | | Proved & Probable | | Proved, Probable & Possible | |
| | EEPCI | PCCEPI | EEPCI | PCCEPI | EEPCI | PCCEPI |
| Base case | 175.2 | 174.5 | 245.4 | 239.4 | 358.7 | 337.1 |
| Oil price – US$50bbl | 55.0 | 66.7 | 104.7 | 109.5 | 179.8 | 175.5 |
| Oil price – US$60/bbl | 139.2 | 141.5 | 206.0 | 199.9 | 310.8 | 291.8 |
| Oil price – US$70/bbl | 223.1 | 216.0 | 310.5 | 292.8 | 445.9 | 411.8 |
| Oil price – US$80/bbl | 307.1 | 290.6 | 422.2 | 391.6 | 584.2 | 533.9 |
| Oil price – US$90/bbl | 391.1 | 365.1 | 533.8 | 490.4 | 705.0 | 640.0 |
| Oil price – US$100/bbl | 470.9 | 433.5 | 643.9 | 587.5 | 822.8 | 745.4 |
| Capex +25% | 170.1 | 170.0 | 241.9 | 234.7 | 353.1 | 332.1 |
| Capex -15% | 178.3 | 177.2 | 248.6 | 242.3 | 362.1 | 340.1 |
| Opex +25% | 101.6 | 109.8 | 161.9 | 164.8 | 264.4 | 253.9 |
| Opex -15% | 219.3 | 213.3 | 298.7 | 284.8 | 418.0 | 389.8 |

Table 6-6 NPV10 (US$MM) Sensitivities of Reserves Net to Savannah as at 1st October 2021

#### 6.6.3.2 Chad-Cameroon Export Transportation System

Indicative Net Present Values (NPV) of estimated after-tax future cashflows accruing to Savannah's share of TOTCo and COTCo have been calculated. The Chad-Cameroon Pipeline System is used to export all crude from the Doba Oil Project as well as crude from other Operators (i.e. Glencore, China National Petroleum Corporation - CNPC, Overseas Petroleum and Investment Corporation – OPIC). OPIC is a subsidiary of Taiwan's national oil company, CPC. Values have been estimated for a base and an upside case scenarios (**Figure 6.1**) of the third party production throughput based on a Wood Mackenzie study* commissioned by Savannah. In each scenario, the Proved & Probable Doba Oil Project forecasted



*The data and information provided by Wood Mackenzie should not be interpreted as advice or relied on for any purpose. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for the use of this data and information* volumes have also been considered. All cases account for c. 17,000bopd crude oil from CNPC being routed to the Djermaya Refinery, near N'Djamena, as well as crude consumed in operations.

Indicative Net Present Values (NPV) of the after-tax future cashflows accruing to EPIL and PCCEPI's share of TOTCo and COTCo are tabulated below in **Table 6-7**. It should be noted that the values presented may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets. The NPVs include estimated brought forward tax balances, but do not include EPIL and PCCEPI's other outstanding liabilities/assets at the evaluation date, and do not relate to the actual dividend stream that may accrue to shareholders.

There are no Reserves or Resources associated with EPIL and PCCEPI's share TOTCo and COTCo.

| NPV10 (US$MM) Net to Savannah | | | | |
|---|---|---|---|---|
| Case | Base | | Upside | |
| | EPIL | PCCEPI | EPIL | PCCEPI |
| Chad Pipeline Company | 10.8 | 8.1 | 11.0 | 8.3 |
| Cameroon Pipeline Company | 277.5 | 201.2 | 358.3 | 259.8 |
| **Total** | **288.3** | **209.3** | **369.3** | **268.0** |

Table 6-7 Indicative NPV10 (US$MM) of EPIL and PCCEPI's share of the Chad and Cameroon Pipeline Companies cashflows as at 1st October 2021

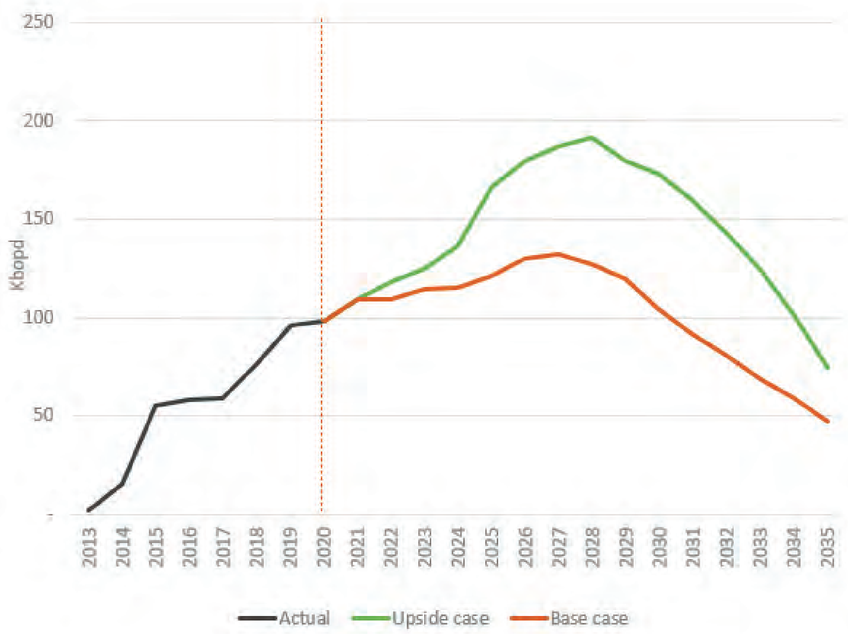



Figure 6.1 Chad-Cameroon Pipeline System forecast third party throughput - Source: Savannah Energy

#### 6.6.3.3 Financial Forecasts

**Table 6-8** and **Table 6-9** show the annual financial forecasts for the Doba Oil Project and ETS, including annual production and throughput.

It is estimated that the assets in aggregate will generate positive cashflow and fiscal revenues for Chad and Cameroon, for a further twenty-five plus years, in line with the terms of the Conventions.

| Year | Gross Production (Kbopd) | Revenue (US$MM) | | Cashflow (US$MM) | |
|---|---|---|---|---|---|
| | Proved & Probable | EEPCI | PCCEPI | EEPCI | PCCEPI |
| 2022 | 30.1 | 285.0 | 213.8 | 78.6 | 46.4 |
| 2023 | 31.6 | 266.0 | 199.5 | 58.5 | 24.1 |
| 2024 | 30.2 | 185.3 | 185.3 | 9.7 | 32.3 |
| 2025 | 29.4 | 249.5 | 186.8 | 61.6 | 26.6 |
| 2026 | 28.6 | 190.9 | 190.5 | 20.4 | 32.3 |
| 2027 | 27.7 | 259.9 | 194.5 | 66.0 | 40.5 |
| 2028 | 26.8 | 199.2 | 198.8 | 28.5 | 39.2 |
| 2029 | 25.7 | 203.2 | 135.0 | 30.1 | -3.6 |
| 2030 | 23.7 | 137.9 | 206.6 | -1.2 | 58.4 |

Table 6-8 Summary Doba Oil Project Production and Financial Forecasts

The total Opex and Capex per barrel of oil produced over the 2022-2030 period is estimated at US$17.7/bbl and US$3.5/bbl, respectively.

| Year | Total Throughput (Kbopd) | Revenue (US$MM) | | Cashflow (US$MM) | |
|---|---|---|---|---|---|
| | Base Case | EPIL | PCCEPI | EPIL | PCCEPI |
| 2022 | 136.8 | 88.5 | 64.3 | 34.4 | 25.0 |
| 2023 | 143.2 | 89.2 | 64.9 | 35.2 | 25.6 |
| 2024 | 142.7 | 78.3 | 57.0 | 35.7 | 25.9 |
| 2025 | 147.6 | 81.1 | 59.0 | 37.6 | 27.3 |
| 2026 | 154.8 | 85.1 | 61.9 | 40.0 | 29.0 |
| 2027 | 156.2 | 87.5 | 63.7 | 41.3 | 30.0 |
| 2028 | 150.1 | 87.5 | 63.7 | 40.4 | 29.3 |
| 2029 | 141.3 | 86.3 | 62.8 | 38.4 | 27.9 |
| 2030 | 124.3 | 82.5 | 60.0 | 34.0 | 24.7 |

Table 6-9 Summary ETS Throughput and Financial Forecasts

The total Opex and Capex per barrel of oil transported over the 2022-2030 period is estimated at US$1.3/bbl and US$0.1/bbl, respectively.

# 7 APPENDIX A: DECLINE CURVE ANALYSIS PLOTS

## 7.1 Kome Field

### 7.1.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.1** and **Figure 7.2** show plots of Oil Rate versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

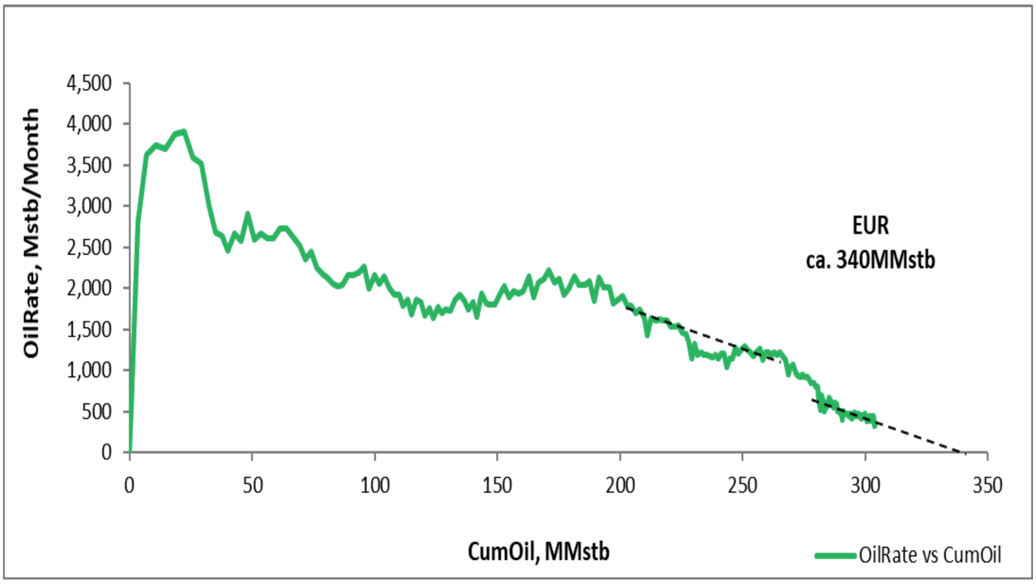



Figure 7.1 Kome field Oil Rate vs Cumulative Oil low case EUR estimation

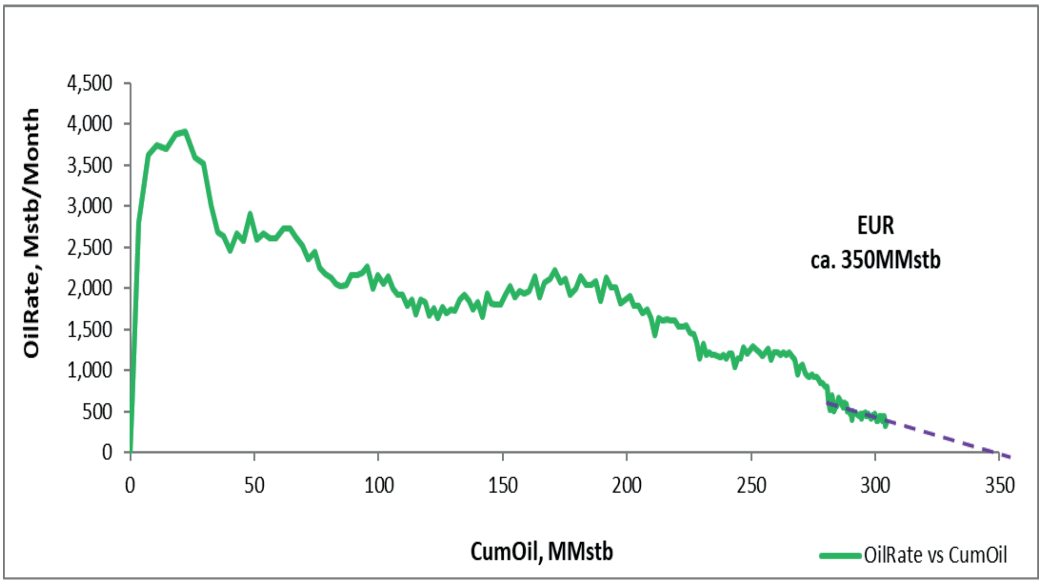



Figure 7.2 Kome field Oil Rate vs Cumulative Oil high case EUR estimation

### 7.1.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.3 and Figure 7.4** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

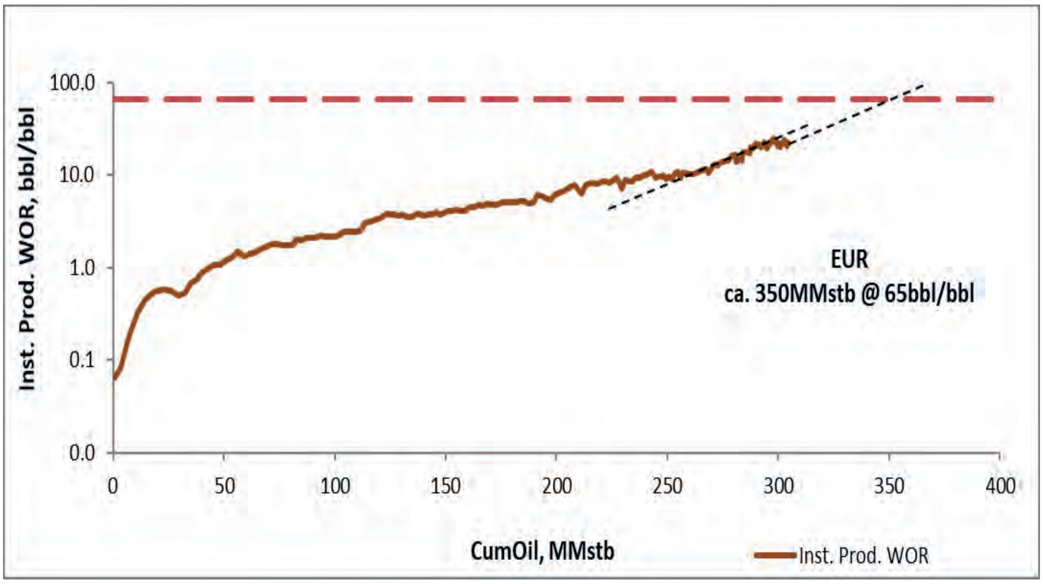



Figure 7.3 Kome field WOR vs Cumulative Oil low case EUR estimation

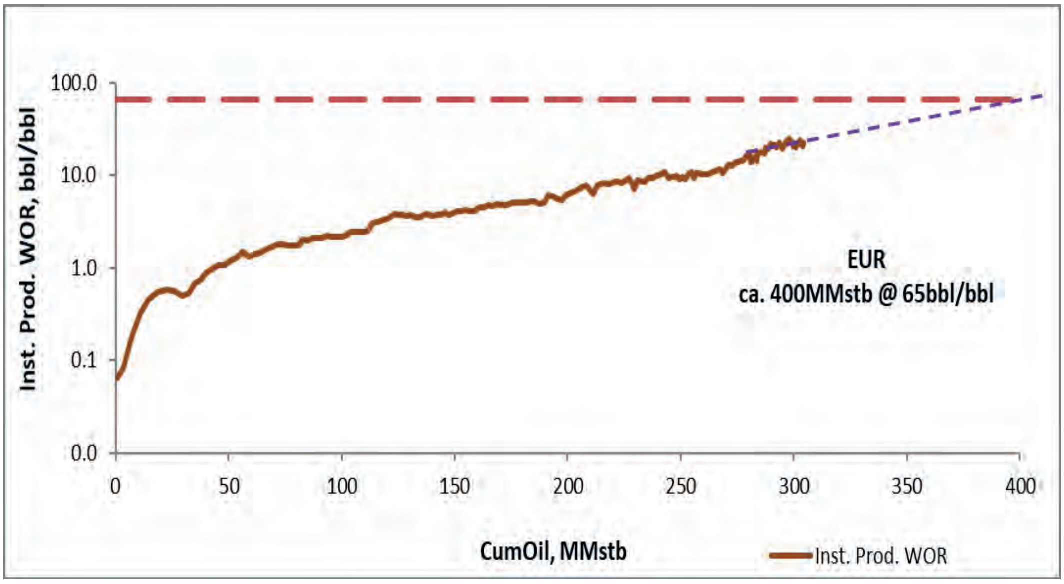



Figure 7.4 Kome field WOR vs Cumulative Oil high case EUR estimation

## 7.2 Bolobo Field

### 7.2.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.5** shows plot of Oil Rate versus Cumulative Oil for the field and identified EUR trend line.

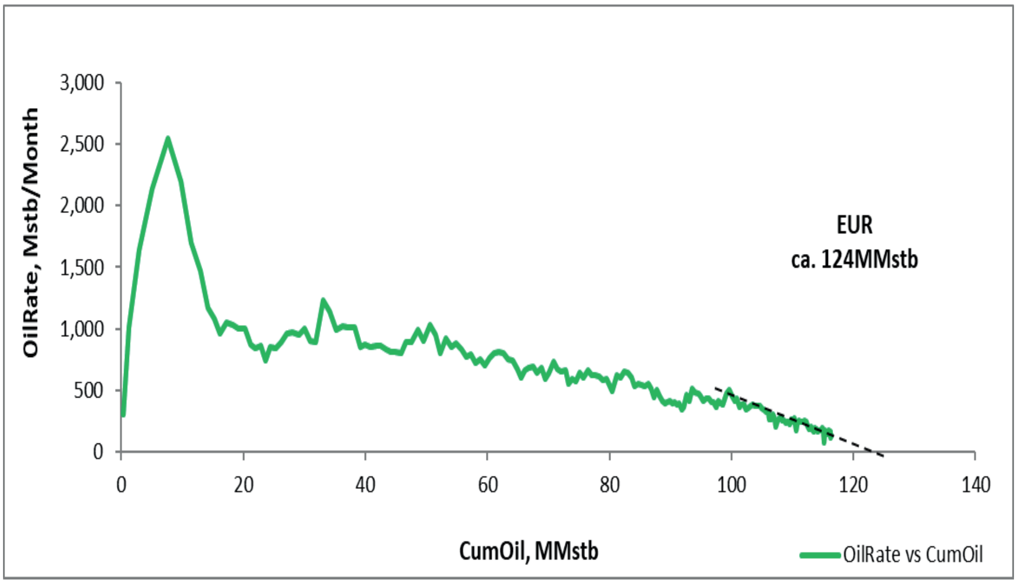



Figure 7.5 Bolobo field Oil Rate vs Cumulative Oil EUR estimation

### 7.2.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.6** and **Figure 7.7** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

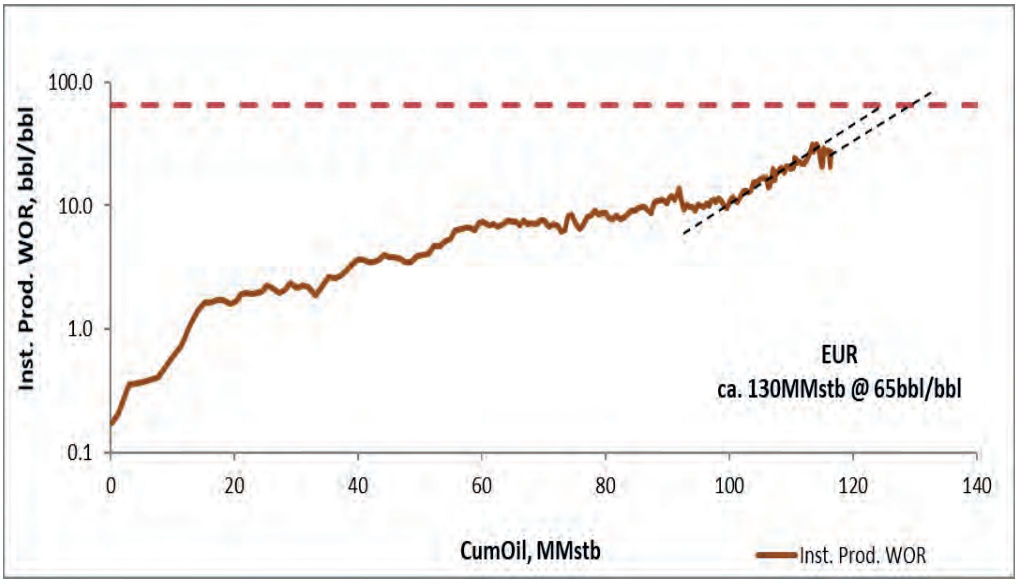



Figure 7.6 Bolobo field WOR vs Cumulative Oil low case EUR estimation

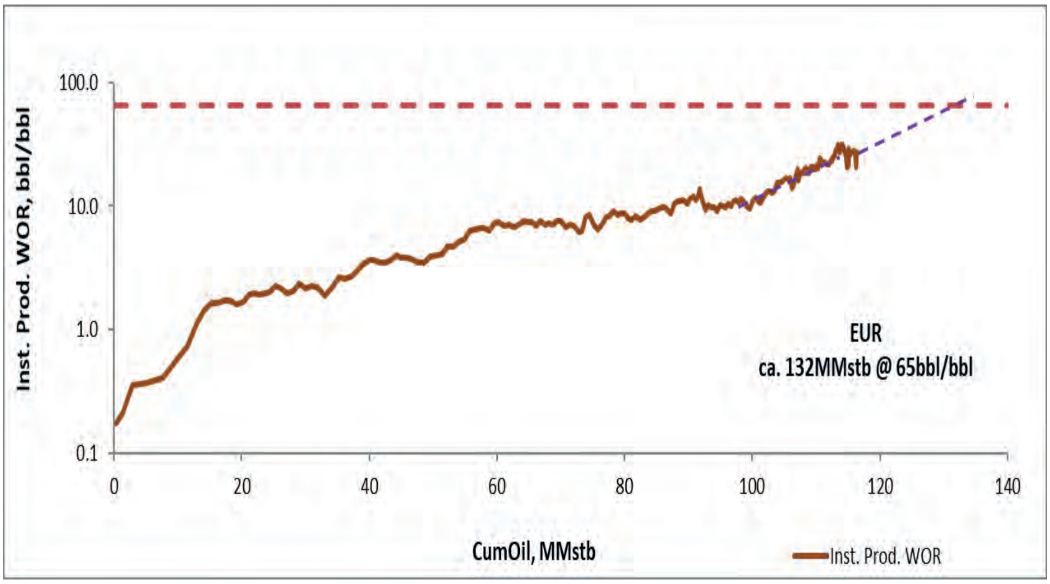



Figure 7.7 Bolobo field WOR vs Cumulative Oil high case EUR estimation

## 7.3 Maikeri Field

### 7.3.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.8** and **Figure 7.9** show plots of Oil Rate versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

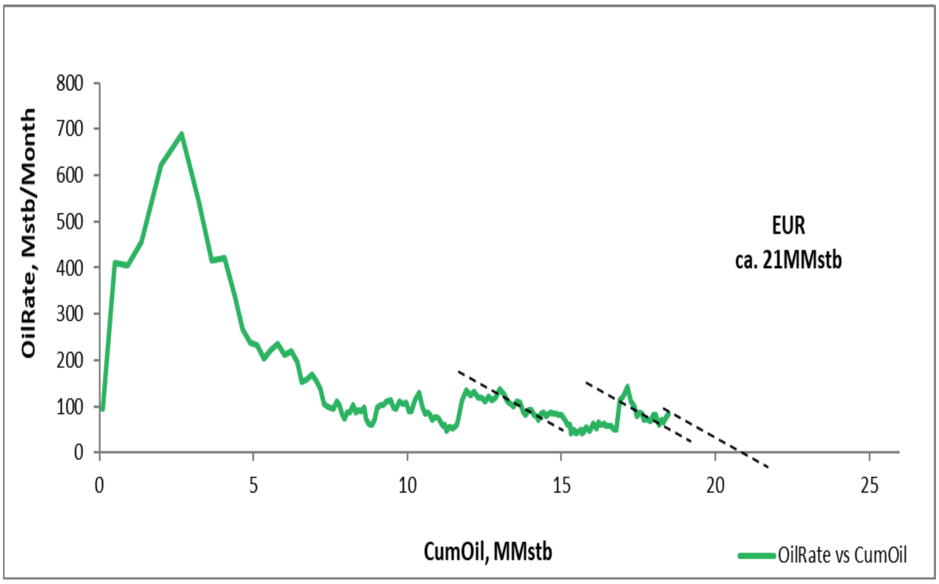



Figure 7.8 Maikeri field Oil Rate vs Cumulative Oil low case EUR estimation

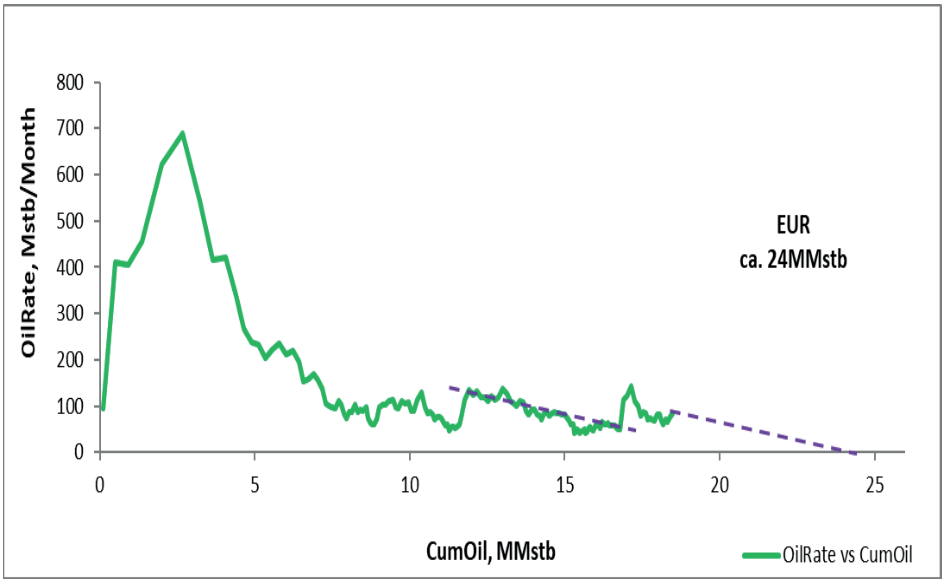



Figure 7.9 Maikeri field Oil Rate vs Cumulative Oil high case EUR estimation

### 7.3.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.10** and **Figure 7.11** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

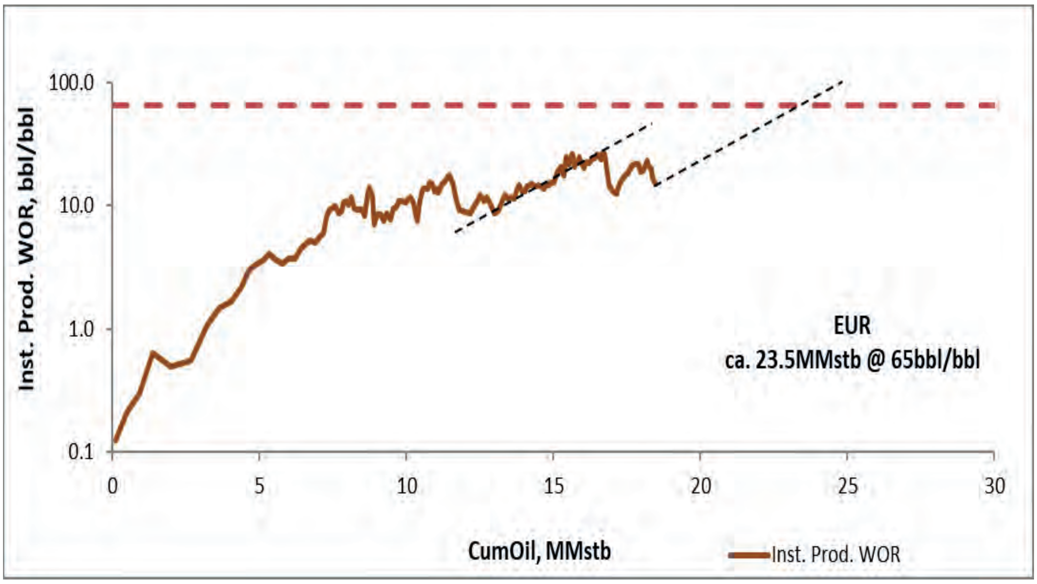



Figure 7.10 Maikeri field WOR vs Cumulative Oil low case EUR estimation

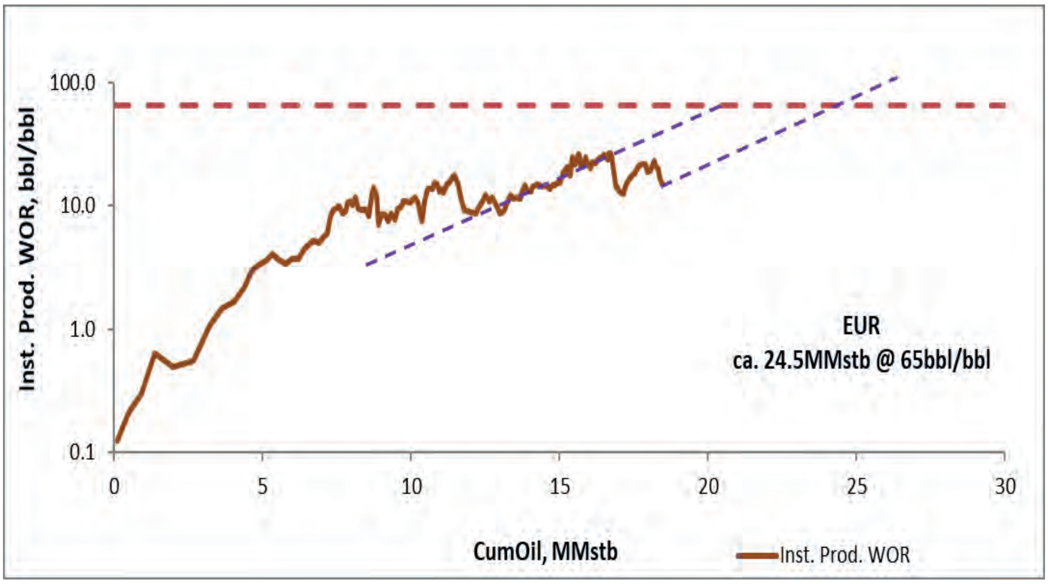



Figure 7.11 Maikeri field WOR vs Cumulative Oil high case EUR estimation

## 7.4 Miandoum Field

### 7.4.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.12** shows plot of Oil Rate versus Cumulative Oil for the field and EUR trend line identified.

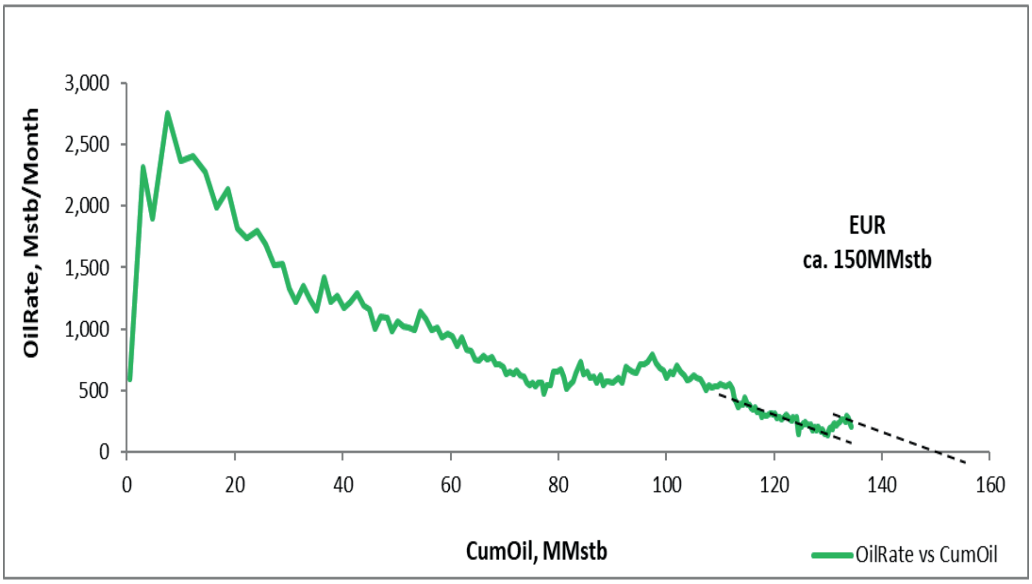



Figure 7.12 Miandoum field Oil Rate vs Cumulative Oil EUR estimation

### 7.4.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.13** and **Figure 7.14** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

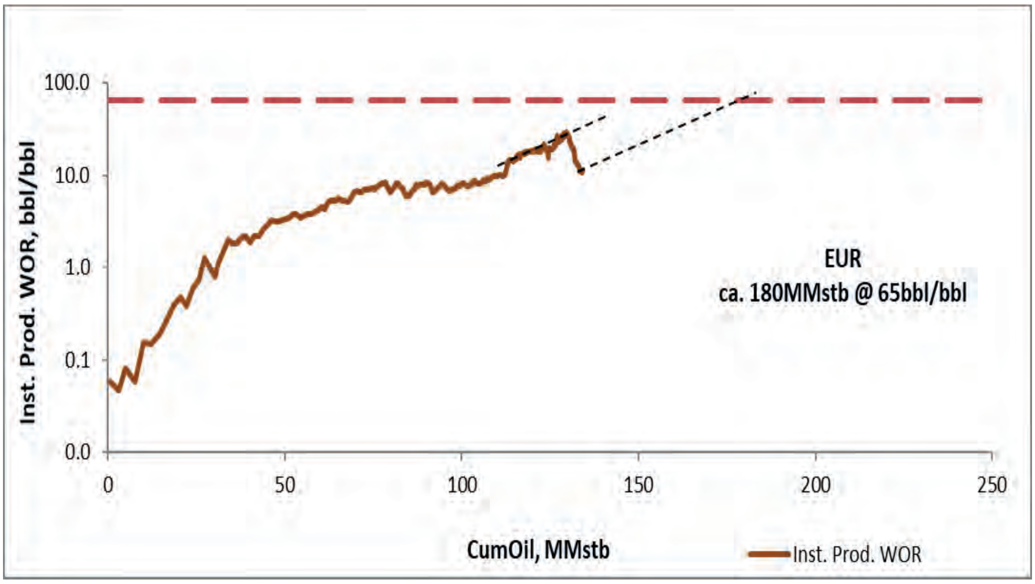



Figure 7.13 Miandoum field WOR vs Cumulative Oil low case EUR estimation

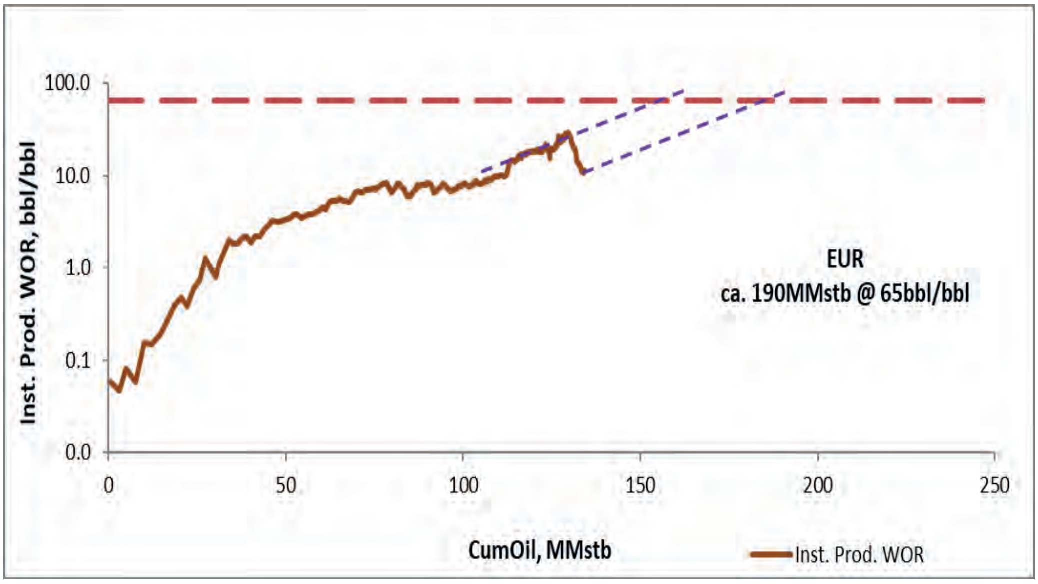



Figure 7.14 Miandoum field WOR vs Cumulative Oil high case EUR estimation

## 7.5 Moundouli Field

### 7.5.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.15** shows plot of Oil Rate versus Cumulative Oil for the field and EUR trend line identified.

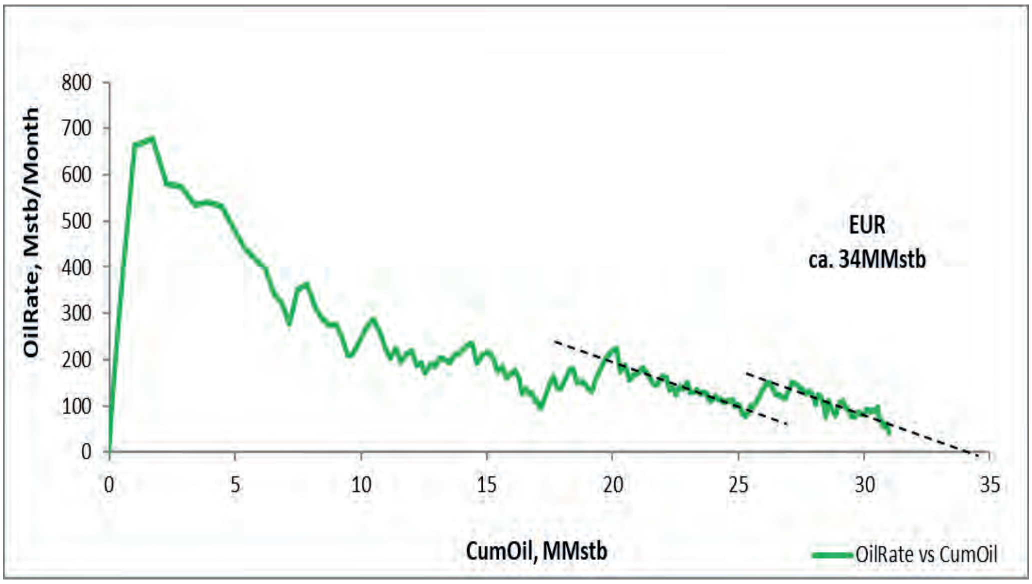



Figure 7.15 Moundouli field Oil Rate vs Cumulative Oil EUR estimation

### 7.5.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.16** and **Figure 7.17** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

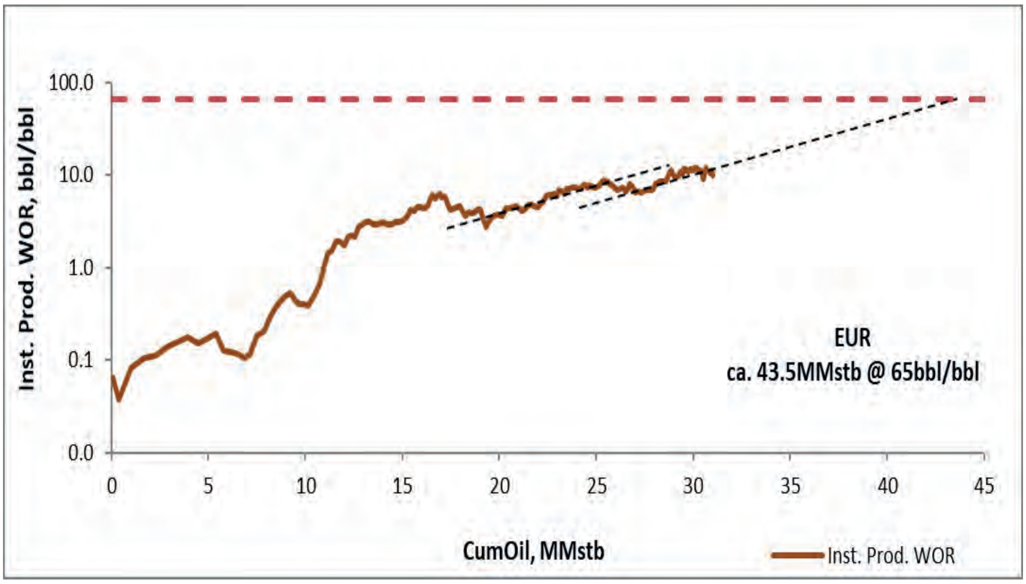



Figure 7.16 Moundouli field WOR vs Cumulative Oil low case EUR estimation

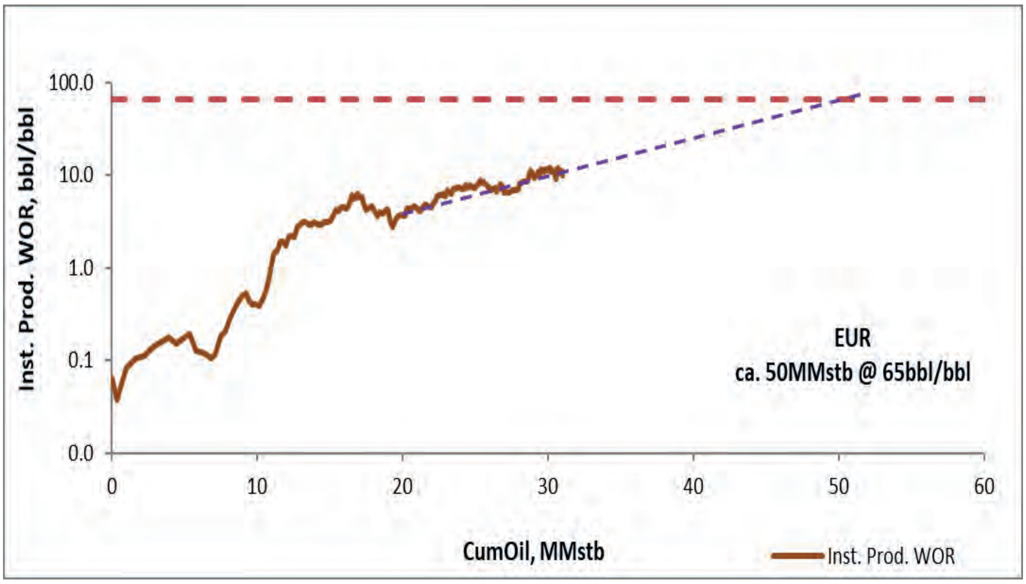



Figure 7.17 Moundouli field WOR vs Cumulative Oil high case EUR estimation

## 7.6 Nya Field

### 7.6.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.18** and **Figure 7.19** show plots of Oil Rate versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

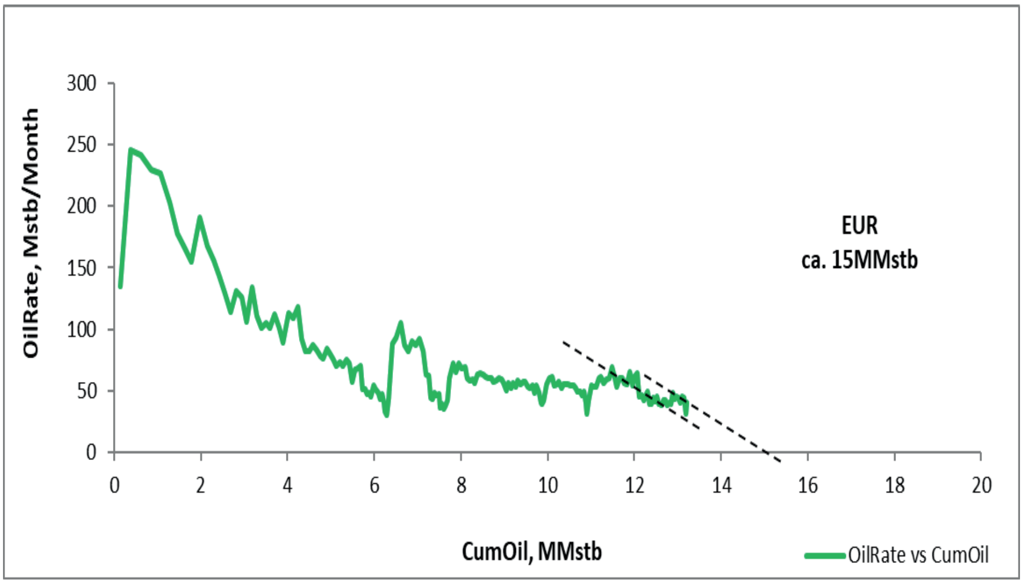



Figure 7.18 Nya field Oil Rate vs Cumulative Oil low case EUR estimation

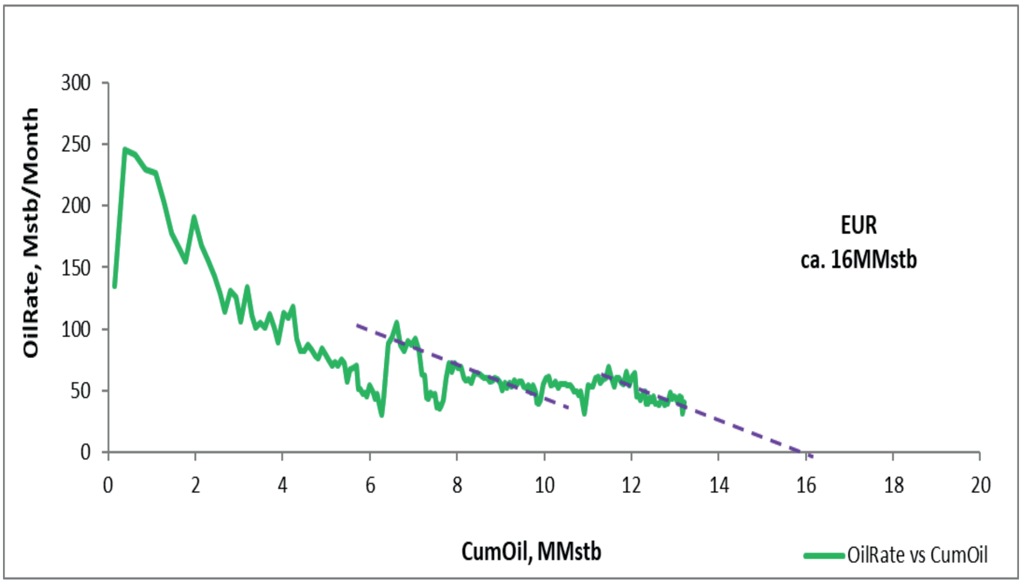



Figure 7.19 Nya field Oil Rate vs Cumulative Oil high case EUR estimation

### 7.6.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.20** and **Figure 7.21** show plots of WOR versus Cumulative Oil for the field and low case and high case EUR trend lines identified.

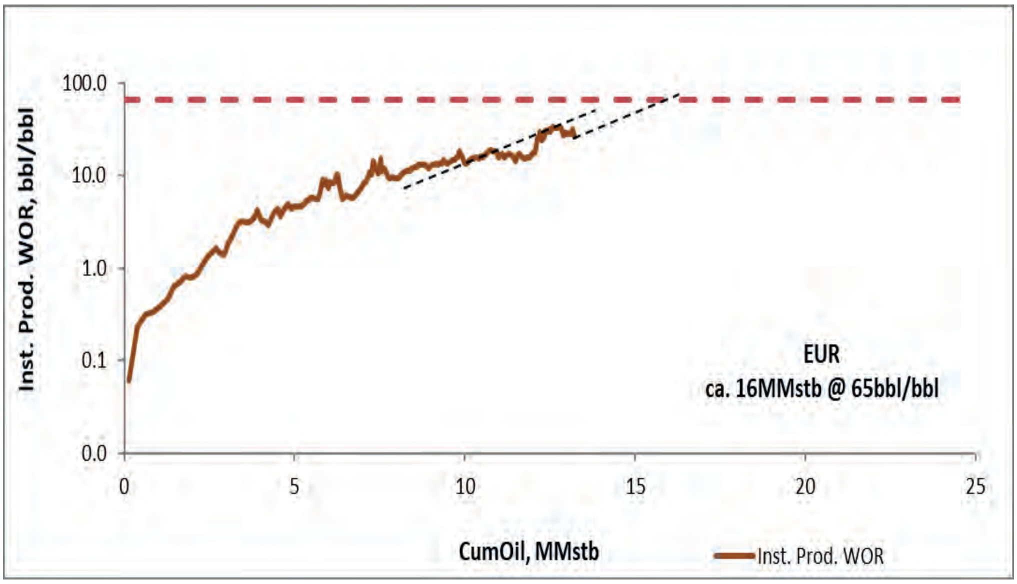



Figure 7.20 Nya field WOR vs Cumulative Oil low case EUR estimation

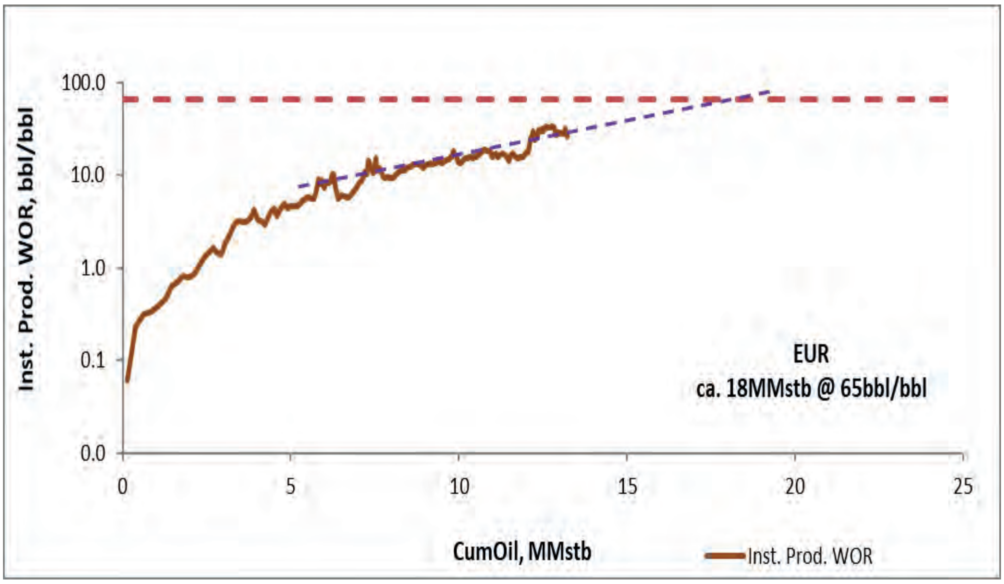



Figure 7.21 Nya field WOR vs Cumulative Oil high case EUR estimation

## 7.7 Timbre Field

### 7.7.1 Oil Rate vs Cumulative Oil Plot EUR Estimation

**Figure 7.22** shows plot of Oil Rate versus Cumulative Oil for the field and EUR trend line identified.

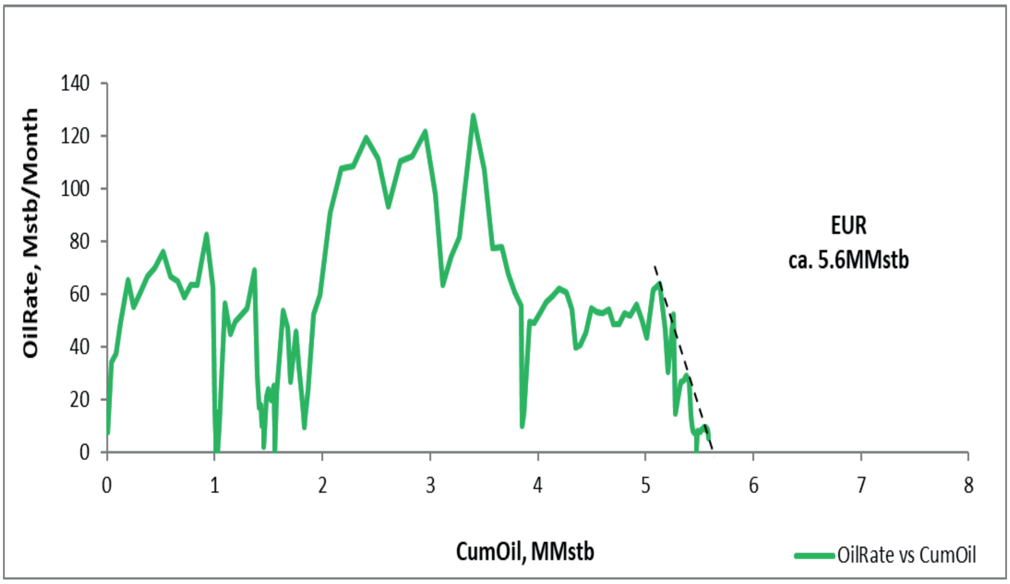



Figure 7.22 Timbre field Oil Rate vs Cumulative Oil EUR estimation

### 7.7.2 WOR vs Cumulative Oil Plot EUR Estimation

**Figure 7.23** shows a plot of WOR versus Cumulative Oil for the field and identified EUR trend line.

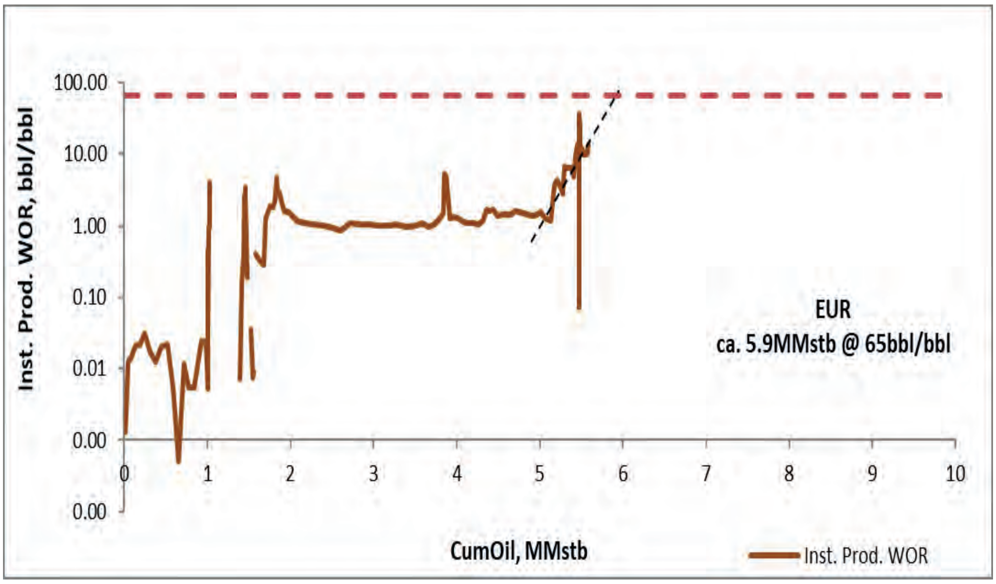



Figure 7.23 Timbre field WOR vs Cumulative Oil EUR estimation

# 8 APPENDIX B: DEFINITIONS

## 8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

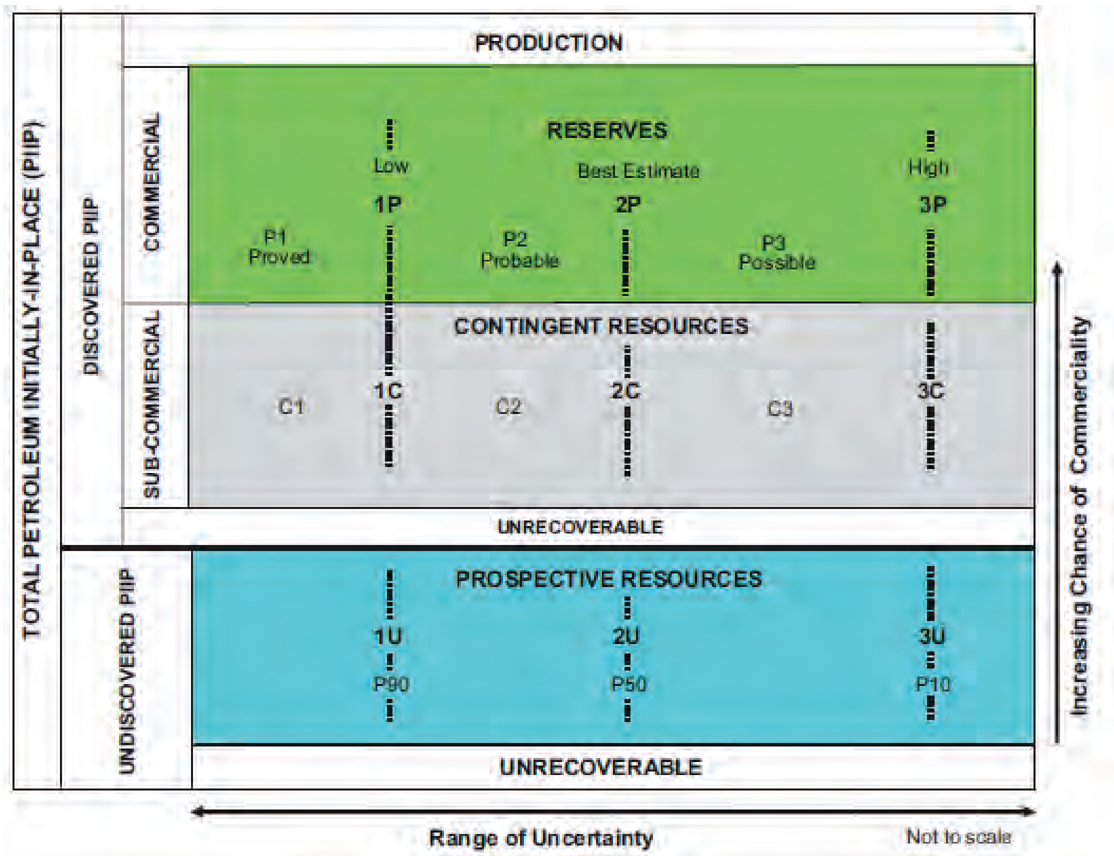



Figure 8.1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

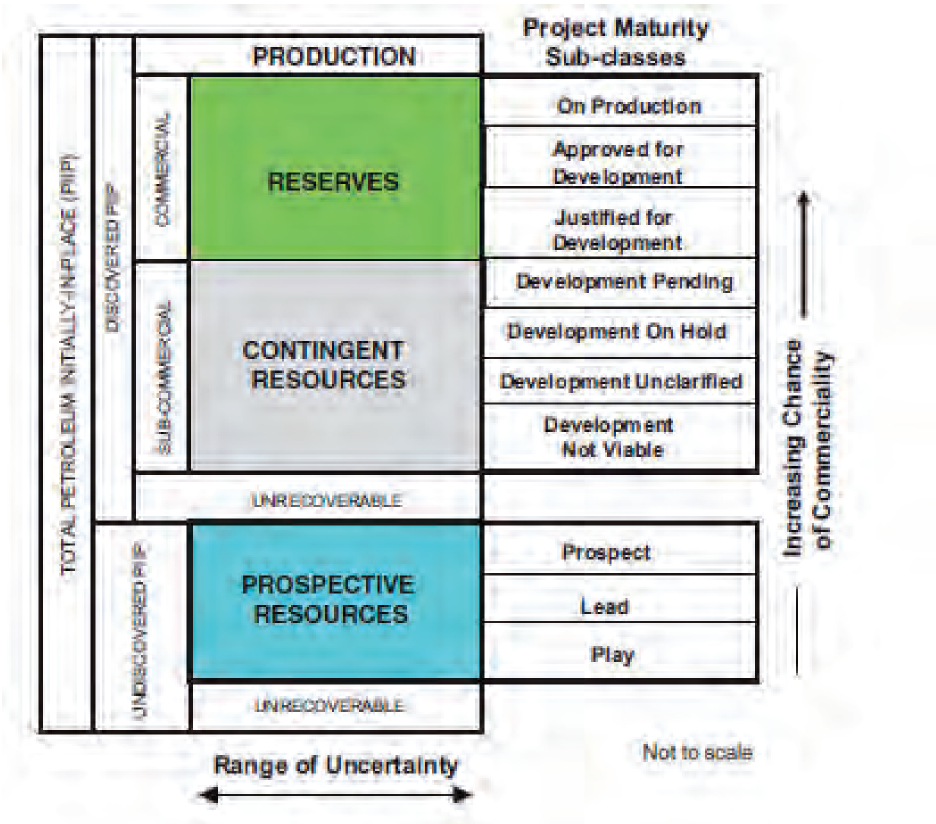



Figure 8.2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

### 8.1.1 Total Petroleum Initially-In-Place

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.

### 8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

### 8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

## 8.2 Production

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.

## 8.3 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 (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), 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.

### 8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

### 8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

### 8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(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

(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

### 8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

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 that the quantities actually recovered will equal or exceed the estimate.

### 8.3.5 Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

### 8.3.6 Possible Reserves

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest 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) Reserves, which is equivalent to the high-estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

## 8.4 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.

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.

Projects classified as Contingent Resources have their sub-classes aligned with the entity’s plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

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.

1C denotes low estimate scenario of Contingent Resources

2C denotes best estimate scenario of Contingent Resources

3C denotes high estimate scenario of Contingent Resources

### 8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

### 8.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are 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.

### 8.4.3 Contingent Resources: 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.

### 8.4.4 Contingent Resources: 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.

## 8.5 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.

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources

2U denotes best estimate scenario of Prospective Resources

3U denotes high estimate scenario of Prospective Resources

### 8.5.1 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.

### 8.5.2 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.

### 8.5.3 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.

### 8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

# 9 APPENDIX C: NOMENCLATURE

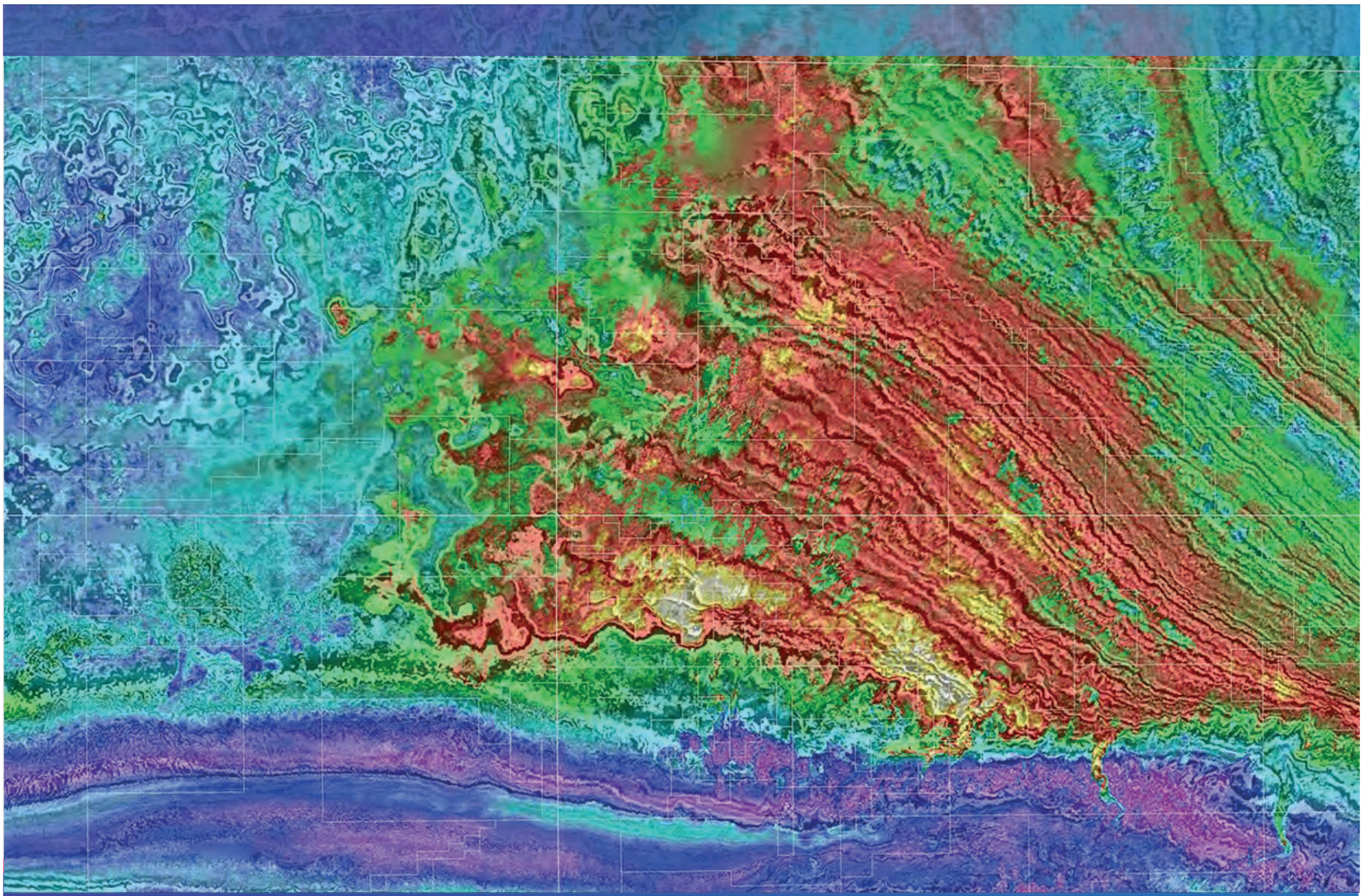
| | |
|---|---|
| 1D, 2D, 3D | 1-, 2-, 3-dimensions |
| 1P | proved |
| 2P | proved + probable |
| 3P | proved + probable + possible |
| API | American Petroleum Institute |
| av. | Average |
| bbl | barrel |
| bbl/d | barrels per day |
| BHP | bottom hole pressure |
| BHT | bottom hole temperature |
| boe | barrel of oil equivalent |
| Bscf | billion standard cubic feet |
| Bscm | billion standard cubic metres |
| c. | circa |
| DHI | direct hydrocarbon indicators |
| DST | drill-stem test |
| DWT | deadweight tonnage |
| E & P | exploration & production |
| E | East |
| e.g. | for example |
| EOR | enhanced oil recovery |
| ESP | Electrical Submersible Pump |
| et al. | and others |
| EUR | estimated ultimately recoverable |
| ftMD | feet measured depth |
| ftss | feet subsea |
| G & A | general & administration |
| G & G | geological & geophysical |
| $g/cm^3$ | grams per cubic centimetre |
| Ga | billion ($10^9$) years |
| GIIP | gas initially in place |
| GIS | Geographical Information Systems |
| GOC | gas-oil contact |
| GOR | gas to oil ratio |
| GR | gamma ray (log) |
| GWC | gas-water contact |
| IOR | improved oil recovery |
| IRR | internal rate of return |
| kg | kilogram |
| km | kilometre |
| $km^2$ | square kilometres |
| Kstb | thousands of standard barrels |
| M & A | mergers & acquisitions |
| m | metre |
| M | thousand |
| m/s | metres per second |
| Ma | million years (before present) |
| mD | millidarcies |
| MD | measured depth |
| MM | million |
| MMbbl | million bbls of oil |
| MMboe | million bbls of oil equivalent |
| MMscfd | million standard cubic feet per day |
| MMstb | million stock tank barrels |
| Mscfd | thousand standard cubic feet per day |
| msec | millisecond(s) |
| MSL | mean sea level |
| mSS | metres subsea |
| Mstb | thousand stock tank barrels |
| N | north |
| NaCl | sodium chloride |
| NGL | natural gas liquids |
| no. | number (not #) |
| NPV | net present value |
| Ø | porosity |
| OWC | oil-water contact |
| P & A | plugged & abandoned |
| perm. | permeability |
| pH | -log H ion concentration |
| plc | public limited company |
| poroperm | porosity-permeability |
| ppm | parts per million |
| PRMS | Petroleum Resource Management System (SPE) |
| psi | pounds per square inch |
| RFT | repeat formation test |
| RT | rotary table |
| S | South |
| SCAL | special core analysis |
| scf | standard cubic feet |
| SPE | Society of Petroleum Engineers |
| SS | sub-sea |
| ST | sidetrack (well) |
| stbbl | stock tank barrel |
| std. dev. | standard deviation |
| STOIIP | stock tank oil initially in place |
| Sw | water saturation |
| Tscf | trillion standard cubic feet |
| TD | total depth |
| TVD | true vertical depth |
| TVDSS | true vertical depth subsea |
| TWT | two-way time |
| US$ | US dollar |
| US$MM | Millions of US dollars |
| VDR | virtual dataroom |

- 1 boe = 6000 scf

- 1 scm = 35.3147 scf

# PART 10

# COMPETENT PERSON'S REPORT FOR THE NIGERIAN ASSETS



# COMPETENT PERSONS REPORT

## Uquo and Stubb Creek Fields, Nigeria

For
Savannah Energy PLC
Strand Hanson Limited
finnCap Ltd
Panmure Gordon (UK) Limited

cgg.com
SEE THINGS DIFFERENTLY

CGG

# DISCLAIMER AND CONDITIONS OF USAGE

## Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

## Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. The capital and operating costs have been combined with production forecasts based on the Reserves or Resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Savannah in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warranty to Savannah Energy PLC's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserves; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Energy PLC.

CGG affirms that from 1st October 2021 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix B** of the CPR.

**Conditions of Usage**

This report was compiled using existing data during the period 5th July 2021 to 1st October 2021. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Savannah Energy PLC for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on Savannah Energy PLC's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

| CGG Services (UK) Limited Reference No: NB540 | | | | |
|---|---|---|---|---|
| **Rev** | **Date** | **Originator** | **Checked & Approved** | **Issue Purpose** |
| 02 | 17th December 2021 | AKS/PC/PMD/ TU | AJW | Final Report |

| **Date** | **Originator** | **Checked & Approved** |
|---|---|---|
| Signed: | ***AKS/PC/PMD/TU*** | |

| Prepared for: | | Prepared By: |
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# 1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) on the petroleum interests held by Savannah Energy PLC (Savannah) in Nigeria, namely, the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream Business (Accugas).

The effective date for the evaluation is 1st October 2021.

## 1.1 Licence Interests

Savannah holds an 80% interest in the exploration, development and production of gas within the Uquo Field through its 80% indirectly owned subsidiary Savannah Energy Uquo Gas Limited (SEUGL). The remaining 20% indirect interest in SEUGL is held by African Infrastructure Investment Managers (AIIM), a leading African-focused private equity firm. SEUGL holds responsibility for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

Savannah also holds a direct 51% operated interest in the Stubb Creek Field through its 100% ownership of Universal Energy Resources Limited (Universal).

In addition, Savannah holds an 80% interest in Accugas, which owns and operates the 200 MMscfd Uquo gas Central Processing Facility (CPF) and c. 260km pipeline network, as well as holding Gas Sales Agreements (GSA) with downstream customers. The remaining 20% interest in Accugas is held by AIIM.

| Asset | Operator | Savannah's Interest (%) | Status | Licence expiry date | Licence Area |
|---|---|---|---|---|---|
| Uquo Gas | SEUGL* | 80% | Production | 2035 | 171 km$^2$ |
| Stubb Creek | Universal | 51% | Production | 2026 | 42 km$^2$ |

** SEUGL is the Operator of the Uquo Gas Project*

Table 1-1 Current Licence Details

For the Uquo Marginal Field, the licence was renewed by the Department of Petroleum Resources (DPR) for a period of 20 years on 18th June 2015. For the Stubb Creek Marginal Field, the licence was renewed by the DPR for a period of 10 years from 1st May 2016.

CGG have assumed, based on its experience, and pursuant to the relevant Marginal Field Guidelines, that the DPR is likely to extend the licences beyond the above tabulated expiry dates, if there are still Reserves to be produced. These extensions would be awarded in several phases until the fields reached the end of their economic lives. The Reserves stated in this CPR therefore assume production to the end of the economic lives of the fields.

## 1.2 Asset Details

### 1.2.1 Uquo Field

The Uquo Field produces gas from 4 wells and has been on production since Q1 2014. Production is sold under a Gas Sale Agreement to Accugas, a company in which Savannah has an 80% interest. Accugas currently processes, distributes and markets the gas to three power plants and a cement factory under long-term take or pay contracts. A summary of the contracts is in **Table 1-2**. To maintain the contracted production rates, Savannah plans to bring onstream 4 additional wells over the next 5 years while Accugas will install compression facilities at the Uquo CPF. A water disposal well is also planned.

### 1.2.2 Stubb Creek Field

The Stubb Creek Field is producing oil from 3 wells and has been on production since Q1 2015. Production is transported via pipeline to the ExxonMobil operated Qua Iboe Terminal. Universal plans to debottleneck the production facility to increase capacity from about 3,000 bopd to 5,000 bopd. A water disposal well is also planned. The Contingent Gas Resources will be developed and sold to Accugas, once the Uquo Field Reserves and Contingent Resources are not sufficient to meet the Daily Contracted Quantity (DCQ).

### 1.2.3 Accugas

The Accugas facilities consist of a two train 200 MMscfd Central Processing Facility (CPF) located near to the Uquo Field, and approximately 260 km of pipelines connecting the CPF to the current three Downstream gas purchasers. Total Daily Contracted Quantity (DCQ) under the three Gas Sales Agreements (GSA) is 174.9 MMscfd, and these GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ). Additional volumes are also contracted under Interruptible GSAs with Mulak Energy Limited (Mulak) and First Independent Power Limited (FIPL).

| Contract term | Calabar Power Plant | Ibom Power Plant | Lafarge Africa Plc (was Unicem Cement Plant) | Mulak Energy Limited | First Independent Power Ltd |
|---|---|---|---|---|---|
| Length of contract | 20 years | 10 years | 25 years | Initial 7 years with a possible extension of 5 years commencing July-23 | 1-year initial term with the possibility for extension |
| Contract end | Sep-37 | Dec-23 | Jan-37 | July-30 (Initial 7-year period) | 30 October 2022 (1-year initial term) |
| DCQ | 131.0 MMscf/d | 19.7 MMscf/d | 24.19 MMscf/d | Variable, max 2.5 MMscf/d | Nominations up to 35 MMscf/d |
| Take or Pay (ToP) | 80% of DCQ | 80% of DCQ | 80% of DCQ | 80% of DCQ | N/A |
| Gas Price | 2019 US$3.59/Mscf increasing in steps to US$5.04/Mscf in 2024 all indexed to US PPI | US$2.24/MMBTU (year commencing March 2021). Indexed to US PPI | 2020 US$5.0/Mscf increasing to US$5.10/Mscf in 2027, indexed to US PPI thereafter | US$5.15/MMBTU indexed to US PPI | US$2.5/MMBTU |

Table 1-2 Details of Accugas Gas Sales Agreements

## 1.3 Reserves and Resources

A summary of the Reserves and Resources associated with the Uquo and Stubb Creek Fields, both gross and net attributable to Savannah, in accordance with the 2018 Petroleum Resource Management System (PRMS), are shown in the tables below. Net attributable Reserves have been derived from Savannah's economic model. Net attributable Contingent and Prospective Resources have been estimated by multiplying gross Resources by the respective ratio derived from the economic model.

| | Reserves | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net attributable | | | Operator |
| | Proved | Proved & Probable | Proved, Probable & Possible | Proved | Proved & Probable | Proved, Probable & Possible | |
| **Oil (MMstb)** | | | | | | | |
| Stubb Creek | 6.0 | 13.4 | 23.2 | 1.3 | 3.1 | 5.8 | Universal |
| **Gas (Bscf)** | | | | | | | |
| Uquo | 402.6 | 567.3 | 682.4 | 322.1 | 453.9 | 545.9 | SEUGL |
| **Condensate (MMstb)** | | | | | | | |
| Uquo | 0.4 | 0.6 | 0.8 | 0.4 | 0.5 | 0.6 | SEUGL |

*Notes*
1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Full definitions of the Reserves categories can be found in Appendix B*

Table 1-3 Reserves as at 1st October 2021

| | Contingent Resources | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net attributable | | | Risk Factor | Operator |
| | 1C | 2C | 3C | 1C | 2C | 3C | | |
| **Oil (MMstb)** | | | | | | | | |
| Stubb Creek | - | - | - | - | - | - | | Universal |
| **Gas (Bscf)** | | | | | | | | |
| Uquo | 66.6 | 82.8 | 101.1 | 53.3 | 66.2 | 80.9 | >75% | SEUGL |
| Stubb Creek | 364.9 | 515.3 | 680.3 | 208.0 | 293.7 | 387.8 | >75% | Universal |

*Notes*

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
5. *Full definitions of the Contingent Resource categories can be found in Appendix B*
6. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-4 Contingent Resources

| | Prospective Resources | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Gross on Licence | | | Net attributable | | | | Operator |
| | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Risk Factor | |
| **Gas (Bscf)** | | | | | | | | |
| Uquo | 325.6 | 513.1 | 842.2 | 260.5 | 410.5 | 673.7 | 25-75% | SEUGL |
| Stubb Creek | 9.0 | 13.9 | 20.9 | 5.1 | 7.9 | 11.9 | 25-75% | Universal |

*Notes*

1. *Prospective Resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
5. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*
6. *Full definitions of the Prospective Resource categories can be found in Appendix B*
7. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-5 Prospective Resources

## 1.4 Economic Evaluation

The Net Present Values (NPV) of future cash flows derived from the exploitation of the Reserves as at 1st October 2021 are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes and are based on a Brent oil price of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

| NPV10 (US$MM) of Reserves Net to Savannah | | | |
|---|---|---|---|
| | **Proved** | **Proved & Probable** | **Proved, Probable & Possible** |
| Uquo (gas and condensate) | 239.1 | 329.1 | 421.7 |
| Stubb Creek oil | 34.2 | 69.5 | 82.7 |
| **Total*** | **273.2** | **398.6** | **504.4** |

* Total may not add up due to rounding

Table 1-6 NPV10 (US$MM) of Reserves Net to Savannah as at 1st October 2021

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below.

| NPV10 (US$MM) Net to Savannah | | | |
|---|---|---|---|
| | **Uquo** | **Stubb Creek** | **Total*** |
| Base case (Proved+Probable) | 329.1 | 69.5 | 398.6 |
| Oil price - US$50/bbl | 324.9 | 58.2 | 383.2 |
| Oil price - US$60/bbl | 327.9 | 66.5 | 394.5 |
| Oil price - US$70/bbl | 330.9 | 73.6 | 404.5 |
| Oil price - US$80/bbl | 333.9 | 79.8 | 413.8 |
| Oil price - US$90/bbl | 337.0 | 86.1 | 423.1 |
| Oil price - US$100/bbl | 340.0 | 91.9 | 431.9 |
| Capex +25% | 324.8 | 68.7 | 393.6 |
| Capex -15% | 331.6 | 69.9 | 401.5 |
| Opex +25% | 319.6 | 67.2 | 386.8 |
| Opex -15% | 334.8 | 71.0 | 405.8 |

* Total may not add up due to rounding

Table 1-7 Proved and Probable NPV10 (US$MM) Sensitivities as at 1st October 2021

The Net Present Values (NPV) of the future cash flows accruing to Accugas have been extracted from Savannah's integrated economic model and are tabulated below for the base case, Proved & Probable (2P) plus 2C. The model has been subject to a high-level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for Accugas (100%) and for Savannah's net 80% interest after deduction of Taxes. It should be noted that there are no gas Reserves or Resources associated with Accugas.

| Case | Accugas (100%) | Net to Savannah |
|---|---|---|
| Base Case (2P+2C) | 694.0 | 555.2 |

Table 1-8 Accugas NPV10s (US$MM)

# 2 INTRODUCTION

## 2.1 Overview

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited. The report evaluates Reserves and Resources associated with the onshore Uquo and Stubb Creek Marginal Fields in which Savannah hold interests. These fields are located near the coast in south-east Nigeria.

Frontier Oil Limited (Frontier) and Universal Energy Resources Limited (Universal), both indigenous Nigerian E&P companies, are Operators of the Uquo and Stubb Creek fields respectively.

Savannah Energy Uquo Gas Limited (SEUGL) has a 100% operating interest in the Uquo gas project (including associated condensate production). Savannah owns an 80% indirect interest in SEUGL, the remaining 20% is held by AIIM. Frontier has a 100% interest in the Uquo oil project.

Savannah has a 51% participating interest in the Stubb Creek field. This interest is held via a 100% interest in Universal, which in turn holds a 51% interest in the field. The remaining 49% interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC).

Savannah also owns an 80% operated interest in Accugas, the owner of the Uquo Gas Processing Facility and associated pipeline network. The remaining 20% is held by AIIM. Accugas purchases Uquo gas production, which it then currently sells to three local power plants and a cement factory. A summary of Savannah's licence interests are tabulated below (**Table 2-1**).

| Asset | Operator | Savannah's Interest (%) | Status | Licence expiry date | Licence Area |
|---|---|---|---|---|---|
| Uquo Gas | SEUGL* | 80% | Production | 2035 | 171 $km^2$ |
| Stubb Creek | Universal | 51% | Production | 2026 | 42 $km^2$ |

** SEUGL is the Operator of the Uquo Gas Project*

Table 2-1 Current Licence Details

The location of the Uquo and Stubb Creek Fields, and the Accugas surface facilities are shown in **Figure 2-1**.

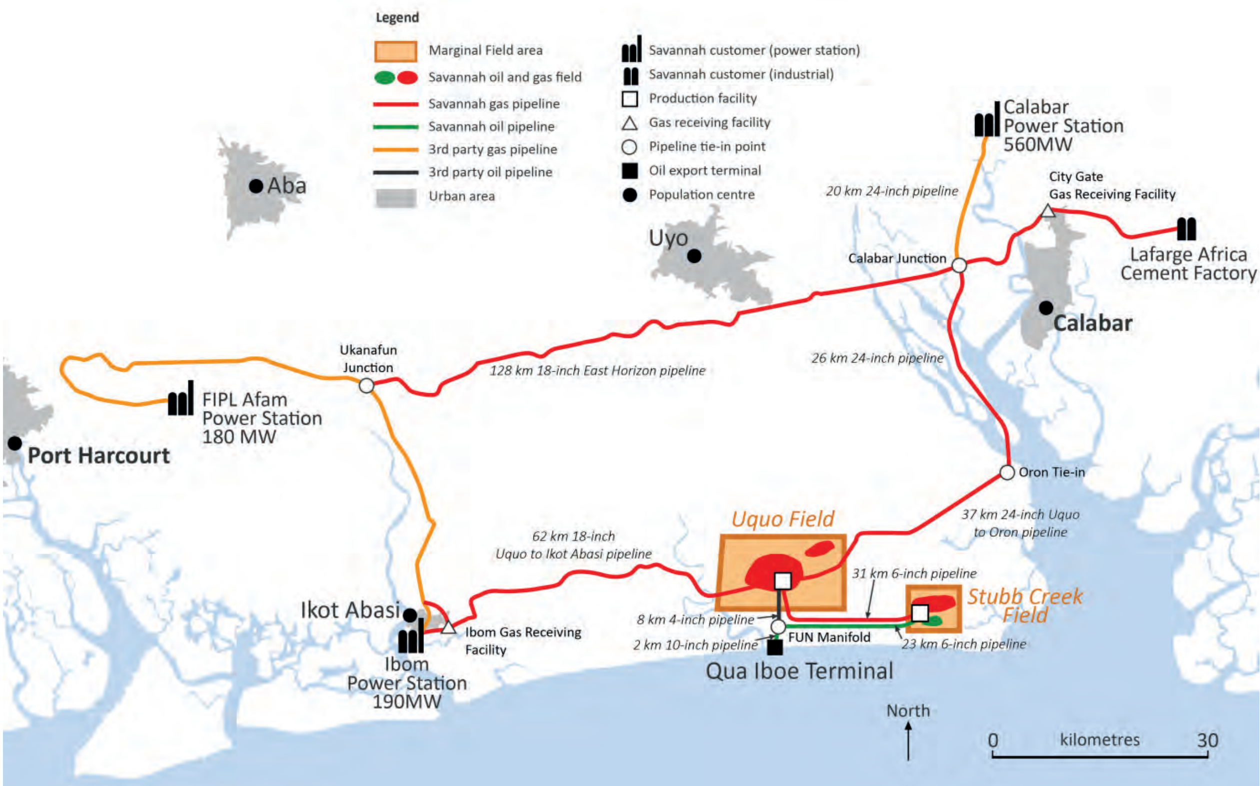



Figure 2-1 Location of Fields and Infrastructure (Source: Savannah, 2021)

## 2.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah's technical teams as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR has included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations, including 3D seismic over Uquo
- 3D geocellular model for Uquo Field
- Historical production and pressure data
- Gas sales contracts and farmout agreements
- Work plans and budgets

In conducting the evaluation, CGG have accepted the accuracy and completeness of information supplied by Savannah, and have not performed any new interpretations, simulations or studies.

No site visit to the facilities has been conducted by CGG as it was not part of the work scope in the letter of engagement.

## 2.3 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Andrew Webb

Andrew Webb has supervised the preparation of this CPR. Andrew is the Asset Evaluation Manager at CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 30 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 25 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

Pablo Cifuentes

Pablo Cifuentes has a BSc in Petroleum Engineering. He has 20 years of experience in the oil and gas industry. Pablo is a specialist in 3D reservoir static model and uncertainty analysis with relevant experience in Colombia, Mexico, Ecuador and Angola. He also has experience in geopressure prediction for the Gulf of Mexico and North Sea.

Pedro Martinez Duran

Pedro Martinez obtained a BSc in Geology at the University of Zaragoza (Spain) in 1993 studying the last two years in Burgundy University (France) and University of Aberdeen. Later he obtained an MPhil in carbonate sedimentology and sequence stratigraphy at the University of Zaragoza, publishing several papers related to these subjects. For some years he pursued a career as an exploration mining geologist (working in Chile, Argentina, Bolivia, USA, Turkey, Portugal, France and Italy) before becoming a petroleum geologist and completing an MSc in Petroleum Geoscience at Royal Holloway in 2011. Pedro as since joined CGG as Petroleum Geologist and Seismic Interpreter. Since then, he has been involved as seismic interpreter in almost all the main multi-client surveys acquired by CGG such as Australia, New Zealand, Banda Arc, Gabon, etc. Pedro is a member of the AAPG, EAGE and PESGB.

Toni Uwaga

Toni Uwaga has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish Sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has written several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright gained an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

## 2.4 Evaluation Methodology

In evaluating the Reserves and Resources associated with the fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation. More detailed descriptions of the workflow and methodologies employed are provided in the relevant sections of this report.

As an initial stage in the evaluation process, the seismic interpretation was reviewed during a visit by CGG to Savannah's London office in October 2018. During the same visit, geological, engineering and commercial issues were also discussed face to face with technical staff. In June 2021, Savannah provided new seismic interpretation and a 3D geocellular model for the Uquo Field and provided a review and official report on the updated gas-initially-in-place for the Uquo Field.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Reserves, production profiles and estimates of capital and operating costs provided by Savannah. The Reserves have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

The evaluation has been performed in accordance with the:

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)
- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

# 3 GEOLOGY AND GEOPHYSICS

## 3.1 Regional geology

The Uquo Field is located within the eastern Niger Delta, which is part of the prolific Niger Delta hydrocarbon province in Southern Nigeria. The Niger Delta is one of the world's largest Tertiary delta systems, covering an area of approximately 75,000km$^2$, which has historically been fed by the Niger, Benue and Cross river systems. The basin is located on the West African continental margin at the site of a triple junction that formed during continental break-up during the Cretaceous. The delta sequence consists of an upward-coarsening regressive sequence of Tertiary clastic sediments up to 12 km thick. The dominant subsurface structures are listric normal faults (flattening downward), which detach close to the top of the underlying marine claystone surface at the top of the Akata Shale. These listric faults provide an array of trapping mechanisms for hydrocarbons in the subsurface, particularly within the associated rollover anticline structures. Major growth faults cross the delta from northwest to southeast, dividing the delta into a series of depobelts that have been prograding south-westwards for approximately 55 Myr (**Figure 3-1**).

The northern boundary fault for each of the depobelts marks the approximate position of the palaeo-coastline during the major progradational stages. Hydrocarbons have been located in all of the depobelts of the Niger Delta, typically in good quality sandstone reservoirs within the main deltaic sequence.

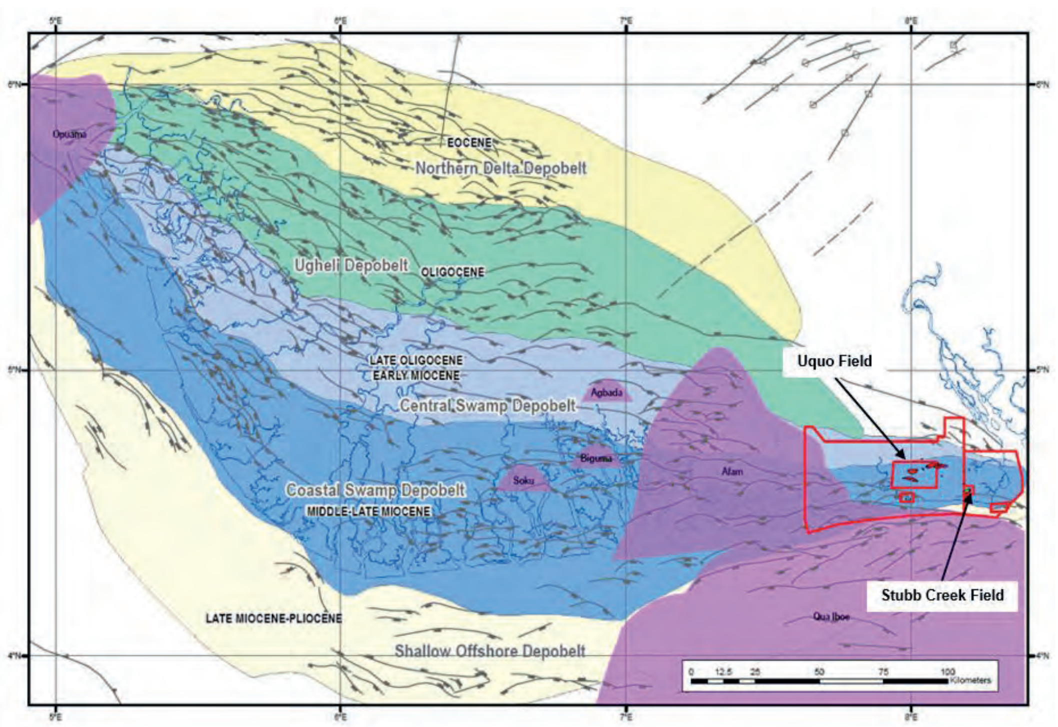



Figure 3-1 Depobelts of the Niger Delta (Source: CGG)

The stratigraphic sequence in the Niger Delta is broadly subdivided into the marine Akata Formation, paralic Agbada Formation and continental Benin Formation (**Figure 3-2**).

Hydrocarbons in the Uquo and Stubb Creek Fields were generated from the prodelta mudstones of Akata Formation and the interbedded paralic mudstones of the Agbada Formation. Upon maturation, hydrocarbons migrated either updip through carrier beds, or vertically along fault planes into the deltaic sandstones of the Early Miocene Agbada Formation. At Uquo and Stubb Creek, the Agbada Formation is represented by the hydrocarbon-bearing “C” and “D” sands. The seal to these sands is provided by interbedded deltaic mudstones, which are thick and competent across the basin.

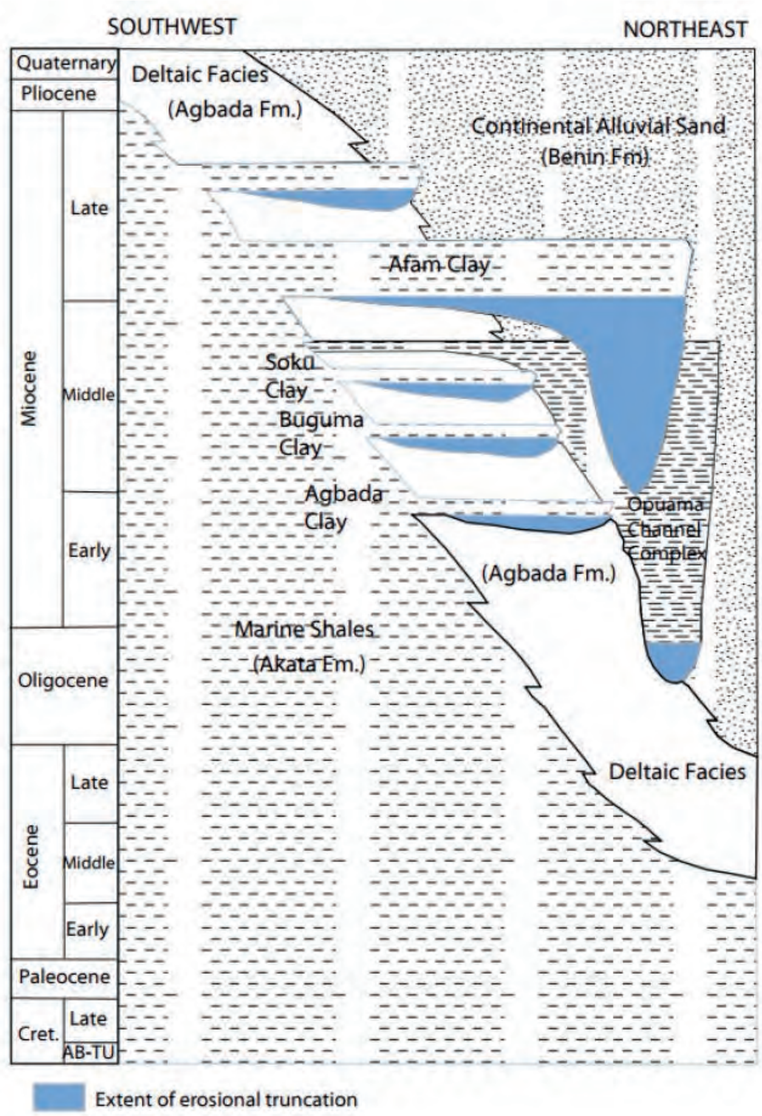



Figure 3-2 Lithostratigraphic column showing the key Tertiary sedimentary sequences in the Niger Delta (Source: Tuttle et al., U.S. Geological Survey, 1999)

## 3.2 Uquo Field

### 3.2.1 Uquo Field Summary

The Uquo Marginal Field Licence is located within OML 13, onshore Nigeria. Gas has been discovered in 13 different 'C' and 'D' sand reservoirs in the Agbada Formation.

The Uquo Field is made up of 3 main areas; Uquo-2 (Uquo-2, 4 & 11 wells), Uquo-3 (Uquo-3, 7 & 8/8ST wells) and Uquo NE (Uquo 9/9ST well), with small volumes also present in Uquo-5 area (Uquo-1, 5, 5ST/6 & 10 wells). The upper 'D' reservoirs contribute the greatest volume of gas in the Uquo area (**Figure 3-3** and **Figure 3-4**).

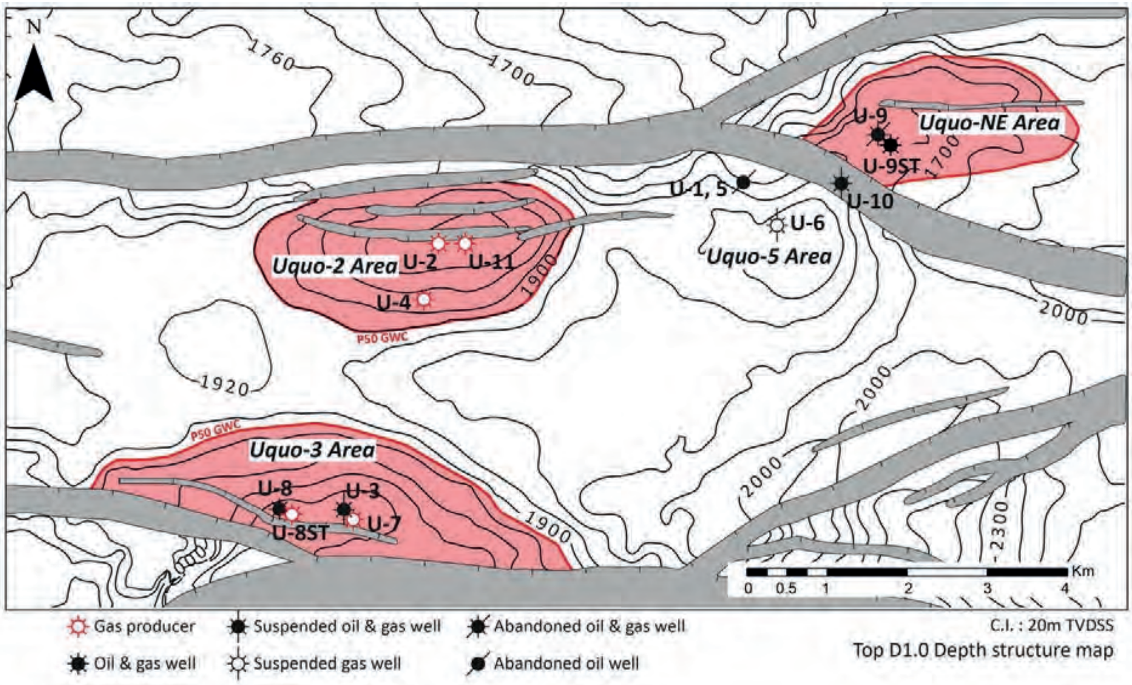



Figure 3-3 Uquo Field structure map (Source: Savannah, 2021)

The Uquo Field was first drilled in 1958 by Shell Petroleum Development Company Nigeria (SPDC); the composite logs from Uquo-1 supplied by Savannah suggest that this well only encountered thin gas intervals, although it was reported to have discovered oil and gas in four sands. The subsequent Uquo-2 well was drilled as an exploration well and encountered significant volumes of gas in all sand units between C9.0 and D5.0 (seven different reservoir intervals). Another exploration well and one appraisal well were drilled in 1971/72; Uquo-3 encountered gas in the D1.0 & D1.3/D1.4 sands, and oil in the D5.0 sand, whereas Uquo-4 encountered gas throughout the D1.0 sand and in the upper part of the D2.0 sand.

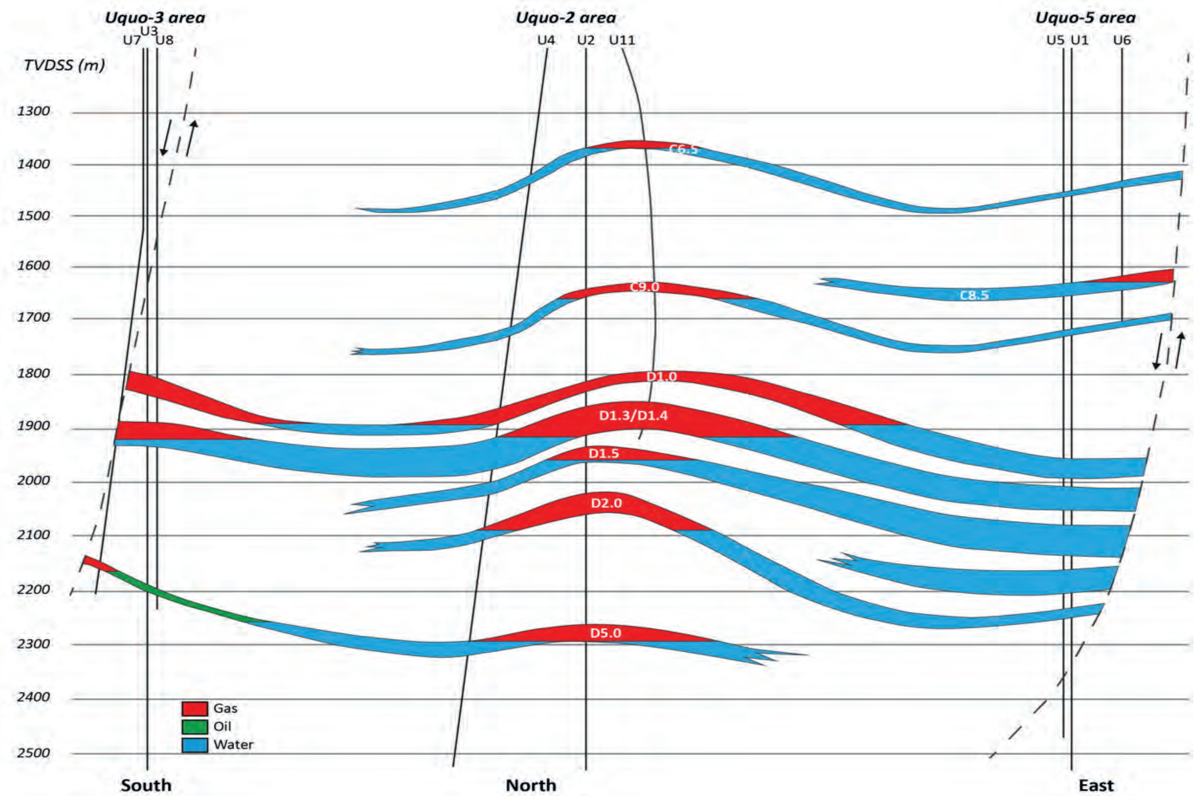



Figure 3-4 Schematic diagram showing the reservoir intervals of the Uquo Field (Source: Savannah, 2021)

Drilling activity restarted in 2008, targeting oil discovered by Uquo-1; the Uquo-5 well failed to confirm the presence of the Uquo-1 oil accumulation. The well was then sidetracked (Uquo-5ST, aka Uquo-6), but was terminated before reaching the target depth due to mechanical problems. However, Uquo-5ST confirmed gas in one reservoir (C8.5). In January 2010, Uquo-3 was worked-over and completed as an oil producer in D5.0 reservoir, Uquo-2 and Uquo-4 were subsequently completed as gas producers in the D2.0 and D1.0 reservoirs respectively. The gas accumulations were appraised by Uquo-7, -8 and -8ST between June and September 2013. Uquo-7 and -8ST were completed in 2014 as gas producers in D1.0 reservoir. Exploration drilling returned to the Uquo area in November 2014, resulting in the Uquo-NE discovery with Uquo-9/9ST suspended as an oil and gas discovery. Uquo-9/9ST well was later completed in D1.6 reservoir – Uquo NE area and is operated as an oil producer by Frontier.

In 2021, Savannah drilled a gas development well, Uquo-11, in the Uquo-2 area. The well has been completed in the D1.0 and D1.3/D1.4 reservoirs. Uquo-11 proved that some 39 feet of the C9.0 reservoir section in nearby well Uquo-2 had been faulted out. Remapping of the Uquo-2 area reservoirs followed, incorporating the correct (greater) thickness of net sand in the area. Log evaluation conducted by Savannah shows that the total net pay thickness for the C9.0, D1.0 and D1.3/D1.4 reservoirs came 71ft above prognosis with a total of 355ft net pay thickness.

### 3.2.2 Uquo Field Subsurface Overview

CGG have carried out an independent analysis of the Uquo Marginal Field Licence using a PSDM (Pre-Stack Depth Migration) 3D seismic volume of 198 km$^2$ supplied by Savannah. This supersedes the 2019 evaluation from

CGG which was based on the original Pre-Stack Time Migration (PSTM) seismic data. The PSDM seismic data was reprocessed by WesternGeco Seismic Nigeria Ltd. in 2020, starting from tapes. A new velocity model has been prepared and the seismic interpretation and volumetrics have been revised.

The seismic survey was acquired between December 2006 and April 2007. Around 24.5 km$^2$ of the licence is not covered by seismic, due to the presence of the Eket Airfield to the west of the licence. In addition, there are areas within the dataset that suffer from poor fold coverage due to the presence of some villages.

Data was provided by Savannah to CGG as a Kingdom™ Project containing wells, horizons, faults and depth maps. The data and interpretations have been QC'd and used as a basis for volumetrics. Composite logs were supplied which contain formation depths as well as fluid contacts, and these have been used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The quality of the seismic data is generally good at the key reservoir levels, although the noted acquisition issues result in a decrease in data quality in a few areas. The footwalls of most of the faults are generally poorly imaged, particularly in the deeper section, which makes the delineation of some of the gas-bearing reservoirs more uncertain. In addition to the Kingdom™ project, Savannah provided reports concerning Petrophysics, Geoscience and Reservoir Engineering studies.

The Uquo Marginal Field Licence area contains several different structural features resulting from a set of listric faults trending in an overall E-W direction with a clear southern tectonic vergence. Listric growth fans were formed as a result of the rotation of both hangingwall and footwall as sedimentation took place.

Roll-over anticline structures are readily seen in the seismic data. A good understanding of the structural framework is vital as the structural highs generated by these features shape the pools in the Uquo area. There are three structural culminations in the main fault block, two in the north (Uquo-2 and 5 areas) which are dip-bounded, and one dip and fault-closed structure in the south (Uquo-3 area). At D1.0 level, Uquo-2 and Uquo-3 areas are in communication (pressure connection proven by production data) as seen in **Figure 3-5**. In the Uquo-2 area, the reservoirs are intersected by planar antithetic faults genetically related to the rotational movement of the main listric fault F2.

The Uquo-3 area has a different structural configuration, in that the reservoirs are trapped in the footwall of the large listric fault labelled as F3. The rotation of the main fault block has resulted in some structural relief into which hydrocarbons have migrated and remained trapped. The southern edges of the Uquo-3 area reservoirs are difficult to pick with accuracy in the deeper section, due to fault shadow effects in the seismic clearly seen in the left hand-side of **Figure 3-5**. Most of the gas reservoirs in the Uquo field are easy to pick; many exhibit a bright amplitude response (**Figure 3-6**) as a result of the presence of gas within a high-quality, porous reservoir. Many also exhibit flat spots, which help to define the contacts in some of the accumulations (if no gas-water contact has been encountered in the wells on-structure).

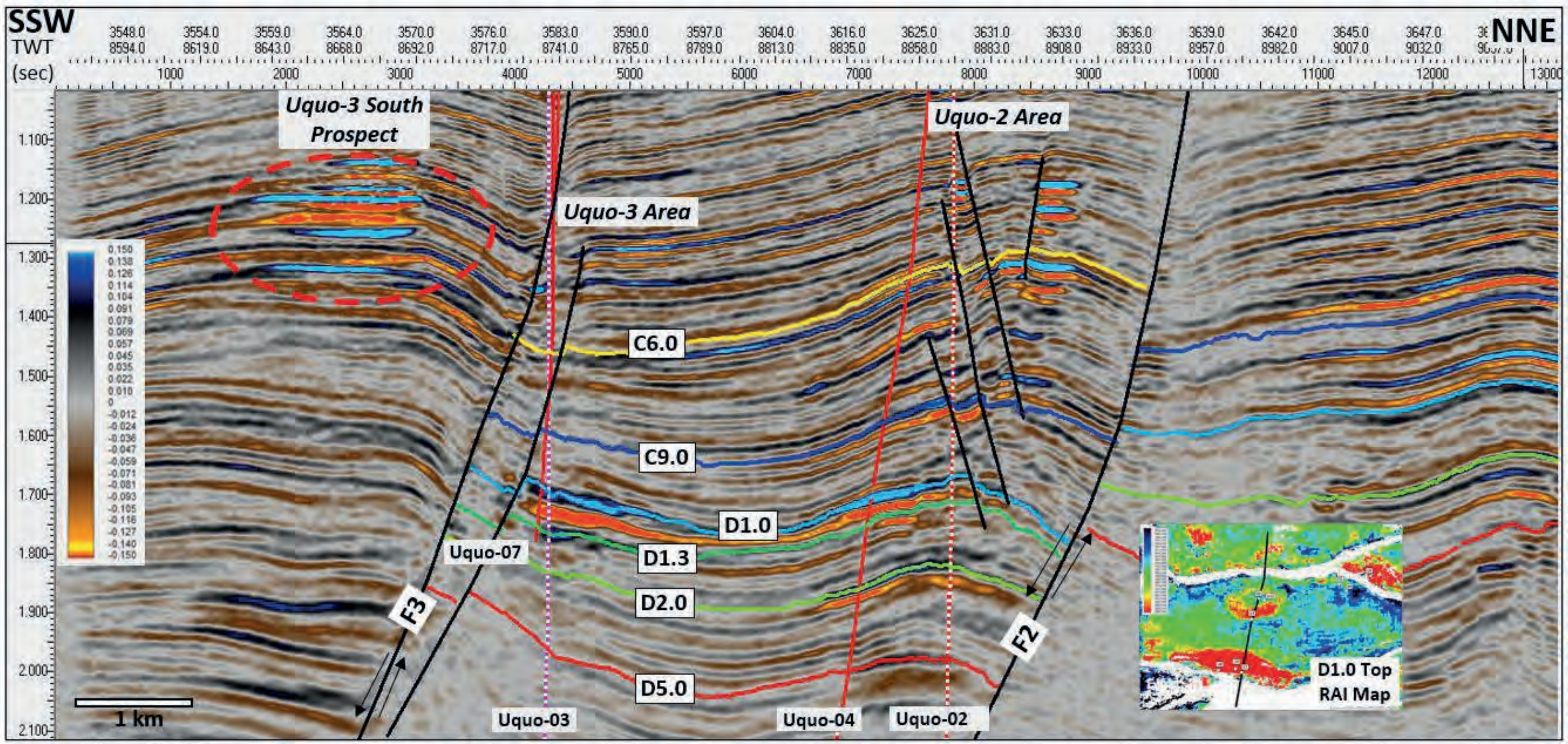



Figure 3-5 SW-NNE seismic line through Uquo-3 and Uquo-2 areas (Source: Savannah, 2021)

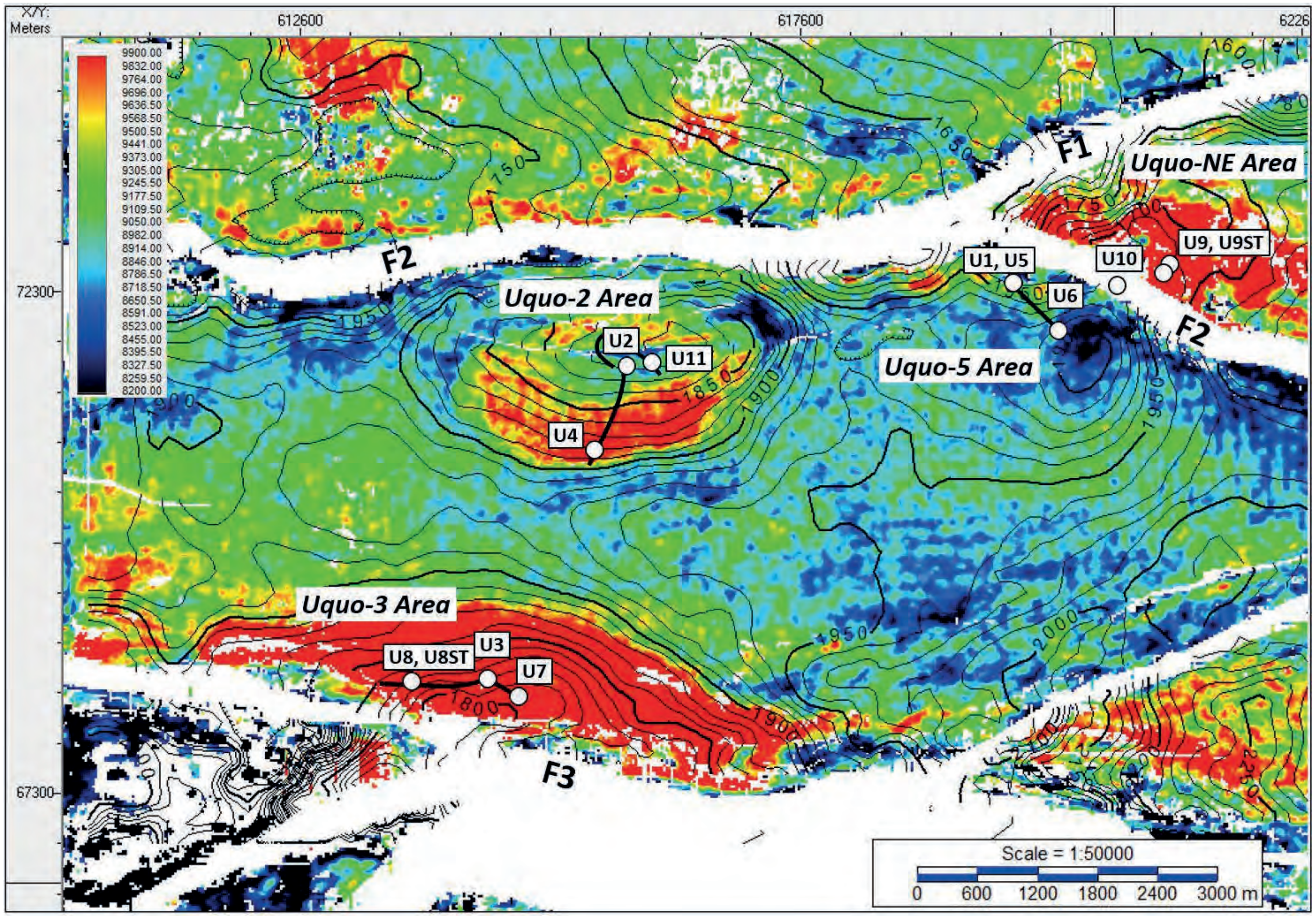



Figure 3-6 Relative Acoustic Impedance at the D1.0 level with depth contours in mSS (Source: Savannah, 2021)

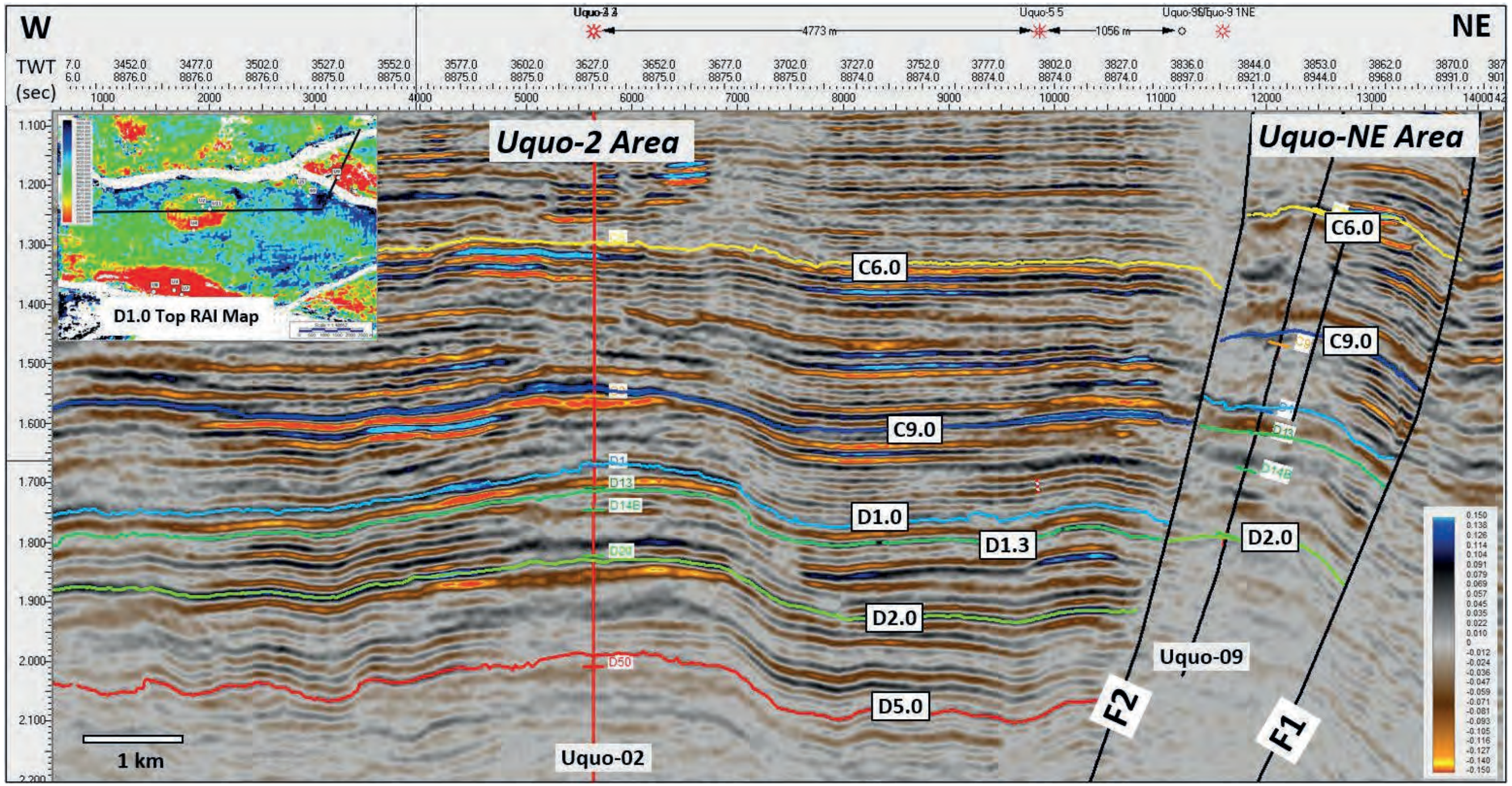



Figure 3-7 E-W Seismic crossline for Uquo-2 and Uquo-NE area showing tops of target units. See inset map for location (Source: Savannah, 2021)

The Uquo-9/9ST discovery is located in a separate fault compartment (**Figure 3-7** and **Figure 3-8**), namely Uquo NE towards the North East of the main fault block. Hydrocarbons were discovered in 9 reservoirs in Uquo-9/9ST well; mainly gas except for the D1.6 and D7.0 reservoirs which encountered oil. The ultimate areal extent of the Uquo-NE shallow gas discovery is unknown, as it extends outside the area of 3D seismic coverage (**Figure 3-6**). The seismic over Uquo-NE area is quite poor (**Figure 3-7** and **Figure 3-8**) in places due to an overlying village, although this is mitigated by the data provided by the exploration well on the structure (Uquo 9/9ST).

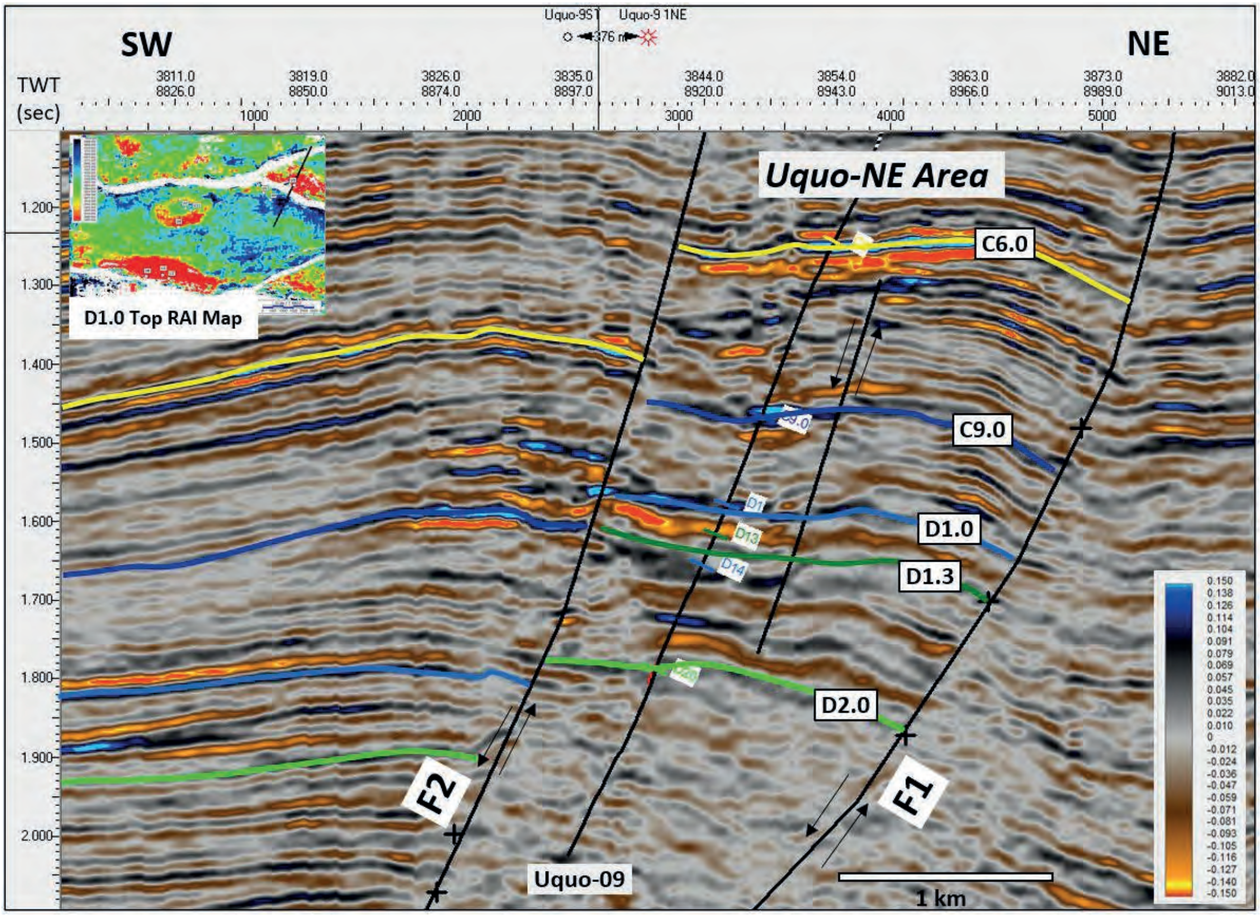



Figure 3-8 N-S Seismic Inline over Uquo-NE area (Source: Savannah, 2021)

The Agbada C and D sand reservoirs are of high quality at the Uquo Field; NTG (Net-To-Gross) is generally in excess of 90% and porosity is usually 27% or higher. In addition to the discovered volumes, Savannah has a series of additional prospects (**Figure 3-9**).

The subsurface team at CGG has completed a thorough geophysical and geological QC of the work supplied by Savannah. For the seismic mapping QC, the Kingdom$^{TM}$ project provided has been used. CGG has independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by reservoir engineering and petrophysics experts who have also provided inputs for the volumetric calculations, which were run through a probabilistic Monte Carlo analysis.

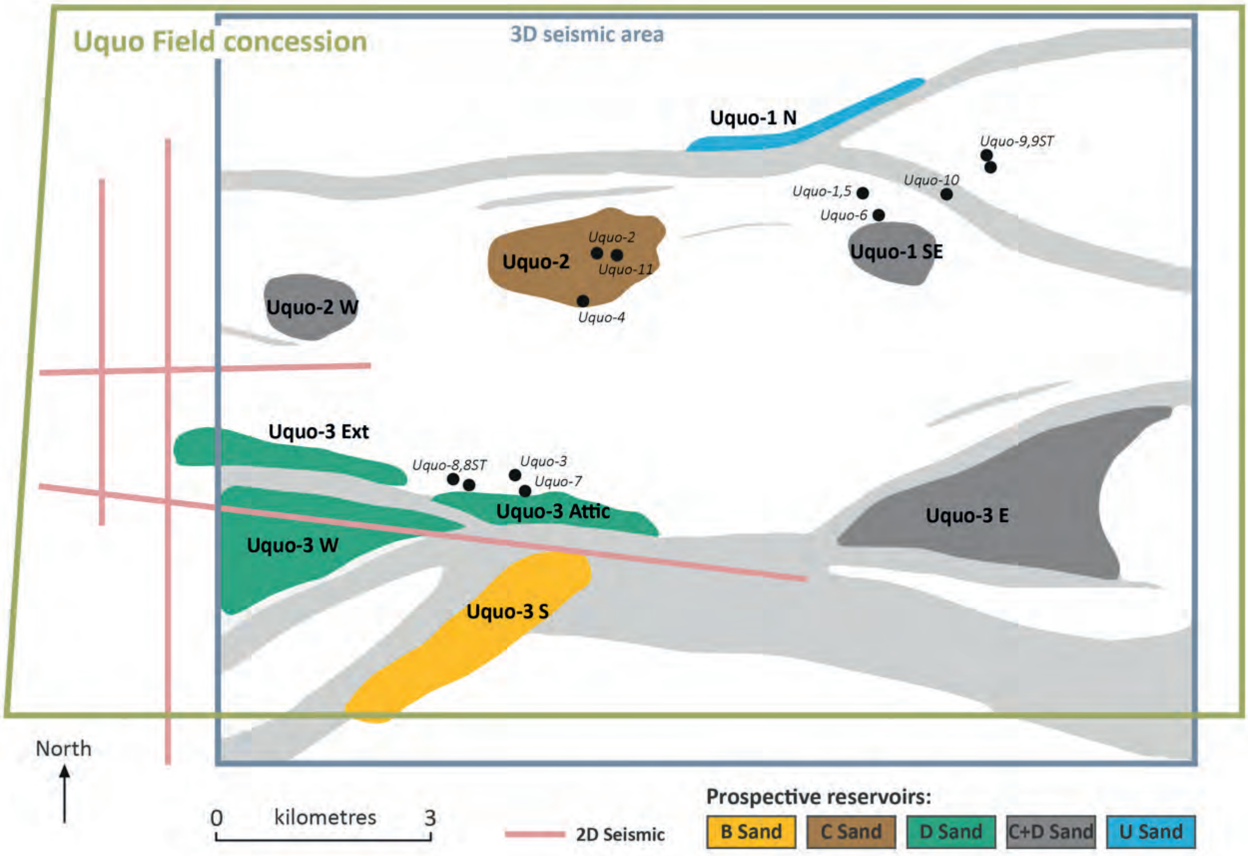



Figure 3-9 Map of prospects in the Uquo Marginal Field Licence area (Source: Savannah, 2021)

In summary, the seismic interpretation of the top and base of the targeted units do not show major issues apart from minor irregularities and misties compared to well tops which is relatively commonplace. Depth maps from the static model were imported back into the Kingdom$^{TM}$ seismic project for QC purposes and no major issues or changes were observed in terms of volumetrics. Given that the seismic reflections are very clear, the resulting depth maps were imported into the geomodel and depth shifted to match well tops without any changes in overall shape, CGG considers that the Gross Rock Volumes (GRV) arising from these maps is reliable.

There is uncertainty in the generation of the velocity model for conversion from time to depth domains. However, CGG considers this has been accounted for using a range of GRV values for P90, P50 and P10 estimates.

### 3.2.3 Uquo Field Petrophysics

The petrophysical data provided for the C and D sands in the Uquo Field and the nearby Etebi well (Savannah, 2019) has been evaluated by CGG in order to obtain P10, P50 and P90 values for the reservoir properties such as the NTG, porosity and hydrocarbon saturations, which were used as inputs for the volumetric calculations. The methodology adopted for petrophysical analysis was found to be reasonable. This comprises the following computations: Volume of clay (Vcl) from GR logs using the Larionov model; and porosity from density log and water saturation using the Simandoux saturation model. An appropriate gas density correction was applied while estimating porosity from the density log, ensuring that calculated porosities are not overestimated. However, there is no density or sonic log available in Uquo-1 and Uquo-6 so effective porosity was estimated using a Vcl-porosity relationship derived from the nearby Uquo-5 well. Density and sonic logs were available only down to the top of the D sands in the Uquo-8 well, thus porosity calculations are based on the sonic logs for the C sands and a Vcl-porosity relationship was applied to the deeper reservoirs. In the well intervals in which the Vcl relationship was used in determining the porosity (Uquo-1, Uquo-6 and deeper section of Uquo-8), the water saturation (Sw) estimates are based on the Archie equation.

The two sets of cut-offs used in deriving the net reservoir/pay are considered to be reasonable;

- Clean sands: porosity (0.16) and Vcl (0.45)
- Shaly sand: porosity (0.10) and Vcl (0.5)
- An uniform Sw cut-off of 0.50 has been applied throughout

Fluid contacts have also been determined from the petrophysical data and these have been used in combination with the Direct Hydrocarbon Indicators (DHI's) and structural closures in determining the Minimum, Most Likely and Maximum GRV’s. **Figure 3-10** presents results from the Uquo-2 well which are representative of the rock properties of the Uquo Field.

During CGG’s estimation of gas-initially-in-place, an appropriate range for average properties has been estimated with reference to the wells that penetrate the reservoir. This was done in each accumulation separately.

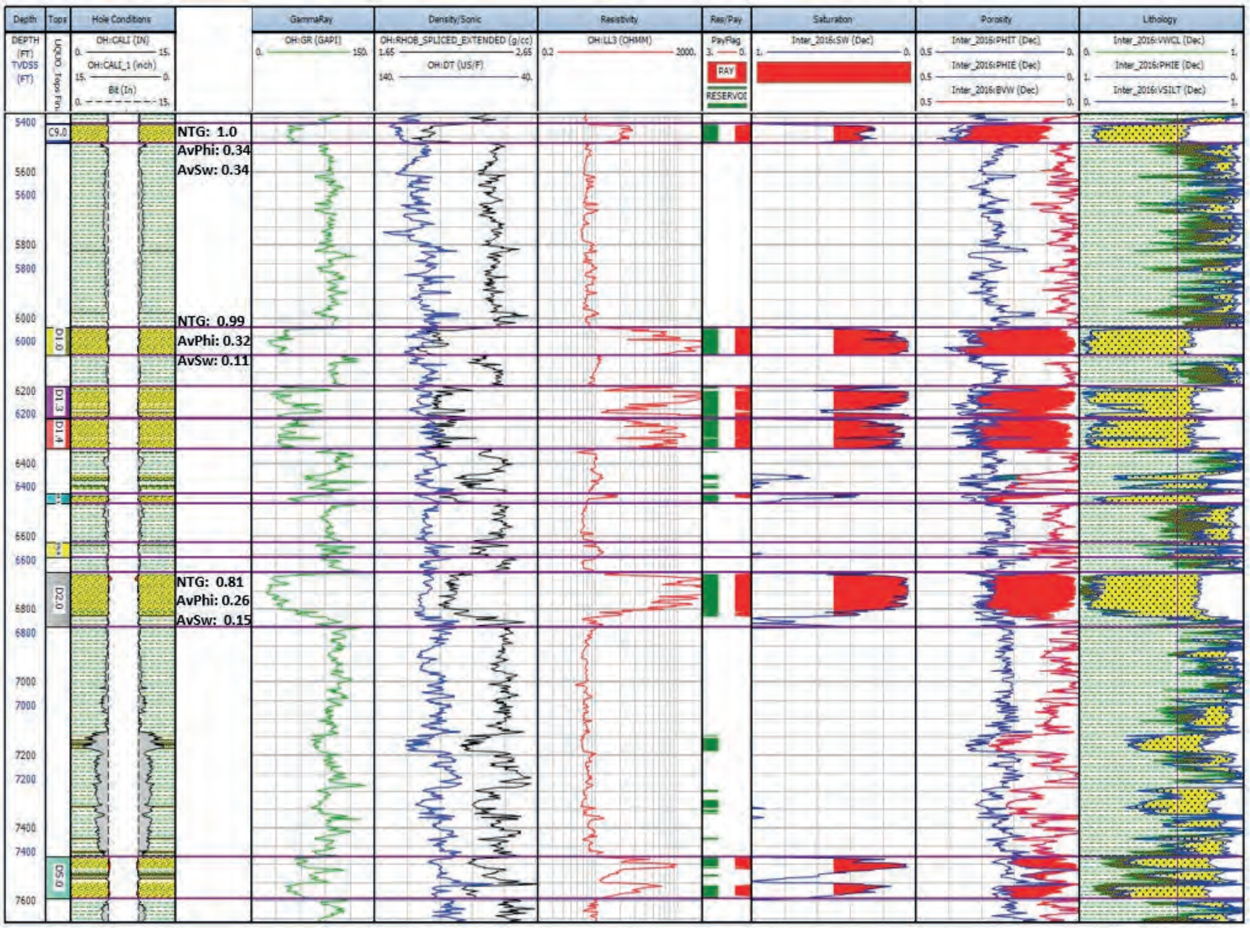



Figure 3-10 Uquo-2 Petrophysical interpretation (Source: Savannah, 2019)

### 3.2.4 Uquo Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs below in Minimum, P50 and Maximum cases using new depth maps, based on newly reprocessed 3D PSDM seismic data. The horizon interpretations for the prospectivity, which have been converted from time to depth surfaces, have been extensively QC'd by CGG and were found to accurately describe the shape and size of the prospects. The prospect volumes are still based on the original Pre-Stack Time Migration (PSTM) data while Savannah is conducting an update of the exploration portfolio.

In addition, the following due diligence has been performed on the data and interpretations supplied, to understand:

- The effect of local use of autotracking on the seismic interpretation
- Conformance of mapped gas reservoirs to seismic Root-Mean-Square (RMS) amplitude anomalies
- Impact of smoothing pass on depth maps
- Impact of snapping to well tops, and method used, on volumes
- Checking of gas-water contacts used in all cases and their basis in evidence
- The selection of average reservoir property ranges for the volumetric analysis

Formation Volume Factors have been generated by CGG; rock properties have been derived from petrophysical analysis results and QC'd by CGG. The inputs have been run as a probabilistic Monte Carlo analysis.

In addition to a straightforward map-based volumetric determination, Savannah have also provided a 3D geocellular model based primarily on seismic maps, seismic attributes and a geological interpretation of the depositional origins of the different reservoir sands. The geological concepts used to distribute properties in three dimensions are considered technically sound and the resulting GIIP values obtained by using this approach and the seismic and facies trends are not significantly different from the simpler map-based method. The 3D model provides a solid QC of data integration and geological concepts employed and may prove useful in supporting future well planning and in understanding production performance.

RMS amplitude maps show anomalies in gas zones to a greater or lesser degree depending on reservoir intervals, these are considered good indicators.

**Table 3-1** and **Table 3-2** provides the gas-initially-in-place volumes as stated by Savannah in their most recent technical report and including updates following the drilling of the Uquo-11 gas well. Comparison of CGG's independently derived map based GIIP values with those of Savannah (2021) indicates very close agreement. CGG has confirmed that the seismic interpretation carried out by Savannah is good, their volumetric assessments of GIIP can be considered sound and the stated range from P90 to P10 is also reasonable. Savannah has also presented to CGG, P/Z plot analysis which corroborates the GIIP in the D1.0 (Uquo-2 & 3 areas) and D2.0 reservoirs.

In light of this result, CGG considers that Savannah's GIIP numbers are generated according to sound technical methods and can be accepted as reasonable.

| Area | Reservoir | Gross GIIP (Bscf) | | |
|---|---|---|---|---|
| | | **P90** | **P50** | **P10** |
| Uquo-2 | D1.0 | 130.0 | 154.0 | 181.0 |
| | D1.3/D1.4 | 111.0 | 132.0 | 157.0 |
| | D2.0 | 105.9 | 132.4 | 155.2 |
| | D5.0 | 26.4 | 30.8 | 35.6 |
| *Sub-total** | | *373.3* | *449.2* | *528.8* |
| Uquo-3 | D1.0 | 270.1 | 322.9 | 371.7 |
| | D1.3/D1.4 | 25.8 | 32.7 | 38.9 |
| *Sub-total** | | *295.9* | *355.6* | *410.6* |
| Uquo NE** | C6.0 | 146.0 | 175.0 | 215.0 |
| **Total*** | | **815.2** | **979.8** | **1154.4** |

** Arithmetic sum*
*** Uquo NE volumes on licence only*

Table 3-1 Uquo Marginal Field GIIP

In addition to the discovered volumes, CGG has reviewed the in-place numbers for the prospects in the Uquo Marginal Field Licence (**Figure 3-9**). **Table 3-3** shows Savannah's in-place volumes for the various Prospects.

| Area | Reservoir | Gross GIIP (Bscf) | | |
|---|---|---|---|---|
| | | P90 | P50 | P10 |
| Uquo-2 | C6.5 | 8.1 | 10.0 | 12.0 |
| | C9.0 | 32.8 | 39.1 | 46.3 |
| *Sub-total** | | *40.9* | *49.1* | *58.3* |
| Uquo NE | D1.0 | 47.5 | 55.1 | 64.5 |
| **Total*** | | **88.4** | **104.2** | **122.8** |

**Arithmetic sum*

Table 3-2 Uquo Marginal Field: GIIP excluded from development plan

| Prospect | Unrisked Gross GIIP (Bscf) | | | CoS (%) |
|---|---|---|---|---|
| | Low | Best | High | |
| Uquo 1SE | 55.7 | 84.8 | 139.9 | 50 |
| Uquo 2 | 5.5 | 15.4 | 39.0 | 73 |
| Uquo 2W | 71.3 | 88.4 | 103.7 | 57 |
| Uquo 3E | 151.5 | 221.7 | 335.7 | 35 |
| Uquo 3S | 114.8 | 154.3 | 200.1 | 66 |
| Uquo 3W | 72.5 | 115.2 | 204.1 | 18 |
| Uquo 3 Extension | 10.2 | 15.1 | 22.6 | 14 |
| Uquo 3 Attic | 13.3 | 23.4 | 42.6 | 17 |
| Uquo 1N | 6.1 | 14.7 | 35.2 | 18 |
| **Total*** | **500.9** | **733.0** | **1122.9** | |

** Arithmetic sum*

Table 3-3 Uquo Unrisked Prospective Resources GIIP

The Chance of Success (CoS) numbers reflect the fact that the licence is in a prolific hydrocarbon-producing basin, with hydrocarbons proven in many reservoir intervals. The principal risk in the licence area is the trap, which is amplified in areas of poor imaging. Fault seal is also key to the successful trapping of many of the prospects, which at depth is particularly poorly imaged due to fault shadows. Thus, reprocessing the seismic volume over the Uquo licence and improving the data quality would likely improve the CoS of many of the prospects. Savannah has conducted the PSDM re-processing of the seismic data in 2020 and is in the process of updating its exploration portfolio. In addition, some of the traps have an increased risk associated with them as the closures extend beyond the edge of the seismic dataset. Reservoir and source are known to be low risk in the licence area and this has been reflected in Savannah's estimated CoS figures. CGG has reviewed Savannah's CoS's and deem them to be reasonable estimates. Prospects with a high CoS (> 50%) exhibit strong amplitude anomalies analogous to the producing gas reservoirs. The Uquo-3S is such a prospect (66% CoS) which is highlighted on **Figure 3-5**.

## 3.3 Stubb Creek Field

### 3.3.1 Stubb Creek Field Summary

The Stubb Creek Marginal Field is located within the block OPL 276, formerly OML 14, onshore Nigeria. The Stubb Creek Field was discovered in 1971 by SPDC, who drilled 3 exploration wells and 1 appraisal well (from 1971-1983). The first well, SC-1 well intersected a 42 m gas column within the C3 sand reservoir, while light oil was later discovered in 1971 with the SC-2 well, principally within the D3 reservoir (and gas with an oil rim in the C9 reservoir). Overall, oil and gas have been discovered in 7 different 'C' and 'D' sand reservoirs in the Agbada Formation within the licence area. Where hydrocarbons are present, C sand reservoirs are typically gas-bearing apart from the C9 reservoir, with the deeper D sand reservoirs containing oil. Outlines of the main reservoirs are shown in **Figure 3-11** and **Figure 3-12**.

Stubb Creek was classified as a Marginal Field in 2002, with Universal becoming the Operator in 2003. Between 2007 and 2009, Universal drilled 5 oil development and one water injection wells, with oil production commencing in January 2015.

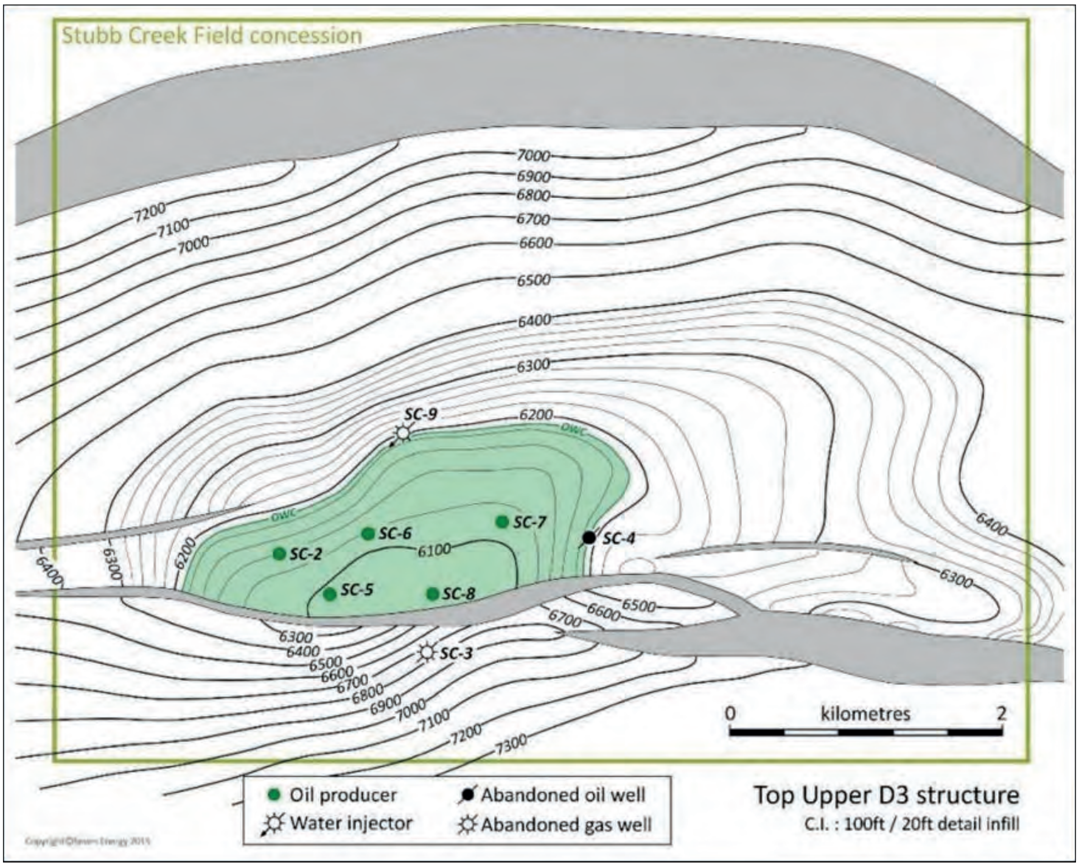



Figure 3-11 Map showing the outline of the Stubb Creek oil field at Upper D3 level (Source: Savannah, 2019)

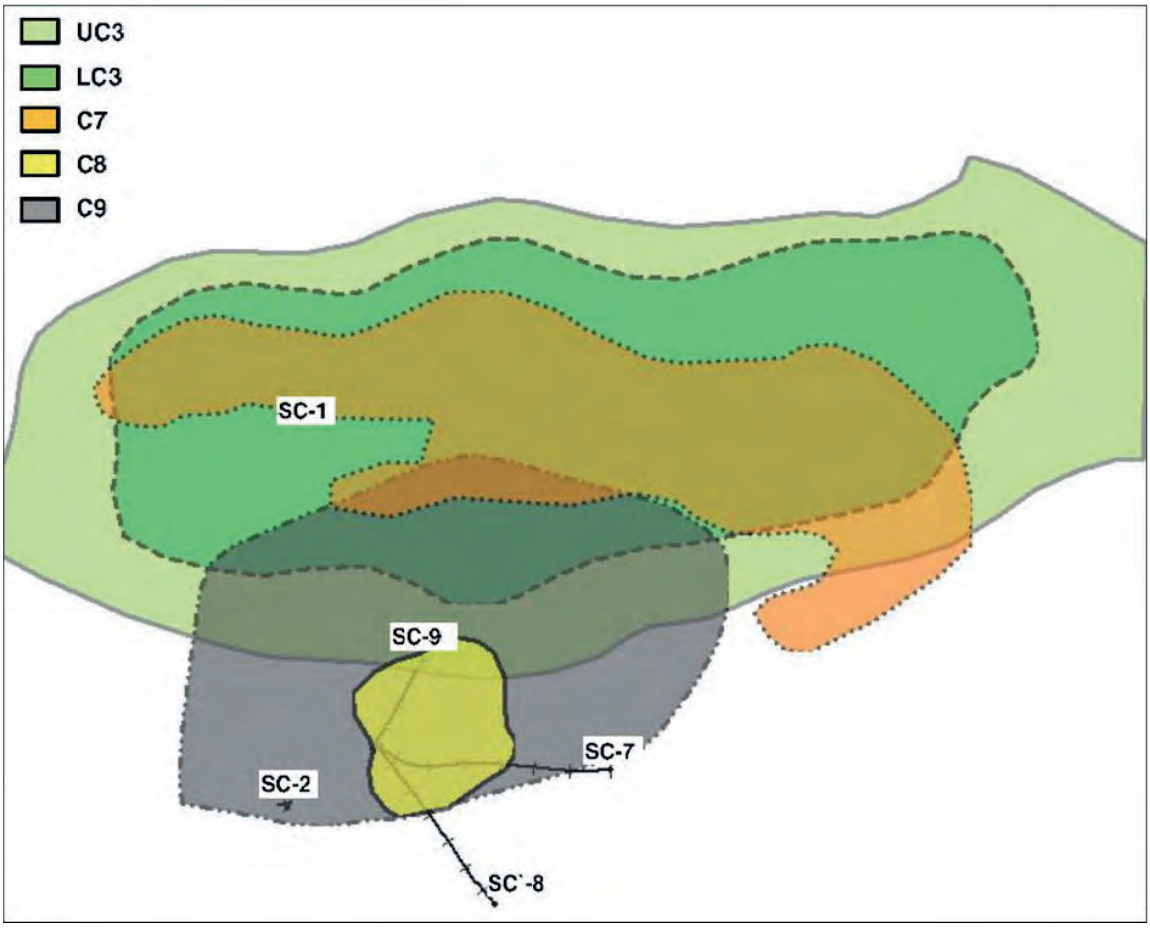



Figure 3-12 Savannah outlines of the C Sand gas reservoirs (Source: Savannah, 2019)

### 3.3.2 Stubb Creek Field Subsurface Overview

CGG have carried out an independent analysis of the in-place volumes using a 3D seismic volume acquired in 2005/2006, which covers an area of 65 km$^2$. The data were supplied as a Kingdom$^{TM}$ project containing wells (with synthetic seismograms), depth grids/horizons and fault interpretations. Composite logs were supplied which contained formation tops as well as fluid contacts which were used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The data quality is generally very good; gas reservoirs are easily distinguished from the background reservoir response as would be expected in shallow, high quality gas-bearing reservoir sands. The seismic volume is a PSTM; it is CGG's opinion that the accuracy of the volumetrics shown below would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration).

In addition to the Kingdom$^{TM}$ project, Savannah has provided reports to assist with CGG's G&G analysis; these include Geoscience and Engineering studies for both C & D reservoirs.

The Stubb Creek Field is comprised of seven different hydrocarbon-bearing intervals, all of which are located within a gently dipping fault block which is downthrown to a major listric fault to the north. The main rollover structure is largely undeformed; however, there is significant E-W trending extensional faulting south of the SC-8 well, creating a series of gravity-driven low angle fault blocks as can be seen in **Figure 3-13**.

The hydrocarbon accumulations occur in a variety of different styles over a relatively small area; the hydrocarbons within the C3 reservoirs are trapped within the crest of the broad rollover anticline, whereas the C7 accumulation appears to be largely stratigraphic in nature. Many of the deeper reservoirs are footwall sands trapped against an extensional fault to the south, with additional structural relief created by the rollover anticline.

The C and D sand reservoirs of the Agbada Formation are generally of very high quality; NTG is generally in excess of 90% with porosities of 30% or higher. The C7 reservoir is anomalously poor quality, although the volumes here are relatively insignificant compared to the C3 and C9 GIIP numbers (note that the C3 accumulation appears to extend beyond the limits of the 3D seismic volume and thus may contain some upside volumes not included here). Most of the reservoirs in the survey are easily picked out on seismic, with flat spots and amplitude anomalies clearly delineating the extent of the gas accumulations (c.f. RMS amplitude map in **Figure 3-15**). In addition to this, Savannah provided Relative Acoustic Impedance (**Figure 3-14**) and Average Energy attributes which show strong agreement with the amplitude data to support Savannah's interpretations.

The oil in the Upper D3 reservoir is light and good quality; API values are c. 42° with a current GOR of 702 scf/bbl. The composition of the non-associated gas in the C sand reservoirs is unknown.

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the reports supplied by Savannah, and using the Kingdom™ project provided have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

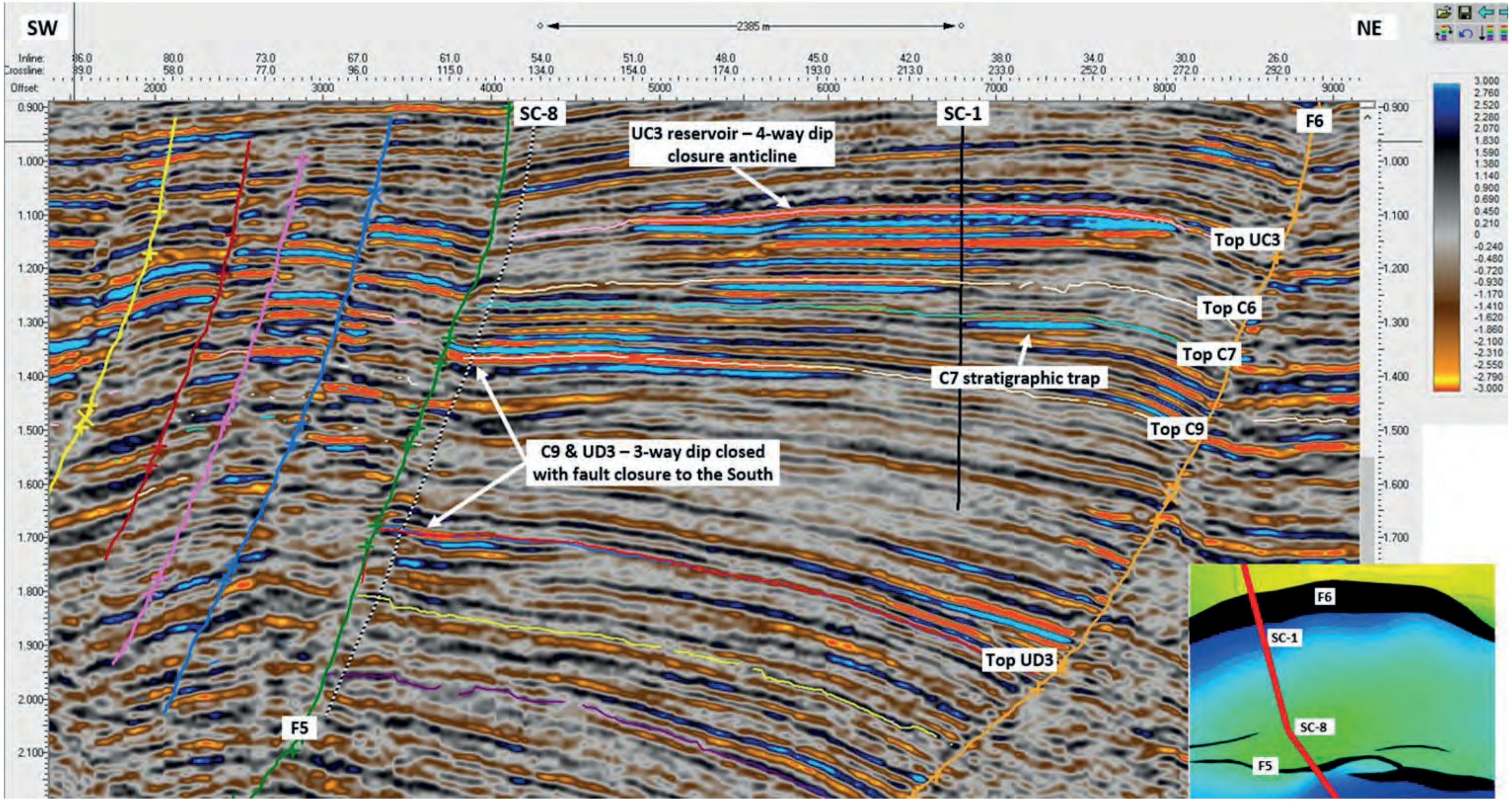



Figure 3-13 SW-NE line through Stubb Creek (Source: Savannah, 2019)

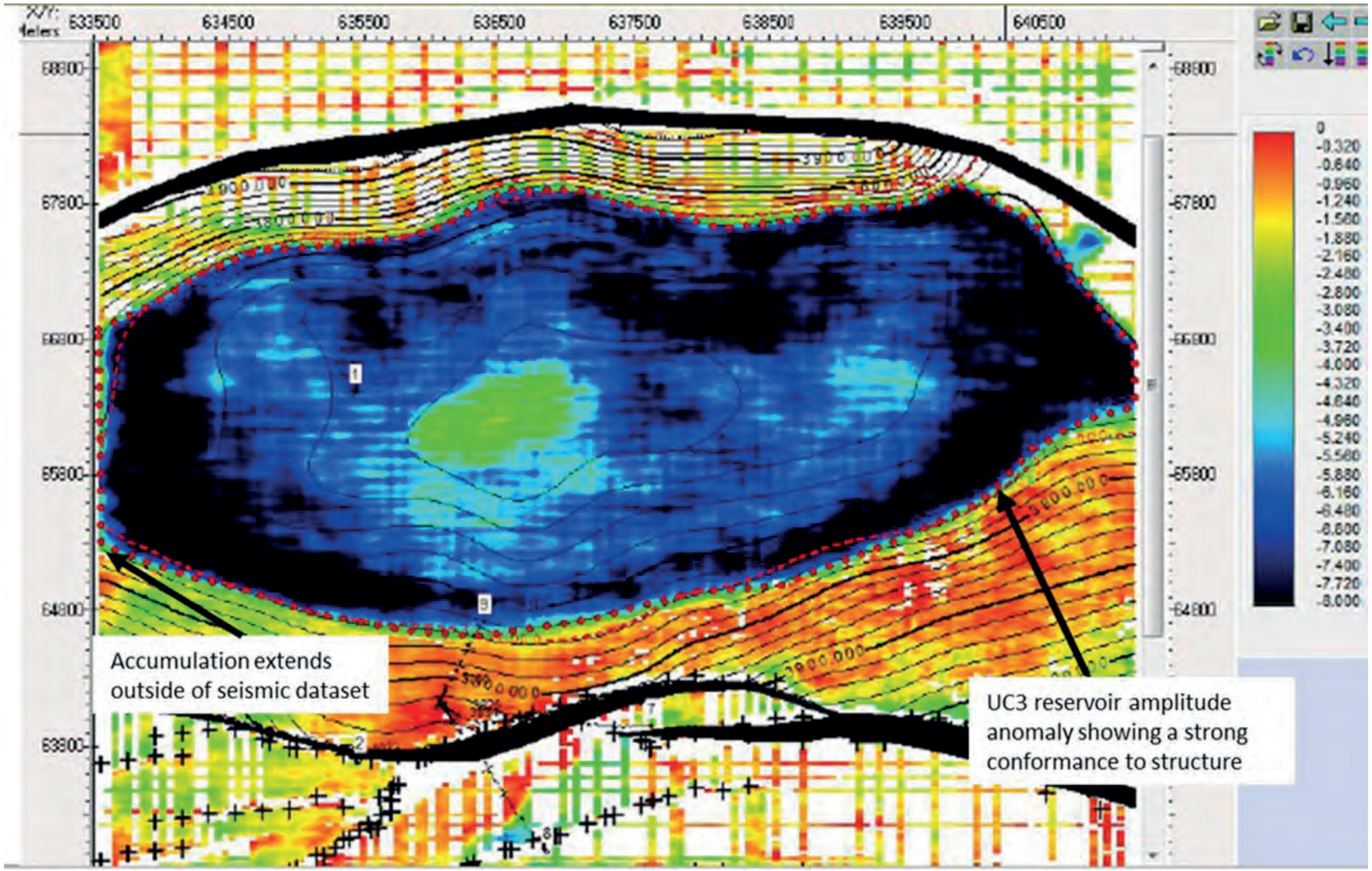



Figure 3-14 Minimum amplitude map (+/-8ms) of the UC3 reservoir - (Source: Savannah, 2019)

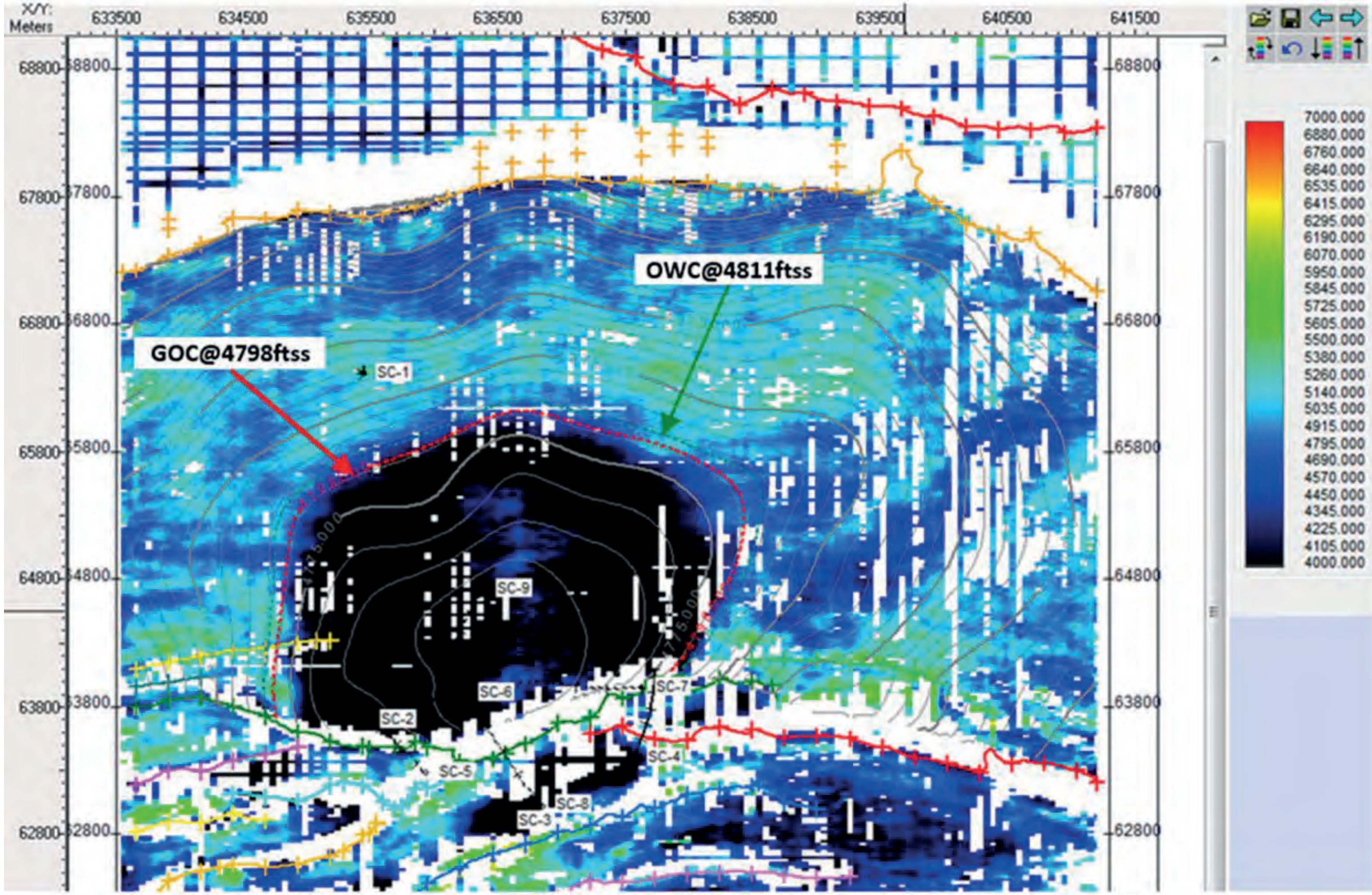
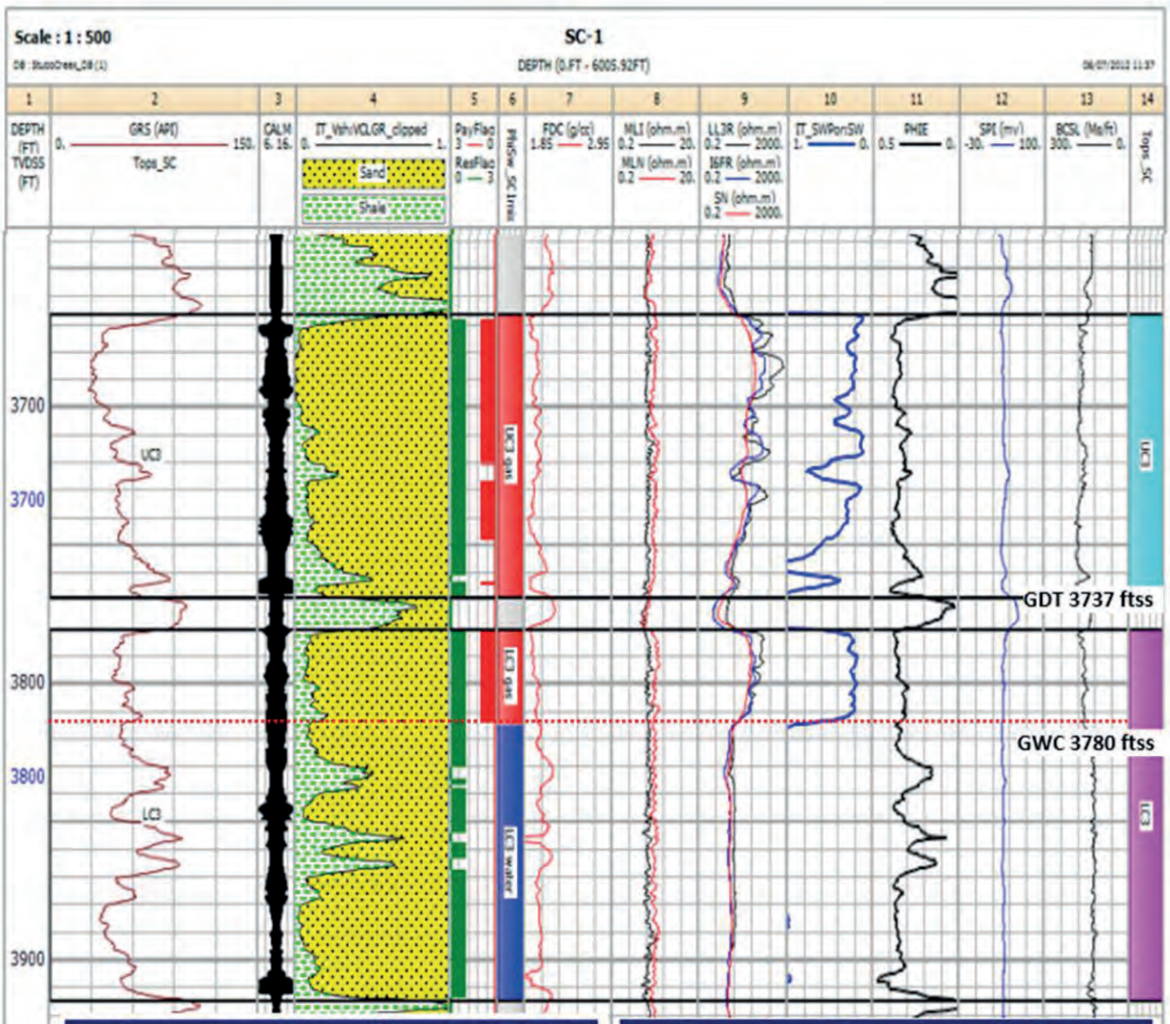



Figure 3-15 C9 Minimum Relative Acoustic Impedance map (Top+8ms) - (Source: Savannah, 2019)

350

### 3.3.3 Stubb Creek Field Petrophysics

CGG have evaluated the petrophysical data provided for the C and D sands in order to obtain P10, P50 and P90 values for the reservoir properties such as NTG (Net-To-Gross), porosity and hydrocarbon saturations. These were used as inputs for the volumetric calculations. The Volume of Clay (Vcl) was derived using a GR method (Larionov model); porosity was estimated based on the density log or sonic (SC-2 has no density log); while the Simandoux method was used to derive water saturation (Sw). The porosity cut-off of 0.1 and Vcl cut-off of 0.4 used to derive net reservoir intervals are considered to be reasonable. Fluid contacts have been determined from the petrophysical data and these have been used in combination with the DHI's and structural closures in determining the Minimum, P50 and Maximum GRV's. **Figure 3-16** and **Figure 3-17** present results from the petrophysical interpretation for the main gas (C3) and oil (UD3) reservoirs.




| Zone Name | Gross | Net | N/G | Av Phi | Av Sw |
|---|---|---|---|---|---|
| UC3 | 102.4 | 98.5 | 0.96 | 0.34 | 0.37 |
| LC3 | 134.0 | 119.0 | 0.89 | 0.33 | 0.78 |

*SC-1 Net reservoir average properties (PHIE>0.1 & Vcl<0.4)*

| Zone Name | Gross | Net | N/G | Av Phi | Av Sw |
|---|---|---|---|---|---|
| UC3 | 102.4 | 73.8 | 0.72 | 0.35 | 0.26 |
| LC3 | 134.0 | 32.8 | 0.25 | 0.34 | 0.24 |

*SC-1 Net Pay reservoir average properties (PHIE>0.1, Vcl<0.4 & Sw<0.5)*

Figure 3-16 SC-1 C3 Gas Reservoir Petrophysical interpretation (Source: Savannah, 2019)

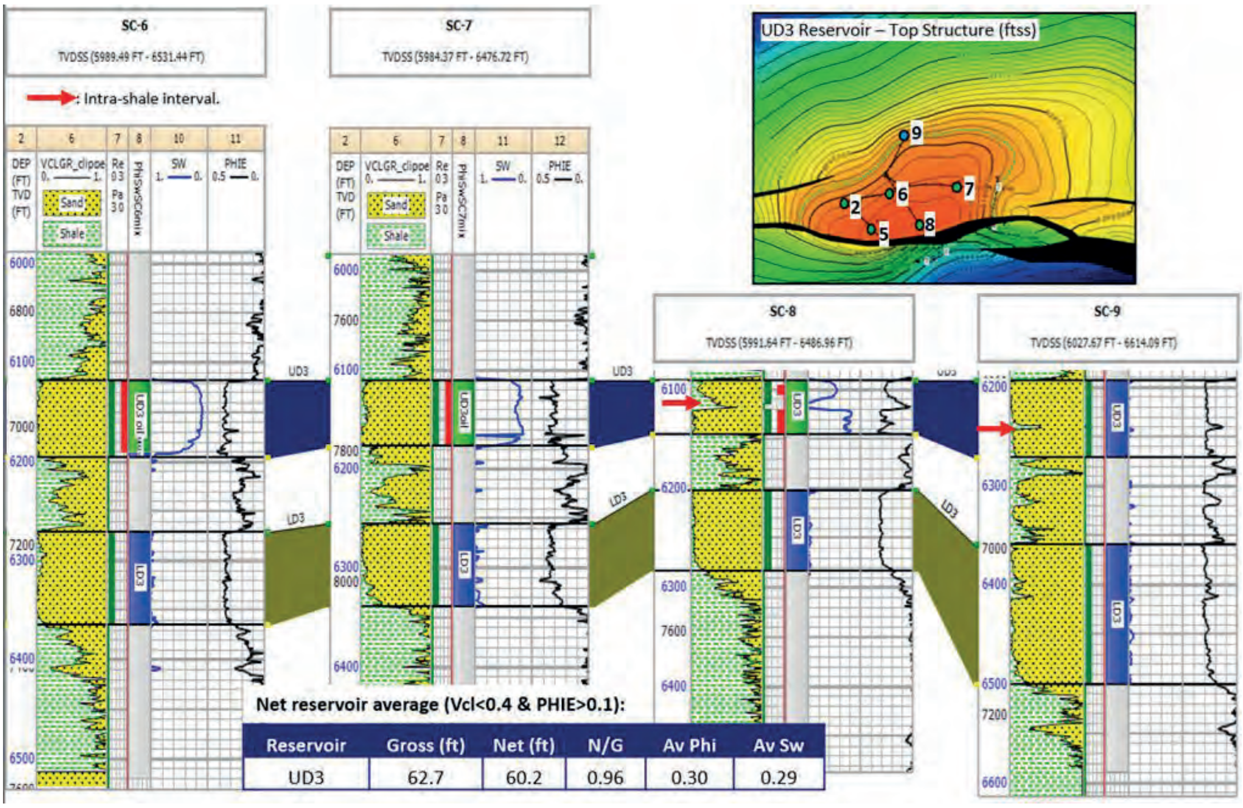



Figure 3-17 Upper D3 Oil Reservoir Petrophysical interpretation (Source: Savannah, 2019)

Stubb Creek Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as previously mentioned, CGG believe that the accuracy of the volumes would be improved by depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes of each of the accumulations/prospects. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Savannah's work and QC'd by CGG Petrophysics expert. The inputs have been run as a probabilistic Monte Carlo analysis.

**Table 3-4** and **Table 3-5** tabulate in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

| Reservoir | Gross GIIP (Bscf) | | |
|---|---|---|---|
| | **P90** | **P50** | **P10** |
| UC3 | 318.5 | 421.0 | 481.0 |
| LC3 | 34.0 | 45.5 | 59.3 |
| C6 (prospect) | 13.8 | 19.8 | 27.8 |
| C7 | 16.1 | 39.4 | 88.1 |
| C8 | 2.6 | 3.9 | 5.6 |
| C9 | 113.8 | 150.3 | 191.5 |
| **Total*** | **482.4** | **656.2** | **819.9** |

** Arithmetic sum, Total excludes C6 (Prospect) and C8 (too small)*

Table 3-4 Stubb Creek Marginal Field GIIP

| Reservoir | Gross STOIIP (MMstb) | | |
|---|---|---|---|
| | **P90** | **P50** | **P10** |
| UD3 | 29.9 | 38.9 | 49.6 |
| C9* | 22.4 | 32.6 | 42.5 |
| **Total**** | **52.3** | **71.5** | **92.1** |

**C9 oil volumes not included in reserves/resources due to difficulty in producing the thin oil rim.*
*** Arithmetic sum*

Table 3-5 Stubb Creek Marginal Field STOIIP

# 4 RESERVOIR ENGINEERING

A review of historical production and pressure data for the Uquo and Stubb Creek fields was conducted with the objective of, in the first instance, to confirm if performance decline has started in the fields. Leveraging on the result of the foregoing, an update of the recoverable volume estimates and production forecast was conducted based on recent geological reviews carried out as part of this report.

## 4.1 Uquo Marginal Field

### 4.1.1 Overview

Gas production started in Q1 2014 in the Uquo field with wells Uquo-2 and Uquo-4. In Q1 2015, wells Uquo-7 and Uquo-8ST came online bringing the total gas producers to four. To-date these are the only gas producing wells in the field.

Uquo-2 is producing gas from the D2.0 reservoir in the Uquo-2 area while Uquo-4 is producing gas from the D1.0 reservoir also in the Uquo-2 area. Uquo-7 and Uquo-8ST are both producing gas from the D1.0 reservoir in the Uquo-3 area.

**Figure 4-1** shows historical daily gas production in the field. Cumulative gas production, as at 30$^{th}$ September 2021, is 211.8 Bscf with associated cumulative condensate production of 0.28 MMstb.

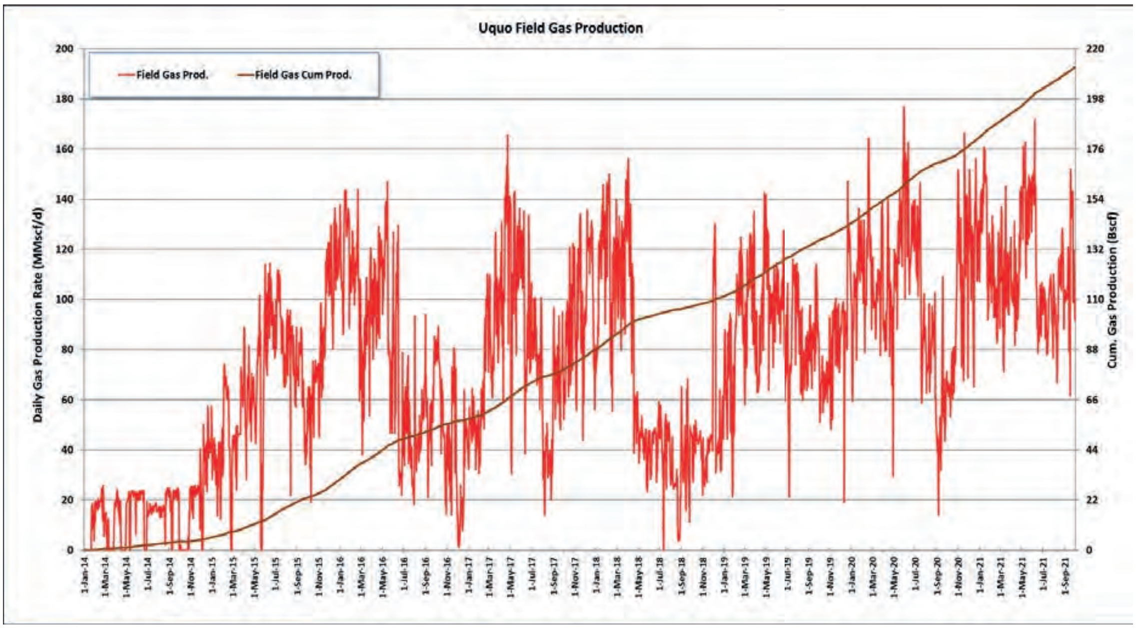



Figure 4-1 Uquo historical gas production as at 30th September 2021

A total of 3 new development wells and one recompletion are planned to develop the Reserves including the recently drilled Uquo-11 well and also the recompletion of the Uquo-3 well. It should be noted that the Uquo-11 has been completed in both the D1.0 and D1.3/D1.4 reservoirs with a single string in the Uquo-2 area. It is planned to initially produce from the D1.0 reservoir and switch production to the D1.3/D1.4 reservoir once the D1.0 reservoir is depleted. **Table 4-1** shows the planned wells and recompletion to develop the field.

| Area | Reservoir | Well(s) | Comments |
|---|---|---|---|
| **Uquo-2** | C6.5 | - | Contingent, Not in development plan |
| | C9.0 | - | Contingent, Not in development plan |
| | D1.0 | Uquo-4, New Well 1 ( Uquo-11) | Producing, Well recently drilled/completed |
| | D1.3/D1.4 | New Well 1 ( Uquo-11) | D1.3/D1.4 behind-sleeve |
| | D2.0 | Uquo-2 | Producing |
| | D5.0 | New Well 2 | |
| **Uquo-3** | D1.0 | Uquo-7 & Uquo-8ST | Producing |
| | D1.3/D1.4 | Uquo-3 recompletion | |
| **Uquo NE** | C6.0 | New Well 3 | |
| | D1.0 | - | Contingent, Not in development plan |

Table 4-1 Summary of Uquo field Gas reservoirs and producing/planned wells

### 4.1.2 Recoverable volumes and Forecast

Uquo field gas recovery factors, as shown in **Table 4-2**, were established as part of the CPR work carried out in 2019 by CGG. These have been retained in this CPR.

Savannah had performed a reservoir simulation study for the Uquo Field. The gas recovery factors estimated by the study were between 75% to 90%. These are based on high permeability gas reservoirs with depletion drive and assuming compression, and are deemed to be reasonable by CGG.

| Case | Low | Best | High |
|---|---|---|---|
| Recovery Factor (%) | 75.3 | 79.5 | 82.3 |

Table 4-2 Summary of Uquo Field gas recovery factors

**Table 4-3** shows gas and condensate technical reserves as at 30$^{th}$ September 2021 in the field for the 1P, 2P and 3P cases. It should be noted that gas from D1.0, D1.3/D1.4 and D2.0 is relatively dry (approx. 97% Methane).

| Area | Reservoir | Low/1P | Best/2P | High/3P |
|---|---|---|---|---|
| Uquo-2 | D1.0 | 130.0 | 154.0 | 181.0 |
| | D1.3/D1.4 | 111.0 | 132.0 | 157.0 |
| | D2.0 | 105.9 | 132.4 | 155.2 |
| | D5.0 | 26.4 | 30.8 | 35.6 |
| Uquo-3 | D1.0 | 270.1 | 322.9 | 371.7 |
| | D1.3/1.4 | 25.8 | 32.7 | 38.9 |
| Uquo NE | C6.0* | 146.0 | 175.0 | 215.0 |
| **GIIP (Bscf)** | **Total**** | **815.2** | **979.8** | **1154.4** |
| Recovery Factor (%) | | 75.3 | 79.5 | 82.3 |
| EUR (Bscf) | | 614.3 | 779.1 | 950.7 |
| Cum. Prod. (as of 30th September 2021) (Bscf) | | 211.8 | 211.8 | 211.8 |
| **Gas Reserves Total*** (Bscf)** | | **402.6** | **567.3** | **739.0** |
| Condensate Reserves Total (MMstb) | | 0.44 | 0.62 | 0.81 |

** Uquo NE volumes on licence only*
*** Arithmetic sum, Total may not add up due to rounding*
**** Total may not add up due to rounding*

Table 4-3 Summary of Uquo Gross Technical Reserves as at 30th September 2021

**Figure 4-2** shows 1P, 2P and 3P gas production profiles for the Uquo Field based on the remaining technical reserves cases outlined in **Table 4-3**. Downtime has been factored into the forecasted profiles as per the downtime allowance stipulated in the GSAs.

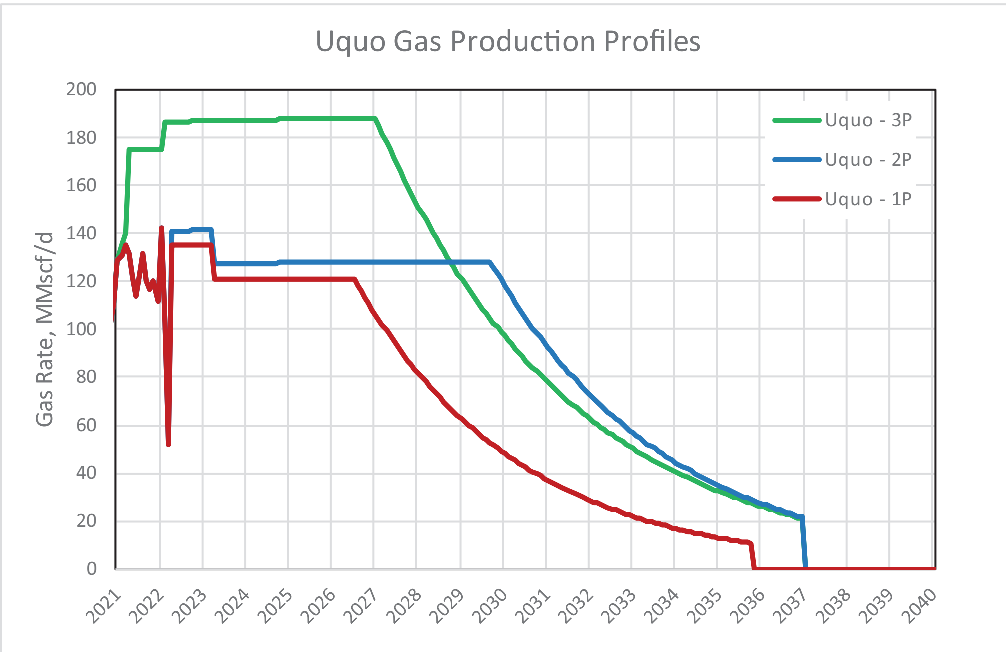



Figure 4-2 Uquo field production forecast profiles (Reserves cases)

**Table 4-4** shows a summary of the Gross Contingent Resources for the Uquo NE area plus C6.5 and C9.0 from the Uquo-2 area. CGG deem the resulting recovery factors to be reasonable for the expected drive mechanism and fluid properties.

| Area | Reservoir | Contingent Resources | | |
|---|---|---|---|---|
| | | Low/1C | Best/2C | High/3C |
| Uquo NE | D1.0 | 47.5 | 55.1 | 64.5 |
| Uquo-2 | C6.5 | 8.1 | 10.0 | 12.0 |
| | C9.0 | 32.8 | 39.1 | 46.3 |
| **Total GIIP* (Bscf)** | | **88.4** | **104.2** | **122.8** |
| Recovery Factor (%) | | 75.3 | 79.5 | 82.3 |
| **Contingent Resources* (Bscf)** | | **66.6** | **82.8** | **101.1** |

** Total may not add up due to rounding*

Table 4-4 Summary of Uquo Gross Contingent Resources

**Table 4-5** shows a summary of the Unrisked Gross Prospective Resources in the Uquo Field. The Prospective Resources are estimated by multiplying the recovery factors by the in-place volumes outlined in **Table 3-2**. Recovery factors ranging from 65% to 75% were used.

| Prospective Resources | Low/1U | Best/2U | High/3U |
|---|---|---|---|
| **GIIP (Bscf)** | 500.9 | 733.0 | 1122.9 |
| Recovery Factor (%) | 65 | 70 | 75 |
| **Gas Resources (Bscf)** | **325.6** | **513.1** | **842.2** |

Table 4-5 Summary of Uquo Gross Unrisked Gross Prospective Resources

## 4.2 Stubb Creek Marginal Field

### 4.2.1 Overview

The Stubb Creek field is currently producing from three oil wells. The three wells which are on production are: SC-6, SC-7 and SC-8 SS (Short String). The average production from each well is c. 1,000 bopd, with a combined rate of around 2,500 bopd (2021 average to 30th September). Cumulative oil production as of 30th September 2021 is 5.4MMstb.

Historical monthly oil production since start-up is shown in **Figure 4-3**. The processing capacity is capped at 3,000 bopd and debottlenecking of the facilities is planned to increase the production capacity to 5,000 bopd. The upgrade, planned for 2023, will enable two more wells, SC-2 and SC-5, to be put on-stream. The wells are already drilled and completed in the Upper D3 reservoir.

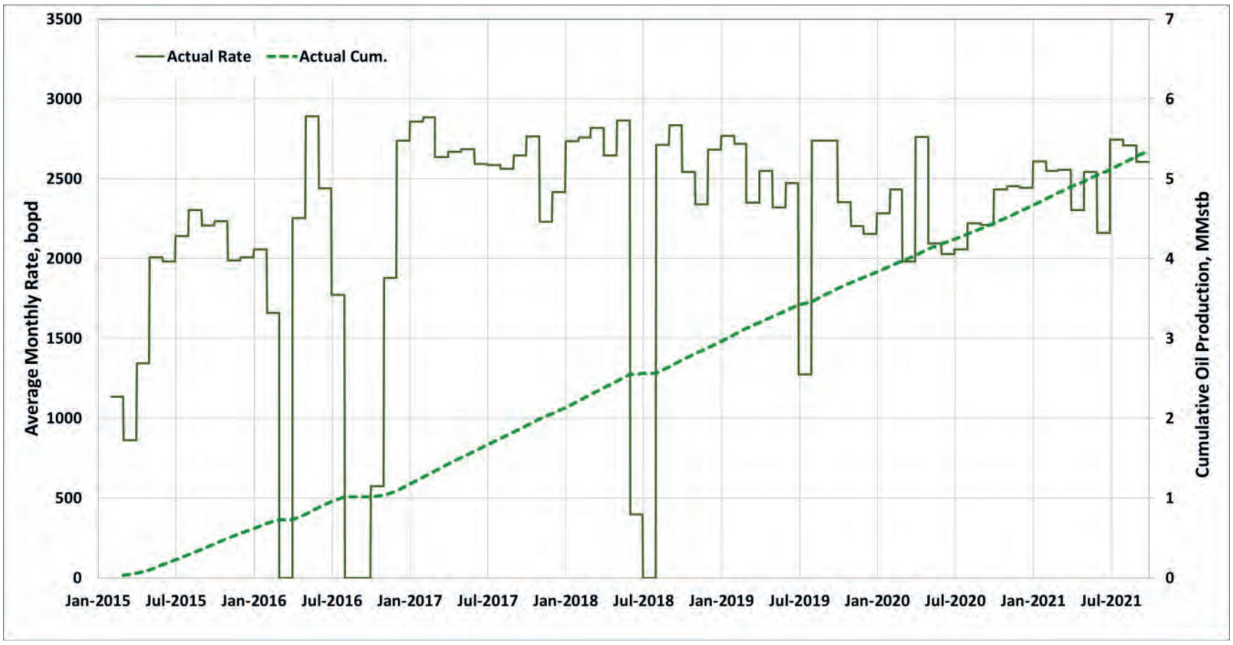



Figure 4-3 Stubb Creek field historical oil production as at 30th September 2021

### 4.2.2 Recovery factor

Stubb Creek recovery factors were established as part of the CPR work carried out in 2019 by CGG. These have been retained in this CPR. The drive mechanism for the UD3 reservoir is a strong aquifer drive, which is confirmed by bottom hole pressure surveys. Due to high reservoir permeability and strong water drive mechanism, the anticipated recovery factors are as shown in **Table 4-6**. CGG deem these recovery factors to be in agreement with regional analogue fields.

| Case | Low | Best | High |
|---|---|---|---|
| Recovery Factor (%) | 40.0 | 50.0 | 58.0 |

Table 4-6 Summary of Stubb Creek field oil recovery factors

### 4.2.3 Recoverable volumes and Forecast

**Table 4-7** shows Oil and Solution Gas Technical Reserves as at 30$^{th}$ September 2021 for the 1P, 2P and 3P cases.

| | Low/1P | Best/2P | High/3P |
|---|---|---|---|
| **STOIIP (MMstb)** | **29.9** | **38.9** | **49.6** |
| Recovery Factor (%) | 40 | 50 | 58 |
| EUR (MMstb) | 12.0 | 19.5 | 28.8 |
| Cumulative Production (as of 30$^{th}$ September 2021) | 5.4 | 5.4 | 5.4 |
| **Reserves (MMstb)** | **6.6** | **14.1** | **23.4** |
| GOR (scf/stb) | | 702 | |
| Solution gas (Bscf) | 4.6 | 9.8 | 16.4 |

Table 4-7 Summary of Stubb Creek Field Gross Technical Reserves as at 30th September 2021

**Figure 4-4** shows the production forecast profiles for Stubb Creek Field for the 1P, 2P and 3P cases. The well performance of the producing wells is used to generate production profiles with different plateau rates in each case. It is assumed that the debottlenecking of the production facility will take place in 2023 and the production will increase to c. 5,000 bopd (Proved + Probable case) by July 2023.

Since production inception, there has been minimal downtime due to production facility maintenance or wells' deliverability. However, a downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

It is also assumed that after the debottlenecking of the production facility, pre-downtime rate values of 4,500, 5,000, and 5,500 bopd of production will be achieved for the 1P, 2P, and 3P scenarios, respectively. This rate will be achieved by opening all the available wells namely SC-2, SC-5, SC-6, SC-7 and SC-8SS.

It should be noted that 12ft of oil exists in the C9.0 reservoir, however due to the limited thickness of the oil leg CGG believes recovery would be challenging. Therefore, no oil Reserves or Resources have been attributed for the C9.0 reservoir.

Annual production rates for the Stubb Creek Field are tabulated in **Appendix A.**

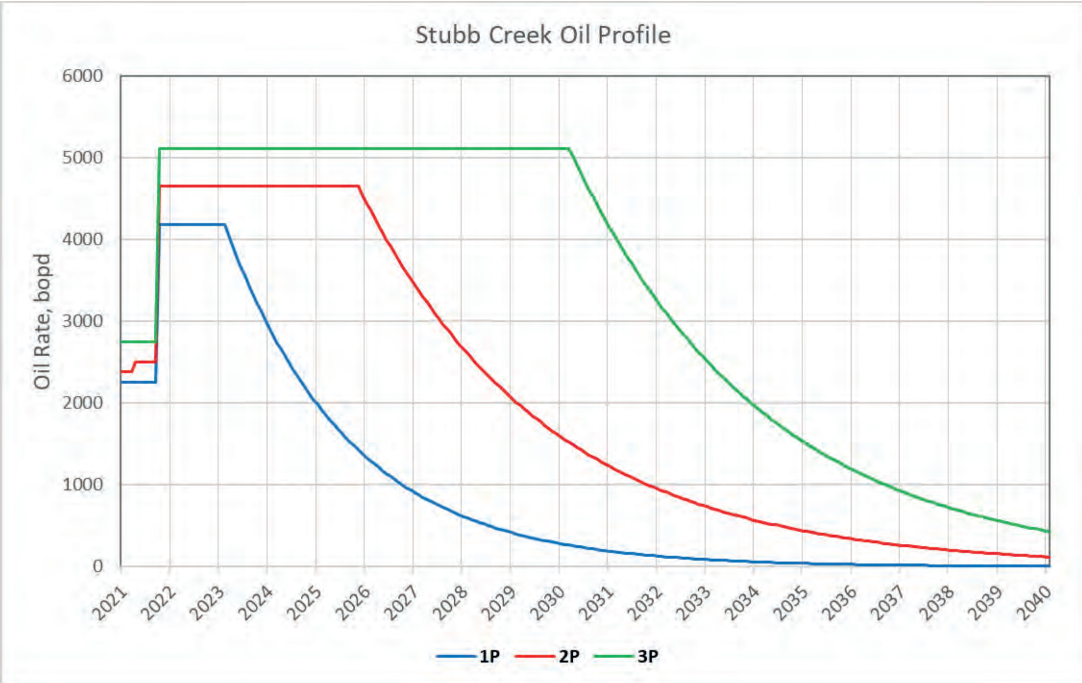



Figure 4-4 Stubb Creek production forecast profiles

A summary of Gross Gas Contingent Resources in the field is shown in **Table 4-8**. These, together with the gas in-place and gas recovery factors, were established as part of the CPR work in 2019 by CGG based on simulation studies and analogue fields, and have been retained in this CPR.

| Contingent Resources | Low/1C | Best/2C | High/3C |
|---|---|---|---|
| **GIIP (Bscf)** | **482.4** | **656.2** | **819.9** |
| Recovery Factor (%) | 76 | 78.5 | 83 |
| **Gas Resources (Bscf)** | **364.9** | **515.3** | **680.3** |

Table 4-8 Summary of Stubb Creek Field Gross Contingent Resources

It is worth noting that the Contingent Resources at Stubb Creek have a relatively high chance of commerciality (>75%) due to the excellent reservoir characteristics and definition of the accumulations based on log and seismic data (**Section 3.3**).

Unrisked Gas Prospective Resources in the field are shown in **Table 4-9**. These, together with the gas in-place and gas recovery factors, were established as part of the CPR work in 2019 by CGG and have been retained in this CPR. The range of recovery factors was based on analogue fields.

| Prospective Resources | Low/1U | Best/2U | High/3U |
|---|---|---|---|
| **GIIP (Bscf)** | **13.8** | **19.8** | **27.8** |
| Recovery Factor (%) | 65 | 70 | 75 |
| **Gas Resources (Bscf)** | **9.0** | **13.9** | **20.9** |

Table 4-9 Summary of Stubb Creek Field Gross Unrisked Prospective Resources

Contingent Resources from Stubb Creek will be developed, once the Uquo Field Reserves and Contingent Resources are not sufficient to meet the Daily Contracted Quantity (DCQ) Accugas's downstream GSAs. **Figure 4-5** shows combined Reserves and Contingent Resources profiles for the Uquo and Stubb Creek fields.

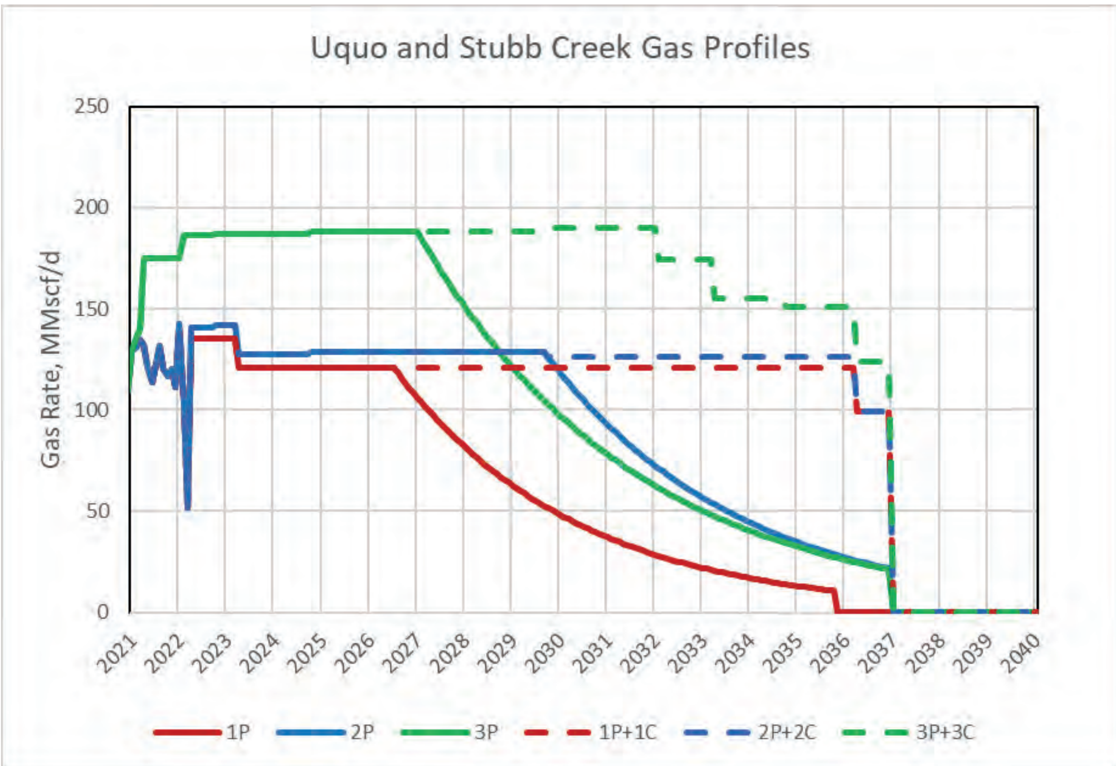



Figure 4-5 Uquo and Stubb creek Fields production forecast profiles (Reserves and Contingent Resources cases)

Annual production rates for all cases are tabulated in **Appendix A**.

# 5 FACILITES AND COSTS

This section presents details of the existing facilities and future development plans for the Uquo and Stubb Creek Fields, and for Accugas. All costs are presented in 2021 terms.

## 5.1 Uquo Field

### 5.1.1 Existing facilities

Dedicated in-field flowlines transport produced gas individually from the producing wells owned by SEUGL to a Central Processing Facility (CPF) owned by Accugas. The gas from the Uquo Field is relatively dry (approximately 97% methane).

### 5.1.2 Development plans

The proposed development plan for Uquo consists of drilling three additional gas development wells, and the recompletion of one well (Uquo-3). The Uquo-11 well, which is included in the three development wells, has recently been drilled and completed.

**Table 5-1** presents the work plan assumed for the 1P, 2P, 3P Reserves and 1C, 2C, 3C Contingent Resources cases. All Reserves cases assume the same work elements but with different timings.

| Year | 1P | 2P | 3P | 1C | 2C | 3C |
|---|---|---|---|---|---|---|
| 2021 | Uquo-11 | Uquo-11 | Uquo-11 | | | |
| 2022 | Uquo-3 Recompletion | | | | | |
| 2023 | 1 gas well | | Uquo-3 Recompletion | | | |
| 2024 | | Uquo-3 Recompletion | 1 gas well | | | |
| 2025 | 1 gas well | 1 gas well | 1 gas well | | | |
| 2026 | | | | | | |
| 2027 | | 1 gas well | | 2 gas well | | 1 gas well |
| 2028 | | | | | | 1 gas well |
| 2029 | | | | | | |
| 2030 | | | | | 1 gas well | |
| 2031 | | | | | 1 gas well | |
| 2032 | | | | | | |
| 2033 | | | | | | |

Table 5-1 Uquo – Reserves and Contingent Resources Well Schedules

The estimated cost of each gas well is US$18MM, comprising US$15MM for the well itself and US$3MM for the flowlines. The recompletion of Uquo-3 is estimated to be US$7.2MM. The total cost is estimated to be approximately US$61MM for each Reserves case, including the remaining cost for the Uquo-11 well recently drilled. There will also be a water disposal well that will be drilled in 2022 at a cost of US$6.5MM.

An additional two wells costing US$18MM each are assumed for the Contingent Resources cases.

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

#### 5.1.3 Operating costs

Operating costs for Uquo Field are assessed to be US$4.9MM per year.

#### 5.1.4 Decommissioning costs

Gross decommissioning costs for the Reserves cases are estimated to be US$7.6MM (2021 terms) for plugging and abandoning the wells, and removing the flowlines.

### 5.2 Stubb Creek Field

#### 5.2.1 Existing facilities

Dedicated in-field flowlines from each well transport production to a 3,000 bopd Early Production Facility (EPF). From the EPF crude is transported via a 23 km 6 inch pipeline to the FUN manifold, and then to the Qua Iboe Terminal. A 31 km 6 inch pipeline has also been constructed to transport produced associated gas to the Uquo CPF, which is now operational and preventing flaring.

#### 5.2.2 Development plans

The proposed Oil development plan for Stubb Creek consists of:

- De-bottlenecking the existing production facility, to increase gross capacity from 3,000 to 5,000 bopd (2023)
- Bringing on stream the two wells already drilled (2023)
- Drilling a water disposal well (2023)

The water disposal well may be needed, based on evidence of strong aquifer support, although there is no water production at the current time.

Total Capex for the above development plan is estimated to be US$28MM comprising US$15MM for the water well and US$13MM for the production facility upgrade and water handling facilities.

For the Contingent Resources gas cases, six new wells are assumed for the 1C case, three new wells are assumed for the 2C case and four new wells are assumed for the 3C case with an estimated cost of US$18MM per well. These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

| Year | 1C | 2C | 3C |
|---|---|---|---|
| 2027 | | | |
| 2028 | | | |
| 2029 | 1 Gas Well | | 1 Gas Well |
| 2030 | 1 Gas Well | | |
| 2031 | | | 1 Gas Well |
| 2032 | 1 Gas Well | 1 Gas Well | |
| 2033 | 1 Gas Well | | |
| 2034 | 1 Gas Well | 1 Gas Well | 1 Gas Well |
| 2035 | 1 Gas Well | | |
| 2036 | | 1 Gas Well | 1 Gas Well |

Table 5-2 Stubb Creek - Contingent Gas Resources Wells Schedule

### 5.2.3 Operating costs

Operating costs for the oil operations are US$7.8MM per year, and an additional US$2MM per year for the Contingent Resources gas case. There is also a crude handling charge of $1.37/bbl for use of the Qua Iboe Terminal.

### 5.2.4 Decommissioning

Gross decommissioning costs for the Reserves case are estimated to be US$18MM (2021 terms) for plugging and abandoning the wells and removing the flowlines and production facility.

## 5.3 Accugas

Accugas owns and operates the midstream gas facilities associated with the Uquo and Stubb Creek Fields. The principal assets comprise the Uquo CPF and the export pipelines.

The Uquo CPF, which is owned and operated by Accugas, consists of two process trains; each with a nameplate capacity of 100 MMscfd. The CPF provides the following services:

- hydrocarbon and water dew-point control,
- condensate stabilisation,
- crude processing,
- power generation.

Gas from the CPF is currently exported through the following pipelines owned and operated by Accugas:

- a 62 km 18 inch pipeline via the Ibom Gas Receiving Facility to the Ibom power station
- a 63 km 24 inch pipeline via the Oron Tie-in to the Calabar Junction and then to the Calabar power station and the Lafarge Africa cement plant
- a 38km 18 inch pipeline from Calabar Junction to the Lafarge Africa cement plant, which is part of the 128 km East Horizon gas pipeline also owned by Accugas

To supply gas to FIPL, a third-party pipeline is used, from the Ibom Gas Receiving Facility, to transport gas delivered to the Afam power station.

Condensate is exported from the CPF via a third-party owned 8 km 4 inch oil pipeline to the FUN manifold and then via a 2 km 10 inch oil pipeline to the ExxonMobil operated Qua Iboe Terminal. The FUN manifold is owned by a JV of the Uquo, Stubb Creek and Qua Iboe Marginal Field Operators.

Locations and details of the CPF and the pipelines are provided in **Figure 5-1**. The Uquo CPF could accommodate an additional 100MMscfd process train if expansion was required and commercially justified.

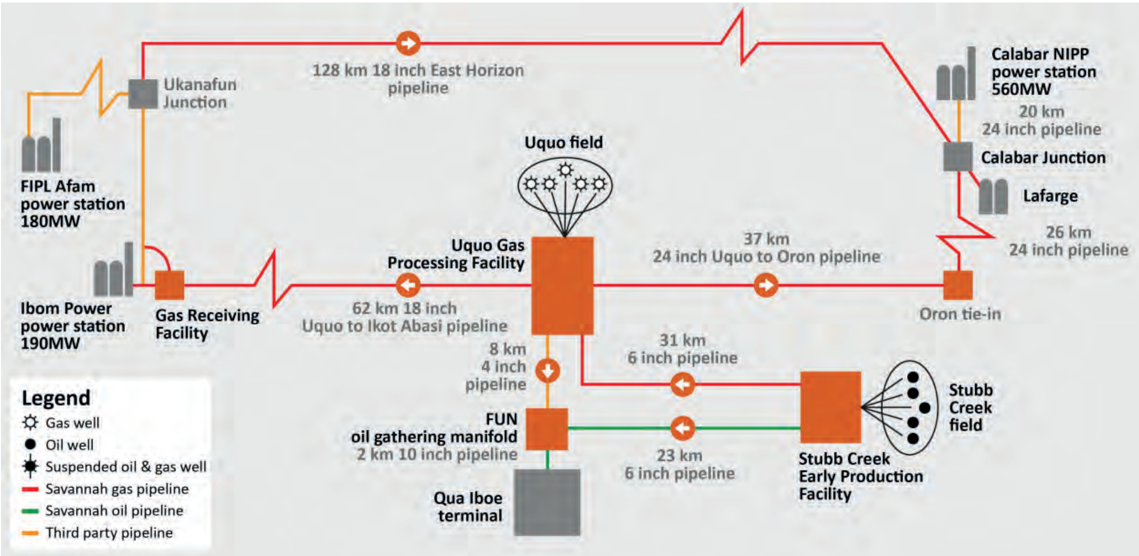



Figure 5-1 Uquo, Stubb Creek, Accugas and associated Infrastructure (Source: Savannah, 2021)

### 5.3.1 Development costs

The CPF currently processes gas from the Uquo Field, but future plans are to install compression facilities and to process gas from other fields, including Stubb Creek.

Savannah has started to order compression equipment for the Uquo gas processing plant during the first half of 2021. Factory Acceptance Tests for the two compressor packages have been successfully carried out and the Front End Engineering Design is in progress.

The planned capex for Accugas totals US$84MM comprising US$37MM for pipelines, US$38MM for compression and US$9MM of other costs.

### 5.3.2 Operating costs

Operating costs are estimated at US$21.5MM in 2022, reducing to US$20.3MM thereafter without non-recurring costs incurred in 2022. In addition, there is a crude handling charge of $1.37/bbl for use of the Qua Iboe Terminal. Accugas will also charge a processing fee of $4.25/bbl to Frontier on any future oil production, although this has not been included in the valuation at this stage.

### 5.3.3 Decommissioning costs

Gross decommissioning costs are estimated to be U$58MM (2021 terms) for removal of the facilities and land re-instatement.

# 6 ECONOMIC EVALUATION

## 6.1 Methodology

Net Present Values (NPVs) and economic Reserves have been calculated using Savannah's Excel™ integrated economic model of the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream business. The model has been subject to a high level review by CGG and found to be in agreement with the fiscal and commercial terms applicable to the licences.

## 6.2 Paying and Revenue interests

Savannah has an 80% participating interest in the Uquo gas project via its indirect 80% interest in SEUGL, which has a 100% interest in the Uquo gas project.

Savannah has a 51% participating interest in the Stubb Creek Marginal Field via a 100% interest in UERL. UERL's paying interest in the field is 20% for oil and 50% for gas, and the profit interest is 35% for oil and 60% for gas.

Savannah has an 80% participating interest in the Accugas Midstream Business.

## 6.3 Fiscal terms

The current Nigerian Marginal Field tax terms applying to Uquo and Stubb Creek Fields do not take account of changes introduced by the 2021 Petroleum Industries Act which will start to apply up to 18 months after the commencement of the Act on 16$^{th}$ August 2021. Accugas is assumed to be subject to standard Nigerian Corporate Income Tax.

The key features of the fiscal regime for Uquo and Stubb Creek assumed in the model are tabulated below.

| | | |
|---|---|---|
| **Oil Royalty** | 0 – 2,000 bpd | 2.5% |
| | 2,001 – 5,000 bpd | 2.5% |
| | 5,001 – 10,000 bpd | 7.5% |
| | 10,001 – 15,000 bpd | 12.5% |
| | > 15,001 bpd | 18.5% |
| | | |
| **Gas Royalty** | 7% | |
| | | |
| **Overriding Royalty (oil)** | 0 – 2,000 bpd | 2.5% |
| | 2,001 – 5,000 bpd | 3.0% |
| | 5,001 – 10,000 bpd | 5.5% |
| | 10,001 – 15,000 bpd | 7.5% |
| | > 15,001 bpd | TBD |
| | | |
| **Education tax** | 2.0% | |
| | | |
| **NDDC levy** | 3.0% | |
| | | |
| **Petroleum Profits Tax (PPT)** | 85% (Uquo tax holiday to end Nov 2018, Stubb Creek 65.75% to end 2019) | |
| | | |
| **CIT** | 30% | |
| | | |
| **Capital allowances** | 100% on exploration, development and the first two appraisal wells. 20% for years 1-4, then 19% for year 5 on other capex. Capital allowances used in any given year are restricted to 85% of assessable profit. | |
| | | |
| **Profit Investment Allowance (PIA)** | 5.0% | |

Table 6-1 Summary of Fiscal Terms

Taxes have been adjusted to allow for brought forward capital allowances and tax losses.

## 6.4 Oil prices

Oil production from Stubb Creek is sold to ExxonMobil at the Qua Iboe Terminal. It is assumed that the price achieved is at a US$1.25/bbl premium to Brent based on historic prices. Condensate is commingled with processed crude and sold at the same premium to Brent.

The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

Sensitivity cases at fixed prices of US$50/bbl, US$60/bbl, US$70/bbl, US$80/bbl, US$90/bbl and US$100/bbl have also been analysed, with the price inflated at 2% per year from January 2022.

### 6.5 Gas prices

Gas from the Uquo Field is sold to Accugas under the Upstream GSA (Gas Sales Agreement). The contract runs until the end of December 2028, and thereafter is extendable to the end of Uquo Field life. The DCQ (Daily Contracted Quantity) is 189.4 MMscfd with a ToP of 80% of the DCQ. The yearly base gas price for each year of the contract is tabulated below. The base price A transfers to base price B at the later of two years from the effective date of the Upstream GSA or after cumulative production under the agreement has reached 110 Bscf.

| Year | Base Price A (unindexed) US$/Mscf | Base Price B (unindexed) US$/Mscf |
|---|---|---|
| 2021 | 1.51 | 1.72 |
| 2022 | 1.58 | 1.80 |
| 2023 | 1.58 | 1.80 |
| 2024 | 1.58 | 1.80 |
| 2025 | 1.58 | 1.80 |
| 2026 | 1.58 | 1.80 |
| 2027 | 1.58 | 1.80 |
| 2028 | 1.58 | 1.80 |

Table 6-2 Details of Upstream Gas Sales Agreement

These prices are adjusted by a “Weighted Average Index” based on the US consumer price index adjustment calculated under the Downstream GSAs. The upstream nominal gas price assumed in the economic model is tabulated below.

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas Price (US$/Mscf) | 1.41 | 1.60 | 1.75 | 1.83 | 1.83 | 2.36 | 2.40 | 2.45 | 2.50 | 2.55 |

Table 6-3 Upstream nominal gas price assumed in the economic model

Accugas sells processed gas under Downstream GSAs to the Ibom and Calabar power plants, and to the Lafarge cement factory. Additional volumes are also contracted under Interruptible GSAs with Mulak Energy Limited (Mulak) and First Independent Power Limited (FIPL). The key terms of each GSA are tabulated below.

| Contract term | Calabar Power Plant | Ibom Power Plant | Lafarge Africa Plc (was Unicem Cement Plant) | Mulak Energy Limited | First Independent Power Ltd |
|---|---|---|---|---|---|
| Length of contract | 20 years | 10 years | 25 years | Initial 7 years with a possible extension of 5 years commencing July-23 | 1-year initial term with the possibility for extension |
| Contract end | Sep-37 | Dec-23 | Jan-37 | July-30 (Initial 7-year period) | 30 October 2022 (1-year initial term) |
| DCQ | 131.0 MMscf/d | 19.7 MMscf/d | 24.19 MMscf/d | Variable, max 2.5 MMscf/d | Nominations up to 35 MMscf/d |
| Take or Pay (ToP) | 80% of DCQ | 80% of DCQ | 80% of DCQ | 80% of DCQ | N/A |
| Gas Price | 2019 US$3.59/Mscf increasing in steps to US$5.04/Mscf in 2024 all indexed to US PPI | US$2.24/MMBTU (year commencing March 2021). Indexed to US PPI | 2020 US$5.0/Mscf increasing to US$5.10/Mscf in 2027, indexed to US PPI thereafter | US$5.15/MMBTU indexed to US PPI | US$2.5/MMBTU |

Table 6-4 Details of Downstream Gas Sales Agreements

The average downstream nominal gas price assumed by year across the contracts in the economic model is tabulated below.

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas Price (US$/Mscf) | 3.94 | 4.27 | 4.47 | 4.96 | 5.04 | 5.12 | 5.22 | 5.31 | 5.42 | 5.52 |

Table 6-5 Downstream average nominal gas price assumed in the economic model

## 6.6 Other assumptions

The following assumptions have also been used by CGG.

| Parameter | Value |
|---|---|
| Discount Rate | 10% |
| Discount Methodology | Monthly |
| Cost /Price Inflation | 2% per annum |
| Valuation Date | 1st October2021 |

Table 6-6 Economic Parameters

## 6.7 Economic results

### 6.7.1 Upstream Assets

The Net Present Values (NPV) of future cash flows derived from the exploitation of the Reserves are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes. The NPVs of Uquo are based on the gas sold under the Upstream GSA and its associated condensate, while Stubb Creek is solely based on oil production.

| NPV10 (US$MM) of Reserves Net to Savannah | | | |
|---|---|---|---|
| | **Proved** | **Proved & Probable** | **Proved, Probable & Possible** |
| Uquo (gas and condensate) | 239.1 | 329.1 | 421.7 |
| Stubb Creek oil | 34.2 | 69.5 | 82.7 |
| **Total** | **273.2** | **398.6** | **504.4** |

Table 6-7 NPV10 (US$MM) of Reserves Net to Savannah as at 1st October 2021

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below for the Proved & Probable case.

| NPV10 (US$MM) Net to Savannah | | | |
|---|---|---|---|
| | **Uquo** | **Stubb Creek** | **Total*** |
| Base case (Proved+Probable) | 329.1 | 69.5 | 398.6 |
| Oil price - US$50/bbl | 324.9 | 58.2 | 383.2 |
| Oil price - US$60/bbl | 327.9 | 66.5 | 394.5 |
| Oil price - US$70/bbl | 330.9 | 73.6 | 404.5 |
| Oil price - US$80/bbl | 333.9 | 79.8 | 413.8 |
| Oil price - US$90/bbl | 337.0 | 86.1 | 423.1 |
| Oil price - US$100/bbl | 340.0 | 91.9 | 431.9 |
| Capex +25% | 324.8 | 68.7 | 393.6 |
| Capex -15% | 331.6 | 69.9 | 401.5 |
| Opex +25% | 319.6 | 67.2 | 386.8 |
| Opex -15% | 334.8 | 71.0 | 405.8 |

Table 6-8 Proved and Probable NPV10 (US$MM) Sensitivities as at 1st October 2021

### 6.7.2 Midstream Assets (Accugas)

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the base case, Proved & Probable (2P) plus 2C. The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of Taxes.

| Case | Accugas (100%) | Net to Savannah |
|---|---|---|
| Base Case (2P+2C) | 694.0 | 555.2 |

Table 6-9 Accugas NPV10s (US$MM)

These sales volumes are initially sourced from Uquo, with additional feedstock expected to come from Stubb Creek, and potentially other sources such as third party gas fields.

It should be noted that there are no gas Reserves or Resources associated with Accugas.

### 6.7.3 Upstream and Midstream Financial Forecasts

**Table 6-10** shows the annual financial forecasts net to Savannah for the Upstream Assets and the Midstream Assets, including annual production/volumes.

| | Total Upstream | | | Total Midstream (Accugas) | | |
|---|---|---|---|---|---|---|
| | Gross Production (Kboepd) | Revenue (US$MM) | FCF (US$MM) | Gross Volumes (Kboepd) | Revenue (US$MM) | FCF (US$MM) |
| **2022** | 21.9 | 71.7 | 38.8 | 19.3 | 146.1 | 42.6 |
| **2023** | 27.3 | 95.3 | 54.4 | 23.6 | 186.6 | 98.3 |
| **2024** | 26.0 | 94.6 | 54.2 | 21.2 | 187.1 | 96.1 |
| **2025** | 26.1 | 103.5 | 51.7 | 21.3 | 190.3 | 98.9 |
| **2026** | 26.2 | 121.1 | 70.2 | 21.4 | 194.1 | 83.4 |
| **2027** | 25.7 | 119.7 | 64.3 | 21.4 | 197.8 | 84.9 |
| **2028** | 24.8 | 116.3 | 61.6 | 21.4 | 201.7 | 86.5 |
| **2029** | 24.0 | 112.8 | 61.5 | 21.4 | 204.5 | 87.3 |
| **2030** | 22.7 | 107.5 | 59.0 | 20.7 | 200.7 | 84.6 |

Table 6-10 Annual financial forecasts net to Savannah for the Upstream Assets and the Midstream Assets

The total Upstream Opex and Capex per barrel of oil equivalent produced over the 2022-2030 period is estimated at US$2/boe and US$1/boe, respectively.

The total Midstream Opex and Capex per barrel of oil equivalent delivered by Accugas over the 2022-2030 period is estimated at US$3/boe and US$1/boe, respectively.

# 7 APPENDIX A: PRODUCTION PROFILES

### Gross Production Profiles: Uquo Field

| | Uquo Field | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gas (MMscf/d) | | | Condensate (bopd) | | | Gas (MMscf/d) | | | Condensate (bopd) | | |
| | 1P | 2P | 3P | 1P | 2P | 3P | 1C | 2C | 3C | 1C | 2C | 3C |
| Q4 2021 | 131.7 | 131.7 | 135.0 | 144.8 | 144.8 | 148.5 | - | - | - | - | - | - |
| 2022 | 115.6 | 115.6 | 177.1 | 127.1 | 127.1 | 194.8 | - | - | - | - | - | - |
| 2023 | 135.4 | 141.4 | 186.7 | 148.9 | 155.5 | 205.4 | - | - | - | - | - | - |
| 2024 | 120.9 | 127.4 | 187.2 | 133.0 | 140.1 | 205.9 | - | - | - | - | - | - |
| 2025 | 120.9 | 127.9 | 187.7 | 133.0 | 140.7 | 206.5 | - | - | - | - | - | - |
| 2026 | 120.9 | 128.4 | 188.2 | 133.0 | 141.2 | 207.0 | - | - | - | - | - | - |
| 2027 | 113.5 | 128.4 | 187.4 | 124.8 | 141.2 | 206.1 | 7.5 | - | 0.9 | 8.2 | - | 0.9 |
| 2028 | 88.3 | 128.4 | 161.3 | 97.1 | 141.2 | 177.5 | 32.6 | - | 26.9 | 35.9 | - | 29.6 |
| 2029 | 67.9 | 128.4 | 129.4 | 74.7 | 141.2 | 142.3 | 45.7 | - | 54.6 | 50.3 | - | 60.0 |
| 2030 | 52.2 | 124.0 | 103.8 | 57.4 | 136.4 | 114.2 | 36.6 | 3.4 | 48.3 | 40.3 | 3.7 | 53.2 |
| 2031 | 40.1 | 99.7 | 83.3 | 44.2 | 109.6 | 91.6 | 28.5 | 26.7 | 38.3 | 31.4 | 29.4 | 42.1 |
| 2032 | 30.9 | 78.0 | 66.8 | 34.0 | 85.8 | 73.5 | 22.2 | 48.2 | 30.4 | 24.4 | 53.0 | 33.4 |
| 2033 | 23.7 | 61.0 | 53.6 | 26.1 | 67.1 | 58.9 | 9.2 | 47.5 | 24.1 | 10.1 | 52.2 | 26.5 |
| 2034 | 18.3 | 47.7 | 43.0 | 20.1 | 52.5 | 47.3 | - | 36.9 | 19.1 | - | 40.5 | 21.0 |
| 2035 | 14.0 | 37.3 | 34.5 | 15.4 | 41.1 | 37.9 | - | 28.6 | 15.1 | - | 31.5 | 16.6 |
| 2036 | 6.6 | 29.2 | 27.6 | 7.3 | 32.1 | 30.4 | - | 22.2 | 12.0 | - | 24.4 | 13.2 |
| 2037 | - | 17.6 | 17.1 | - | 19.4 | 18.8 | - | 13.3 | 7.3 | - | 14.7 | 8.1 |

### Gross Production Profiles: Stubb Creek Field

| | Stubb Creek Field | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil (bopd) | | | Gas (MMscf/d) | | | Gas (MMscf/d) | | | Condensate (bopd) | | |
| | 1P | 2P | 3P | 1P | 2P | 3P | 1C | 2C | 3C | 1C | 2C | 3C |
| Q4 2021 | 2,250 | 2,389 | 2,750 | 1.6 | 1.7 | 1.9 | - | - | - | - | - | - |
| 2022 | 2,250 | 2,500 | 2,750 | 1.6 | 1.8 | 1.9 | - | - | - | - | - | - |
| 2023 | 3,218 | 3,575 | 3,933 | 2.3 | 2.5 | 2.8 | - | - | - | - | - | - |
| 2024 | 3,815 | 4,650 | 5,115 | 2.7 | 3.3 | 3.6 | - | - | - | - | - | - |
| 2025 | 2,640 | 4,650 | 5,115 | 1.9 | 3.3 | 3.6 | - | - | - | - | - | - |
| 2026 | 1,794 | 4,650 | 5,115 | 1.3 | 3.3 | 3.6 | - | - | - | - | - | - |
| 2027 | 1,219 | 4,150 | 5,115 | 0.9 | 2.9 | 3.6 | - | - | - | - | - | - |
| 2028 | 828 | 3,218 | 5,115 | 0.6 | 2.3 | 3.6 | - | - | - | - | - | - |
| 2029 | 563 | 2,496 | 5,115 | 0.4 | 1.8 | 3.6 | 7.3 | - | 4.3 | 8.1 | - | 4.7 |
| 2030 | 383 | 1,935 | 5,115 | 0.3 | 1.4 | 3.6 | 32.1 | - | 37.1 | 35.3 | - | 40.8 |
| 2031 | 260 | 1,501 | 4,885 | 0.2 | 1.1 | 3.4 | 52.3 | - | 68.7 | 57.5 | - | 75.5 |
| 2032 | 177 | 1,164 | 3,900 | 0.1 | 0.8 | 2.7 | 67.8 | 0.2 | 90.4 | 74.6 | 0.2 | 99.4 |
| 2033 | 120 | 903 | 3,057 | 0.1 | 0.6 | 2.1 | 88.0 | 17.9 | 96.6 | 96.8 | 19.7 | 106.2 |
| 2034 | 82 | 700 | 2,397 | 0.1 | 0.5 | 1.7 | 102.7 | 41.8 | 93.1 | 112.9 | 46.0 | 102.4 |
| 2035 | 55 | 543 | 1,879 | 0.0 | 0.4 | 1.3 | 106.9 | 60.5 | 103.6 | 117.6 | 66.5 | 113.9 |
| 2036 | 38 | 421 | 1,474 | 0.0 | 0.3 | 1.0 | 114.3 | 75.0 | 111.5 | 125.7 | 82.5 | 122.7 |
| 2037 | 26 | 326 | 1,155 | 0.0 | 0.2 | 0.8 | 74.3 | 43.3 | 68.5 | 81.7 | 47.7 | 75.3 |
| 2038 | 17 | 253 | 906 | 0.0 | 0.2 | 0.6 | - | - | - | - | - | - |
| 2039 | 12 | 196 | 710 | 0.0 | 0.1 | 0.5 | - | - | - | - | - | - |
| 2040 | 8 | 152 | 557 | 0.0 | 0.1 | 0.4 | - | - | - | - | - | - |

# 8 APPENDIX B: DEFINITIONS

## 8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

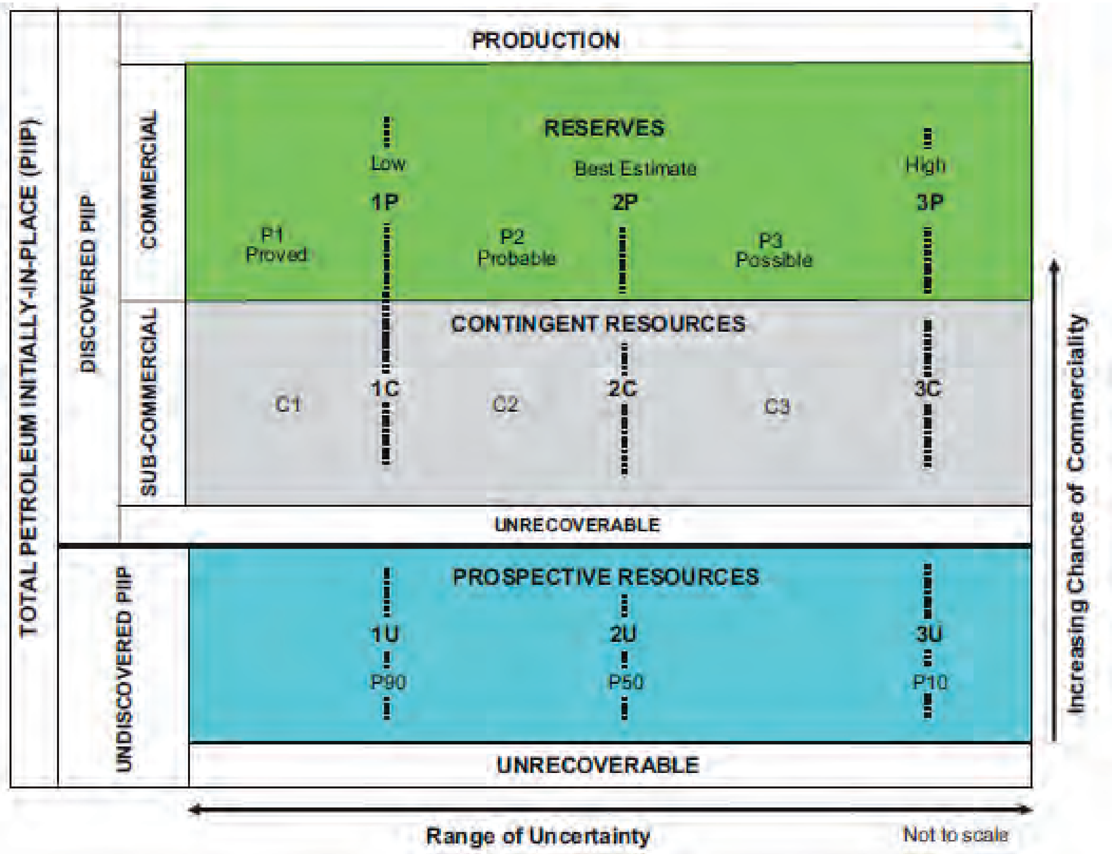



Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

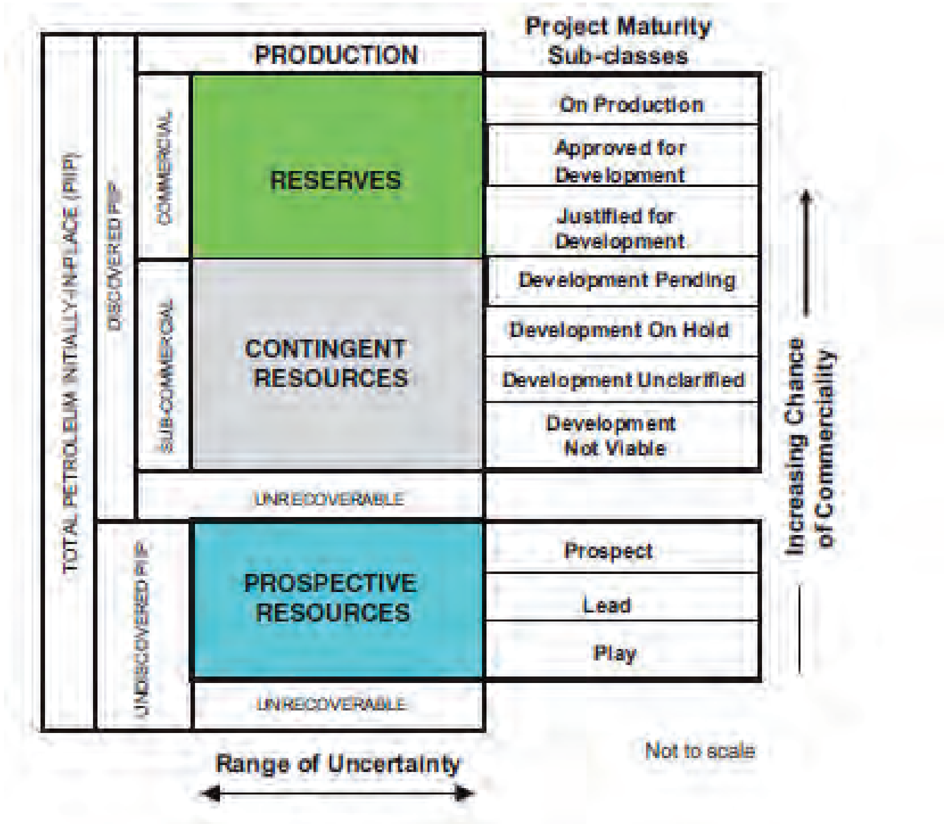



Figure 8-2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

### 8.1.1 Total Petroleum Initially-In-Place

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.

### 8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

### 8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

## 8.2 Production

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.

## 8.3 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 (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), 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.

### 8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

### 8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

### 8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(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
(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

#### 8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

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 that the quantities actually recovered will equal or exceed the estimate.

#### 8.3.5 Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

#### 8.3.6 Possible Reserves

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest 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) Reserves, which is equivalent to the high-estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

### 8.4 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.

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.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

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.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

### 8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

### 8.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are 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.

### 8.4.3 Contingent Resources: 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.

#### 8.4.4 Contingent Resources: 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.

### 8.5 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.

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources
2U denotes best estimate scenario of Prospective Resources
3U denotes high estimate scenario of Prospective Resources

#### 8.5.1 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.

### 8.5.2 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.

### 8.5.3 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.

### 8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

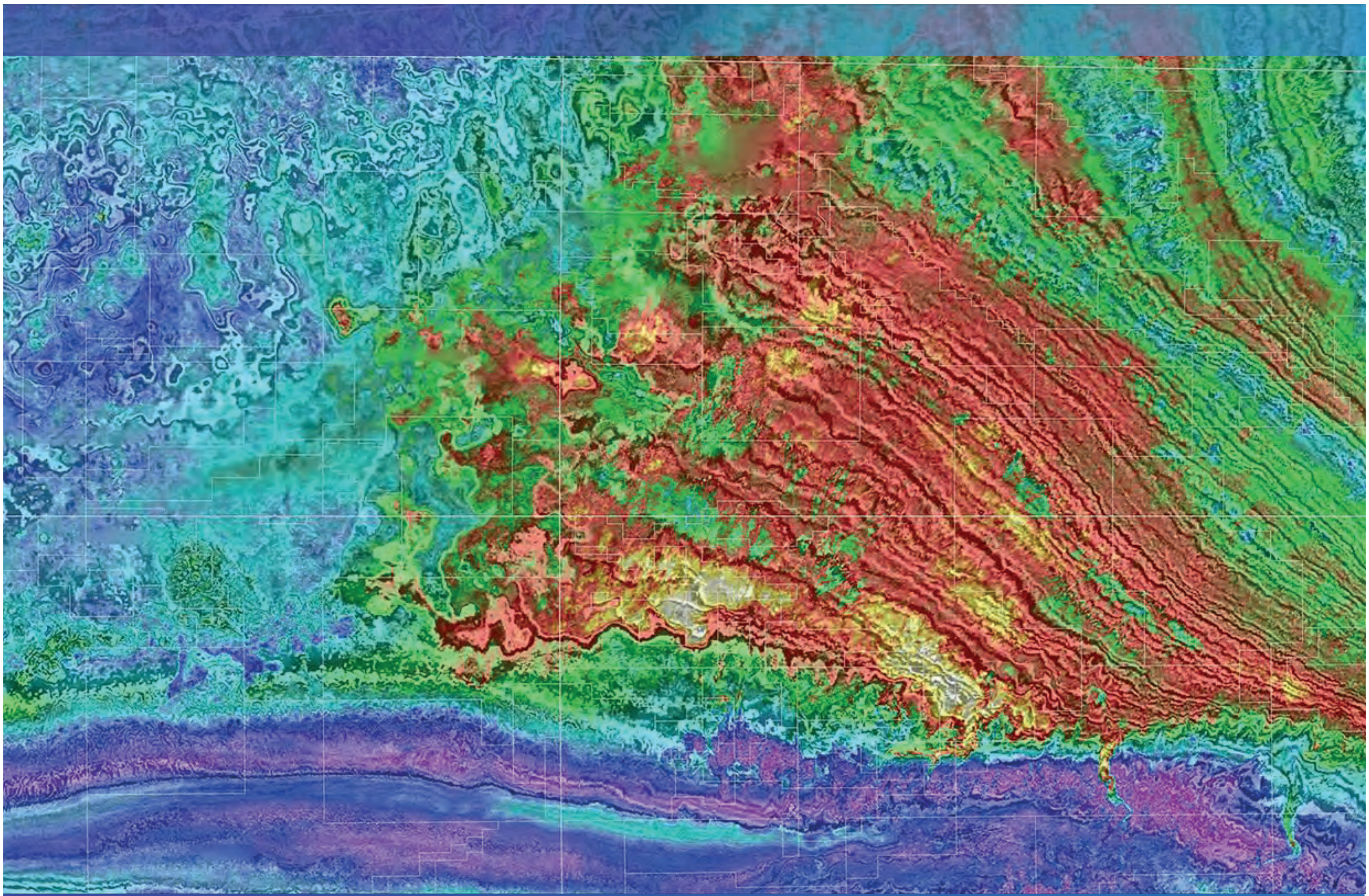
# 9 APPENDIX B: NOMENCLATURE

| | |
|---|---|
| API | American Petroleum Institute |
| bbl | barrel |
| Bscf | billion standard cubic feet |
| BHT | bottom hole temperature |
| BHP | bottom hole pressure |
| boe | barrel of oil equivalent |
| bbl/d | barrels per day |
| Btu | British thermal unit |
| c. | circa |
| $CO_2$ | carbon dioxide |
| 1-D, 2-D, 3-D | 1-, 2-, 3-dimensions |
| DHI | direct hydrocarbon indicators |
| DST | drill-stem test |
| E & P | exploration & production |
| e.g. | for example |
| et al. | and others |
| EUR | estimated ultimately recoverable |
| G & A | general & administration |
| G & G | geological & geophysical |
| $g/cm^3$ | grams per cubic centimetre |
| Ga | billion ($10^9$) years |
| GIIP | gas initially in place |
| GOC | gas-oil contact |
| GOR | gas to oil ratio |
| GR | gamma ray (log) |
| GWC | gas-water contact |
| HI | hydrogen index |
| kg | kilogram |
| kmIOR | kilometre |
| $km^2$ | square kilometres |
| M & A | mergers & acquisitions |
| m | metre |
| M | thousand |
| MM | million |
| Ma | million years (before present) |
| Mbbl/d | thousands of barrels per day |
| Mscf | thousand standard cubic feet |
| mD | millidarcies |
| MD | measured depth |
| MFS | maximum flooding surface |
| MMbbl | million bbls of oil |
| MMboe | million bbls of oil equivalent |
| MMscf/d | million standard cubic feet per day |
| mSS | metres subsea |
| m/s | metres per second |
| msec | millisecond(s) |
| MSL | mean sea level |
| NaCl | sodium chloride |
| NPV | net present value |
| no. | number (not #) |
| OWC | oil-water contact |
| 1P | proved |
| 2P | proved + probable |
| 3P | proved + probable + possible |
| P & A | plugged & abandoned |
| perm. | permeability |
| pH | -log H ion concentration |
| Ø | porosity |
| plc | public limited company |
| por. | Porosity |
| ppm | parts per million |
| PRMS | Petroleum Resource Management System (SPE) |
| psi | pounds per square inch |
| RFT | repeat formation test |
| RT | rotary table |
| SCAL | special core analysis |
| scf | standard cubic feet |
| SPE | Society of Petroleum Engineers |
| SS | sub-sea |
| ST | sidetrack (well) |
| stb | stock tank barrel |
| std. dev. | standard deviation |
| STOIIP | stock tank oil initially in place |
| Sw | water saturation |
| Tscf | trillion standard cubic feet |
| TD | total depth |
| TVD | true vertical depth |
| TVDSS | true vertical depth subsea |
| TWT | two-way time |
| US$ | US dollar |
| US$MM | Millions of US dollars |
| WHFP | wellhead flowing pressure |
| WHSP | wellhead shut-in pressure |
| wt% | percent by weight |

- 1 boe = 6000 scf
- 1 scm = 35.3147 scf

# PART 11

# COMPETENT PERSON'S REPORT FOR THE NIGERIEN ASSETS



# COMPETENT PERSONS REPORT

## R1234 Licence Area, Agadem Basin, Niger

For
Savannah Energy PLC
Strand Hanson Limited
finnCap Ltd
Panmure Gordon (UK) Limited

cgg.com

SEE THINGS DIFFERENTLY

# DISCLAIMER AND CONDITIONS OF USAGE

**Professional Qualifications**

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

**Data and Valuation Basis**

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. The capital and operating costs have been combined with production forecasts based on the Reserves or Resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cashflow technique. In estimating the future cashflows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Savannah Energy PLC in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warranty to Savannah Energy PLC's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserves; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Energy PLC.

CGG affirms that from 1st October 2021 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix A** of the CPR.

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This report was compiled using existing data during the period 1st February 2021 to 1st October 2021. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

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The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

| CGG Services (UK) Limited Reference No: BP510 | | | | |
|---|---|---|---|---|
| **Rev** | **Date** | **Originator** | **Checked & Approved** | **Issue Purpose** |
| 01 | 17th December 2021 | AKS/PC/PMD/ TU | AW | Final Report |

| Date | Originator | Checked & Approved |
|---|---|---|
| Signed: | ***AKS/PC/PMD/TU*** | |

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# 1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) relating to the R1234 licence area (the Licence Area) operated by Savannah in the Agadem Rift Basin (ARB), Niger.

Savannah Energy Niger is the Operator of the R1234 Licence Area with a 100% ownership. Savannah has a 95% interest in Savannah Energy Niger.

| Licence | Operator | Savannah Interest (%) | Status | Licence expiry date | Licence Area |
|---|---|---|---|---|---|
| R1234* | Savannah Energy Niger | 95% | Exploration | 2031 | 13,655 km$^2$ |

Table 1-1 Current Licence Details

*The Company has agreed with the Ministry of Petroleum to amalgamate the four licence areas (covered by the previous R1/R2 PSC and the R3/R4 PSC) into a single PSC. The new PSC (being the R1234 PSC) will be valid for up to 10 years from the date of signing the agreement. The new PSC has been approved by the Council of Ministers on 16 December 2021.

The Licence Area covers an area of 13,655km$^2$, representing approximately 50% of the original Agadem permit which was mandatorily relinquished in July 2013 by the China National Petroleum Corporation (CNPC). The Agadem Rift Basin is a part of the wider Central African Rift System (**Figure 1-1**) in which significant oil has been discovered. In the Agadem Rift Basin, three fields are currently on production. Oil from the three fields is currently evacuated by pipeline to the Zinder refinery, located in Niger.

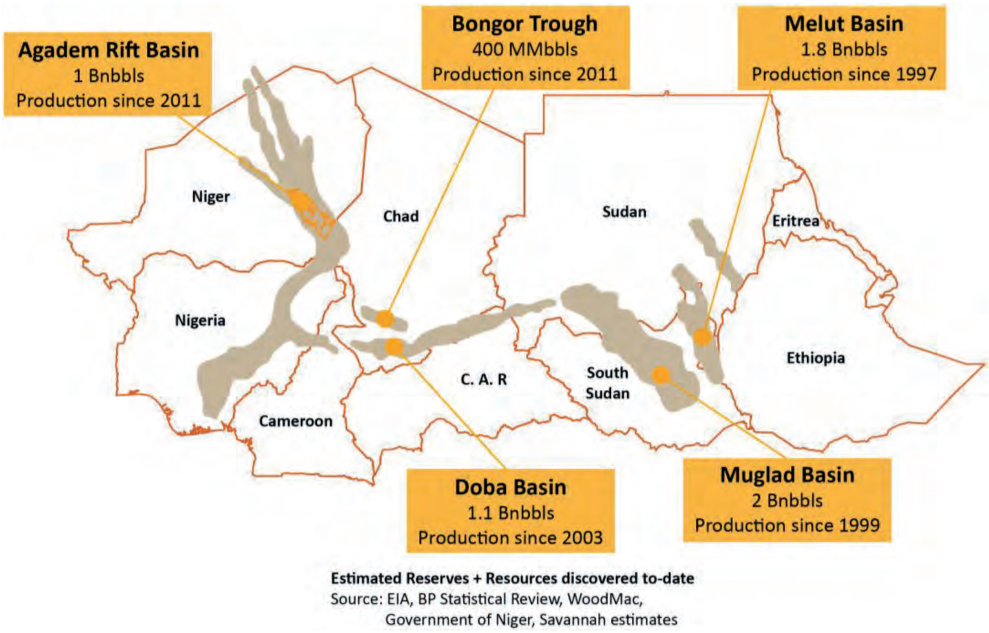



Figure 1-1 The Central African Rift System Discovered Resources (*Source: Savannah, 2021*)

Between 2008 and 2019, CNPC markedly increased the success rate of exploration in the basin, with c. 110 discoveries from 137 wells (80% success rate) establishing 2P Reserves of just under 1 billion barrels. Most of the discoveries were made in the Sokor Alternances and demonstrate the low risk profile of this Tertiary play. In addition, several light oil discoveries have been made in the Cretaceous Yogou play directly to the south east of Savannah's R3 area, which highlight the potential of this under-explored play.

Following its entry into Niger in 2014, Savannah has built a comprehensive database composed of existing 2D/3D seismic and well data, which have been interpreted to both build and de-risk the current exploration portfolio. To complement the existing dataset, Savannah acquired a Full Tensor Gravity Gradiometry (FTG) and High-Resolution Airborne Magnetic (HRAM) surveys in 2014/2015 over the full Agadem Rift Basin. Back in 2016, Savannah identified the R3 East area as a low risk exploration region (93% success rate in surrounding wells), believed to be an extension of the light oil play successfully drilled by CNPC. To derisk this area, Savannah completed the acquisition and processing of an 806km$^2$ 3D seismic survey in 2016/2017. Interpretation of the survey confirmed a number of previously identified Tertiary structures in the Sokor Alternances, and five of these were subsequently drilled in a back-to-back campaign in 2018. These discoveries (namely Bushiya, Amdigh, Kunama, Eridal and Zomo) confirm the presence of light sweet crude and a good quality reservoir analogue to the currently producing fields. Amdigh's STOIIP estimates show the discovery to be one of the 10 largest in the basin. It should be noted that the average size of the Savannah discoveries, c. STOIIP of 30MMstb, is in-line with the basin exploration statistics.

Savannah has built an exploration portfolio containing a total of 146 prospects and leads to-date (**Figure 1-2**) with a total Unrisked Best Estimate of c. 6.7 bn bbls Oil Initially In-Place. In addition to the prospect and lead inventory within proven plays, Savannah has also identified several new, potentially significant exploration plays which offer genuine high risk, high reward upside.

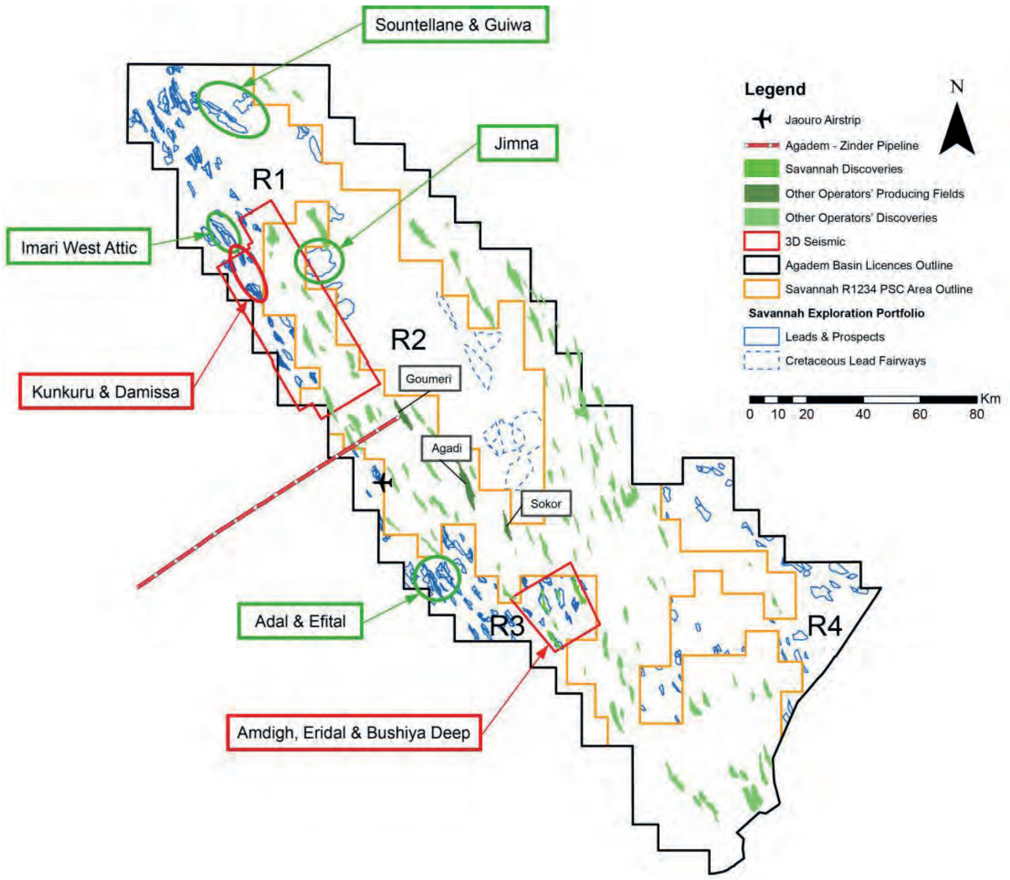



Figure 1-2 Savannah's Prospects and Leads Portfolio (*Source: Savannah, 2021*)

CGG has estimated STOIIP and Resource volumes for the five discoveries made on the R3 area in 2018 and a subset of eleven prospects and leads from Savannah's extensive exploration portfolio comprising of up to 146 prospects and leads, and has also provided estimates of the yet-to-find resources in the Licence Area. The eleven prospects and leads have been identified as potential candidates for the next exploration drilling campaigns across the Licence Area.

In addition, CGG has calculated expected recovery factors, and verified indicative economics for the early development scheme proposed by Savannah. CGG has conducted a technical review of the five discoveries that have been drilled in 2018, namely: Bushiya, Amdigh, Eridal, Kunama and Zomo. **Figure 1-3** is a map of the R3 East area showing the five oil discoveries which oil sampling confirm oils to be medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur). The reservoir quality varies from medium (E1 and E2) to high (E3 to E5) and is in-line with the neighbouring CNPC producing fields and discoveries.

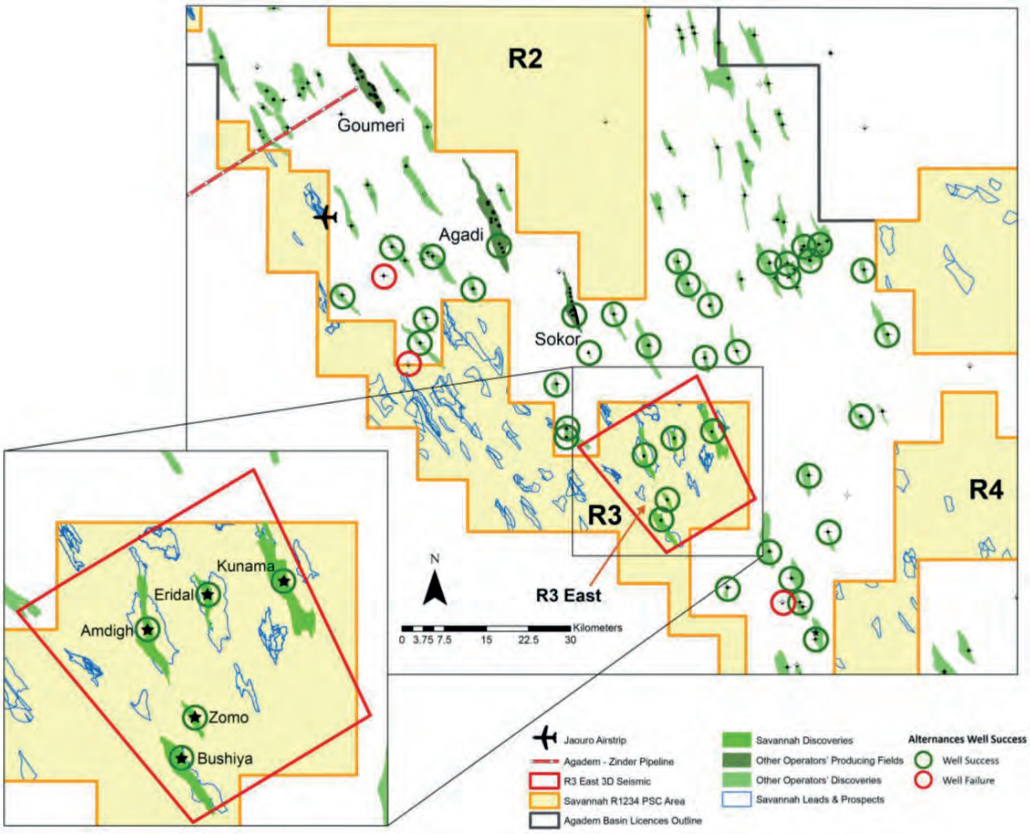



Figure 1-3 Map showing the location of the five 2018's discoveries (*Source: Savannah, 2021*)

CGG has used expected recovery factors for the discoveries from analysis of the existing producing fields in the basin. Based on this analysis and benchmarking against other analogue fields, CGG has applied recovery factors of 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Contingent Resources cases, respectively.

Contingent and Prospective Resources have been calculated by CGG in accordance with the Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) and the AIM Note for Oil and Gas Companies (2009) for the discoveries and identified prospects and leads; these are summarised in the following tables.

| | Contingent Resources (MMstb) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Gross | | | Net attributable | | | | |
| **Discovery** | 1C | **2C** | 3C | 1C | **2C** | 3C | **Risk factor** | **Operator** |
| **Amdigh** | *7.2* | 18.4 | *83.9* | *6.8* | 17.5 | *79.7* | low | Savannah |
| **Eridal** | *4.3* | 6.2 | *8.5* | *4.0* | 5.9 | *8.1* | low | Savannah |
| **Bushiya** | *3.3* | 6.2 | *12.9* | *3.2* | 5.9 | *12.3* | low | Savannah |
| **Kunama** | *1.8* | 4.2 | *9.3* | *1.8* | 4.0 | *8.8* | low | Savannah |
| **Zomo*** | | 0.2 | | | 0.2 | | medium | Savannah |
| **Total**** | ***16.7*** | **35.0** | ***114.6*** | ***15.8*** | **33.3** | ***109.1*** | | |

* Indicative Resources pending PSDM evaluation,
** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

*Notes*

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
   *Risk factor: low = > 75%, medium = 25% - 75%, high = <25%*
5. *Full definitions of the Contingent Resource categories can be found in Appendix A*
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*

Table 1-2 Contingent Resources

Similar to the Contingent Resources, CGG has applied recovery factors of 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Prospective Resource cases, respectively. Individual stratigraphic reservoir volumes have been summed probabilistically, in order to calculate an overall prospect or lead resource total. Most prospects and leads are composed of stacked targets in the Upper Sokor, Sokor Alternances and Yogou formations which will be accessible from a single well trajectory.

CGG has reviewed Savannah's in-house methodology for assessing gross mean Unrisked STOIIP for the selected eleven prospects and leads, and found it to be reasonable. CGG has also validated Savannah's volumetric input parameters, and found them to be reasonable. CGG has further evaluated Savannah's assessment of exploration risk, and found that to be reasonable too. Although some differences do exist between CGG and Savannah, this level of disparity often results from small differences in data interpretation and calculation methodology. Savannah has completed the Pre-Stack Depth Migration (PSDM) processing for the R3 East seismic survey in 2019. Based on the newly interpreted PSDM, 3D geocellular models have been built for the Amdigh and Eridal discoveries. Savannah has stated that the resulting oil in-place volumes are in-line with the PSTM based estimates presented in this report. CGG has not reviewed these latest estimates at this stage, since Savannah is still progressing with further work on the other discoveries and its exploration portfolio.

| Prospect/Lead | Unrisked Prospective Resources (MMstb) | | | | | | Risk factor |
|---|---|---|---|---|---|---|---|
| | Gross | | | Net | | | |
| | Low Estimate | **Best Estimate** | High Estimate | Low Estimate | **Best Estimate** | High Estimate | |
| **Bushiya Deep** | *1.8* | 7.6 | *22.5* | *1.7* | 7.3 | *21.3* | *medium* |
| **Amdigh Deep** | *2.6* | 10.9 | *32.7* | *2.4* | 10.4 | *31.0* | *medium* |
| **Eridal Deep** | *1.7* | 6.9 | *20.0* | *1.6* | 6.6 | *19.0* | *medium* |
| **Adal** | *3.2* | 20.6 | *72.6* | *3.0* | 19.6 | *69.0* | *medium* |
| **Efital** | *8.7* | 44.0 | *130.0* | *8.3* | 41.8 | *123.5* | *medium* |
| **Sountellane** | *9.4* | 35.8 | *108.2* | *8.9* | 34.0 | *102.8* | *medium* |
| **Damissa** | *13.2* | 66.9 | *188.1* | *12.5* | 63.6 | *178.7* | low |
| **Imari W Attic** | *8.8* | 45.4 | *149.5* | *8.3* | 43.1 | *142.0* | high |
| **Guiwa** | *6.5* | 30.0 | *89.8* | *6.2* | 28.5 | *85.3* | high |
| **Kunkuru** | *1.9* | 10.4 | *31.3* | *1.8* | 9.9 | *29.8* | low |
| **Jimna** | *17.2* | 81.5 | *254.8* | *16.3* | 77.4 | *242.0* | high |
| **Total*** | ***74.9*** | **360.1** | ***1099.4*** | ***71.2*** | **342.1** | ***1044.4*** | |

* Arithmetic sum, Total may not add exactly due to rounding

*Notes*

1. *Prospective Resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from the probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *Full definitions of the Prospective Resource categories can be found in Appendix A*
5. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
   *Risk factor: low = > 75%, medium = 25% - 75%, high = <25%*
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*
7. *Savannah is the Operator of the assets*

Table 1-3 Selected Prospective Resources (for a subset of 11 out of 146 prospects/leads portfolio)

CGG has conducted a separate 'yet-to-find' analysis, which estimates the quantity of oil that may ultimately be expected to be found on Savannah's Licence Area, based on previous discoveries made in the basin. This is a proprietary methodology created by CGG and does not reflect a replication of Savannah's work. The method calculates discovered STOIIP per km$^2$ for areas with similar characteristics, which are then adjusted and applied to the Licence Area. It should be noted that these yet-to-find volumes are not linked to Savannah's planned exploration campaign. They are estimates of what could ultimately be discovered across the plays analysed, assuming a seismic and exploration drilling campaign of similar density to that employed to-date. The results of this analysis are presented in **Table 1-4**.

| Licence | Gross Prospective Resources – "yet to find" (MMstb) | | | | | |
|---|---|---|---|---|---|---|
| | Unrisked | | | Risked | | |
| | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate |
| **R1234** | **2561** | **6801** | **9987** | **1000** | **2695** | **3868** |

Table 1-4 Estimate of gross Unrisked and Risked "yet to find" Resources

Since the drilling of the five discoveries, Savannah has developed an Early Production Scheme (EPS) which includes evacuation of crude via a new 90km pipeline between Amdigh and the Goumeri Export Station (GES) (**Figure 1-4**). The proposed development plan utilises an Early Production Facility (EPF) to be installed at Amdigh, which will permit early revenues. The recent development in the construction of the Niger to Benin export route is a milestone, that provides Savannah with an alternative route for its crude but more importantly it will enable the full potential of the Licence Area to be unlocked.

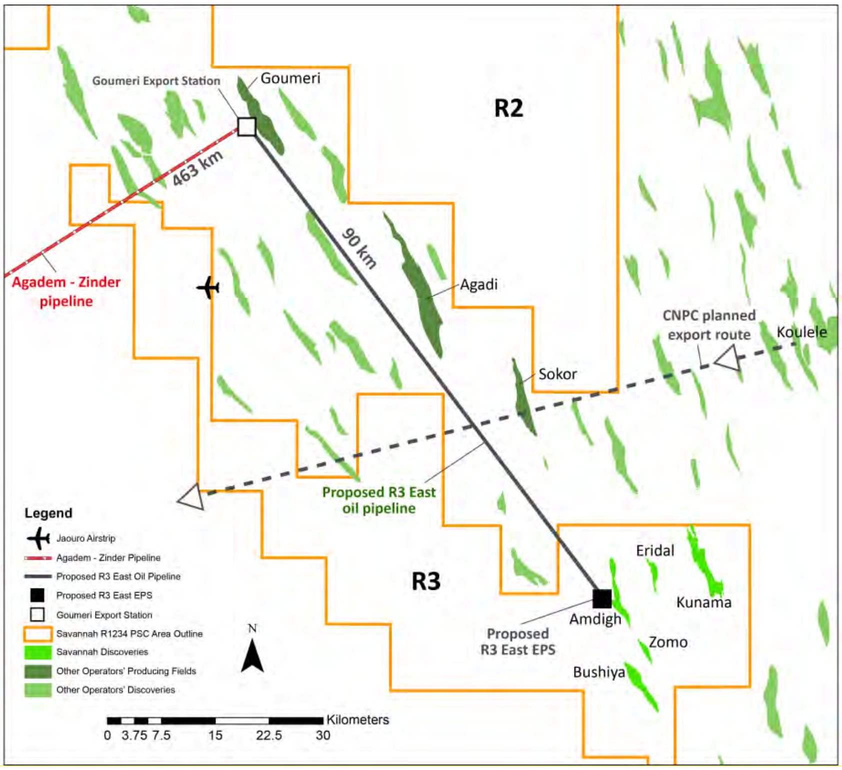



Figure 1-4 Proposed Early Production Scheme Development (Source: Savannah, 2021)

The proposed Development Scheme is summarised below.

Phase 1 - Early Production

- Expected to deliver a plateau of c. 1,500 bopd from initial well testing
- Procurement and installation of a 5,000 bopd Early Processing Facility (EPF)
- Planned construction of a c. 90km pipeline between the EPF and the Goumeri Export Station (GES). Crude is then piped to the SORAZ refinery at Zinder (using the existing 463km Agadem to Zinder pipeline)

Phase 2 - Ramp-up and Further Development

- Use of existing EPF and 90km pipeline
- Construction of a gathering system which will enable the fields tested in Phase 1 to be fully developed and tied into the EPF
- Drilling Appraisal and Development wells
- Production expected to ramp up to around 5,000 bopd which will continue to be handled by the refinery at Zinder

The results of the economic analysis are presented in the table below and are based on a US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year

| Case | 2C |
|---|---|
| NPV0 (US$MM) | 443.3 |
| NPV10 (US$MM) | 150.2 |
| NPV10/bbl (US$) | 6.4 |

*Notes*

1. *NPVs are based on net economic production to Savannah of 23 MMstb and post 15% government back-in right*

Table 1-5 Indicative Economics (net to Savannah) for Discoveries

NPV10 sensitivities have also been performed on costs and oil price. The results of this analysis are tabulated below.

The break-even refinery gate oil price, which would enable Savannah to generate a 10% IRR on the development would be approximately US$30/bbl, assuming costs at this oil price level would be reduced by at least 20% from those prevailing at US$60/bbl. CGG has assessed this assumption and considers it to be reasonable.

As a further sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately US$100MM net to Savannah.

| Case | 2C |
|---|---|
| Base case | 150.2 |
| +15% factor on costs | 122.3 |
| -15% factor on costs | 176.7 |
| Oil price - US$50/bbl | 70.4 |
| Oil price - US$60/bbl | 142.0 |
| Oil price - US$70/bbl | 197.4 |
| Oil price - US$80/bbl | 248.9 |
| Oil price - US$90/bbl | 297.3 |
| Oil price - US$100/bbl | 344.0 |
| Production volume +25% | 214.1 |
| Year 1 production 2,500 bopd | 156.9 |

Table 1-6 Sensitivities for Indicative Economics (NPV10 net to Savannah, US$MM)

# 2 INTRODUCTION

## 2.1 Overview

The R1234 Licence Area is located in the oil prolific Agadem Rift Basin (ARB) in South East Niger. The Licence Area covers a c.13,655km$^2$ area, representing approximately 50% of the original Agadem permit which was mandatorily relinquished by CNPC in July 2013. The location of the assets is provided in **Figure 2-1**.

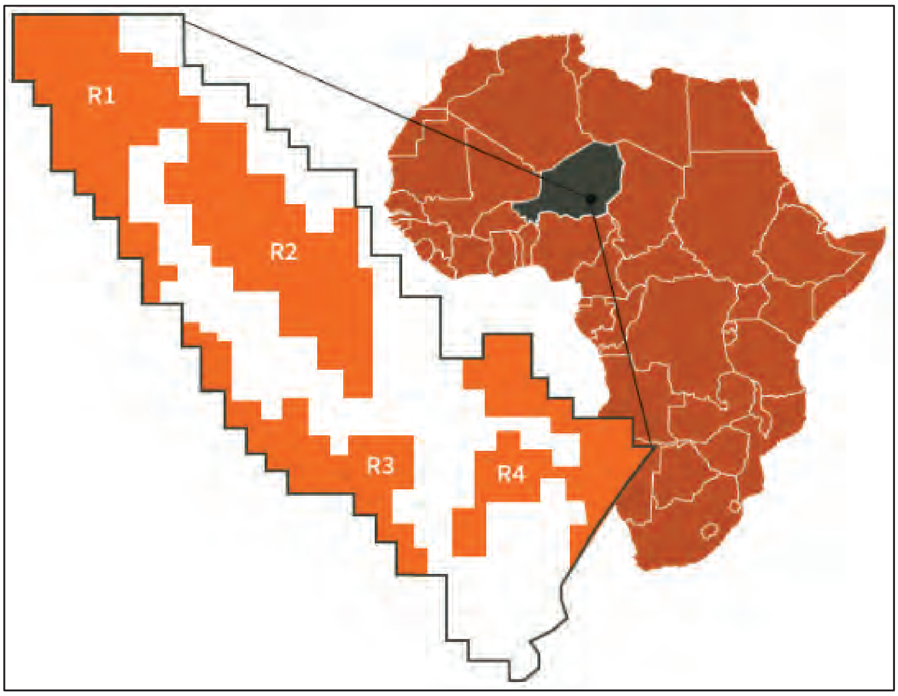



Figure 2-1 Map showing location of the assets (*Source: Savannah, 2017*)

Savannah's licence is situated in the Mesozoic to Cenozoic Agadem Rift Basin of Eastern Niger. The Agadem Rift Basin (ARB) is comparable in scale to the North Sea rift system (**Figure 2-2**). The rift basins of Niger are part of the Central African Rift System. The Central African Rift System is a proven hydrocarbon province in Niger, Chad, Sudan and South Sudan. The topography in the Licence Area is relatively flat and although it is a desert there are no significant mobile sand dunes. The area is c.200km away from the nearest major population centres. Wells drilled to-date have been vertical or slightly deviated and to the best of our knowledge have been completed using industry standard drilling procedures and equipment.

This assessment is based on information provided by Savannah, by the Niger Ministry of Energy and Petroleum to Savannah, and on information in previous CGG in-house studies of African rift systems.

Savannah Energy Niger is the Operator of the R1234 Licence Area with a 100% ownership. Savannah has a 95% interest in Savannah Energy Niger.

The basin shows classic rift geometries (**Figure 2-3**) and in the Savannah Licence contains multiple stacked hydrocarbon plays **(Figure 2-4**).

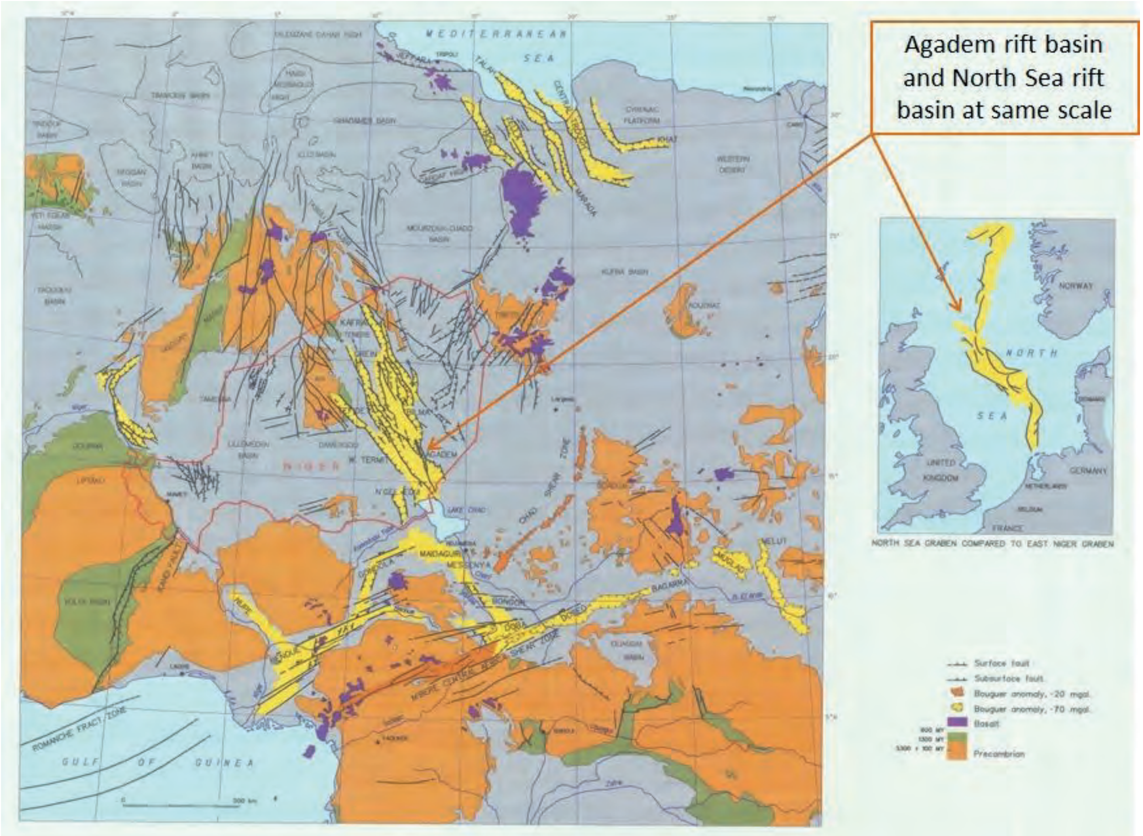



Figure 2-2 Map comparing magnitudes of the basins of Niger and the North Sea

(Source: Niger Ministry of Energy & Petroleum, and in-house Robertson studies, 2017)

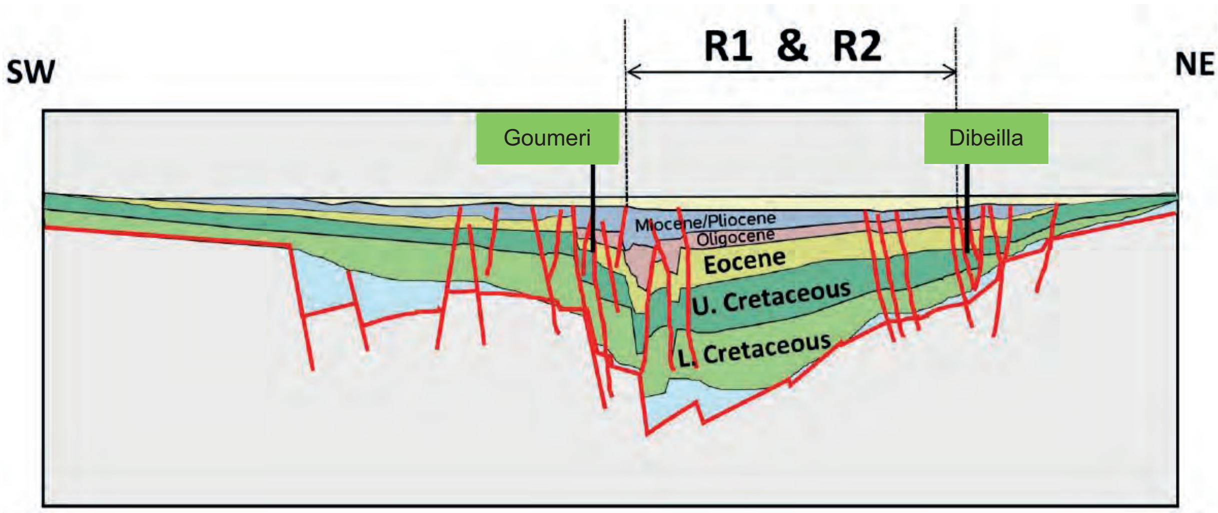



Figure 2-3 Schematic South-West to North-East Cross-Section through the Agadem Rift Basin, Niger

(Source: Niger Ministry of Energy & Petroleum and Savannah, 2017)

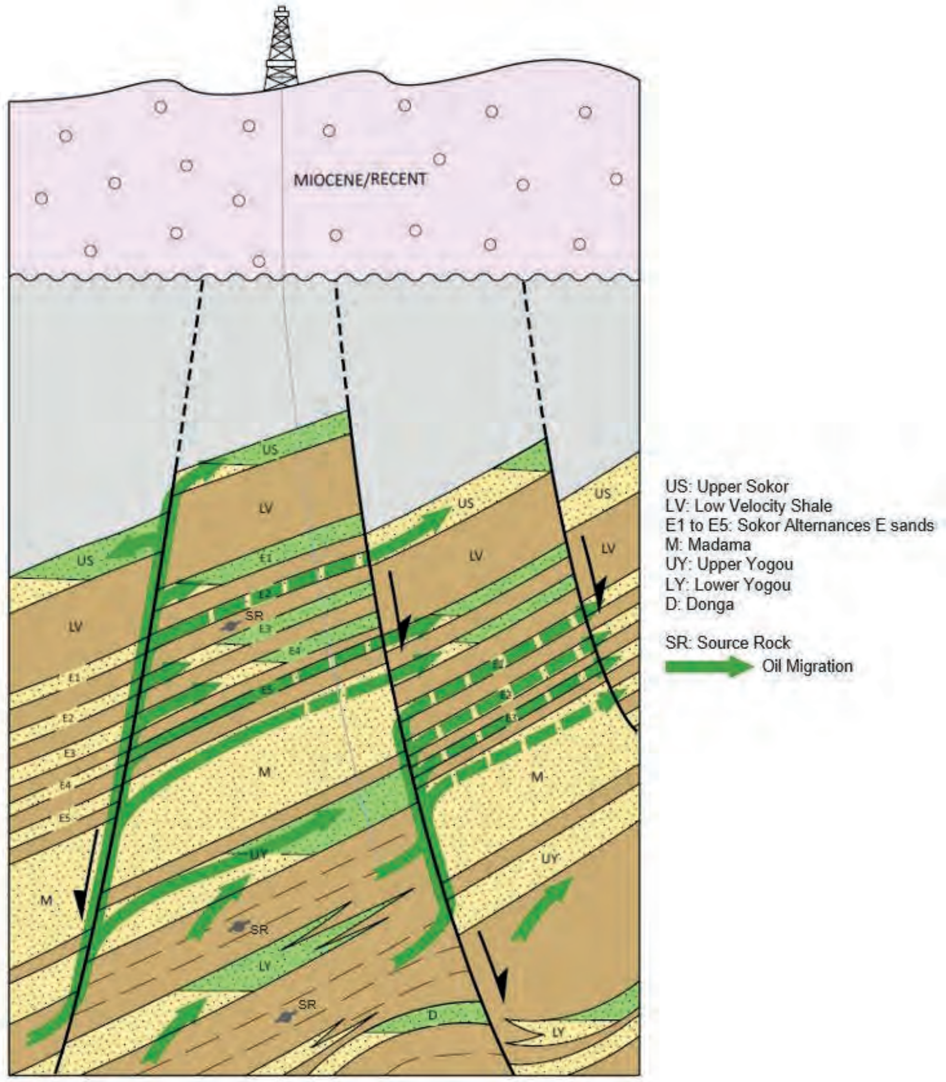



Figure 2-4 Schematic South-West to North-East cartoon cross-section to illustrate the main trapping and charging mechanisms in the Agadem Rift Basin *(Source: Savannah, 2019)*

## 2.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah's technical team as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR has included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Work plans and budgets

In conducting their evaluation, CGG has relied upon the accuracy and completeness of information supplied by Savannah. As the assets in question are in the exploration phase, no site visit has been conducted by CGG.

## 2.3 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Andrew Webb

Andrew Webb has supervised the preparation of this CPR. Andrew is the Asset Evaluation Manager CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 30 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Rob Crossley

Dr Rob Crossley has provided petroleum geological inputs to this CPR. He is Chief Geologist in the Geoconsulting Group at CGG, having joined the company as sedimentologist in 1986. He graduated in 1976 with a PhD jointly from the Universities of London and Lancaster. He has particular expertise in the geology of petroleum systems in rift basins and now has 31 years' experience in the upstream oil and gas industry. Rob's involvement with asset evaluation projects has been global but focused predominately in Europe, Africa, Middle East, Far East and South America.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 25 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

Toni Uwaga

Toni Uwaga has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish Sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell

Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has written several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright gained an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

## 2.4 Evaluation methodology

In evaluating the Resources associated with the discovered fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation.

As an initial stage in the evaluation process, Savannah demonstrated the seismic interpretations during a visit by CGG to their office in October 2019. During the other visits, geological, engineering and commercial issues were also discussed face to face with Savannah's technical staff.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Resources, projections of production profiles and estimates of capital and operating costs provided by Savannah. The Resources have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

In addition, CGG has estimated resource volumes for eleven indicative prospects and leads selected by Savannah from its exploration portfolio. These prospects and leads are currently under consideration as potential further drilling candidates in Savannah's next exploration drilling campaign. CGG has also provided estimates of the yet-to-find resources in the licence.

In estimating the resource volumes for the prospects and leads, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Resource ranges (low, mid and high cases) have been determined using probabilistic methods.

The evaluation has been performed in accordance with the:

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)
- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

# 3 RESOURCE DESCRIPTION

## 3.1 Tectonostratigraphy

The onset of rifting commenced in the Lower Cretaceous and subsidence continued into the Late Cretaceous. The basin was subjected to a tectonic event in the Santonian-Campanian that caused rift flank uplift and folding of the sediments in the basin floor. Subsidence subsequently continued steadily into the Cenozoic. A second major phase of rift faulting occurred in the Oligo-Miocene, before the basin returned to slow subsidence through the Plio-Pleistocene.

The sedimentary fill of this rift basin contains interbedded packages of sandstone and shale with a total thickness of more than 5km across much of the area. The depositional setting is predominantly fluvial and lacustrine, with marine incursions occurring during the Late Cretaceous. Shales units are often organic-rich, containing both algal and terrestrial kerogen. Shales at Cretaceous level have entered the oil window across much of the basin. The latest phase of rifting was in the northern part of the basin accompanied by minor igneous centres, but these centres were too small to have a major influence on thermal maturity of the basin.

The basin received substantial clastic fluvial input, and sedimentation kept pace with subsidence for prolonged periods. This ensured that sand-rich sequences were repeatedly deposited across much of the area. Seismic interpretation suggests that there was a period in the Late Cretaceous when subsidence outpaced sedimentation and this was accompanied by uplift of the basin margins. Erosion of the basin flanks provided a potential additional source of sand that could be emplaced by gravitational flow into the deeper water settings.

Consequently, the basin offers source and reservoir potential in multiple stratigraphic intervals, including at levels that to-date have received few well penetrations. The fault blocks created by late Cenozoic faulting formed the traps targeted by almost all exploration drilling to-date, whereas the structures formed by Santonian-Campanian tectonics are essentially unexplored.

## 3.2 Depositional models

It is important that the correct depositional model is applied, since this affects the way in which potential resources in undrilled acreage and the appropriate recovery factors, are estimated.

The Agadem Rift Basin contains a sedimentary fill of more than 5km and forms part of the Central African Rift System. However, it is apparent from the seismic and well data that, in the Licence Area, classical rift basin depositional models, involving deep lake basins, prograding deltas and alluvial fans along fault scarps, do not apply. The reflector packages at seismic scale are remarkably layer-cake, with minimal evidence of prograding or shingled features. Inter-well correlation of wireline packages tens to hundreds of metres thick is relatively straight-forward over distances of tens of kilometres. Sands at the E3 level in the NW part of the basin, which are normally too thin to be considered in volumetric estimates, often contain oil. Since these sands are far above the oil window, the oil indicates that the thin sands have substantial lateral continuity in order to connect to the faults which provide the vertical migration conduits. The depositional models need also to address the paucity of peats, coals, evaporites and conglomerates through most of the section.

Savannah's biostratigraphy data suggests that throughout the Cenozoic and Cretaceous, deposition occurred in a relatively arid climatic regime, but with substantial influxes of fresh water. In the context of local aridity, this implies input from major rivers. This input persisted irrespective of whether the depositional setting in the basin was entirely terrestrial or was subjected to marine flooding. These conditions are compatible with CGG's in-house palaeogeographic and palaeoclimatic modelling for the area.

The layer cake depositional geometries are interpreted by CGG as resulting from sedimentation keeping pace with subsidence because of high influxes of fluvial clastic sediment. The high fluxes of clastic sediment appear not to be due to rapid erosion of local highs, since extraclast conglomerates are largely absent. The amount of core data available is limited but suggests that the sandstone sequences are fine to medium grained, with quartzose pebbles (less than 10mm in diameter) occurring only occasionally in the Madama Formation. Our overall interpretation is therefore of rivers with relatively large discharges draining wet climatic areas, traversing a low relief landscape and depositing their sediment in a shallow basin in an arid setting.

## 3.3 Petroleum geology of stratigraphic units

### 3.3.1 Upper Sokor Formation

Savannah currently carries oil volumes at this level in six of the prospects and leads reviewed. This represents a potentially important new play in the basin, and so has warranted particular scrutiny. This new play is supported by seismic, hydrocarbon shows and well testing.

The phase of rift faulting that created most of the structural traps in the proven Sokor Alternances and Yogou plays post-dated deposition of the Upper Sokor and so also created structural traps at the Upper Sokor level.

Many of the Eocene exploration wells were drilled vertically to target footwall closures at the Sokor Alternances, and so either penetrated the Upper Sokor in hanging-wall sections, or failed to fully penetrate the Upper Sokor sequence, owing to the magnitude of heave on the bounding fault. Consequently, the Upper Sokor is under-represented in the existing well data sets, so estimation of resource potential at this level cannot be determined directly from the existing exploration statistics. The geological context of this potential play was therefore examined in order to provide a basis for resource estimation and geological risking.

**Hydrocarbon charge:** Basin modelling undertaken by Savannah indicates that source rocks at Cretaceous levels would have been oil mature at the time of Oligo-Miocene rifting, so the rift faulting could have provided charge pathways into the Upper Sokor. Subsequent burial by late syn-rift fill and during post-rift basinal subsidence, might have resulted in additional maturation at Cretaceous levels, potentially resulting in further charge to the stacked plays.

In order to reach the Upper Sokor play, hydrocarbons have to penetrate the Low Velocity Shale (LVS). This shale is present throughout the basin, and is typically about 100m thick, so is potentially a barrier to vertical migration. However, oil has been recovered from the Upper Sokor level in at least six wells, and shows have been reported at this level in at least another 12 wells. Most shows at this level are in areas remote from igneous features, so contact metamorphic maturation of shales above the LVS is not considered by CGG to be the explanation for the majority of shows in the Upper Sokor. Consequently, it is concluded that rift faults have provided migration pathways through the LVS in some areas.

It is not clear whether these shows occur exclusively up-dip from faults with throws greater than 100m, which would juxtapose Sokor Alternances sands against Upper Sokor sands, or whether temporary dilation on fault planes by tectonic movement and/or hydrocarbon fluid pressure provided migration paths directly through the Low Velocity Shale.

**Biodegradation:** Ordinarily bitumen formation through biodegradation might be considered an important risk in hydrocarbon basins at depths of less than 1600m. The Upper Sokor is the shallowest play identified to-date in the Basin, with most prospects and leads identified to-date occurring at depths of less than 1600m, compared with depths of about 1600m to 3500m for the other plays. CGG has not encountered accounts of significant bitumen deposits in this basin, so biodegradation is not considered to be a major issue. Nonetheless, some evidence of biodegradation, as interpreted from gas chromatograms, does occur in 15 of the oils examined by IGI (2015). The 15 biodegraded oils range in API gravity from about 17° to 30°.

The available evidence, which is limited, suggests that the oils found in the Sokor Alternances and Yogou formations come from a mixture of marine and lacustrine sources. Wax is present in some oils but does not appear to be a dominant feature of the hydrocarbons reported to-date.

The relationship between biodegradation, API and viscosity is not straight-forward, particularly in the case of the wax component of crudes. Biodegradation may contribute to decreased API gravity, but the negative impact of a slight API decrease can be offset by lowered pour points and less wax deposition in pipework and processing facilities (Wenger *et al.*, 2002).

To conclude, there is no available evidence that oils at Upper Sokor level have been damaged by biodegradation, but also the number of penetrations that could potentially have penetrated oil accumulations at Upper Sokor level is very limited, so this remains an area of uncertainty at the shallowest levels.

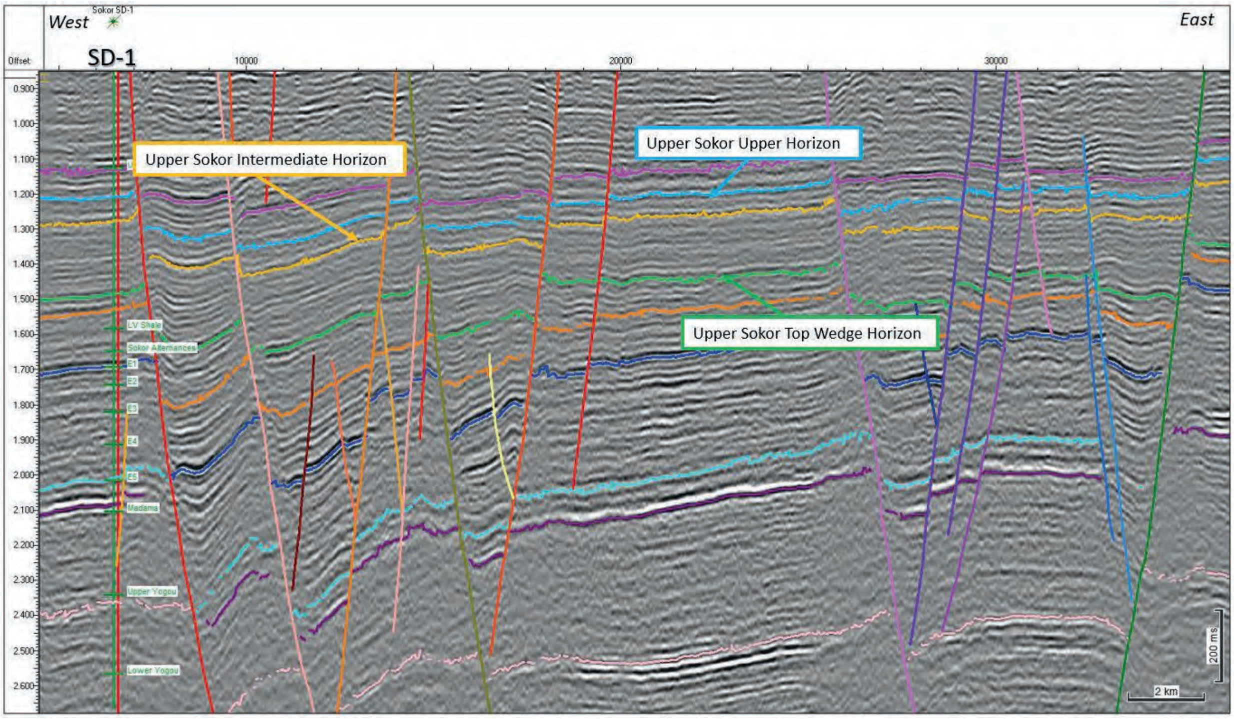



Figure 3-1 W-E 3D seismic profile through Sokor SD-1 well, in the R3 East 3D (*Source: Niger CPR 2017*). The Upper Sokor contains variable amplitudes within a subtle sedimentary wedge above the LV Shale (green to orange markers)

**Depositional model:** The wells show that the Upper Sokor comprises reservoir-seal couplets similar to those in the Sokor Alternances. Seismic review suggests these sand-shale sequences in the lower part of the Upper Sokor show a mixture of layer cake and gentle wedge geometries. The wedges thicken towards some faults. Most of the displacement on these faults was much later, but it appears that a brief phase of minor movement occurred on some faults during deposition of the lower part of the Upper Sokor. These features are illustrated in **Figure 3-1**. Modern Lake Chad provides a potentially useful analogue for the depositional model envisaged for the Upper Sokor. The gross tectonostratigraphy of modern Lake Chad is similar in that the clastic inputs to the area have evidently been sufficient to infill all the accommodation space created in the Niger to Chad sectors of the basin during late Cenozoic rifting.

The hydrological budget of the Lake Chad is nearly balanced, with most of its water inflowing from the south. Inflow is via groundwater throughout the year, and is supplemented by major flow in rivers during the southern wet season. The subdued geometry of the lake basin ensures that the lake shows large fluctuations in area in response to modest changes in lake level, and this occurs on time-scales of tens to thousands of years. The result is that lake-margin swamps are largely ephemeral and the organic matter is rapidly oxidised when the lake recedes, so no peat accumulates over most of the basin. The groundwater-fed swamps on the southern margin are potential exceptions that may allow some peat accumulation.

The advance and retreat of the shorelines results in laterally persistent sheets of sand. In addition, the lake flats exposed during low stands become areas of sand deposition, with reworking by ephemeral run-off and by wind. The result can be sand systems that show excellent sorting and lateral continuity, though individual beds of sand may be no more than a few metres thick.

These patterns resemble features revealed by horizon slice amplitude extraction in the lower part of the Upper Sokor. The extractions on sandy intervals could be interpreted as representing a coalescence of sandy facies including broad curving beach ridges, irregular fluvial sand sheets, and sand reworked by wind or waves. The extractions on more mud-rich horizons suggest a more homogeneous distribution of facies which in this context might include mud-dominated lacustrine-alluvial deposits, with the higher amplitudes including peat deposits preserved preferentially on the subsiding side of faults.

There is no obvious difference in reflector character between the Upper Sokor and the underlying Sokor Alternances in seismic sections. These interpretations therefore also support the relatively layer-cake depositional model adopted here for the Sokor Alternances, with correspondingly beneficial implications for hydrocarbon production.

### 3.3.2 Sokor Alternances Formation

Savannah currently carries oil volumes at this level in six of the prospects and leads reviewed.

This play has been extensively drilled within the retained acreage of the Agadem Rift Basin, and the discovery data mostly reflect the success of this play. The oil at Eocene level represents leakage from Cretaceous levels, predominantly up faults and across faults where sands are juxtaposed. The faults were mostly active in the late Oligocene, and modest subsidence, not accompanied by major faulting, has continued since.

The Sokor Alternances contain many more reservoir/top seal couplets than the Upper Yogou. Only a small proportion of the Sokor Alternances Eocene sands contain oil – probably because of trap leakage across faults in these relatively sandy sequences. It is unusual to find more than three or four charged reservoirs in the Eocene fields.

### 3.3.3 Madama Formation

Savannah does not currently carry any oil volumes at this level in the prospects and leads reviewed.

The Madama Formation is present in all wells drilled to that depth across the basin. This formation has a distinctive seismic character that could be traced across the basin on all seismic reviewed.

In many fault blocks, the Madama Formation may carry attic oil trapped against shales in the Lower Sokor Alternances. CGG thus views the Madama Formation as a potential subject of prospective resource volume upside.

### 3.3.4 Yogou Formation

Savannah currently carries oil volumes at this level in ten of the prospects and leads reviewed.

Basin modelling, and the distribution of discoveries across the Agadem Rift Basin, demonstrates that the majority of the oil in the Eocene accumulations was generated from Cretaceous source rocks, at Yogou or deeper levels. The Yogou reservoirs effectively sit within the oil window, with very short migration paths from kitchen to trap. The Yogou reached maximum maturity during the subsidence which post-dated Oligo-Miocene faulting, and today the Yogou sequence remains in the oil window across much of the basin. It is therefore inferred that whilst some traps at Yogou level may temporarily have been breached during faulting, charge of Yogou traps will have continued through to the present day.

In the Dinga Slope and Dinga Ridge areas, a number of large structures, that are visible on 2D seismic at Yogou level, do not exist at shallower Eocene levels. These large structures show relatively few Cenozoic faults.

Review of 2D and 3D seismic across the basin suggests that the Yogou Formation was deposited during the sag phase that post-dated Cretaceous rifting. CGG interprets the relationships exhibited on seismic and the new biostratigraphic data obtained by Savannah from cores at Upper Yogou level, as indicating that deposition of Upper Yogou sands (and ultimately Madama sands), was triggered by tectonic movements during the Santonian to early Maastrichtian. This correlates with a regional tectonic event that affected several Cretaceous rift basins along the Central African Rift System.

Review of the available porosity-depth data suggests that the Yogou sands lie on a trend that is 2-3% higher than that of the Eocene section. This might be a function of overpressure, or initially better quality reservoir facies.

Review of the available log profiles suggests that multiple reservoir-seal couplets are present in the Yogou, and as long as there are on average four or more of these, then the numbers of separate accumulations at Yogou and Eocene Sokor Alternances levels can be expected to be similar.

At Yogou level, shale seals will be more compacted, and consequently more effective than at Eocene level, where shale seals are proven by numerous accumulations. In addition, review of the 3D seismic data shows that faults at Eocene levels tend to merge into a smaller number of faults at greater depth. This means that the risk of trap breaching by faults is reduced at Yogou level. This in turn means that traps are more likely to be filled to-spill at Yogou levels than within the Eocene and Miocene sections.

There will be several Yogou structures where fault seal risk is high because the sand-rich Madama Formation is on the downthrown side of the fault trap. However, in contrast to the situation in the Eocene, where the distribution of cross-fault leakage into sands is hard to predict, such structures at base Madama level should be readily imaged on 3D seismic, and thus should be avoidable for drilling.

The reduction in numbers of faults with depth suggests that the size of individual fault block traps will be greater at Yogou than at Eocene levels.

Recently, testing of the Upper Cretaceous Yogou reservoirs has proven productive, giving similar, or better, flow rates than in the Eocene section. The good reservoir performance appears to result from a combination of reasonable retained porosities and lower viscosity oils than in the Eocene section.

### 3.3.5 Lower Yogou and Donga Formation

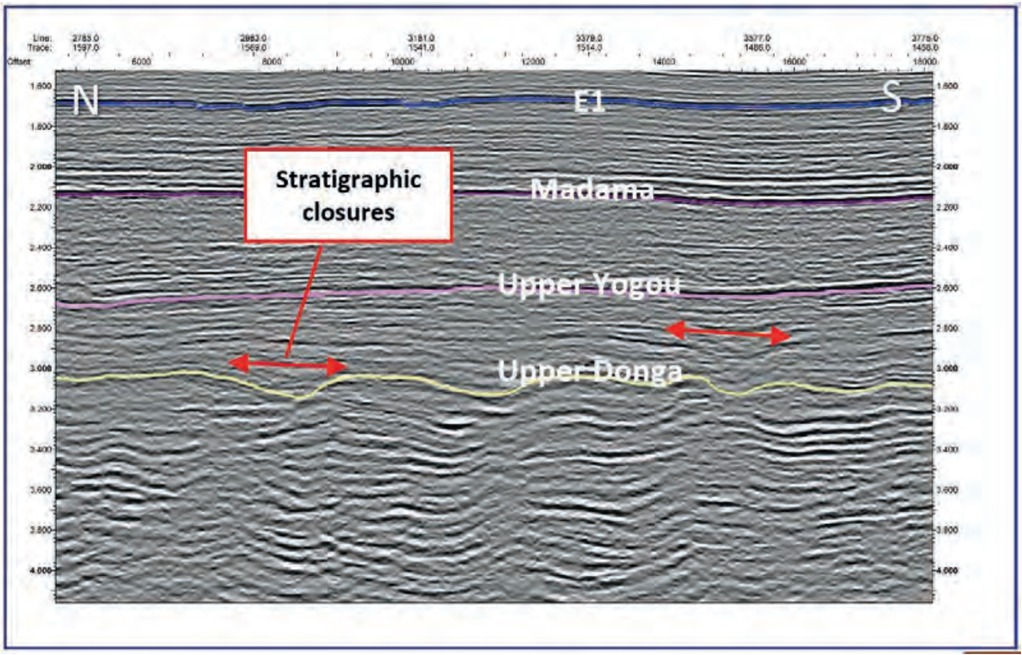
Cretaceous folding and Cenozoic faulting together form an additional set of trapping geometries beneath Savannah's acreage at Lower Yogou and Donga levels. **Figure 3-2** illustrates these features. In some parts of Savannah's acreage these intervals are found at depths that are relatively easily drillable.

The depositional setting implied by biostratigraphic data, limited geochemical analyses, and the widespread occurrence of gas shows far outside the footprint of the main gas window at Yogou level suggests that a mature source rock is present at Donga or deeper levels.

Thin sandstones occur at Donga and older stratigraphic units in wells around the basin edges, and nothing is known about sand distributions beneath the basin axis, but the amplitude variations at these depths suggest that multiple lithologies, potentially including reservoir facies, may be present.

The Donga interval is modelled as being within the gas window in the deepest parts of the basin, so any oil source rocks present will have charged reservoirs in this and overlying intervals before oil expulsion started from the Yogou source rocks. It is not presently clear what proportion of reservoirs in this interval will now be gas charged rather than containing oil.

Savannah has only evaluated the play potential in this stratigraphic interval, following on from its detailed investigations of the Upper Yogou prospectivity. For this reason, Savannah has not yet interpreted the interval to the level where prospects and leads can be added to its proprietary exploration portfolio. The play is, however, included in this yet-to-find analysis included in this CPR (**Section 4.3**).



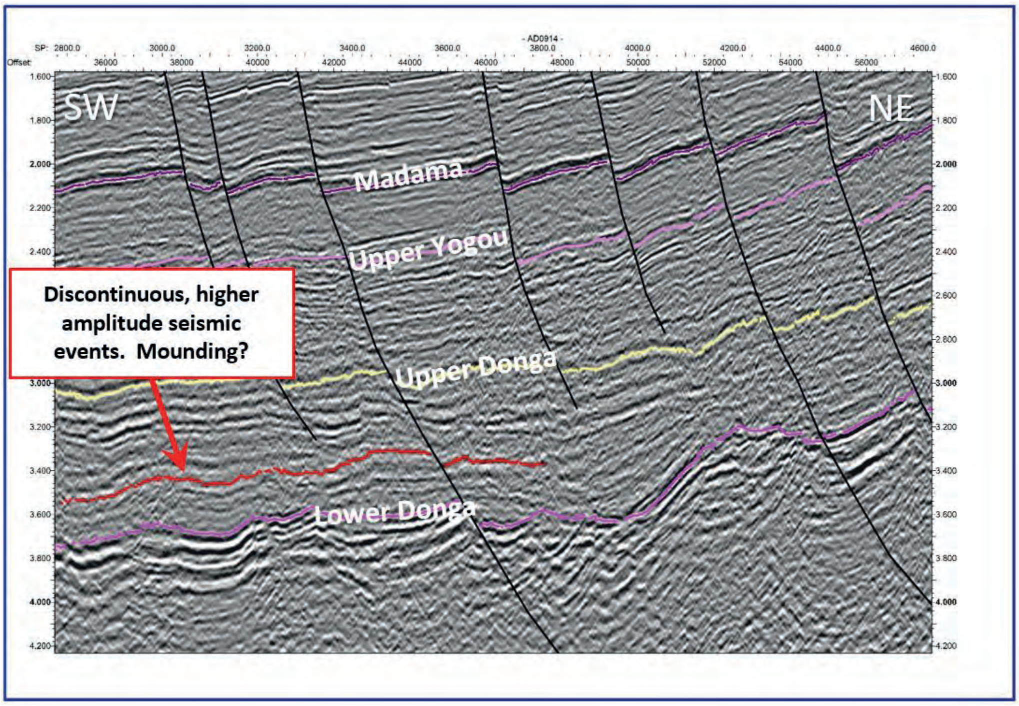




Figure 3-2 Structures at the Lower Yogou and Donga levels – Top: Arbitrary line within the R3 East 3D seismic survey Bottom: 2D seismic line within the R4 area *(Source: Savannah, 2019)*

**References**

Wenger, L. M., Davis, C.L. and Isaksen, G.H., 2002. Multiple Controls on Petroleum Biodegradation and Impact on Oil Quality. SPE Reservoir Evaluation & Engineering, October, p. 375-383.

## 3.4 Discoveries

In 2018, Savannah selected five prospects to be drilled from their portfolio in the R3 East portion of the Licence area. Of the five wells drilled (i.e. Amdigh-1, Eridal-1, Bushiya-1, Kunama-1 and Zomo-1), all found hydrocarbons within the Sokor Alternances (Eocene age) and can be considered discoveries giving a success rate of 100%. The high success rate is aligned with to-date basin statistics with c. 115 discoveries from 142 wells (>80% success rate).

All the structures are within the R3 East 3D seismic survey acquired by Savannah in 2016/2017 and also lie within the NW-SE regional oil discovery trend observed in the neighbouring CNPC licence (**Figure 3-3**).

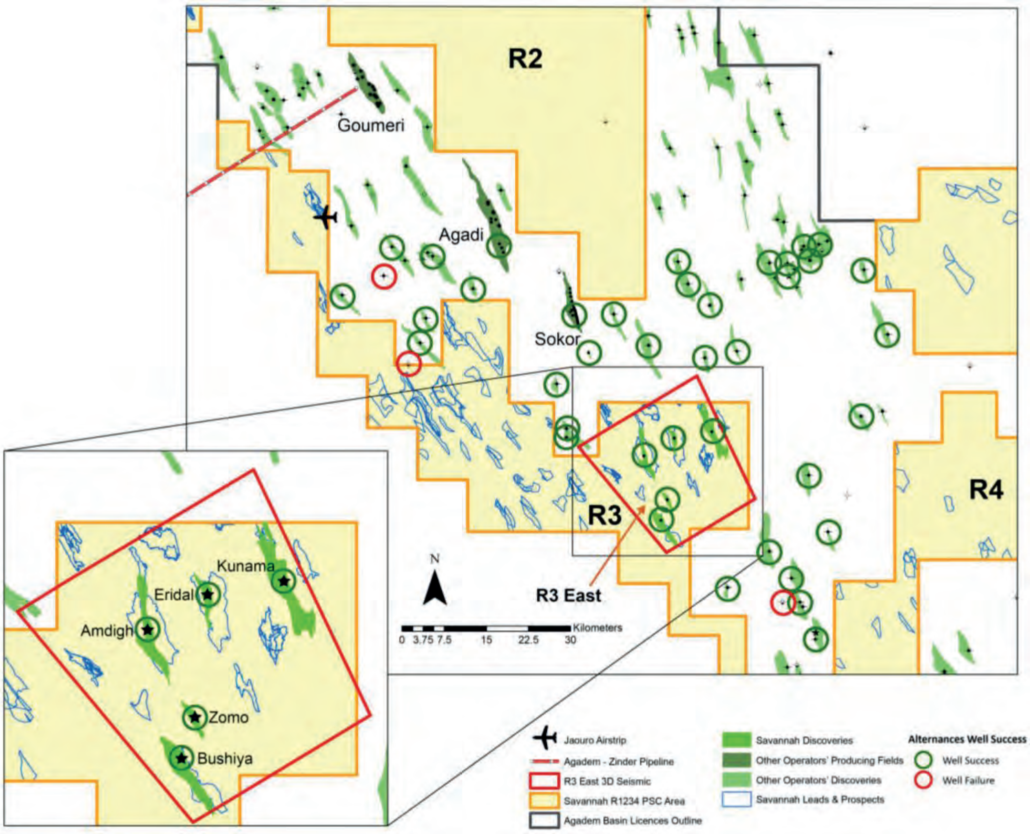



Figure 3-3 Location map of discoveries within the R3 East 3D survey (red polygon, source: Savannah*, 2021)*

CGG had access to Savannah's seismic project interpretation and performed a detailed QC of the interpreted closure areas (polygons) for the discoveries, confirming that the numbers of the estimated areas were reliable. All the well information mentioned below was provided by Savannah, and no further interpretation or petrophysical analyses were performed by CGG. Graphs and all the petrophysical parameters used in the Savannah volumetric calculations are extracted from documents given to CGG (R3 East Feasibility Study Report, Corporate and Technical presentations). It should be noted that the seismic interpretation used to generate depth maps and volumetric estimates is based on the Pre-Stack Time Migration (PSTM) R3 East 3D dataset processed in 2017. Savannah has now completed a Pre-Stack Depth Migration (PSDM) re-processing of the R3 East 3D seismic survey and its interpretation. Based on the newly interpreted PSDM, 3D geomodels have been built for the Amdigh and Eridal discoveries. Savannah has stated that the resulting oil in-place volumes are in-line with the PSTM based estimates. CGG has not reviewed these latest estimates at this stage, since Savannah is still progressing with further work on the other discoveries and its exploration portfolio.

### 3.4.1 Amdigh discovery

Located in the central-north of the R3 East 3D survey, the trap consists of a tilted fault block, and encountered oil columns (c. 20m total net pay) in sequences E1, E2 and E3 of the Sokor Alternances. The well was drilled down to a TD of 2469 m MDBRT (2049 m TVDSS) after penetrating 55 m into the Madama Fm (**Figure 3-4**). The presence of oil in the E1 and E2 was confirmed by recovery of oil samples and by the interpretation of Reservoir Formation Tester (RFT) pressure data. The analysis of the E1 sample show an oil API gravity of 27.5° which is consistent with offset wells along trend and the depth/API trend observed across the basin. Based on the RFT interpretation, the E3 interval was considered as pay.

Within the same discovery, Savannah identified different segments for the E1, E2 and E3 (**Figure 3-5**), which were taken into consideration. The discovery well is drilled in segments 1&2, and it is considered that segment 3 is very likely to be in pressure communication due to the low displacement on the bounding fault especially towards the top of the structure. It is less clear if segments 4, 5 and 6 also form part of the discovery and hence those segments have been removed from the low and most likely cases and only considered in the high case (**Section 4**).

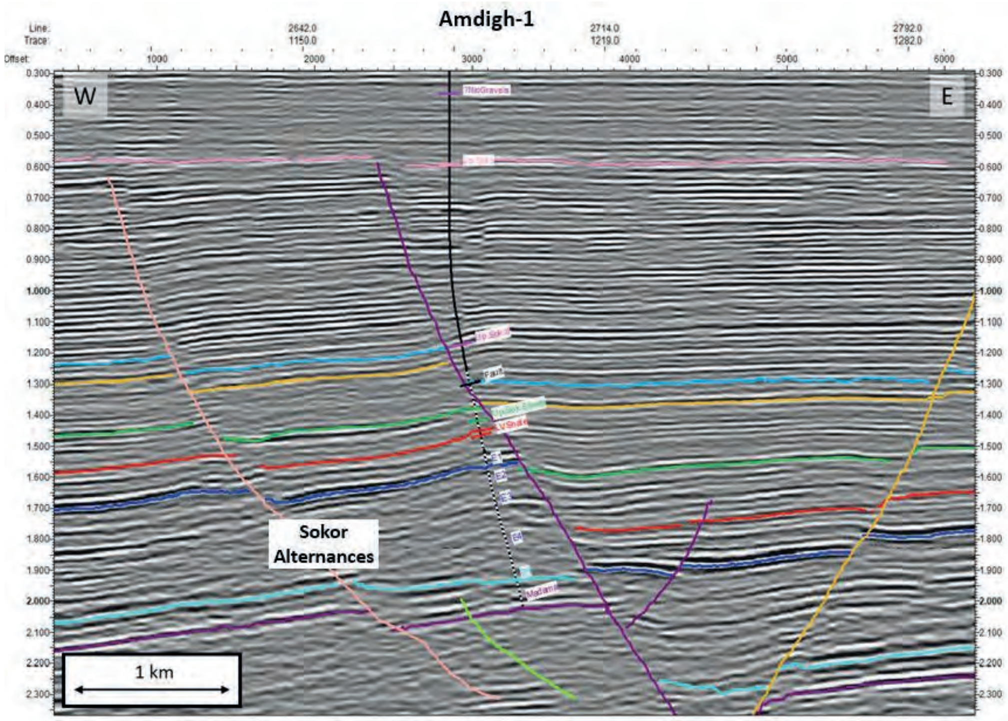



Figure 3-4 PSTM Seismic Section through the Amdigh-1 discovery well (Source: Savannah, 2019)

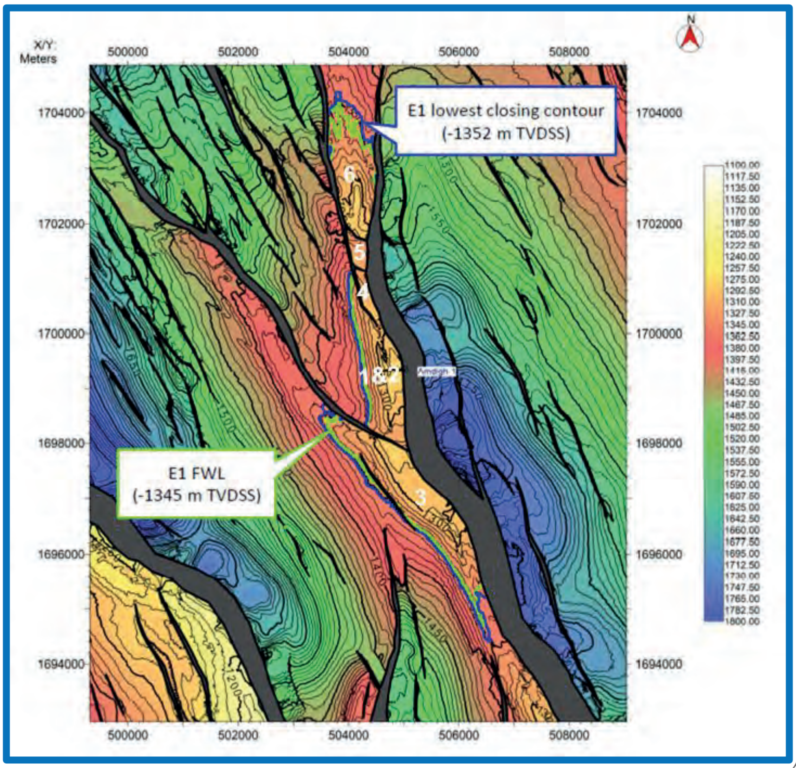



Figure 3-5 Amdigh E1 structural depth map (based on PSTM dataset) and the six segments *(Source: Savannah, 2019)*

### 3.4.2 Bushiya discovery

This discovery is situated in the southern part of the R3 East 3D survey, and the trap is a tilted fault block type. Bushiya-1 was drilled down to a TD of 2200 m MDBRT (1811 m TVDSS) after penetrating 109 m into the Madama Fm (**Figure 3-6** and **Figure 3-7**). Two oil columns were encountered in the E1 and E3 intervals with an estimated c. 10 m total net pay. The E1 column was proven by recovery via RFT of a 24.2°API oil sample, inline with the Amdigh-1 oil analysis from the same interval. The E3 oil column was interpreted from the RFT pressure data.

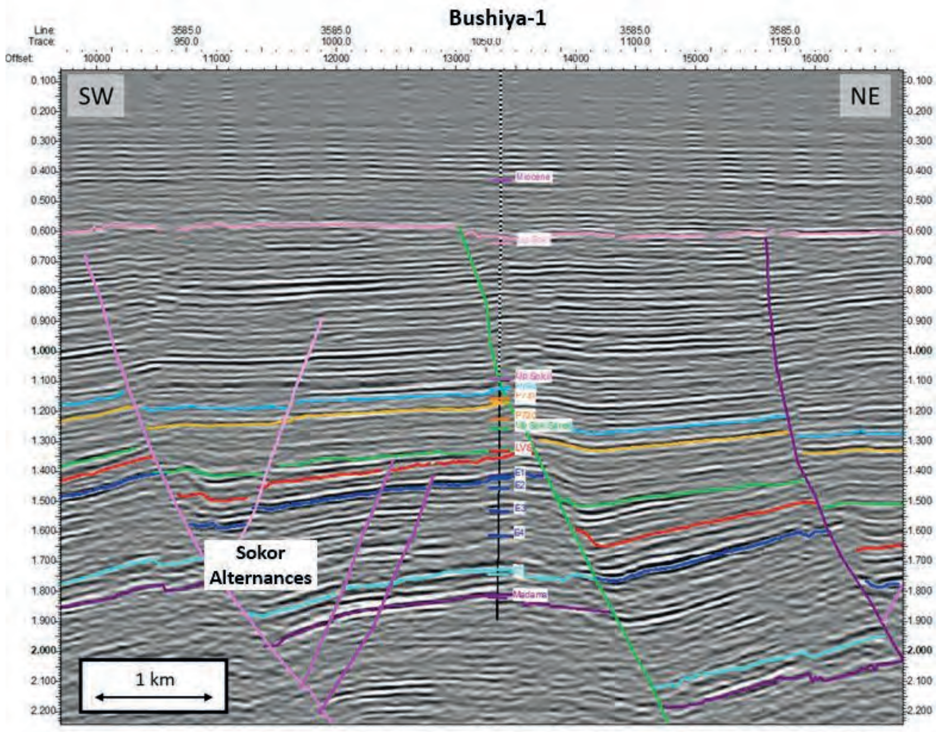



Figure 3-6 PSTM Seismic Section through Bushiya-1 discovery well *(Source: Savannah, 2019)*

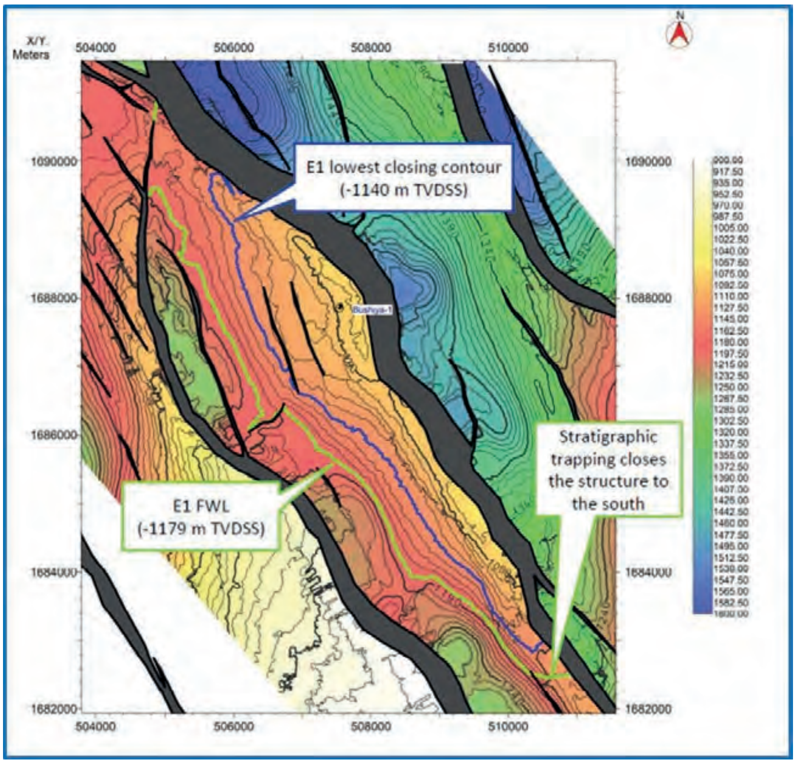



Figure 3-7 Bushiya E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

### 3.4.3 Kunama discovery

The Kunama-1 discovery is located in a slightly tilted block and was drilled down to a TD of 2460 m MDBRT (2118 m TVDSS) after penetrating 100 m into the Madama Fm (**Figure 3-8** and **Figure 3-9**). An oil column was proven in the E1 interval in the Sokor Alternances by recovery of 28°API oil in an RFT sample. A second oil sample of 24.6°API gravity was recovered by RFT in the E5 interval. A total net pay of c. 9 m was interpreted from logs. As for the oil recovered in Amdigh-1 and Bushiya-1, the oils in both E1 and E5 intervals are light. RFT pressure interpretation at Kunama was used to define a range of contact for subsequent STOIIP estimation.

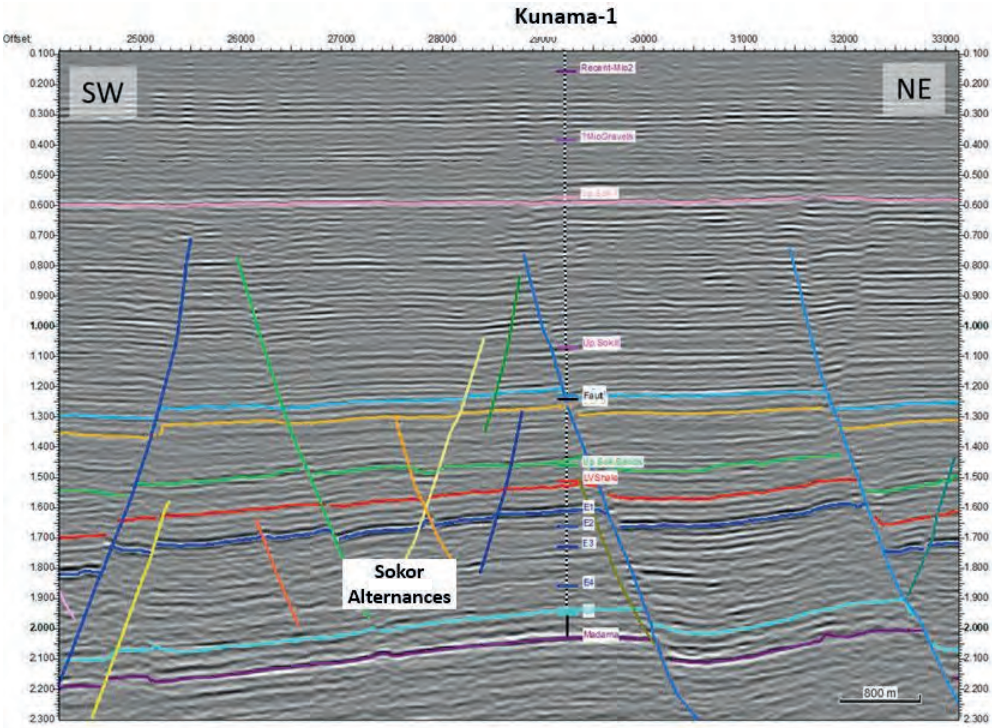



Figure 3-8 PSTM Seismic Section through discovery well Kunama-1 *(Source: Savannah, 2019)*

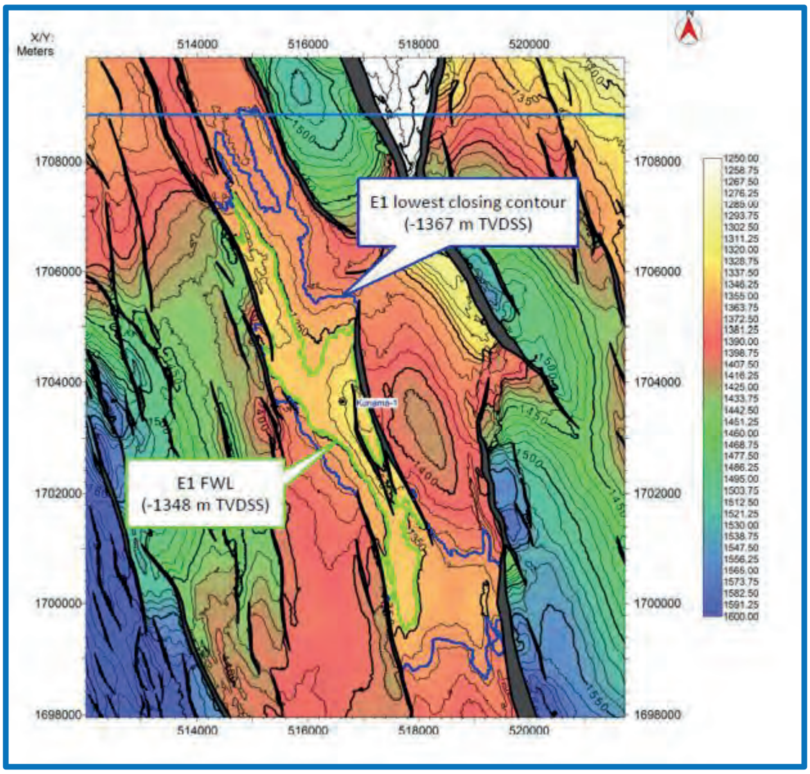



Figure 3-9 Kunama E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

### 3.4.4 Eridal discovery

This is a tilted fault block, located to the east of Amdigh. Eridal-1 was drilled down to a TD of 2542 m MDBRT (2203 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-10** and **Figure 3-11**). The well encountered oil in the Sokor Alternances E1 section (c.10 m net pay), as proven by RFT gradient analysis, a RFT oil sample (33 °API) and petrophysical analysis. Interpretation of the RFT pressure data show that the E1 sand contains an oil column which is continuous within the pay section.

Along the same structural trend but to the south the Ourami-1 well (oil shows present in the Alternances) penetrated these levels but was likely drilled out of closure.

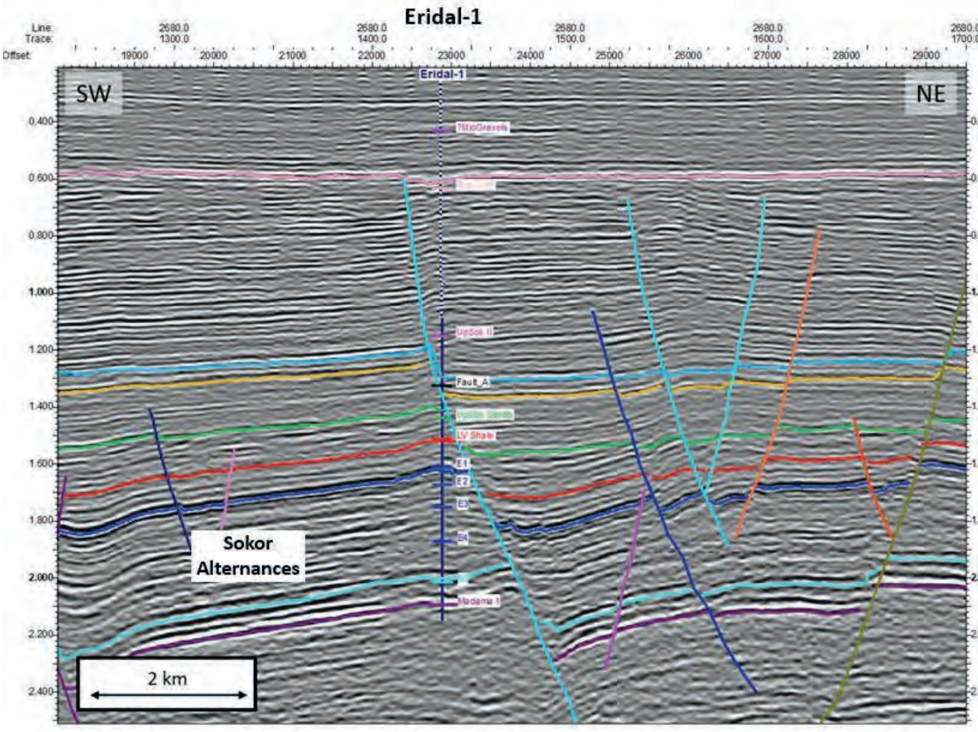



Figure 3-10 PSTM Seismic Section through Eridal-1 discovery well *(Source: Savannah, 2019)*

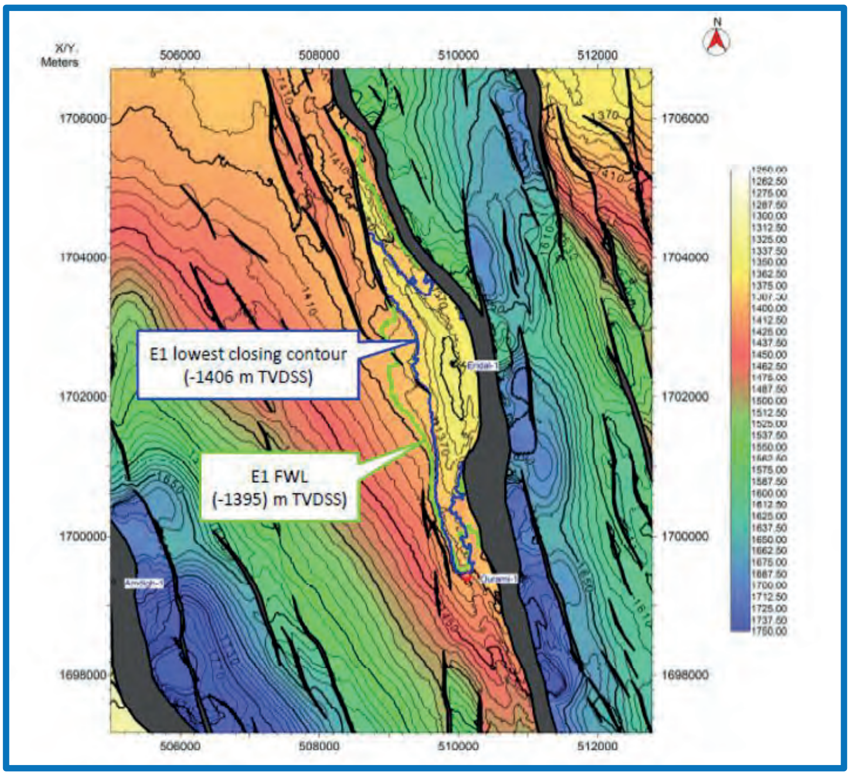



Figure 3-11 Eridal E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

### 3.4.5 Zomo discovery

The Zomo-1 well was drilled on a structure immediately along strike from the Amdigh discovery and was drilled down to a TD of 2499 m MDBRT (2119 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-12** and **Figure 3-13**). The well encountered an oil column (5.4 m net pay) in the E1 interval of the Sokor Alternances. An oil sample was recovered with an API gravity of 23.7°.

An extensive RFT program was carried out in Zomo-1 to investigate its hydrocarbon column and possible relationship of the column to the proven columns in Amdigh-1. According to Savannah's interpretation, the RFT analysis proves that the oil columns in Zomo-1 and Amdigh-1 are separate.

Overall, the oils discovered in the five discoveries are medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur) which is consistent with offset wells along trend and the depth/API trend observed across the basin.

Petrophysical analysis results in high calculated water saturations throughout the proven pay zone where oil was recovered. The implied low oil saturations are considered incompatible with the rest of the dataset for the well. Furthermore, oil producers in neighbouring fields also exhibits low oil saturations based on petrophysical interpretation but are actually good oil producers. Therefore, the estimated pay has been adjusted by Savannah to take account of this uncertainty in water-saturation which CGG has judged a conservative approach to the net pay estimation.

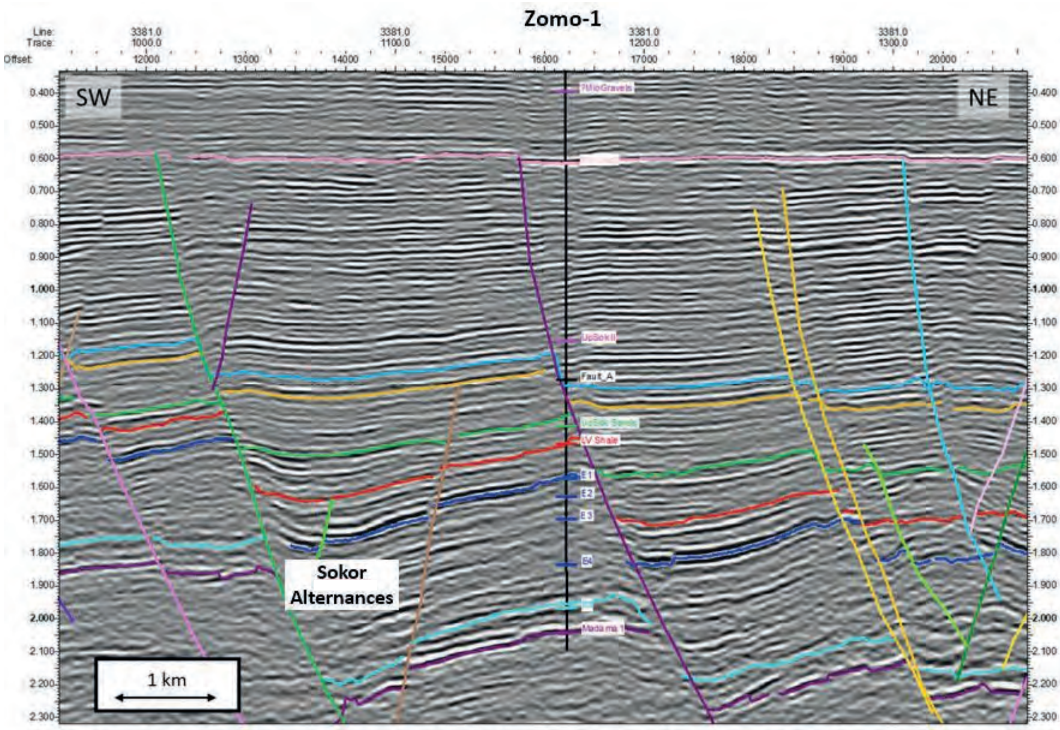



Figure 3-12 PSTM Seismic Section through Zomo-1 discovery well *(Source: Savannah, 2019)*

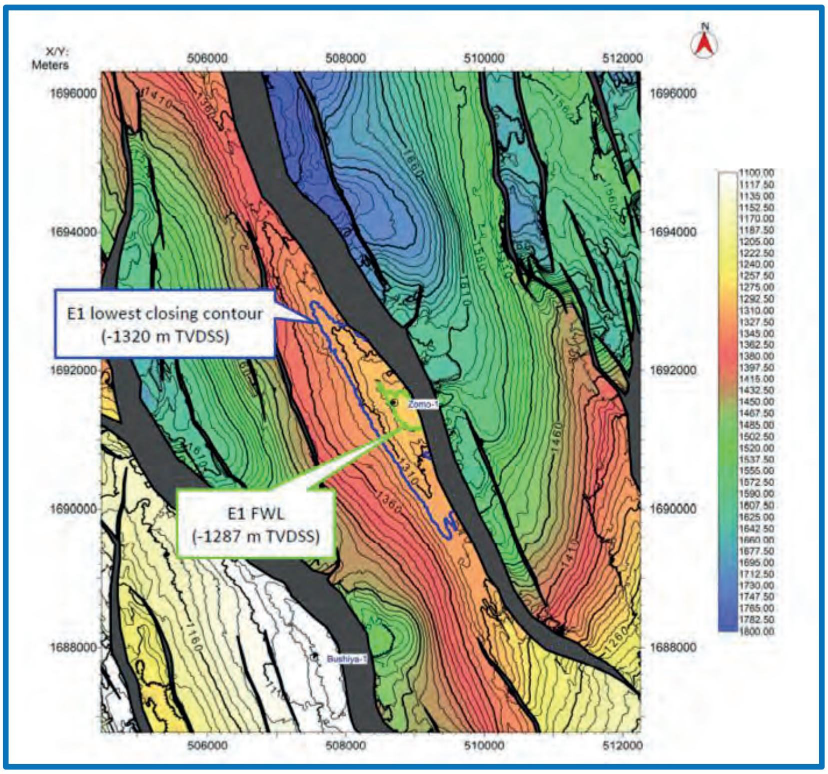



Figure 3-13 Zomo E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

## 3.5 Prospects and Leads

The high discovery rate (>80% including the Savannah discoveries) within the Eocene Sokor Alternances demonstrates the richness of the basin. The discoveries follow two trends of rift-related tilted fault blocks on either side of the main rift and merge into one zone at the southern end. The central part of the main rift, across the R2 area, has less faulting of Oligocene-Miocene age, and has not been as extensively explored. This area could contain more subtle larger traps, especially in the Cretaceous intervals.

Within the Sokor Alternances, the main risk is the fault seal which requires sand/shale juxtaposition. The historical drilling show that within this interval, there is sufficient shale in the section to result in there being a high chance that there will be sand against shale in at least one of the sands, which the high success rate validates. Variations in fault throw could result in restricting trap size on any given sand interval, but this could result in increasing the area of seal in one of the other sands. In the R3 area, there are five Sokor Alternances sand intervals (E1 through E5) thus maximising the chance of success. R3 East lies within the western fault and discovery trend, as can be seen in **Figure 2.4**. The R3 Central area has only 2D coverage and thus the Sokor Alternances Formation has to be treated as a single unit, for the purposes of volumetric calculation, as the individual sand intervals cannot be seismically defined.

As noted in **Section 3.3.1**, the overlying Upper Sokor sands are usually offset from the crest of the Sokor Alternances, by virtue of the configuration of the fault block. As most exploration wells in the basin have been vertical, and have targeted crests at the Sokor Alternances, closures at the Upper Sokor level have been frequently been missed by the drill bit. Closures at the Upper Sokor are thus valid exploration targets, and these traps have a better chance of sealing faults. In the future, Savannah aims to design its exploration wells in such a way to evaluate multiple targets at both stratigraphic levels in a single well bore.

The older parts of the Cretaceous Yogou Formation have not been widely targeted by earlier operators and thus this represents a target in areas where it is shallow enough. Several discoveries have been made in the Upper Yogou around the basin.

There have been numerous seismic programs in the area, comprising 2D lines of various vintages and modern 3D, as shown in **Figure 3-14**. The 3D surveys relevant to this review of the prospects are the R3 East 3D and the Dinga 3D, as outlined in red in **Figure 3-15**. The eleven prospects and leads reviewed by CGG are presented in **Figure 3-16.**

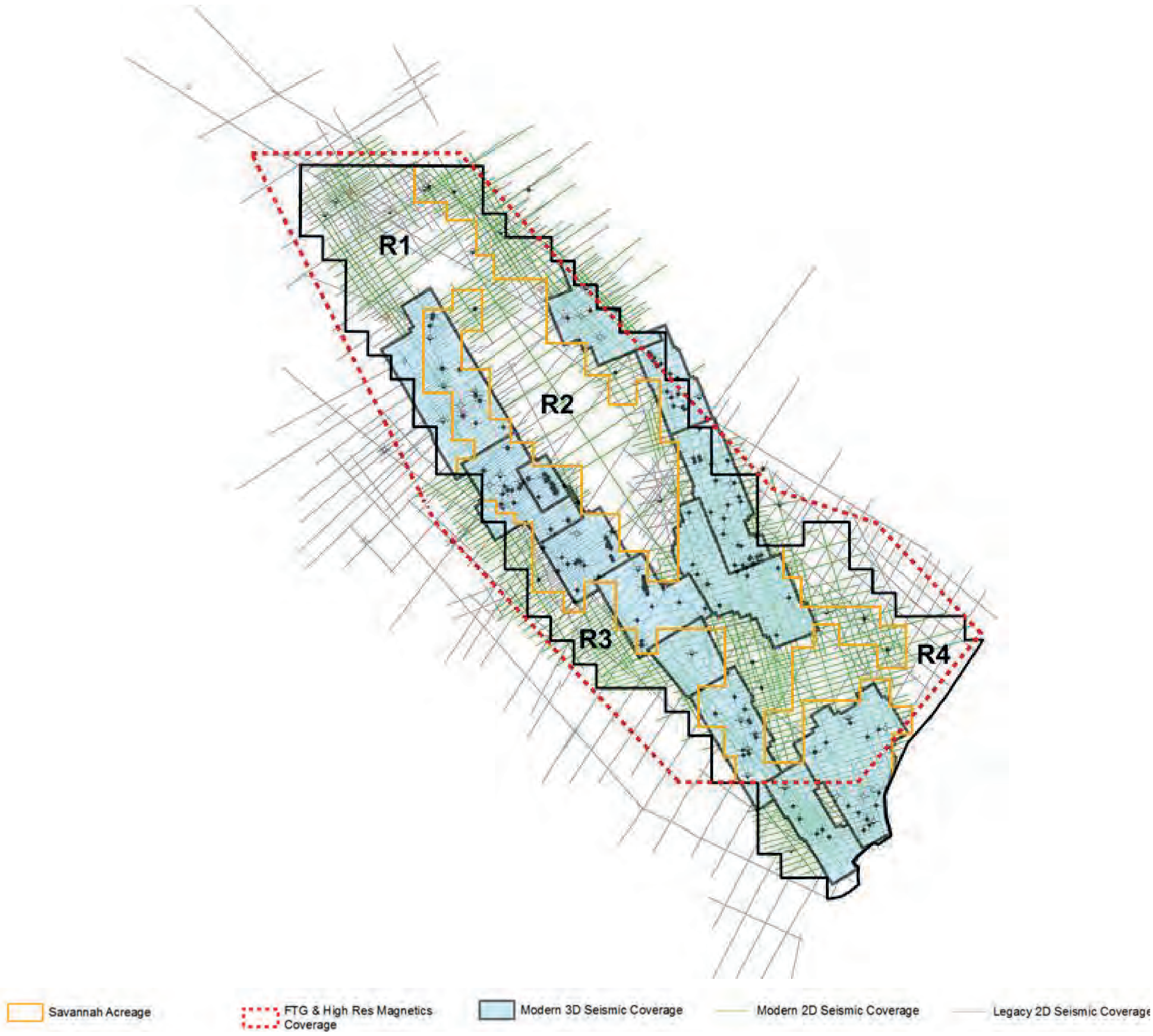



Figure 3-14 Seismic coverage in the Agadem Rift Basin *(Source: Savannah, 2019)*

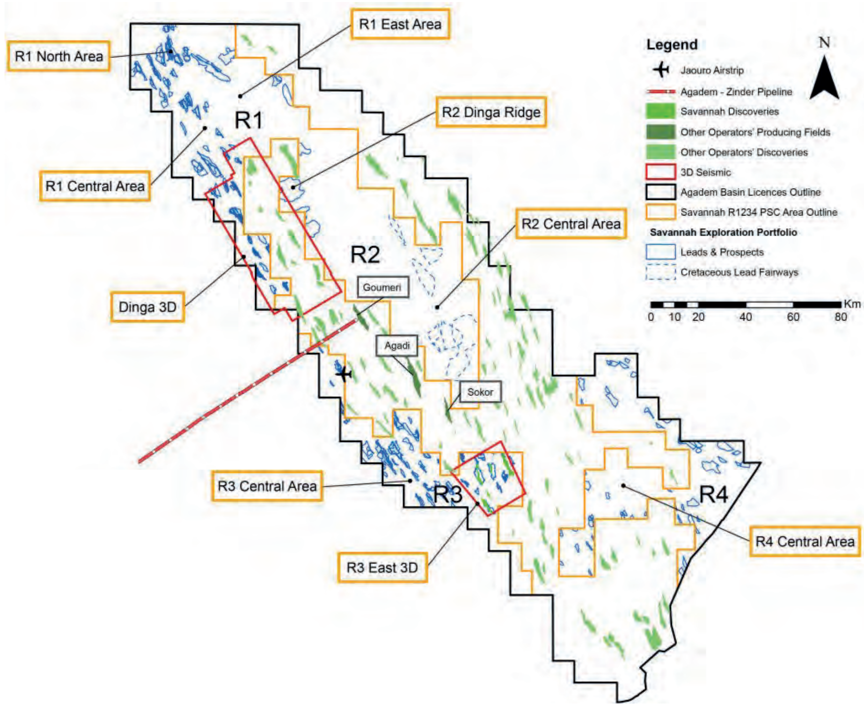



Figure 3-15 Savannah Prospects and Leads Portfolio with discovered fields and relevant 3D surveys (*Source: Savannah, 2021*)

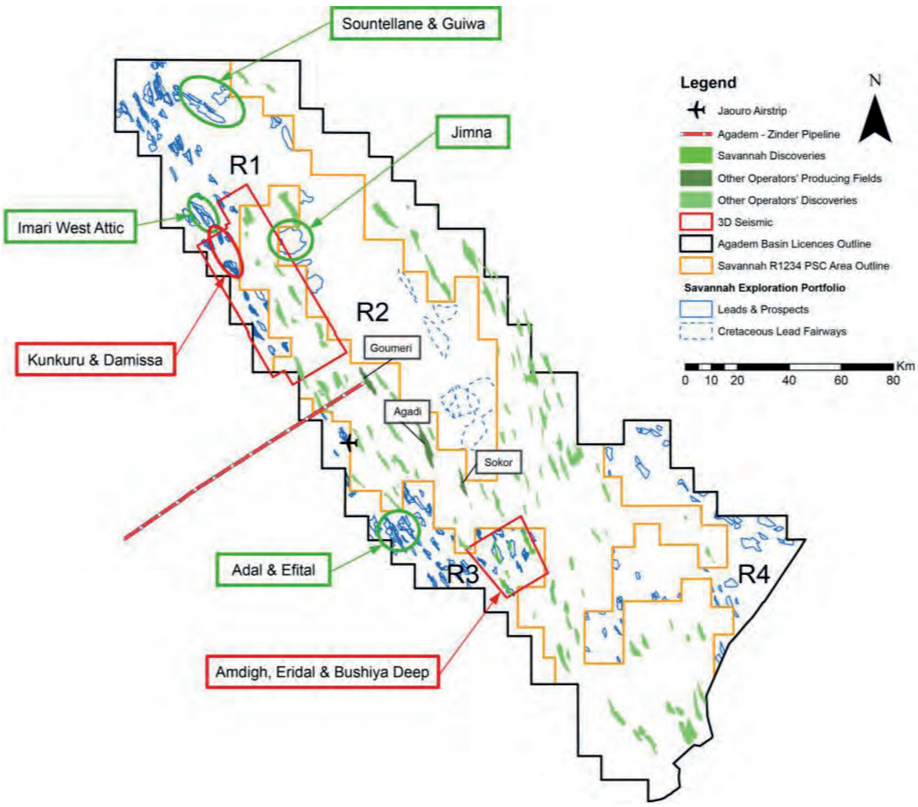



Figure 3-16 Map showing Prospects and Leads assessed by CGG (*Source: Savannah, 2021*)

# 4 RESOURCE ESTIMATION

## 4.1 Discoveries

CGG has estimated STOIIP and Resource volumes for the five discoveries resulting from Savannah's 2018 exploration drilling campaign. Based on the data provided, CGG made an independent estimation of the STOIIP with its own methodology to verify the estimated volumes of oil proposed by Savannah.

While visiting Savannah's offices (Data Room accessed 11th November 2019), CGG were provided access to the seismic data of the R3 East 3D survey in Kingdom™ in order to verify the seismic interpretation and confirm the closure polygon areas selected for each discovery as inputs for the volumetric calculations.

Currently the depth conversion for the discoveries is based on the pre-drill depth map which has had a uniform shift applied for each individual discovery interval to tie the grid to the wells. A PSDM volume has now being interpreted, which has used the velocity information at the wells and better constrains the geometries of the discoveries. Update of the Contingent Resources for all discoveries based on PSDM seismic data is pending further work by Savannah.

Based on those structural maps, a series of Area-Depth tables were created by Savannah to use in their calculations for each discovery, reservoir and in the case of Amdigh even for each segment. These were used to estimate the Gross Rock Volume (GRV).

Additionally, the volumetric estimations performed by Savannah for each discovery and reservoir levels were made available which included all input parameters.

CGG have carried out an independent review of the available data to perform their own estimations of the in-place volume ranges. The results show an overall match between the two estimations. The alteration of the distributions generally leads to a slightly wider range of values but overall, only minor differences are observed.

The results of CGG estimations are summarised in the following tables:

| Discovery | STOIIP (MMstb) | | |
|---|---|---|---|
| | P90 | P50 | P10 |
| Amdigh | 31.3 | 65.9 | 254.3 |
| Eridal | 18.5 | 22.3 | 25.8 |
| Bushiya | 14.5 | 22.0 | 39.2 |
| Kunama | 8.0 | 14.9 | 28.1 |
| Zomo* | | 0.7 | |
| **Total**** | **72.4** | **125.1** | **347.4** |

* Single deterministic case only

** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Table 4-1 STOIIP to be developed by Discovery

It should be noted that in the case of Amdigh, only segments 1, 2 and 3 are assumed to be developed in the low and best cases. Therefore, **Table 4-1** does not include all the STOIIPs for the P90 and P50 cases. The total STOIIP for Amdigh including all segments is 43.6 MMstb, 89.4 MMstb and 254.3 MMstb in the P90, P50 and P10 cases, respectively. Amdigh's STOIIP estimate show the discovery to be one of the ten largest in the basin.

| Discovery | Contingent Resources (MMstb) | | |
|---|---|---|---|
| | 1C | 2C | 3C |
| Amdigh | 7.2 | 18.4 | 83.9 |
| Eridal | 4.3 | 6.2 | 8.5 |
| Bushiya | 3.3 | 6.2 | 12.9 |
| Kunama | 1.8 | 4.2 | 9.3 |
| Zomo* | | 0.2 | |
| **Total**** | **16.7** | **35.0** | **114.6** |

* Indicative Resources pending PSDM evaluation

** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Table 4-2 Gross Contingent Resources

## 4.2 Prospects and leads

CGG has reviewed eleven exploration prospects and leads from Savannah's portfolio. The principal conclusions of our review of these prospects and leads are that: (1) the methodology used by Savannah to estimate gross mean Unrisked Prospective STOIIP volumes on these prospects and leads has been assessed as reasonable; (2) in aggregate, the structural prospects in the Alternances CGG assessed are seen as carrying a low exploration risk profile (i.e. carrying a similar risk profile to those drilled elsewhere in the basin to-date).

The basis for sand thickness, porosity, oil saturation and FVF values were all found to be reasonable. Minimum and maximum areas of accumulation were, in almost all cases, also found to be reasonable, or were slightly modified by CGG for this review. The known traps are not filled to-spill. The geological implications of this are discussed further in the discussion of "yet-to-find".

This review was undertaken to provide an independent validation of Savannah's numbers, as such a simplified version of the Savannah pay thickness approach was adopted, so that any differences in geological interpretation can be more readily compared.

The CGG depositional model summarised in **Section 3.2**, implies that "layer cake" geometries may apply to many of the reservoirs. **Section 5.3** describes CGG's engineering-based evaluation of Recovery Factor ranges that are considered reasonable for the basin. Both approaches suggest that Recovery Factors could be relatively high. CGG has concluded that a Recovery Factor of 28% should be used as a "Mid Case" for the purposes of this evaluation.

The existence of a stratigraphic play or plays across the basin could add a significant amount of potential resource, particularly in those areas where structural trapping and fault density are less apparent. Potential stratigraphic traps can be demonstrated to exist over large areas where sand distribution is likely to be controlled by subtle changes in thickness, facies type and topography. This is particularly the case where up-dip pinchouts have been mapped by Savannah, such as the Yogou interval across large parts of the R2 portion of the Licence area.

### 4.2.1 Geological uncertainty

CGG is generally in agreement with Savannah's mapping of prospects and leads in terms of minimum and maximum closure areas. When CGG's maximum closure areas are run on a fill-to-spill basis, the resulting unrisked STOIIP's are much larger than expected from Savannah's field size distribution for the basin. This supports the concept that many of the traps in the upper levels of the petroleum system in the Agadem Rift Basin may not be filled to-spill, and justifies Savannah's approach to mapping accumulation areas.

Savannah's proprietary geochemical modelling made available to CGG shows that the source systems in the Agadem Rift Basin started generating oil relatively recently: Donga and Yogou - mid Cenozoic to present day, base Sokor - Miocene to present day and main body of the Sokor section - Miocene to present day (but confined to the Dinga Trough). The modelled volumes of oil expelled are very large, at up to: 60 mmbbl/km$^2$ (Donga), 80 mmbbl/km$^2$ (Lower Yogou), 97 mmbbl/km$^2$ (Top Yogou), 50 mmbbl/km$^2$ (Base Sokor), 30 mmbbl/km$^2$ (Sokor in the Dinga Trough).

These volume estimates suggest that the basin has generated far more oil than is required to fill the traps to-spill. There are two possible explanations for why the traps are not filled to-spill. First, despite the relatively recent timing of oil generation, much of the oil may have leaked to surface. If this was the case, a high proportion of the wells drilled to-date would have encountered oil or bitumen whilst drilling through the shallow section. In the data reviewed, only six of the many wells drilled in this basin are reported to contain oil accumulations in the Upper Sokor and shallower section. However, the vast majority of the Upper Sokor penetrations were not drilled in closure and therefore this play remains largely under-explored.

CGG therefore considers the interpreted lack of fill-to-spill at individual traps to be due either due to leakage through the fault seals to traps at higher levels, or because of charge limitations. The charge limitations seem likely to be due either to the position of the trap on local migration pathways or due to retention of oil at deeper levels.

The importance of recognising that the traps are probably larger than the mapped accumulations becomes significant when considering yet-to-find in the deeper parts of the basin, where seals are likely to be better and the traps are closer to the mature source systems. Consequently, the deeper traps are more likely to be filled to-spill where charge volumes are adequate.

### 4.2.2 Risk factors

The standard industry methodology of assigning probabilities to the different components of the petroleum system has been employed. The product of these components then provides an estimate of the overall chance of successfully encountering hydrocarbons at the target (i.e. the geological chance of success).

Note that for the purposes of this evaluation, CGG defines a ‘target’ as a potentially hydrocarbon-filled trap at a specific stratigraphic level (e.g. Sokor Alternances or Upper Yogou). One prospect or lead may incorporate many stacked targets, and these may be evaluated by a single exploration well. Savannah has previously used the term ‘target’ in a different way to define the wrapped-up volume that incorporates all prospective reservoir intervals.

Most of the petroleum system elements are interpreted to be operating successfully for each prospect or lead. CGG considers that the greatest sources of risk at each target to be potential leakage through fault seals, and specific migration pathways/local charge volumes. In terms of the wrapped-up volume, the question of which target or targets will retain hydrocarbons represents uncertainty, not risk.

These elements are to some extent independent: geometries of juxtaposition of sand against shale, or the extent of shale smear on the fault, may mean that hydrocarbon is trapped in one target, whereas the seal for an underlying or overlying target may be breached.

In order to account for the multiple horizons in each prospect, the range of STOIIP and geological chance of success has been calculated for each target. These have then been combined probabilistically to derive an unrisked and risked distribution of STOIIP for each prospect.

The results from the five exploration wells confirm the prediction, both by CGG and Savannah, that the Alternances targets are low risk; oil was found in all five wells in this interval. The shallower level Upper Sokor targets were predicted to be high risk, and oil accumulations were not found at this level in any of the five wells.

### 4.2.3 STOIIP and Prospective Resource estimation

The table below summarises CGG’s assessment of the STOIIP and Prospective Resources for the prospects and leads shown in **Figure 3-16**. This table only presents 11 out of 146 prospects and leads identified by Savannah. Recovery factors of 23%, 28% and 33% have been associated with the P90, P50 and P10 probabilistically derived STOIIP cases respectively, in order to calculate Recoverable Resources. The derivation of these recovery factors is explained in **Section 5.0**.

| Area | Prospect/lead | | STOIIP (MMstb) | | | |
|---|---|---|---|---|---|---|
| | | | P90 | P50 | P10 | Mean |
| R3 East | Bushiya Deep | Yogou Prospect | 8.0 | 27.3 | 68.1 | 33.6 |
| R3 East | Amdigh Deep | Yogou Prospect | 11.2 | 39.1 | 99.0 | 48.6 |
| R3 East | Eridal Deep | Yogou Prospect | 7.4 | 24.8 | 60.5 | 30.3 |
| R3 Central | Adal | Lead Total | 13.9 | 73.6 | 220.0 | 87.8 |
| R3 Central | Efital | Lead Total | 37.8 | 157.0 | 394.0 | 170.0 |
| R1 | Sountellane | Lead Total | 40.7 | 128.0 | 328.0 | 161.0 |
| R1 | Damissa | Prospect Total | 57.4 | 239.0 | 570.0 | 283.0 |
| R1 | Imari West Attic | Lead Total | 38.1 | 162.0 | 453.0 | 211.0 |
| R1 | Guiwa | Upper Sokor Lead | 28.2 | 107.0 | 272.0 | 132.0 |
| R1 | Kunkuru | Prospect Total | 8.2 | 37.3 | 94.9 | 45.6 |
| R2 | Jimna | Yogou Lead | 74.8 | 291.0 | 772.0 | 130.0 |
| **Total*** | | | **325.7** | **1286.1** | **3331.5** | **1332.9** |

* Arithmetic sum

*Notes:*

1. *The volumes for individual prospect and lead totals are calculated probabilistically*

Table 4-3 Unrisked STOIIP by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

| Area | Prospect/lead | | Unrisked Prospective Resources (MMstb) | | | | |
|---|---|---|---|---|---|---|---|
| | | | Gross | | | | |
| | | | Low Estimate | Best Estimate | High Estimate | Risk factor | Operator |
| R3 East | Bushiya Deep | Yogou Prospect | 1.8 | 7.6 | 22.5 | medium | Savannah |
| R3 East | Amdigh Deep | Yogou Prospect | 2.6 | 10.9 | 32.7 | medium | Savannah |
| R3 East | Eridal Deep | Yogou Prospect | 1.7 | 6.9 | 20.0 | medium | Savannah |
| R3 Central | Adal | Lead Total | 3.2 | 20.6 | 72.6 | medium | Savannah |
| R3 Central | Efital | Lead Total | 8.7 | 44.0 | 130.0 | medium | Savannah |
| R1 | Sountellane | Lead Total | 9.4 | 35.8 | 108.2 | medium | Savannah |
| R1 | Damissa | Prospect Total | 13.2 | 66.9 | 188.1 | low | Savannah |
| R1 | Imari W Attic | Lead Total | 8.8 | 45.4 | 149.5 | high | Savannah |
| R1 | Guiwa | Upper Sokor Lead | 6.5 | 30.0 | 89.8 | high | Savannah |
| R1 | Kunkuru | Prospect Total | 1.9 | 10.4 | 31.3 | low | Savannah |
| R2 | Jimna | Yogou Lead | 17.2 | 81.5 | 254.8 | high | Savannah |
| | **Total*** | | **74.9** | **360.1** | **1099.4** | | |

* Arithmetic sum

*Notes:*

1. *The volumes for individual prospect and lead totals are calculated probabilistically*

2. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
*Risk factor: low = > 75%, medium = 25% - 75%, high = <25%*

Table 4-4 Unrisked Prospective Resources by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

## 4.3 Yet-to-find analysis

The starting point for this analysis was the existing basin discovery density data which were then extrapolated into Savannah's acreage on the basis of structural domains. Using the available exploration data, CGG then estimated a geological adjustment factor to allow for variations within the structural domains that could affect prospect density and size. This includes lateral changes in fault density (which could affect prospect density in these predominantly structural traps) and vertical changes in structure and trap quality, that could result in different trap sizes from those in the Sokor Alternances (the discovery density data is derived almost entirely from drilling in the Sokor Alternances).

CGG then applied standard geological risking for Source, Reservoir, Charge, Trap and Preservation in order to estimate the chance of each play being successful in each structural domain in the Licence Area. **Table 4-5** summarises CGG's overall assessment of the Low, Best and High Case estimates, both unrisked and risked, for the R1234 Licence Area.

| | Gross Prospective Resources – "yet to find" (MMstb) | | | | | |
|---|---|---|---|---|---|---|
| | Unrisked | | | Risked | | |
| Licence | Low estimate | Best estimate | High estimate | Low estimate | Best estimate | High estimate |
| **R1234** | **2561** | **6801** | **9987** | **1000** | **2695** | **3868** |

Table 4-5 Unrisked and risked gross "Yet to Find" prospective resource estimates

Across the Licence Area as a whole, the estimated average play geological chance of success (GCOS) for the Alternances in exploration terms is high (>75%). The lower geological chance of success estimated for the other plays mostly reflects uncertainty due to the limited amount of properly targeted drilling of those levels, rather than specific negative geological information.

# 5 RESERVOIR ENGINEERING

The main objective of CGG's reservoir engineering work was to provide an independent assessment of Savannah's estimated recovery per well (EUR/well) and recovery factor estimation. The following sections summarise the analysis.

## 5.1 Discovery PVT Evaluation

PVT samples were taken in four of the 2018 R3 East discovery wells. Downhole samples were retrieved in all cases via the wireline RFT tool; the samples are summarised below in **Table 5-1**. Overall, the discovered oils are medium to light (24 º to 33 º API) with a low sulphur content (<0.5 wt. %).

| Indicator | Unit | Bushiya-1 | Amdigh-1 | Kunama-1 | Eridal-1 |
|---|---|---|---|---|---|
| Depth | mMD | 1476.8 | 1712.4 | 1673.8 | 1719.4 |
| E-Sequence | | E1 | E1 | E1 | E1 |
| Type | | Dead Oil | Dead Oil | Dead Oil | Dead Oil |
| Oil Density | g/cm$^3$ | 0.9078 | 0.8893 | 0.8861 | 0.8591 |
| Oil API @ 60ºF | °API | 24.2 | 27.5 | 28 | 33.0 |

Table 5-1 Summary of Downhole samples

Savannah has used the Corelab PVT laboratory analysis results, alongside knowledge of offset well oil characteristics from previous analogue studies, to construct PVT models for use in production modelling. These PVT models were constructed within the industry-standard Petroleum Experts MBAL software package. The PVT models were applied for modelling both within MBAL as well as Petroleum Experts PROSPER (well modelling). Oil properties within the PVT models were varied with pressure/temperature by utilising PVT correlations from the literature.

## 5.2 Discovery Reservoir modeling

Savannah have built a Material Balance model using Petroleum Experts MBAL software for the 2018 discoveries. This R3 East MBAL model has been utilised primarily to:

- Capture and collate the data collected as part of the 2018 drilling program and learnings from prior and ongoing studies of Agadem Rift Basin (ARB) analogues into a model of the discovered reservoirs
- Simulate development scenarios to capture a range of potential production outcomes
- Conduct sensitivities to key uncertainties – importantly STOIIP & aquifer strength

Production profiles created from this model have been based on all available data and are specific to the underlying reservoir, well and project constraint assumptions of the scenario, many of which are uncertain. In order to be able to improve the prediction of water influx rates and timing, type curves have been derived from analogue fields.

## 5.3 Recovery factor estimation

The recovery factor is the recoverable amount of hydrocarbon-initially-in-place, normally expressed as a percentage. CGG has reviewed the MBAL work that has been carried out by Savannah with investigated Recovery Factor Sensitivity based on varying Aquifer Strength and water injection strategy. In light of the previous work that has been done on recovery factor estimation in the pre well estimates and the review of analogy and Empirical correlations, the approach that has been used is viewed as reasonable. CGG has applied recovery factors presented in **Table 5-2** to the STOIIP figures to calculate recoverable volumes.

| Case | R.F. % |
|---|---|
| **Low** | 23.0 |
| **Mid** | 28.0 |
| **High** | 33.0 |

Table 5-2 Summary of recovery factor used for resource assessment

**Figure 5-1** shows the base case from the MBAL model used in the indicative economics which demonstrates that Savannah is being conservative in its approach to the development and expected Ultimate Recovery. CGG have reviewed the assumptions and inputs into the MBAL model and believes that it has been built in a through manner and does not overstate the potential from the discoveries given the uncertainties and lack of well test data at this time.

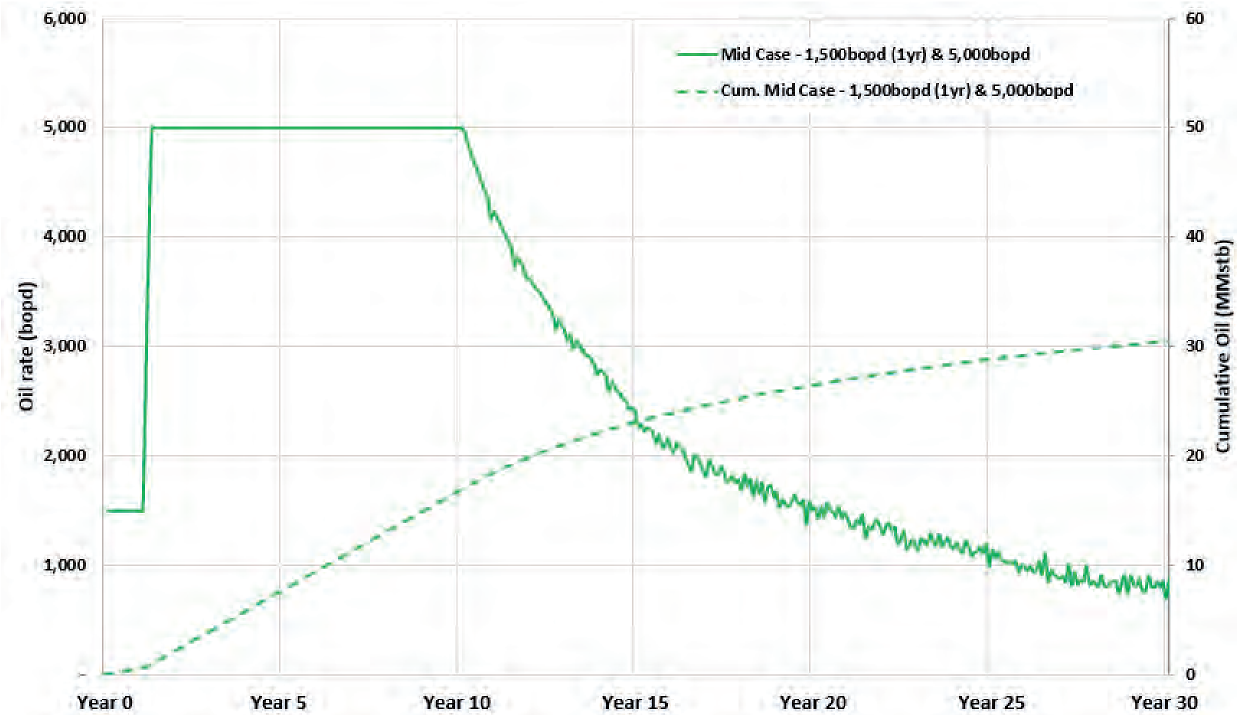



Figure 5-1 Base case Oil forecast for R3 East discoveries

# 6 DEVELOPMENT SCENARIOS

Savannah have prepared an early development scheme for exploiting the recent oil discoveries made by the company in the R3 East area. This development scheme is described and reviewed by CGG in the following sections.

Three fields (namely Goumeri, Sokor and Agadi) are on production in close proximity to the recent Savannah discoveries. CNPC currently sells domestically to the c. 20 kbpd capacity Zinder refinery, via the 463 km Agadem to Zinder domestic pipeline. The Société de Raffinage de Zinder (SORAZ) which operates the refinery, is a joint venture between CNPC (60%) and the Niger government (40%).

## 6.1 R3 East – Early Production Scheme

An Early Production Scheme has been proposed by Savannah, based on existing developments in the basin. The facility would be located at the Amdigh discovery, given its size and location relative to potential export routes. It is planned to develop the discoveries in two phases:

- Phase 1 – Early Production
- Phase 2 – Ramp-Up and Further Development

**Figure 6-1** outlines the key components of the scheme.

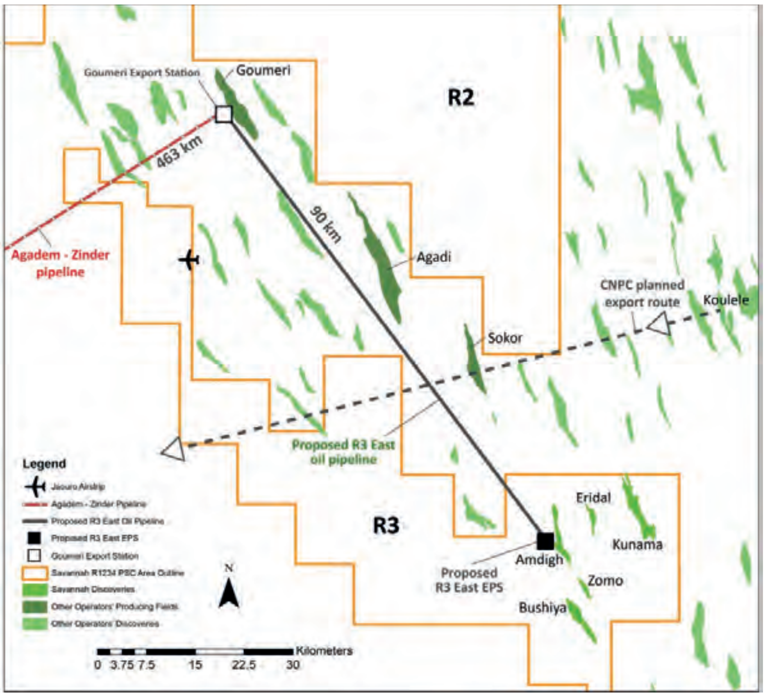



Figure 6-1 Proposed Early Production Scheme Development *(Source: Savannah, 2021)*

### 6.1.1 Phase 1 - Early Production

Phase 1 involves completion and production testing of Amdigh-1, Eridal-1, Bushiya-1 and Kunama-1 wells, with production processed using an EPF. Crude would then be exported via a planned c. 90km pipeline between the EPF and the Goumeri Export Station (GES). The crude would then be piped to the Zinder refinery (using the existing 463km Agadem to Zinder pipeline). Expected plateau rates are c. 1,500 bopd, which is scheduled after the completion of the well testing.

The key components of the Phase 1 development are detailed in **Figure 6-2** and **Figure 6-3**.

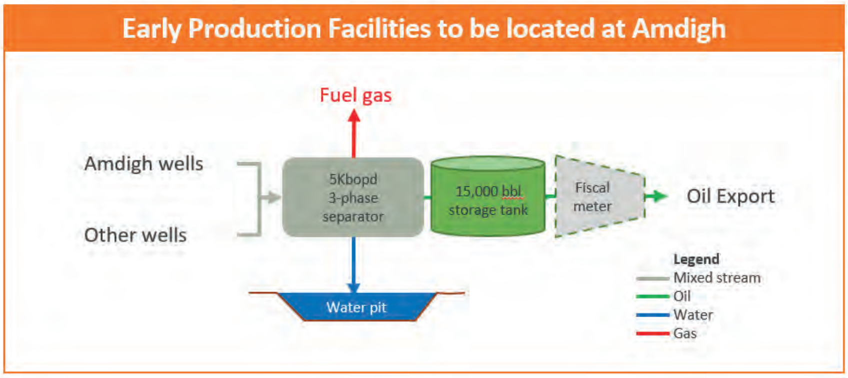



Figure 6-2 R3 East Early Production Facilities *(Source: Savannah, 2021)*

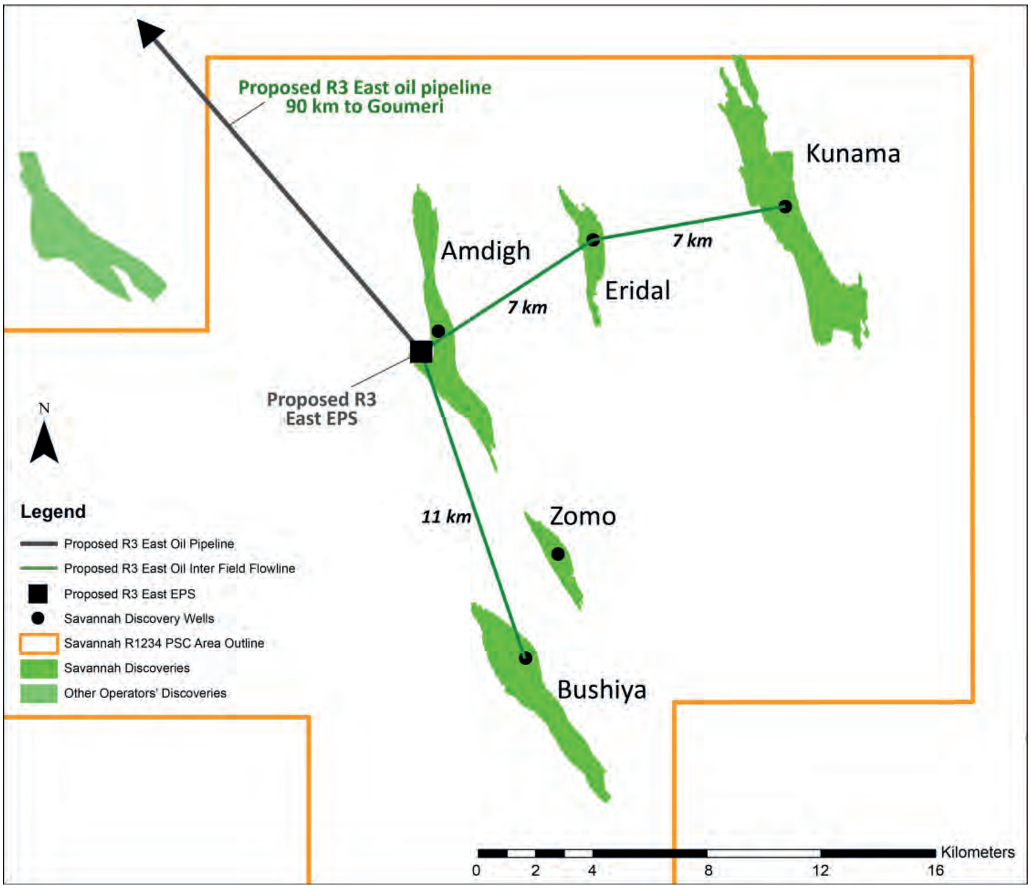



Figure 6-3 R3 East Early Production Development (Source: Savannah, 2021)

Total capital costs for Phase 1 have been estimated and are detailed in **Table 6-1**.

| Item | Cost, US$MM |
|---|---|
| Completion and production testing of Amdigh-1, Eridal-1, Bushiya-1 and Kunama-1 wells | 7.7 |
| EPF construction costs | 4.3 |
| Amdigh to Goumeri pipeline | 16.9 |
| Other Capex (e.g. flowline, export station, civil works) | 5.4 |
| **Total** | **34.3** |

Table 6-1 Phase 1 Capex Estimate

Operating costs for Phase 1 over the first year are estimated at US$0.5MM per month, consisting of EPF, pipeline, unloading station, water treatment and allocated in-country overhead costs. An additional US$0.02MM per month per well is estimated for pump fuel, water treatment of US$0.04MM per month and pipeline costs of US$0.9 per barrel.

Operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 20,000 bopd and a total annual cost of US$32.9MM per year. Based on the 5,000 bopd plateau rate, this equates to approximately US$0.68MM per month (equivalent to c. US$4.5 per barrel).

CGG has reviewed the proposed development solution and costs for Phase 1, and consider them to be reasonable.

### 6.1.2 Phase 2 – Ramp-Up and Further Development

After the initial production phase, further wells will be drilled to ramp up the production to 5,000 bopd, which will continue to be handled by the SORAZ refinery at Zinder. A simple water treatment facility will also be installed at Amdigh.

After the ramp up there will be additional cost associated with further drilling and intra field flowlines. This will create a gathering system to enable fields tested in Phase 1 to be fully developed and tied back to the Amdigh EPF.

Total capital costs for Phase 2 have been estimated and are detailed in **Table 6-2**. This cost will be spread over the full life of fields. The total external funding requirement for Phase 1 and 2, prior to the project becoming self-funding, is estimated at US$69.2MM (2021 prices).

| Item | Cost, US$MM |
|---|---|
| Production/Injection Development wells | 146.4 |
| Intra-field flowlines | 4.3 |
| Water treatment | 4.0 |
| **Phase 2 Total** | **154.7** |
| **Phase 1& 2 external funding requirement** | **69.2** |

Table 6-2 Phase 2 Capex Estimate

Operating costs for Phase 2 are estimated at US$0.5MM per month, consisting of EPF, pipeline, unloading station, water treatment and allocated in-country overhead costs. An additional US$0.02MM per month per well is estimated for pump fuel, water treatment of US$0.04MM per month and pipeline costs of US$0.9 per barrel.

Operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 20,000 bopd and a total annual cost of US$32.9MM per year. Based on the 5,000 bopd plateau rate, this equates to approximately US$0.68MM per month (equivalent to c. US$4.5 per barrel).

Abandonment costs are assumed to be 15% of Phase 1 and Phase 2 Capex.

CGG has reviewed the proposed development solution and costs for Phase 2, and consider them to be reasonable.

## 6.2 Export Pipeline Construction

Existing production in the Agadem Rift Basin (ARB) is currently transported through a 463 km pipeline to the domestic refinery at Zinder, located in the south of Niger. However, as the refinery has an approximate nominal capacity of only 20,000 bopd, an alternative evacuation route is required in order to maximise production from within the ARB where up to 1 Bbbl of 2P Reserves have been proven by CNPC in the adjacent licences to Savannah.

To meet this requirement, in September 2019 CNPC signed a Transportation Convention with the government of Niger to construct a 2,000 km oil export pipeline running from Koulele in Agadem (near the R3 area) to Port Seme on the Atlantic coast in Benin (**Figure 6-4**) (1,298 km in Niger, 684 km in Benin). This is understood to be CNPC's largest cross-border pipeline and is estimated to cost in the region of US$7 billion. The new international Niger-Benin export pipeline is expected to be completed in 2022.

Under the terms of the R1234 PSC, Savannah has access to Third Party infrastructure under terms that guarantee the owner a 12.5% return. On this basis Savannah estimate that the pipeline tariff would be in the order of US$14 per barrel in 2021 terms.

The development schemes for Savannah's discoveries to-date outlined in this report, do not assume usage of this export pipeline. However, due to its proximity to the R3 East discoveries and Savannah adjacent prospects, it does offer an alternative route to realise the full potential of Savannah's assets.

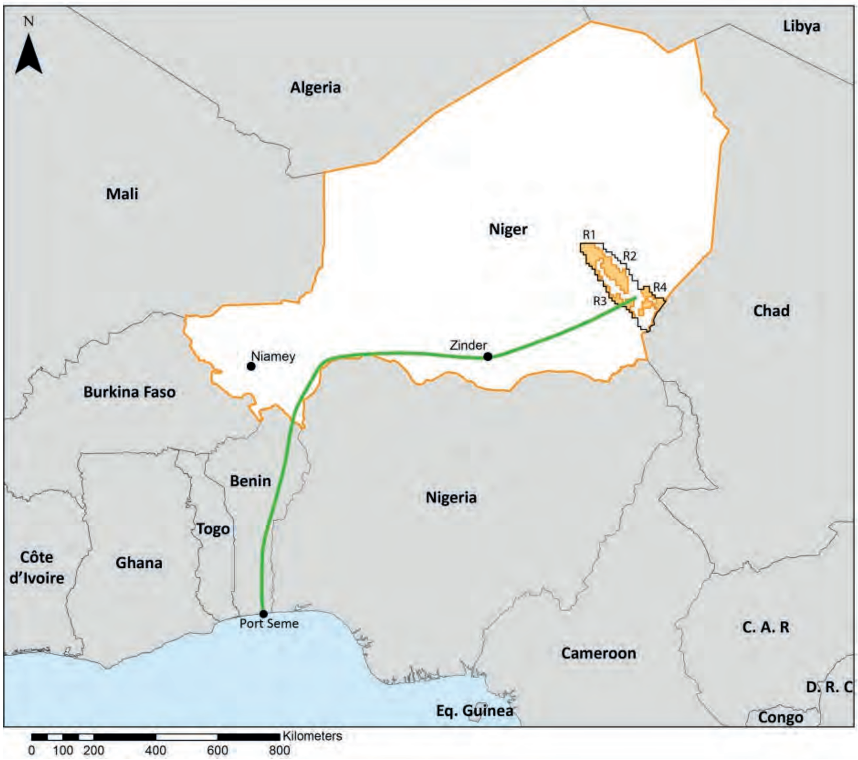



Figure 6-4 Proposed Route of Niger to Benin Export Pipeline *(Source: Savannah, 2021)*

# 7 INDICATIVE ECONOMICS

## 7.1 Methodology

Net Present Values (NPVs) have been calculated using Savannah's Excel™ economic model of the R1234 PSC. The model has been subject to a high-level review by CGG, and found to be in agreement with the fiscal and commercial terms applicable to the contract area.

## 7.2 Input assumptions

The previous R1/R2 and R3/R4 Licence Areas were originally subject to separate Production Sharing Contracts (PSCs) between Savannah Energy Niger (the Contractor) and the Republic of Niger. Savannah has agreed with the Ministry of Petroleum to amalgamate the four licence areas (covered by the previous R1/R2 PSC and the R3/R4 PSC) into a single PSC. The new PSC (being a R1234 PSC) will be valid for up to 10 years from the date of signing the agreement. Savannah has a 95% Contractor interest in the PSC.

The key terms of the amalgamated PSC as understood by CGG are presented in the following sections.

#### 7.2.1.1 Signature bonus:

A signature bonus of US$1.0MM will be payable on signing the amalgamated PSC.

#### 7.2.1.2 Royalties:

There is an oil royalty of 12.5% levied on the gross sales revenue less pipeline transportation costs.

#### 7.2.1.3 Cost Oil:

Exploration, capital, and operating costs can be recovered from 70% of gross revenues less royalties. Unrecovered costs in any year can be carried forward. There are approximately US$190MM of historic costs available for recovery at the valuation date.

#### 7.2.1.4 Profit oil:

Profit oil is shared between the State and Savannah depending on the value of an R-factor as shown in **Table 7-1**. The R-factor is calculated as follows:

*(cumulative cost and profit oil less exploitation costs)/ (cumulative exploration and capital costs)*

| R-Factor | Contractor | State |
|---|---|---|
| < 1.0 | 60% | 40% |
| 1.0 – 1.49 | 55% | 45% |
| 1.5 -1.99 | 50% | 50% |
| > 2.0 | 45% | 55% |

Table 7-1 Profit Oil rates

#### 7.2.1.5 Corporation tax:

No corporation tax is payable in Niger.

#### 7.2.1.6 State participation:

The state has back-in rights to 15% of the Contractor's share of profit oil.

### 7.2.2 Oil prices

It is understood from Savannah that currently, production from the ARB is sold to the SORAZ refinery at a government agreed fixed price of US$42 per barrel. When the CNPC Niger-Benin export pipeline is completed, it is expected that the domestic price will achieve parity with the price of exported crude. It is therefore assumed that at this point the refinery gate price achieved by Savannah will be equivalent to the Brent price less a discount of US$9.5 per barrel to account for the expected export and domestic pipeline transportation costs. Production start-up is currently expected post-completion of the Niger-Benin export pipeline.

The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

Sensitivity cases at fixed prices of US$50/bbl, US$60/bbl, US$70/bbl, US$80/bbl, US$90/bbls and US$100/bbl have also been analysed, with the price inflated at 2% per year from January 2022.

### 7.2.3 Other

Other assumptions used by CGG in the economic evaluation are tabulated below.

| Parameter | Value |
|---|---|
| Discount Factor | 10% |
| Discount Methodology | Monthly |
| Cost Inflation | 2% per annum |
| Discount Date | 1st October 2021 |

Table 7-2 Other assumptions

## 7.3 Results

Indicative economics have been determined for the 2C resource case. The economics presented are net to Savannah's 95% interest.

| Case | 2C |
|---|---|
| NPV0 (US$MM) | 443.3 |
| NPV10 (US$MM) | 150.2 |
| NPV10/bbl (US$) | 6.4 |

*Notes*

1. *NPVs are based on net economic production to Savannah of 23 MMstb and post 15% government back-in right*

Table 7-3 Indicative economics (net Savannah) for Discoveries

NPV10 sensitivities have also been performed on costs and oil price. The results of this analysis are tabulated below.

The break-even refinery gate oil price, which would enable Savannah to generate a 10% IRR on the development would be approximately US$30/bbl, assuming costs at this oil price level would be reduced by at least 20% from those prevailing at US$60/bbl. CGG has assessed this assumption and considers it to be reasonable.

As a further sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately US$100MM net to Savannah.

| Case | 2C |
|---|---|
| Base case | 150.2 |
| +15% factor on costs | 122.3 |
| -15% factor on costs | 176.7 |
| Oil price - US$50/bbl | 70.4 |
| Oil price - US$60/bbl | 142.0 |
| Oil price - US$70/bbl | 197.4 |
| Oil price - US$80/bbl | 498.9 |
| Oil price - US$90/bbl | 297.3 |
| Oil price - US$100/bbl | 344.0 |
| Production volume +25% | 214.1 |
| Year 1 production 2,500 bopd | 156.9 |

Table 7-4 Sensitivities for Indicative Economics (NPV10 net to Savannah, US$MM)

# 8 APPENDIX A: DEFINITIONS

## 8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

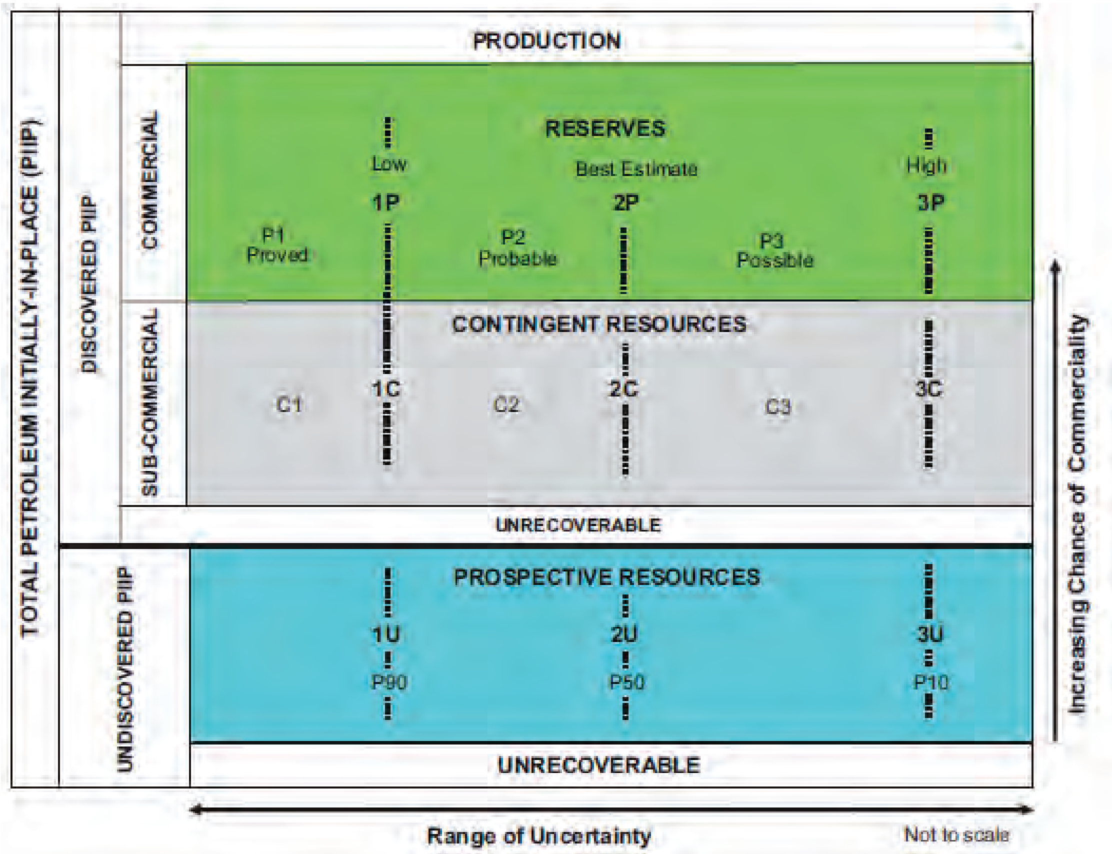



Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

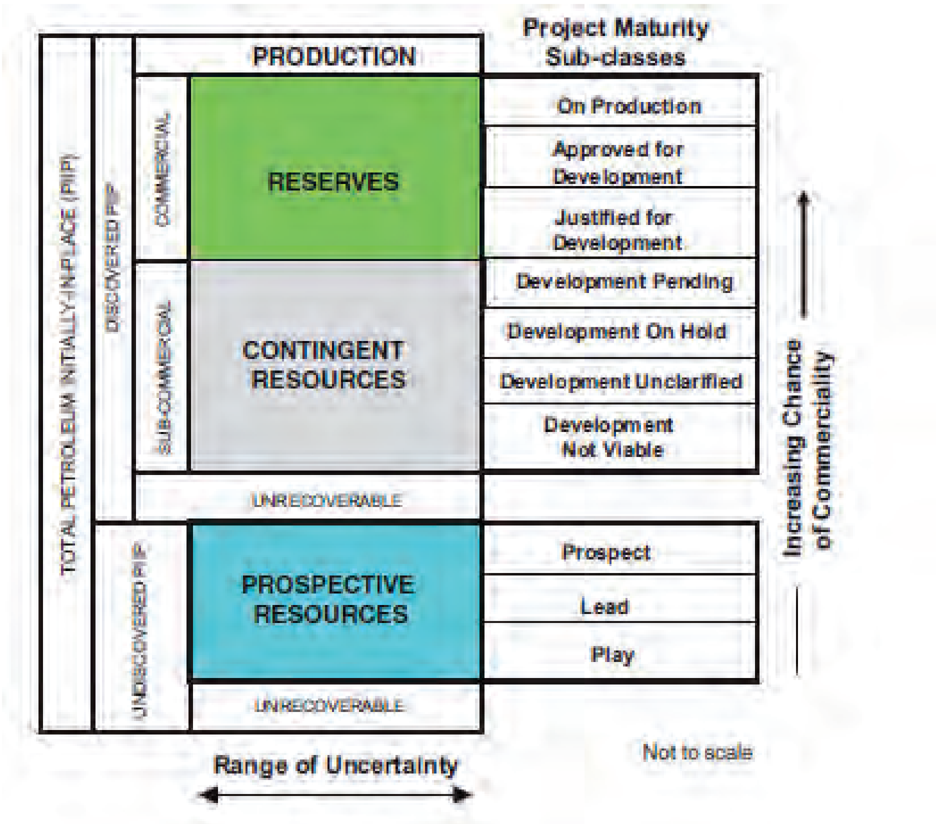



Figure 8-2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

### 8.1.1 Total Petroleum Initially-In-Place

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.

### 8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

### 8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

## 8.2 Production

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.

## 8.3 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 (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), 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.

### 8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

### 8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

### 8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(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

(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

### 8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

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 that the quantities actually recovered will equal or exceed the estimate.

### 8.3.5 Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

### 8.3.6 Possible Reserves

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest 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) Reserves, which is equivalent to the high-estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

## 8.4 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.

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.

Projects classified as Contingent Resources have their sub-classes aligned with the entity’s plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

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.

1C denotes low estimate scenario of Contingent Resources

2C denotes best estimate scenario of Contingent Resources

3C denotes high estimate scenario of Contingent Resources

### 8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

### 8.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are 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.

### 8.4.3 Contingent Resources: 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.

### 8.4.4 Contingent Resources: 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.

## 8.5 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.

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources

2U denotes best estimate scenario of Prospective Resources

3U denotes high estimate scenario of Prospective Resources

### 8.5.1 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.

### 8.5.2 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.

### 8.5.3 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.

### 8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

# 9 APPENDIX B: NOMENCLATURE

| | |
|---|---|
| 1D, 2D, 3D | 1-, 2-, 3-dimensions |
| 1P | proved |
| 2P | proved + probable |
| 3P | proved + probable + possible |
| API | American Petroleum Institute |
| av. | Average |
| bbl | barrel |
| bbl/d | barrels per day |
| BHP | bottom hole pressure |
| BHT | bottom hole temperature |
| boe | barrel of oil equivalent |
| Bscf | billion standard cubic feet |
| BV | bulk volume |
| c. | circa |
| $CO_2$ | carbon dioxide |
| DHI | direct hydrocarbon indicators |
| DST | drill-stem test |
| E & P | exploration & production |
| E | East |
| e.g. | for example |
| EOR | enhanced oil recovery |
| ESP | Electrical Submersible Pump |
| et al. | and others |
| EUR | estimated ultimately recoverable |
| ftMD | feet measured depth |
| ftss | feet subsea |
| G & A | general & administration |
| G & G | geological & geophysical |
| $g/cm^3$ | grams per cubic centimetre |
| Ga | billion ($10^9$) years |
| GIIP | gas initially in place |
| GOC | gas-oil contact |
| GOR | gas to oil ratio |
| GR | gamma ray (log) |
| GWC | gas-water contact |
| $H_2S$ | hydrogen sulphide |
| HI | hydrogen index |
| IOR | improved oil recovery |
| IRR | internal rate of return |
| kg | kilogram |
| km | kilometre |
| $km^2$ | square kilometres |
| LST | lowstand systems tract |
| LVL | low-velocity layer |
| M & A | mergers & acquisitions |
| m | metre |
| M | thousand |
| m/s | metres per second |
| Ma | million years (before present) |
| Mbbl/d | thousands of barrels per day |
| mD | millidarcies |
| MD | measured depth |
| MM | million |
| MMbbl | million bbls of oil |
| MMboe | million bbls of oil equivalent |
| MMscfd | million standard cubic feet per day |
| MMstb | million stock tank barrels |
| Mscfd | thousand standard cubic feet per day |
| msec | millisecond(s) |
| MSL | mean sea level |
| mSS | metres subsea |
| N | north |
| NaCl | sodium chloride |
| no. | number (not #) |
| NPV | net present value |
| Ø | porosity |
| OWC | oil-water contact |
| P & A | plugged & abandoned |
| perm. | permeability |
| pH | -log H ion concentration |
| plc | public limited company |
| por. | Porosity |
| ppm | parts per million |
| PRMS | Petroleum Resource Management System (SPE) |
| psi | pounds per square inch |
| RFT | repeat formation test |
| RT | rotary table |
| S | South |
| SCAL | special core analysis |
| scf | standard cubic feet |
| SPE | Society of Petroleum Engineers |
| SS | sub-sea |
| ST | sidetrack (well) |
| stb | stock tank barrel |
| std. dev. | standard deviation |
| STOIIP | stock tank oil initially in place |
| Sw | water saturation |
| Tscf | trillion standard cubic feet |
| TD | total depth |
| TVD | true vertical depth |
| TVDSS | true vertical depth subsea |
| TWT | two-way time |
| US$ | US dollar |
| US$MM | Millions of US dollars |
| VDR | virtual dataroom |

- 1 boe = 6000 scf
- 1 scm = 35.3147 scf

## PART 12

## ADDITIONAL INFORMATION

### 1 RESPONSIBILITY

1.1 The Company and its Directors (whose names and functions appear on page 12 of this document) accept responsibility, both individually and collectively, for the information contained in this document. To the best of the knowledge and belief of the Directors (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. All the Directors accept individual and collective responsibility for compliance with the AIM Rules.

1.2 CGG Services (UK) Limited, whose registered address is at CGG Crompton Way, Manor Royal Estate, Crawley, West Sussex RH10 9QN, accepts responsibility for its reports set out in Parts 9, 10 and 11 of this document. To the best of the knowledge and belief of CGG (which has taken all reasonable care to ensure that such is the case) the information contained in its reports are in accordance with the facts and do not omit anything likely to affect the import of such information.

### 2 INCORPORATION AND GENERAL

2.1 The Company was incorporated in England and Wales on 3 July 2014, under the name of Savannah Petroleum PLC (registered number 09115262), as a public limited company under the Act. The Company changed its name to Savannah Energy PLC on 16 April 2020.

2.2 The Company's registered office and its principal place of business is at 40 Bank Street, London E14 5NR (telephone number 0203 102 6897 or, if dialing from outside the United Kingdom, +44 203 102 6897).

2.3 The Company is domiciled in the United Kingdom.

2.4 The accounting reference date of the Company is 31 December and will remain so on Re-Admission.

2.5 The website address for the Company for the purposes of AIM Rule 26 is www.savannah-energy.com.

2.6 The principal legislation under which the Company operates is the Act.

2.7 On 22 July 2014, the Company obtained a certificate pursuant to section 761 of the Act entitling it to do business and borrow and on 1 August 2014, the Company's Ordinary Shares were admitted to trading on the AIM market operated by the London Stock Exchange plc.

2.8 The Company's auditors are BDO LLP, a firm of chartered accountants registered with the Institute of Chartered Accountants in England and Wales.

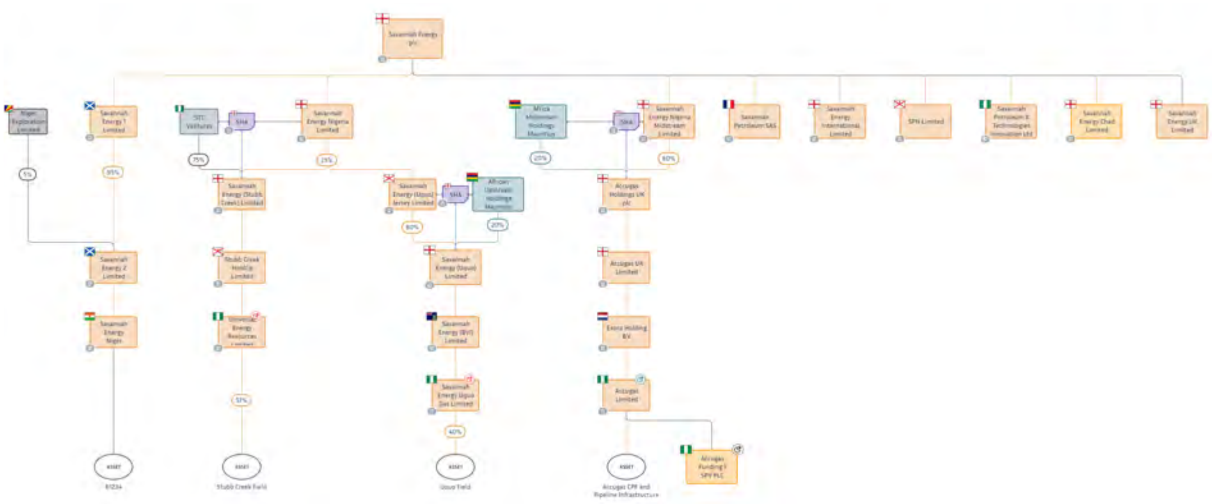
2.9 The Company is the ultimate holding company of the Existing Group and, from Completion, the Enlarged Group. On Restoration of the Existing Ordinary Shares to trading, the Company will have the following subsidiaries and other undertakings:

| *Name (Jurisdiction)* | *Registered Office* | *Principal Activity* | *Issued Share Capital* |
|---|---|---|---|
| Savannah Energy 1 Limited (Scotland – SC453751) | 50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ | Subsidiary company | 15,737,894 A1 ordinary shares of £0.000000001 each, two A2 ordinary shares of £0.000000001 each and 1,000,000,020 B ordinary shares of $0.000000001 each |

| *Name (Jurisdiction)* | *Registered Office* | *Principal Activity* | *Issued Share Capital* |
|---|---|---|---|
| Savannah Energy 2 Limited (Scotland – SC467099) | 50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ | Subsidiary company | 105,264 ordinary shares of $0.00001 each |
| Savannah Energy Niger S.A. (Niger-RCCM NI-NIA-2014-B1940) | 124 Rue des Ambassades AM-8, BP 11272, Niamey, Niger | Exploration and extraction of petroleum and natural gas | 1,000 shares of CFA 10,000 each |
| SPN Limited (Jersey – 117216) | 11 Bath Street, St Helier, Jersey, JE4 8UT | Subsidiary company | 10,000 limited liability shares of £1.00 each |
| Savannah Petroleum SAS (France – 811 283 043) | 3-5 Rue Saint-Georges, 75009, Paris, France | Services company | 1 share of €1.00 |
| Savannah Energy International Limited (England – 10344619) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1 ordinary share of £0.01 |
| Savannah Energy Nigeria Midstream Limited (England – 11685648) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1 ordinary share of $1.00 |
| Savannah Energy Nigeria Limited (England – 11290084) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1 ordinary share of $1.00 |
| Savannah Energy (Stubb Creek) Limited (England – 11309541) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 75 A ordinary shares of $1.00 each and 25 B ordinary shares of $1.00 each |
| Accugas Holdings UK plc (England – 11950135) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 62,502 ordinary shares of £1.00 each |
| Accugas UK Limited (England – 12257421) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 3 ordinary shares of £1.00 each |
| Exoro Holding B.V. (Netherlands – 27307262) | Fascinatio Boulevard 350, Rotterdam, 3065wb, Netherlands | Subsidiary company | 18,769 shares of €1.00 each |
| Accugas Limited (Nigeria – 881197) | 35 Kofo Abayomi Street, Victoria Island, Lagos State | Gas processing, marketing and distribution | 10,424,329 shares of NGN 1.00 each |
| Accugas Funding 1 SPV PLC (Nigeria – 1810276) | 35 Kofo Abayomi Street, Victoria Island, Lagos State | Subsidiary company | 100,000,000 shares of NGN 1.00 each |
| Stubb Creek Holdco Limited (Jersey – 128339) | 11 Bath Street, St Helier, Jersey, JE4 8UT | Subsidiary company | 302 shares of $0.01 each |

| *Name (Jurisdiction)* | *Registered Office* | *Principal Activity* | *Issued Share Capital* |
|---|---|---|---|
| Universal Energy Resources Limited (Nigeria – 429120) | 25 Idoro Road, Uyo, Akwa Ibom State, Nigeria | Exploration and extraction of petroleum and natural gas | 480,000,000 shares of NGN 1.00 each |
| Savannah Energy (Uquo) Jersey Limited (Jersey – 130188) | 11 Bath Street, St Helier, Jersey, JE4 8UT | Subsidiary company | 3 shares of $1.00 each |
| Savannah Energy (Uquo) Limited (England – 12292632) | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1,250 ordinary shares of $0.001 each |
| Savannah Energy (BVI) Limited (British Virgin Islands – 1032686) | Midocean Chambers PO Box 805, Road Town, Tortola, British Virgin Islands | Subsidiary company | 56,068,924 class no. 1 ordinary shares with no par value |
| Savannah Energy Uquo Gas Limited (Nigeria – 659675) | 35 Kofo Aboyomi Street, Victoria Island, Lagos, Nigeria | Exploration and extraction of petroleum & natural gas | 100,000,000 shares of NGN 1.00 each |
| Savannah Petroleum & Technologies Innovations Ltd (Nigeria – 1399618) | 18/24 Ajisegiri Str, Oshodi, Lagos | Subsidiary company | 10,000,000 shares of NGN 1.00 each |
| Savannah Energy Chad Limited | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1 ordinary share of $1.00 |
| Savannah Energy UK Limited | 40 Bank Street, London, United Kingdom, E14 5NR | Subsidiary company | 1 ordinary share of $1.00 |

2.10 A structure chart showing the principal members of the Group is shown below:



2.11 The Company owns 98 per cent. of the issued share capital of SE1L. The remaining two per cent. is owned by directors and current and former senior employees of the Group pursuant to the 2014 LTIP, described in paragraph 4.

2.12 The Company owns indirectly:

2.12.1 (via SE1L) 100,000 ordinary shares in the capital of SE2L, and Niger Exploration is the holder of 5,264 ordinary shares in the capital of SE2L. The articles of association of SE2L contain a "drag-along" provision pursuant to which SE1L can force Niger Exploration to sell its shares in SE2L in the event SE1L is selling the shares that it owns in SE2L. Niger Exploration is 95 per cent. beneficially owned and 100 per cent. controlled by Yacine Wafy, the Group's Vice President for West Africa; Savannah Niger is a wholly owned subsidiary of SE2L.

2.12.2 (via Savannah Energy Nigeria Limited) 25 B ordinary shares in the capital of Stubb Creek Topco and STC Joint Venture Limited is the holder of the other 75 A ordinary shares in the capital of Stubb Creek Topco. The shareholders' agreement between Savannah Energy Nigeria Limited and STC Joint Venture Limited is described in paragraph 10.6 of Part 14 of this document; and

2.12.3 (via Savannah Energy Nigeria Midstream Limited) 50,002 ordinary shares in Accugas Holdings UK plc and Africa Midstream Holdings Mauritius (a subsidiary of AIIM) is the holder of the other 12,500 ordinary shares in issue. Accugas UK Limited, Exoro Holdings B.V., Accugas Limited and Accugas Funding I SPV PLC are wholly owned subsidiaries of Accugas Holdings UK plc.

2.13 Savannah Niger, Accugas Limited, SEUGL and Universal Energy Resources Limited are the principal operating subsidiaries of the Group.

2.14 Following completion of the Exxon Acquisition, the Company will acquire, either directly or indirectly, the following principal subsidiary undertakings:

| *Name* | *Registered Office* | *Principal Activity* | *Issued Share Capital* | *Percentage Ownership* |
|---|---|---|---|---|
| Esso Exploration and Production Chad Inc. | Office Number 2 Pineapple Business Park, Nassau, Bahamas | Holding company | 2 ordinary shares | 100% |
| Esso Pipeline Investments Limited | Office Number 2 Pineapple Business Park, Nassau, Bahamas | Holding company | 1,000 common shares | 100% |
| Tchad Oil Transportation Company | Klemat 2e, Arrondissement | Trading company | 76,836 ordinary shares | 40.19% |
| Cameroon Oil Transportation Company | 164 Rue Toyota, Bonapriso, Douala, Cameroon | Trading company | 678,553 ordinary shares | 41.06% |

2.15 Following completion of the PETRONAS Acquisition, the Company will acquire, either directly or indirectly, the following principal subsidiary undertakings:

| *Name* | *Registered Office* | *Principal Activity* | *Issued Share Capital* | *Percentage Ownership* |
|---|---|---|---|---|
| PETRONAS Carigali Chad Exploration & Production Inc. | Maples Corporate Services Limited P.O. Box 309, George Town, Grand Cayman, Cayman Islands | Holding company | 2 ordinary shares | 100% |
| PETRONAS Carigali (Chad EP) Inc. | Maples Corporate Services Limited P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1 | Trading company | 2 ordinary shares | 100% |
| Doba Pipeline Investment Inc. | Maples Corporate Services Limited P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1 | Holding company | 2 ordinary shares | 100% |
| Tchad Oil Transportation Company | Klemat 2e, Arrondissement | Trading company | 76,836 ordinary shares | 30.16% |
| Cameroon Oil Transportation Company | 164 Rue Toyota, Bonapriso, Douala, Cameroon | Trading company | 678,553 ordinary shares | 29.77% |
| PETRONAS Chad Marketing Inc. | Maples Corporate Services Limited P.O. Box 309, George Town, Grand Cayman, Cayman Islands BW1 | Trading company | 2 ordinary shares | 100% |

## 3 SHARE CAPITAL

3.1 The share capital history of the Company from 1 January 2018 to the date of this document is as follows:

3.1.1 On 9 February 2018, 514,885,980 Ordinary Shares were issued.

3.1.2 On 26 June 2018, the English High Court confirmed the cancellation of the Company's share premium amount, which was effected by way of a special resolution of the Company dated 3 May 2018.

3.1.3 On 28 January 2019, 62,800,000 Ordinary Shares were issued for cash at an issue price of £0.28 per Ordinary Share.

3.1.4 On 14 November 2019, (i) 90,666,308 Ordinary Shares were issued for cash at a price of £0.24 per Ordinary Share; and (ii) 25,972,677 Ordinary Shares were issued for cash at a price of £0.28 per Ordinary Share.

3.2 For the purposes of implementing the Exxon Acquisition and the PETRONAS Acquisition, the following resolutions in connection with the Company's share capital will be proposed at the General Meeting in relation to the share capital of the Company:

3.2.1 that the Exxon Acquisition be and is hereby approved for all purposes, including, without limitation, for the purposes of Rule 14 of the AIM Rules for Companies published by the London Stock Exchange plc and that the Directors be and are hereby authorised to take all steps necessary or, in the opinion of the Directors, desirable, to give effect to the Exxon Acquisition, including without limitation, waiving, amending, varying or extending any of the conditions and terms of the Exxon Acquisition;

3.2.2 that the PETRONAS Acquisition be and is hereby approved for all purposes, including, without limitation, for the purposes of Rule 14 of the AIM Rules for Companies published by the London Stock Exchange plc and that the Directors be and are hereby authorised to take all steps necessary or, in the opinion of the Directors, desirable, to give effect to the PETRONAS Acquisition, including without limitation, waiving, amending, varying or extending any of the conditions and terms of the PETRONAS Acquisition;

3.2.3 that the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £416,010.62, such authority to expire at the next annual general meeting of the Company, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked);

3.2.4 that the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £58,066.96, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked);

3.2.5 that the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £101,114, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked);

3.2.6 that the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £23,853.46, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked);

3.2.7 that the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by the resolution set out in paragraph 3.2.3 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by the resolution set out in paragraph 3.2.3 above. This power shall cease to have effect when the authority conferred by the resolution set out in paragraph 3.2.3 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired;

3.2.8 that the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by the resolution set out in paragraph 3.2.4 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by the resolution set out in paragraph 3.2.4 above. This power shall cease to have effect when the authority conferred by the resolution set out in paragraph 3.2.4 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired;

3.2.9 that the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by the resolution set out in paragraph 3.2.5 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by the resolution set out in paragraph 3.2.5 above. This power shall cease to have effect when the authority conferred by the resolution set out in paragraph 3.2.5 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired; and

3.2.10 that the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by the resolution set out in paragraph 3.2.6 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by the resolution set out in paragraph 3.2.6 above. This power shall cease to have effect when the authority conferred by the resolution set out in paragraph 3.2.6 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired.

3.3 The Company's issued fully paid share capital as at the date of this document is, and on Re-Admission will be, as follows:

| | *Present* | | *Immediately following Re-Admission*[(1)] | |
|---|---|---|---|---|
| | *Number* | *Nominal Value* | *Number* | *Nominal Value* |
| Issued and fully paid | 996,408,412 | £996,408.41 | 1,306,098,819 | £1,306,098.82 |

(1) Assumes Re-Admission will be of the Further Enlarged Share Capital.

3.4 The net asset value of an Ordinary Share as at 30 June 2021 was approximately 17.1 pence (the "Net Asset Value Per Share").

3.5 The Ordinary Shares in issue on Re-Admission are capable of being held in either registered or uncertificated form. In the case of Ordinary Shares held in uncertificated form, the Articles permit the holding and transfer of Ordinary Shares through CREST. CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by written instrument. The records in respect of Ordinary Shares held in uncertificated form will be maintained by Euroclear UK and Ireland Limited and the Company's registrar, Computershare Investor Services plc (details of which are set out on page 13).

3.6 The Ordinary Shares are denominated in Pounds Sterling.

3.7 The Company does not have in issue any equity securities not representing share capital.

3.8 The Company does not hold any treasury shares and no Ordinary Shares or other shares in the Company were held by, or on behalf of, any member of the Group.

3.9 The International Security Identification Number for the Ordinary Shares is GB00BP41S218.

3.10 Save as disclosed in this paragraph 3 and paragraph 4 below of this Part 12:

3.10.1 there are no convertible securities, exchangeable securities or securities with warrants;

3.10.2 no person has any acquisition rights and or obligations over authorised but unissued capital, and there is no undertaking to increase the capital; and

3.10.3 no capital of the Company or any member of the Group is under option or is agreed, conditionally or unconditionally, to be put under option.

## 4 INCENTIVE SCHEMES

4.1 The Company has granted options and awards under a number of share plans. These are detailed below and are as follows:

4.1.1 the 2014 Long-Term Incentive Plan;

4.1.2 the 2015 Supplemental Plan;

4.1.3 the Employee Plan 2018; and

4.1.4 the Officers Plan 2020

4.2 On 23 December 2021 the Company adopted two new share plans. These are detailed below as follows:

4.2.1 the Employee 2014/15 Replacement Plan; and

4.2.2 the Employee Plan 2021.

### 4.3 2014 LTIP

4.3.1 ***Introduction***

On 28 November 2014, the Company established a management long-term incentive equity incentive plan. The 2014 LTIP is now closed and is not expected to be reopened.

4.3.2 ***Type of award***

Under the terms of the existing 2014 LTIP, participants subscribe for shares in SE1L, with an entitlement to exchange such shares for Ordinary Shares if the closing middle market quotation of the Ordinary Shares on any day equals or exceeds £1.68 (the "Hurdle Price").

4.3.3 ***Performance conditions and vesting of awards***

(a) The number of Ordinary shares that can be acquired by participants following the Hurdle Price being achieved will be determined on the date of the share exchange in accordance with the following formula:

$X = A - ((AxB)/C)$

Where:

X is the number of Ordinary Shares to be issued on exchange (rounded to the nearest whole number);

A is the number of SE1L shares being exchanged;

B is £0.56 (being the price at which the Ordinary Shares were admitted to dealing on AIM at the time of the Company's admission to AIM); and

C is the closing middle market quotation of the Ordinary Shares on the date of the share exchange.

(b) If the Hurdle Price is met prior to the vesting date, the award will not vest until the vesting date and the relevant participants will not be able to exchange their SE1L shares for Ordinary Shares until after the vesting date unless there is a change of control of the Company, or the individual ceases to be an employee or director of a member of the Group.

4.3.4 ***Cessation of employment***

(a) Awards issued pursuant to the 2014 LTIP will be subject to full or partial forfeiture if the relevant participant ceases to be either: (i) employed by a member of the Group; or (ii) a director of a member of the Group prior to the vesting date (a "Leaver") (other than awards held by Andrew Knott, which are not subject to any forfeiture provisions).

(b) Pursuant to the terms of the forfeiture provisions, the relevant participant will be required to transfer the following proportion of his or her awards for nil consideration to the Company or a person nominated by the Company:

(i) 100 per cent. if the participant becomes a Leaver within 2.5 years of being issued the awards;

(ii) 0 per cent. if the participant becomes a Leaver after five years of being issued the awards; and

(iii) if the participant becomes a Leaver at or after 2.5 years of being issued the awards but before the fifth anniversary of the awards being issued, the proportion will be determined by the following formula: 50 – 50((Y-2.5)/2.5), where Y is the number of years that have elapsed between the awards being issued and the participant becoming a Leaver.

4.3.5 ***Proposed surrender of awards***

As is detailed in paragraph 24 of Part 1 of this document, it is proposed that certain awards made under the 2014 LTIP shall be surrendered and replaced with options to subscribe for up to 14,743,701 new Ordinary Shares granted pursuant to Employee 2014/15 Replacement Plan. Following such surrender, the only awards under the 2014 LTIP that will continue in existence are those held by former employees of the Group which did not lapse at the time of cessation of their employment.

4.4 **2015 Supplemental Plan**

4.4.1 On 30 July 2015, the Company established a supplemental share option plan. The 2015 Supplemental Plan is now closed and is not expected to be reopened.

4.4.2 The 2015 Supplemental Plan has been implemented and structured principally on the same terms as the 2014 LTIP, subject to the following differences:

(a) the aggregate number of any issued or unissued Ordinary Shares being the subject of the 2014 LTIP and the 2015 Supplemental Plan from time to time shall not exceed ten per cent. of the Company's fully diluted share capital;

(b) one half of the equity available under the 2015 Supplemental Plan and the 2014 LTIP shall be awarded to Andrew Knott;

(c) the share price hurdle rate is £1.14 per Ordinary Share;

(d) options granted pursuant to the 2015 Supplemental Plan will vest and become exercisable on the earliest to occur of: (i) the Company's share price on any day equalling or exceeding £1.14 per Ordinary Share; (ii) any person or group of persons acting in concert obtaining control of 30 per cent. or more of the Company's issued share capital (other than the existing concert party); (iii) the sale of a substantial proportion of the Group's assets (as shall be determined by the Company's Remuneration and Nomination Committee in its sole discretion; and (iv) the passing of a resolution for the voluntary winding up of the Company;

(e) options granted pursuant to the 2015 Supplemental Plan will be granted over unissued Ordinary Shares, rather than shares in SE1L; and

(f) options granted pursuant to the 2015 Supplemental Plan will lapse in the event that a participant ceased to be either: (i) employed by a member of the Group; or (ii) a director of a member of the Group prior to 28 November 2017.

#### 4.4.3 *Proposed surrender of awards*

As is detailed in paragraph 24 of Part 1 of this document, it is proposed that certain awards made under the 2015 Supplemental Plan shall be surrendered and replaced with options to subscribe for up to 9,109,756 new Ordinary Shares granted pursuant to the Employee 2014/15 Replacement Plan. Following such surrender, the only awards under the 2015 Supplemental Plan that will continue in existence are those held by former employees of the Group which had not lapsed at the time of cessation of their employment.

### 4.5 Employee Plan 2018

#### 4.5.1 *Introduction*

(a) On 15 June 2018, the Company established an employee share option plan.

(b) The Employee Plan 2018 is a discretionary share plan administered by the Board or a committee appointed by the Board.

(c) Any employee (including an executive director) of the Group will be eligible to participate in the Employee Plan 2018 at the discretion of the Board.

(d) The Board must not grant an option which would cause the number of Ordinary Shares allocated under the Employee Plan 2018 and any other share plan adopted by the Company from time to time to exceed such number as represents approximately 10 per cent of the fully diluted ordinary share capital of the Company in issue from time to time.

(e) Awards shall be granted in the form of options to acquire Ordinary Shares. Before Ordinary Shares are allotted pursuant to the exercise of any awards, the Board may decide to pay a cash amount equal to the value of the Ordinary Shares that the participant would otherwise have recorded, less the aggregate exercise price payable (the "gain"). Alternatively, the Board may deliver to the participant for nil or nominal value a number of Ordinary Shares with a value equal to the gain.

(f) Awards may be granted over pre-existing Ordinary Shares held by the EBT.

(g) The extent to which an award shall vest shall be determined by the Board by reference to a performance condition measuring the Company's total shareholder return ("TSR"). For the purposes of this performance condition, TSR shall be calculated as the volume weighted average price of the Ordinary Shares over any period of 30 continuous dealing days within a period of five years from the relevant date of grant, plus the aggregate value of any dividends paid by the Company per Ordinary Share during such period. A performance condition may be amended or substituted if an event occurs which causes the Board to consider that an amendment/substitution would be appropriate and would not be materially less difficult to satisfy.

(h) Awards which are subject to performance conditions will normally vest as soon as practicable after the performance condition has been satisfied. Awards will normally be exercisable from the date of vesting until the tenth anniversary of the grant date.

(i) Various provisions will apply to the awards as set out below in the event of serious misconduct on the part of the participant where such conduct would justify their summary dismissal. At any time up to the date of vesting of an award, the Board may cancel the award or impose further conditions on it if the event described above occurs.

4.5.2 ***Ceasing to provide services to the Group: unvested awards***

(a) If a participant in the Employee Plan 2018 ceases employment by reason of death, ill-health, injury, disability or for any other reason at the Board's discretion (a "Good Leaver"), any unvested award he holds will usually continue and vest at the normal vesting date. The Board will have discretion to vest the award at cessation of employment. If a participant in the Employee Plan 2018 ceases employment and is not a Good Leaver, he will be a "Bad Leaver" and his award will lapse.

(b) The extent to which an award held by a Good Leaver vests will be determined by reference to the extent to which any performance condition has been satisfied (as determined by the Board in the event of vesting before the end of the performance period). Unless the Board determines otherwise, the extent to which an award vests will be reduced to take account of the proportion of the vesting period that has elapsed at the date of cessation of employment.

4.5.3 ***Corporate events***

(a) In the event of a change of control of the Company, unvested awards will vest as soon as practicable, to the extent determined by the Board having regard to the extent to which any performance condition has been satisfied at the date of change of control (as determined by the Board) and/or such other factors as the Board considers appropriate. The Board may also take into account the extent to which the vesting period has elapsed in determining the extent of vesting.

(b) If other events occur, such as a winding up of the Company, demerger, delisting, special dividend or other event which, in the opinion of the Board, may affect the current or future value of Ordinary Shares, the Board may determine that awards will vest on the same basis as in the event of a change of control.

4.5.4 ***Adjustment of Awards***

In the event of a variation of the Company's share capital or a demerger, delisting, special dividend, rights issue or other event, which may, in the Board's opinion, affect the current or future value of Ordinary Shares, the number of Ordinary Shares subject to an award and/or the exercise price and/or any performance condition attached to awards, may be adjusted.

4.5.5 ***Amending the Employee Plan 2018, termination of the Employee Plan 2018 and further terms of awards***

(a) The Board may amend the Employee Plan 2018 at any time, provided that the approval of the Company's Shareholders in a general meeting will be required for any amendments to the advantage of participants relating to eligibility, limits, the basis for determining a participant's entitlement to, and the terms of, the Ordinary Shares comprised in an award and the impact of any variation of capital to become effective.

(b) However, any minor amendment to benefit administration, to take into account legislative changes, or to obtain or maintain favourable tax treatment, exchange control or regulatory treatment may be made by the Board without Shareholder approval.

(c) The Employee Plan 2018 will in normal circumstances terminate on its tenth anniversary, but the rights of existing participants will not be affected by any termination.

4.5.6 ***Proposed surrender of awards***

As is detailed in paragraph 24 of Part 1 of this document, it is proposed that certain awards made under the Employee Plan 2018 shall be surrendered and replaced with options to subscribe for up to 3,196,863 new Ordinary Shares granted pursuant to the Employee Plan 2021. Following such surrender, the only awards under the Employee Plan 2018 that will continue in existence are those held by the Company's CEO, Andrew Knott.

**4.6 Officers Plan 2020**

4.6.1 On 30 April 2020, the Company established a non-tax advantaged share option plan. The main features of the non-tax advantaged Officers Plan 2020 are set out below.

4.6.2 ***Eligibility***

Options may be granted to officers (whether or not employees) of the Group. The Board has an absolute discretion as to the selection of individuals to whom options may be granted.

4.6.3 ***Grant of Options***

Options may generally be granted at any time provided that such grant is not in breach of the AIM Rules or the Market Abuse Regulations. No options may be granted after the tenth anniversary of the adoption of the Officers Plan 2020

4.6.4 ***Exercise Price***

The exercise price shall be as specified by the Board at the date of grant of each option. Where such option is a right to subscribe for new Ordinary Shares, the exercise price in respect of that option shall not be less than the nominal value of an Ordinary Share.

4.6.5 ***Limits on Grant of Options***

There is no overall limit on awards that may be made under the Officers Plan 2020 by reference to the issued share capital of the Company.

4.6.6 ***Performance Targets***

The exercise of options granted under the Officers Plan 2020 is not subject to the meeting of any performance targets.

4.6.7 ***Variation of Share Capital***

In the event of any variation of the share capital of the Company, the Board may make such adjustment as it considers appropriate to the aggregate number or description of option shares and/or the exercise price.

4.6.8 ***Vesting of Options***

Options granted under the Officers Plan 2020 are not subject to any vesting criteria and are exercisable at any time.

4.6.9 ***Rights and Restrictions***

An option granted under the Officers Plan 2020 is not transferable. Options are exercisable within a limited time period which varies depending on the circumstances in which they have become exercisable and any terms specified in the option contract. Options will lapse if they are not exercised within the applicable period. Options will lapse in any event on the tenth anniversary of the date of grant, if not exercised before that date.

4.6.10 ***Alteration of the Employee Plan***

The Board may at any time alter or add to any of the provisions of the Officers Plan 2020 in any respect provided that no alterations or additions shall be made to options granted before the alteration or addition without the consent of the affected option holders.

**4.7 Employee 2014/15 Replacement Plan**

4.7.1 On 23 December 2021, the Company established a non-tax advantaged share option plan. The main features of the Employee 2014/15 Replacement Plan are set out below.

4.7.2 ***Eligibility***

Options may be granted to employees (including executive directors) and officers (whether or not employees) of the Group. Whereas the Board has an absolute discretion as to the selection of employees or officers to whom options may be granted, it is intended that options will only be granted under the Employee 2014/15 Replacement Plan to participants who have surrendered awards granted to them under the 2014 LTIP and the 2015 Supplemental Plan.

4.7.3 ***Grant of Options***

Options may be granted by the Board at any time, provided that such grant is not in breach of the AIM Rules or the Market Abuse Regulations. No options may be granted after the tenth anniversary of the date of adoption of the Employee 2014/15 Replacement Plan.

4.7.4 ***Exercise Price***

The exercise price shall be as specified by the Board at the date of grant of each option. Where such option is a right to subscribe for new Ordinary Shares, the exercise price in respect of that option shall not be less than the nominal value of an Ordinary Share.

4.7.5 ***Limits on Grant of Options***

There is no overall limit on awards that may be made under the Employee 2014/15 Replacement Plan by reference to the issued share capital of the Company.

4.7.6 ***Performance Targets***

The Board may determine and specify that the exercise of an option is conditional upon the meeting of performance targets. Such performance targets are at the discretion of the Board and can differ from employee to employee.

4.7.7 ***Variation of Share Capital***

In the event of any variation of the share capital of the Company, the Board may make such adjustment as they consider appropriate to the aggregate number or description of option shares and/or the exercise price.

4.7.8 ***Vesting of Options***

Options will become exercisable once they have vested. Options granted within 3 months of Admission to replace surrendered awards (granted under the 2014 LTIP and 2015 Supplemental Plan) that are subject to performance targets will vest on the earlier of (i) the relevant performance target having been satisfied or waived or when the Board in its discretion has deemed the performance targets to be satisfied, or (ii) an exit involving (broadly) the sale of 30 per cent. or more of the ordinary share capital of the Company, the sale of 20 per cent. or more of the Group's assets or a voluntary winding-up. If the employee or office holder’s employment or office ceases, they will be entitled to retain the option (the holding period having already been satisfied under the original surrendered award).

4.7.9 ***Rights and Restrictions***

An option granted under the Employee 2014/15 Replacement Plan is not transferable. Options are exercisable within a limited time period which varies depending on the circumstances in which they have become exercisable and any terms specified in the option contract. Options will lapse if they are not exercised within the applicable period. Options will lapse in any event on the tenth anniversary of the date of grant, if not exercised before that date.

4.7.10 ***Alteration of the Employee 2014/15 Replacement Plan***

The Board may at any time alter or add to any of the provisions of the Employee 2014/15 Replacement Plan in any respect.

**4.8 Employee Plan 2021**

4.8.1 On 23 December 2021, the Company established a non-tax advantaged share option plan. The main features of the Employee Plan 2021 are set out below.

4.8.2 ***Eligibility***

Options may be granted to employees (including executive directors) of the Group. The Board has an absolute discretion as to the selection of employees to whom options may be granted.

4.8.3 ***Grant of Options***

Options may be granted by the Board at any time, provided that such grant is not in breach of the AIM Rules or the Market Abuse Regulations. No options may be granted after the tenth anniversary of the date of adoption of the Employee Plan 2021.

4.8.4 ***Exercise Price***

The exercise price shall be as specified by the Board at the date of grant of each option. Where such option is a right to subscribe for issued Ordinary Shares (for example, shares held the EBT), the exercise price in respect of that option may be nil. Where such option is a right to subscribe for new Ordinary Shares, the exercise price in respect of that option shall not be less than the nominal value of an Ordinary Share.

4.8.5 ***Limits on Grant of Options***

There is no overall limit on awards that may be made under the Employee Plan 2021 by reference to the issued share capital of the Company.

4.8.6 ***Performance Targets***

The Board may determine and specify that the exercise of an option is conditional upon the meeting of performance targets. Such performance targets are at the discretion of the Board and can differ from employee to employee.

4.8.7 ***Variation of Share Capital***

In the event of any variation of the share capital of the Company, the Board may make such adjustment as they consider appropriate to the aggregate number or description of option shares and/or the exercise price.

4.8.8 ***Vesting of Options***

Options will become exercisable once they have vested. Options granted within 3 months of Admission to replace surrendered options (granted under the Employee Plan 2018) and to new participants and that are not subject to performance conditions will vest in five tranches during a five year vesting period (one-fifth on each of the first, second, third, fourth and fifth anniversary of the date of grant). If the option holder's employment ceases before the end of the five year period the employee may normally only exercise their option to the extent it has vested.

4.8.9 ***Rights and Restrictions***

An option granted under the Employee Plan 2021 is not transferable. Options are exercisable within a limited time period which varies depending on the circumstances in which they have become exercisable and any terms specified in the option contract. Options will lapse if they are not exercised within the applicable period. Options will lapse in any event on the tenth anniversary of the date of grant, if not exercised before that date.

4.8.10 ***Lock-in***

Following an option being exercised, an option holder may be prohibited from selling the acquired Ordinary Shares for a period of up to 24 months, subject to customary exceptions and Group equity-holding / share dealing policies. Such period and exceptions and Group policies, if applicable, will be notified to each option holder at the time of grant of their options.

4.8.11 ***Malus and Clawback***

In certain circumstances, where there has been unsatisfactory actions by an option holder, the Board may reduce the option it by such number of option shares as the Board considers to be fair and reasonable, taking account of all circumstances that the Board considers to be relevant. Where the option has already been exercised, the Board may determine a cash clawback amount in relation to the Ordinary Shares acquired on such exercise.

4.8.12 ***Alteration of the Employee Plan 2021***

The Board may at any time alter or add to any of the provisions of the Employee Plan 2021 in any respect.

4.9 **Awards**

4.9.1 As at the date of this document, 42,624,837 Ordinary Shares are held in the EBT. As is detailed in paragraph 24 of Part 1 of this document, it is proposed that the EBT subscribes for a further 58,066,951 new Ordinary Shares at nominal value following the passing of Resolutions 4 and 8 at the General Meeting. Following such subscription, the EBT will hold 100,691,788 Ordinary Shares (equal to approximately 7.7 per cent. of the Further Enlarged Share Capital).

4.9.2 As at the date of this document, awards under the 2014 LTIP, the 2015 Supplemental Plan, the Employee Plan 2018 and the Officers Plan 2020 have been granted (excluding any awards that have already lapsed or been surrendered) over: (i) 15,299,683 A1 ordinary shares in the capital of SE1L, and (ii) 39,257,522 Ordinary Shares (equal to approximately 3.94 per cent. of the Existing Ordinary Shares) (of which 29,128,923 Ordinary Shares are held by the EBT).

4.9.3 Following: (i) the proposed surrender of certain existing options granted pursuant to the 2014 LTIP, the 2015 Supplemental Plan and the Employee Plan 2018, and (ii) the grant of new options pursuant to the Employee 2014/15 Replacement Plan and the Employee Plan 2021 following the passing of Resolutions 4, 6, 8, and 10 at the General Meeting, awards will have been granted (excluding any awards that have already lapsed or been surrendered) over (i) 555,982 ordinary shares in the capital of SE1L, and (ii) 63,715,431 Ordinary Shares (equal to approximately 4.9 per cent. of the Further Enlarged Share Capital) (of which 38,843,131 Ordinary Shares are held by the EBT).

4.9.4 As at the date of this document, the following awards have been made to Directors and Senior Managers:

| *Directors* | *Share options over shares in SE1L issued pursuant to 2014 LTIP* | *Share options over Ordinary Shares issued pursuant to 2015 Supplemental Plan* | *Share options over Ordinary Shares issued pursuant to Employee Plan 2018* | *Share options over Ordinary Shares issued pursuant to Officers Plan 2020* |
|---|---|---|---|---|
| Andrew Knott | 11,588,574 | 5,446,630 | 21,312,418 | 2,200,000 |
| David Jamison | 273,883 | 128,725 | – | – |
| Mark Iannotti | 547,765 | 2,257,450 | – | – |
| Stephen Jenkins | 1,785,714 | 1,019,501 | – | – |
| Sir Stephen O'Brien | – | – | – | 142,857 |
| David Clarkson | – | – | – | 142,857 |
| **Senior Managers** | | | | |
| Nick Beattie | – | – | – | 187,500 |
| Antoine Richard | – | – | 1,065,621 | – |

4.9.5 The Company intends, immediately following the passing of the Resolutions at the General Meeting, to make the following awards to Directors and Senior Managers under the Employee 2014/15 Replacement Plan and the Employee Plan 2021:

| *Directors* | *Proposed share options to be granted under the Employee 2014/15 Replacement Plan 2021 over unissued Ordinary Shares* | *Proposed share options to be granted under the Employee Plan 2021 over Ordinary Shares held by the EBT* |
|---|---|---|
| Andrew Knott | 17,035,204 | – |
| David Jamison | 402,608 | – |
| Mark Iannotti | 2,805,215 | – |
| Stephen Jenkins | 2,805,215 | – |
| **Senior Managers** | | |
| Nick Beattie | – | 5,806,695 |
| Antoine Richard | – | 3,871,130 |

4.9.6 Following the granting of the awards referred to in paragraph 4.9.5 above, the following awards will have been made to Directors and Senior Managers:

| *Directors* | *Share options issued pursuant to the Employee Plan 2018 over Ordinary Shares held by the EBT* | *Share options issued pursuant to the Officers Plan 2020 over Ordinary Shares held by the EBT* | *Share options granted under the Employee 2014/15 Replacement Plan 2021 over unissued Ordinary Shares* | *Share options granted under the Employee Plan 2021 over Ordinary Shares held by the EBT* |
|---|---|---|---|---|
| Andrew Knott | 21,312,418 | 2,200,000 | 17,035,204 | – |
| David Jamison | – | – | 402,608 | – |
| Mark Iannotti | – | – | 2,805,215 | – |
| Stephen Jenkins | – | – | 2,805,215 | – |
| Sir Stephen O'Brien | – | 142,857 | – | – |
| David Clarkson | – | 142,857 | – | – |
| **Senior Managers** | | | | |
| Nick Beattie | – | 187,500 | – | 5,806,695 |
| Antoine Richard | – | – | – | 3,871,130 |

## 5 ARTICLES OF ASSOCIATION

The Articles provide, amongst other things:

### 5.1 Voting rights

Subject to any special rights or restrictions as to voting for the time being attached to any shares, at a general meeting of the Company every member who is present in person (including any corporation present by its duly authorised representative) shall on a show of hands have one vote and every member present in person or by proxy shall on a poll have one vote for each share of which he is a holder. The Directors may accept the appointment of a proxy contained in an electronic communication subject to such terms and conditions as the Directors may determine. In the case of joint holders, the vote of the senior who tenders a vote, whether in person or by proxy, shall be accepted to the exclusion of the votes of the other joint holders.

5.2 **Restrictions on voting**

Unless the Board determines otherwise, no member is entitled to vote at a general meeting, either in person or by proxy, or to exercise any privilege as a member, or be reckoned in a quorum, in respect of any share held by him unless all calls presently payable by him in respect of that share, whether alone or jointly with any other person, together with interest and expenses (if any) have been paid to the Company.

5.3 **Dividends**

5.3.1 Subject to the provisions of the Act and of the Articles, the Company may by ordinary resolution declare dividends to be paid to members according to their respective rights and interests in the profits of the Company. However, no dividend shall exceed the amount recommended by the Board and no dividend shall be payable except out of the profits of the Company available for distribution.

5.3.2 Subject to the provisions of the Act, the Board may declare and pay such interim dividends (including any dividend payable at a fixed rate) as appear to the Directors to be justified by the profits of the Company available for distribution.

5.3.3 Except as otherwise provided by the rights attached to shares, all dividends:

(a) shall be declared and paid according to the amounts paid up (otherwise than in advance of calls) on the shares on which the dividend is paid;

(b) shall be apportioned and paid proportionately to the amounts paid up on the shares during any portion or portions of the period in respect of which the dividend is paid, but if any share is issued on terms that it shall rank for dividend as from a particular date, it shall rank for dividend accordingly; and

(c) may be declared in any currency.

5.3.4 All dividends unclaimed for a period of 12 years after having been declared or become due for payment shall (if the Directors so resolve) be forfeited and shall cease to remain owing by the Company.

5.3.5 The Board may, with the authority of an ordinary resolution of the Company, or in the case of an interim dividend may without the authority of an ordinary resolution, direct that payment of any dividend declared may be satisfied wholly or partly by the distribution of assets, and in particular of paid up shares or debentures of any other company, or in any one or more of such ways.

5.3.6 The Board may deduct from any dividend or other monies payable to any person on or in respect of a share, all such sums as may be due to the Company on account of calls or otherwise in relation to the shares of the Company from him.

5.4 **Distribution of assets on a winding up**

If the Company is wound up, the surplus assets remaining after payment of all creditors shall be divided among the members in proportion to the capital held by them respectively and, if the surplus assets are insufficient to repay the whole of the capital, the losses shall be borne by the members in proportion to the capital held. If the Company is wound up, the liquidator may, with the sanction of a special resolution of the Company and any other sanction required by law, divide among the members in specie the whole or any part of the assets of the Company. The resolution may provide for and sanction a distribution of any specific assets amongst different classes of members otherwise than in accordance with their existing right. In such an event, every member shall have the right of dissent.

5.5 **Transfers of shares**

5.5.1 Every member may transfer all or any of his shares which are in certificated form by instrument of transfer in writing in any usual form or in any form approved by the Board, left at the registered office of the Company (or such other place as the Board may determine) and accompanied (except in the case of a transfer by a person to whom the Company is not required by law to issue a certificate and to whom a certificate has not been issued or in the case of a renunciation) by the certificate of the shares to which it relates and such other evidence as the Board may reasonably require to prove the title of the transferor (or person renouncing) and the due execution of the transfer or renunciation by him or, if the transfer or renunciations is executed by some other person on his behalf, the authority of that person to do so. The transferor is deemed to remain the holder of the shares concerned until the name of the transferee is entered in the register of members.

5.5.2 Unless the Directors otherwise determine, a transfer of shares will not be registered if the transferor or any other person appearing to be interested in the transferor's shares has been duly served with a notice under section 793 of the Act, has failed to supply the information required by such notice within 14 days and the shares in respect of which such notice has been served represent at least 0.25 per cent. of their class, unless the member is not himself in default as regards supplying the information required and proves to the satisfaction of the Directors that no person in default as regards supplying such information is interested in any of the shares the subject of the transfer, or unless such transfer is by way of acceptance of a takeover offer, in consequence of a sale on a recognised stock exchange or a sale to an unconnected party.

5.6 **Variations of rights**

5.6.1 If at any time the share capital of the Company is divided into shares of different classes, any of the rights for the time being attached to any share or class of shares in the Company may be varied or abrogated in such manner (if any) as may be provided by such rights or, in the absence of any such provision, with the consent of the holders of not less than three-quarters in nominal value of the issued shares of the class sanctioning the resolution at a general meeting of the holders of shares of the class. The quorum at any such meeting shall be not less than two persons holding or representing by proxy at least one-third of the nominal amount paid up on the issued shares of the class in question and at an adjourned meeting not less than one person holding shares of the class in question or his proxy.

5.6.2 Subject to the terms of issue of or rights attached to any shares, the rights or privileges attached to any class of shares shall be deemed not to be varied or abrogated by the creation or issue of any new shares ranking *pari passu* in all respects.

5.7 **Changes in capital**

Subject to the provisions of the Act, the Company in general meeting may from time to time by ordinary resolution increase its share capital, consolidate and divide all or any of its share capital into shares of a larger amount, cancel any shares which at the date of the passing of the resolution have not been taken or agreed to be taken by any person and diminish the amount of its share capital by the amount of the shares so cancelled and sub-divide all or any of its shares into shares of smaller amount. The Company may also, subject to the provisions of the Act and to any rights for the time being attached to any shares, purchase its own shares and, by special resolution, reduce its share capital or any capital redemption reserve fund or any share premium account in any way.

5.8 **Issues of shares**

5.8.1 Subject to the Act and to any relevant authority of the Company in general meeting required by the Act, the Board may offer, allot (with or without conferring rights of renunciation), grant options over or otherwise deal with or dispose of shares or grant rights to subscribe for or convert any security into shares to such persons, at such times and upon such terms as the Board may decide. No share may be issued at a discount.

5.8.2 Subject to the Act, the Company may at any time pass an ordinary resolution permitting the Directors to generally and unconditionally allot ordinary shares for a period of up to five years from the passing of the ordinary resolution.

5.9 **Remuneration of Directors**

5.9.1 The salary or remuneration of any Director appointed to hold any employment or executive office in accordance with the Articles may be either a fixed sum of money, or may altogether or in part be governed by business done or profits made or otherwise determined by the Board, and may be in addition to or in lieu of any fee payable to him for his service as Director in accordance with the Articles.

5.9.2 If by arrangement with the Board any Director shall perform or render any special duties or services outside his ordinary duties as a Director and not in his capacity as a holder of employment or executive office, he may be paid such reasonable additional remuneration (whether by way of salary, commission, participation in profits or otherwise) as the Board may determine.

5.10 **Pensions and gratuities for Directors**

The Board may exercise all the powers of the Company to provide pensions or other retirement or superannuation benefits and to provide death or availability benefits or other allowances or gratuities (whether by insurance or otherwise) for any person who is or has at any time been a Director of the Company or any company which is a holding company or a subsidiary undertaking of or allied to or allocated with the Company or any such holding company or subsidiary undertaking or any predecessor in business of the Company or of any such holding company or subsidiary undertaking, and for any member of his family (including a spouse or former spouse) and any person who is or was dependent on him.

5.11 **Directors' interests in contracts**

Subject to the Act and provided he has declared the nature and extent of his interest in accordance with the requirements of the Act, a Director who is in any way, whether directly or indirectly, interested in an existing or proposed transaction or arrangement with the Company may:

5.11.1 be a party to, or otherwise interested in, any transaction or arrangement with the Company or in which the Company is otherwise (directly or indirectly) interested;

5.11.2 act by himself or through his firm in a professional capacity for the Company (otherwise than as auditor) and he or his firm shall be entitled to remuneration for professional services as if he were not a Director;

5.11.3 be or become a director or other officer of, or employed by, or a party to a transaction or arrangement with, or otherwise interested in, any body corporate in which the Company is otherwise (directly or indirectly) interested; or

5.11.4 hold any office or place of profit with the Company (except as auditor) in conjunction with his office of Director for such period and upon such terms, including as to remuneration as the Board may decide.

5.12 **Restrictions on Directors' voting**

5.12.1 Save as provided in the Articles, a Director shall not vote on, or be counted in the quorum in relation to, any resolution of the Directors or of a committee of the Directors concerning any contract, arrangement, transaction or any other proposal whatsoever to which the Company is or is to be a party and in which he has an interest which is to his knowledge a material interest otherwise than by virtue of his interests in shares or debentures or other securities of or otherwise in or through the Company, unless the resolution concerns any of the following matters:

(a) the giving by him of any security, guarantee or indemnity for any money or any liability which he, or any other person, has lent or obligations he or any other person has undertaken at the request, or for the benefit, of the Company or any of its Subsidiary undertakings;

(b) the giving of any security, guarantee or indemnity to any person for a debt or obligation which is owed by the Company or any of its subsidiary undertakings, to that other person if the Director has taken responsibility for some or all of that debt or obligation;

(c) a proposal or contract relating to an offer of any shares or debentures or other securities for subscription or purchase by the Company or any of its subsidiary undertakings, if the Director takes part because he is a holder of shares, debentures or other securities, or if he takes part in the underwriting or sub-underwriting of the offer;

(d) any arrangement for the benefit of employees of the Company or any of its Subsidiary undertakings which only gives him benefits which are also generally given to employees to whom the arrangement relates;

(e) any arrangement involving any other company in which the Director (together with any person connected with the Director) has any interest of any kind in that company (including an interest by holding any position in that company or by being a shareholder of that company);

(f) a contract relating to insurance which the Company can buy or renew for the benefit of the Directors or a group of people which includes Directors; or

(g) a contract relating to a pension, superannuation or similar scheme or a retirement, death, disability benefits scheme or employees' share scheme which gives the Director benefits which are also generally given to the employees to whom the scheme relates.

5.12.2 The Board may authorise, to the fullest extent permitted by law any matter which would otherwise result in a Director infringing his duty to avoid a situation in which he has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the interest of the Company, provided that the Director in question, and any other interested Director, are not counted in the quorum at any board meeting at which such matter is authorised.

### 5.13 Number of Directors

Unless otherwise determined by the Company by ordinary resolution, the number of Directors shall not be less than two but shall not be subject to any maximum number.

### 5.14 Directors' appointment and retirement

5.14.1 Directors may be appointed by the Company by ordinary resolution or by the Board. If appointed by the Board, a Director holds office only until the next annual general meeting and shall retire from office but shall be eligible for re-appointment. Each Director shall retire from office at the third annual general meeting after the annual general meeting or general meeting (as the case may be) at which he was previously appointed. A director shall not be required to hold any shares in the Company.

5.14.2 If: (i) at the annual general meeting in any year any resolution or resolutions for the appointment or re-appointment of the persons eligible for appointment or re-appointment of the persons eligible for appointment or re-appointment as Directors are put to the meeting and lost; and (ii) at the end of that meeting the number of Directors is fewer than any minimum number of Directors required, all retiring Directors who stood for re-appointment at that meeting shall be deemed to have been re-appointed as Directors and shall remain in office, but may only act for the purpose of convening general meetings of the Company and perform such duties as are essential to maintain the Company as a going concern, and not for any other purpose.

5.14.3 In addition to any power of removal conferred by the Act, the office of Director shall be vacated if he is requested to resign by all of the other Directors by notice in writing.

### 5.15 Borrowing powers

The Directors may exercise all the powers of the Company to borrow money and to mortgage or charge all or any part of its undertaking, property and assets (present and future) and uncalled capital and, to create and issue debenture and other securities and give security either outright or as collateral security for any debt, liability or obligation of the Company or any third party. The Board shall restrict the borrowings of the Company, and exercise all voting or powers of control exercisable by the Company in relation to its subsidiary undertakings (if any) so as to secure (but as regards the subsidiary undertakings only so far as by such exercise it can secure) that the aggregate of the amounts borrowed by the Group and remaining outstanding at any time (excluding intra-Group borrowings) shall not without the previous sanction of an ordinary resolution of the Company exceed US$2.5 billion.

### 5.16 Untraced shareholders

Subject to the Articles, the Company may sell any shares in the Company registered in the name of a member remaining untraced for 12 years who fails to communicate with the Company following advertisement of an intention to make such a disposal. Until the Company can account to the member, the net proceeds of sale will be available for use in the business of the Company or for investment, in either case at the discretion of the Directors. The proceeds will not carry interest.

### 5.17 Meetings

#### 5.17.1 *Annual General Meetings*

The Company shall comply with the requirements of the Act regarding the holding of an annual general meeting.

#### 5.17.2 *General Meetings*

All general meetings other than annual general meetings shall be called general meetings. General meetings may be called whenever the Board thinks fit or when one has been requisitioned in accordance with the Act.

A general meeting is to be called on at least 14 days' notice in writing exclusive of the day on which it is served or deemed to be served and the day on which the meeting is to be held. A general meeting can be called on shorter notice if a majority in number of the members having a right to attend and vote at the general meeting, being a majority together holding not less than 95 per cent. in nominal value of the shares giving that right, consent. Subject to Section 318(1) of the Act, two members present in person or by proxy and entitled to vote shall be a quorum for all purposes.

### 5.18 Rights attaching to Ordinary Shares

5.18.1 The Ordinary Shares rank *pari passu* in the following respects:

(a) they are in all respects identical;

(b) they are of the same nominal value and the same amount per Ordinary Share has been paid up;

(c) they carry the same rights as to unrestricted transfer, attendance and voting in general meetings and in all other respects; and

(d) they are entitled to dividends at the same rate and for the same period so that at the next ensuing distribution to the dividend payable on each Ordinary Share will be the same amount.

5.18.2 All of the Existing Ordinary Shares are fully paid and freely transferable.

## 6 DIRECTORS, SENIOR MANAGERS' AND OTHER INTERESTS

6.1 The names of the Directors and Senior Managers of the Company are set out in paragraph 17 of Part 1 of this document.

6.2 The interests (within the meaning of sections 820-825 of the Act) of each Director and Senior Manager and (so far as is known to the Directors and Senior Managers having made all reasonable enquiries) persons connected with them (within the meaning of section 252 of the Act) and any member of the Director's and Senior Manager's family (as defined in the AIM Rules) in the issued share capital of Company, all of which are legal and beneficial (except as noted below) in the issued share capital of the Company as at the Last Practicable Date are as follows:

| *Names* | *As at the Last Practicable Date Ordinary Shares* | *%* | *Following completion of the Placing and Subscription Ordinary Shares* | *%* |
|---|---|---|---|---|
| **Directors** | | | | |
| Andrew Knott | 36,942,019 | 3.71 | 48,555,409 | 3.89 |
| David Jamison | 651,009 | 0.07 | 651,009 | 0.05 |
| Steve Jenkins | 463,800 | 0.05 | 722,198 | 0.06 |
| Mark Iannotti | 3,667,984 | 0.37 | 5,367,984 | 0.43 |
| Sir Stephen O'Brien | 275,601 | 0.03 | 533,999 | 0.04 |
| David Clarkson | 1,113,692 | 0.11 | 1,630,488 | 0.13 |
| **Senior Managers** | | | | |
| Nick Beattie | – | – | – | – |
| Antoine Richard | – | – | – | – |

6.3 Save as disclosed in this document, no Director or Senior Manager has any interest in the share capital or loan capital of the Company or any of the subsidiaries of the Company nor does any person connected with the Directors or Senior Managers (within the meaning of section 252 of the Act) have any such interests, whether beneficial or non-beneficial.

**Other Interests of Directors in the Group**

6.4 Andrew Knott owns legal and beneficial title to one ordinary share in the capital of each of LCP1 and Lothian Investment Partners Limited ("LIP"), comprising 100 per cent. of the issued share capital in each of LCP1 and LIP. LIP owns legal and beneficial title to one ordinary share in the capital of Lothian Capital Partners 2 Limited, comprising 100 per cent. of the issued share capital in Lothian Capital Partners 2 Limited. LCP1, LIP and Lothian Capital Partners 2 Limited together own the legal and voting interest in 36,942,019 Ordinary Shares, being 3.71 per cent. of the Existing Ordinary Shares.

6.5 The Directors hold or have held the following directorships (in addition to the Company) and/or are or have been a partner in the following partnerships within the five years prior to the date of this document:

| *Name* | *Current directorships and partnerships* | *Previous directorships and partnerships* |
|---|---|---|
| Andrew Allister Knott | Lothian Capital Partners 2 Limited<br>Lothian Capital Partners 1 Limited<br>Lothian Partners Limited<br>Borealis Alaska Oil, Inc. | Savannah Energy 1 Limited<br>Savannah Energy 2 Limited<br>Lothian Oil & Gas Partners LLP<br>Djado Gold Limited<br>Franklin Petroleum Newfoundland Limited<br>Osprey Petroleum Limited<br>Scotia Oil & Gas LLP<br>Golden Eagle Petroleum Limited<br>Scotia Oil & Gas Exploration Limited<br>Savannah Energy International Limited |
| David Lawrence Jamison | Lowquest Limited<br>DLJ Partners Ltd<br>Energy Development and Investments UK Limited<br>Jamison Family Property Management LLP | Aquila Energy International Limited |

| *Name* | *Current directorships and partnerships* | *Previous directorships and partnerships* |
| --- | --- | --- |
| Stephen Ian Jenkins | Hedgepig Growth Limited<br>Oil & Gas Independents' Association Limited<br>Terrain Energy Limited<br>Talon Energy Ltd<br>Microenergy Generation Services Limited<br>Evoterra Limited<br>Viaro Energy Limited | Groliffe Limited<br>Postgate Petroleum Limited<br>Encounter Oil Limited<br>Circle Oil plc<br>Offshore Decommissioning Services Limited |
| Mark Iannotti | Rocksteady Restaurant Enterprises Limited<br>Galore Holdings Ltd<br>Djado Gold plc<br>Djado Gold Company Limited<br>Fitness Life Limited | Savannah Energy 1 Limited |
| Sir Stephen Rothwell O'Brien | IVCC<br>Observe Limited<br>Motability Operations Group plc<br>Department for International Trade<br>Friends of the Global Fund Europe | N/A |
| David Clarkson | Adergy Limited<br>Storegga Geotechnologies Limited | Bowleven plc<br>Bowleven New Ventures Limited<br>Bowleven (Kenya) Limited<br>Bowleven Resources Limited<br>Bowleven (Zambia) Limited<br>FirstAfrica Oil Limited<br>Bowleven Cameroon Limited<br>Sound Energy plc |

6.6 Subject to paragraph 6.7, no Director has:

6.6.1 any unspent convictions in relation to indictable offences or convictions in relation to fraudulent offences;

6.6.2 been bankrupt or the subject of an individual voluntary arrangement;

6.6.3 been a director of any company which had a receiver appointed or went into compulsory liquidation, creditors voluntary liquidation, administration or company voluntary arrangement, or made any composition or arrangement with its creditors generally or with any class of its creditors while he was a director or within the 12 months after he had ceased to be a director of that company;

6.6.4 been a partner of any partnership which went into compulsory liquidation, administration or partnership voluntary arrangement, while he was a partner or within the 12 months after he ceased to be a partner in that partnership;

6.6.5 been the owner of any asset which has been placed in receivership or a partner in any partnership which has been placed in a receivership while he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

6.6.6 had any public criticism by statutory or regulatory authorities (including recognised professional bodies); or

6.6.7 been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of any company.

6.7 Steve Jenkins was a director of Circle Oil plc when it was placed into liquidation through a creditors' voluntary winding up on 20 February 2017.

6.8 Save as set out below, the Company is not aware of any person (other than any Director or Senior Manager) who is directly or indirectly interested in three per cent. or more, of the issued share capital or voting rights of the Company:

| | *As at the Last Practicable Date* | | *Following completion of the Placing and Subscription* | |
|---|---|---|---|---|
| *Shareholder* | *Ordinary Shares* | *%* | *Ordinary Shares* | *%* |
| Premier Miton Group plc | 90,727,656 | 9.11 | 109,367,656 | 8.76 |
| TT International Asset Management Limited | 90,259,078 | 9.06 | 120,031,485 | 9.62 |
| Standard Life Aberdeen plc | 82,782,701 | 8.31 | 121,439,749 | 9.73 |
| Capital Group Companies, Inc. | 64,599,102 | 6.48 | 96,128,672 | 7.70 |
| VR Global Partners, L.P. | 57,125,356 | 5.73 | 57,125,356 | 4.58 |
| Ingalls & Snyder | 53,787,000 | 5.40 | 72,768,426 | 5.83 |
| JO Hambro Capital Management | 51,384,489 | 5.16 | 64,401,527 | 5.16 |
| Cavendish Fiduciary Jersey Limited | 51,206,396 | 5.14 | 51,206,396 | 4.10 |

6.9 As at the Last Practicable Date, so far as the Directors are aware, no person, directly or indirectly, jointly or severally, exercises or could exercise control over the Company.

6.10 As at the Last Practicable Date, so far as the Directors are aware, there are no arrangements the operation of which may at a later date result in a change of control of the Company.

6.11 None of the Company's major holders of Ordinary Shares listed in paragraph 6.8 has voting rights which are different from other holders of Ordinary Shares.

6.12 There are no loans made or guarantees granted or provided by any member of the Group to or for the benefit of any Director or Senior Manager.

6.13 In respect of the Directors and Senior Managers, there are no potential conflicts of interest between any duties they have to the Company and their private interests and/or other duties they may have.

6.14 No Director or any member of his immediate family nor any person connected with him (within the meaning of section 252 of the Act) has a related financial product (as defined in the AIM Rules for Companies) referenced to Ordinary Shares.

## 7 DIRECTORS' SERVICE CONTRACTS AND REMUNERATION

The services of the Directors are provided to the Group under the following agreements:

### 7.1 Executive Directors

#### 7.1.1 *Andrew Knott*

Andrew Knott became a director of the Company on its incorporation on 3 July 2014. Mr Knott is appointed as Chief Executive Officer. This service agreement shall continue until terminated by the Company on 12 months' written notice. Under the terms of the agreement, Mr Knott is entitled to an annual salary of £525,000, which will be payable on a monthly basis and, at the sole discretion of the Company's remuneration committee, a bonus of up to three times his annual salary. Mr Knott will also be eligible to participate in any management incentive programme that the Group may adopt. Mr Knott will receive an employer's pension contribution equal to ten per cent. of his annual salary. There is a right to place Mr Knott on gardening leave during all or any part of his notice period. The service agreement provides for early termination, *inter alia*, in the event of a serious breach of the agreement. Mr Knott's service agreement will be terminated in the event that Mr Knott ceases to be a Director.

7.2 **Non-Executive Directors**

7.2.1 ***Steve Jenkins***

On 26 July 2014, Mr Jenkins was appointed as non-executive chairman. The appointment shall continue until terminated by either the Company or Mr Jenkins on six months' written notice. Mr Jenkins is paid an annual fee of £175,000 payable monthly.

7.2.2 ***Sir Stephen O'Brien***

On 21 December 2017, Sir Stephen O'Brien was appointed as non-executive vice chairman. The appointment shall continue until terminated by either the Company or Sir Stephen O'Brien on six months' written notice. Sir Stephen O'Brien is paid an annual fee of £60,000 payable monthly.

7.2.3 ***David Clarkson***

On 21 December 2017, Mr Clarkson was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Clarkson on six months' written notice. Mr Clarkson is paid an annual fee of £60,000 payable monthly.

7.2.4 ***Mark Iannotti***

On 3 July 2014, at incorporation of the Company, Mr Iannotti was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Iannotti on six months' written notice. Mr Iannotti is paid an annual fee of £60,000 payable monthly.

7.2.5 ***David Jamison***

On 26 July 2014, Mr Jamison was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Jamison on six months' written notice. Mr Jamison is paid an annual fee of £60,000 payable monthly.

7.3 **Directors' Appointment Details**

| *Name* | *Date of Appointment* | *Date of Expiration of Current Term of Office* |
|---|---|---|
| Andrew Knott | 3 July 2014 | 2023 AGM |
| Mark Iannotti | 3 July 2014 | 2023 AGM |
| David Jamison | 26 July 2014 | 2023 AGM |
| Steve Jenkins | 26 July 2014 | 2023 AGM |
| Sir Stephen O'Brien | 21 December 2017 | 2023 AGM |
| David Clarkson | 21 December 2017 | 2023 AGM |

## 8 EMPLOYEES

8.1 As at 31 December 2020, the Savannah Group had 211 employees and, as at the date of this document, the Savannah Group has 232 employees.

| *Location* | *Number of Employees* |
|---|---|
| United Kingdom | 43 |
| Niger | 15 |
| Nigeria | 174 |

## 9 RELATED PARTY TRANSACTIONS

9.1 Save as disclosed in this document, or the related party transaction notes contained in the financial statements incorporated by reference in this document, none of the Directors has any interest, beneficial or non-beneficial, in the share or loan capital of the Company.

9.2 Save as disclosed in this document, or the related party transaction notes contained in the financial statements incorporated by reference in this document, none of the Directors has any interest, direct or indirect, in any assets that have been or are proposed to be acquired or disposed by, or leased to, the Group and no contract or arrangement exists in which any Director is materially interested and which is significant in relation to the business of the Group.

## 10 INVESTMENTS

Save as disclosed in this document, there are no investments made, being made by the Company or to be made in the future in respect of which firm commitments have been made.

## 11 PROPERTY

The Company's principal establishment (which is leased and used as an office facility) is located at 40 Bank Street, London E14 5NR. The Company also has establishments in: (i) Lagos, Nigeria; (ii) Uyo, Nigeria; (iii) Eket, Nigeria; (iv) Abuja, Nigeria; (v) Niamey, Niger; (vi) St Helier, Jersey; and (vii) Paris, France.

## 12 WORKING CAPITAL

The Directors are of the opinion that, after having made due and careful enquiry, the working capital available to the Company and the Group will be sufficient for its present requirements, that is for at least the next 12 months from the date of this document.

In making the above working capital statement, the Directors, as required by the ESMA Recommendations, are required to assess whether there is sufficient margin or headroom to cover a reasonable worst case scenario.

COVID-19 has resulted in significantly increased levels of uncertainty for many companies, with a wide range of possible financial impacts, resulting in challenges to COVID-19-impacted businesses in producing sufficiently reliable forecasts of their future financial performance to determine the reasonable worst case scenario.

## 13 LITIGATION

13.1 Subject to the following paragraphs in this paragraph 13, no member of the Group is or has been involved in any governmental, legal or arbitration proceedings and the Company is not aware of any such proceedings pending or threatened by or against the Group during the 12 months preceding the date of this document which may have or have had in the recent past a significant effect on the financial position or profitability of the Group.

13.2 Two former directors of the Company, Ms Isatou Semega-Janneh and Michael Wachtel, have raised claims in the UK Employment Tribunal against the Company in connection with their respective exits from the Company. The Company, having taken legal advice, believes such claims are spurious and are without merit, and is vigorously defending them.

## 14 NO SIGNIFICANT CHANGE STATEMENT

14.1 Save as disclosed in this document, there has been no significant change in the trading or financial position of the Existing Group since 30 June 2021, the date to which the last interim accounts of the Existing Group were published.

14.2 Save as disclosed in this document, there has been no significant change in the trading or financial position of the Exxon Target Companies and the PETRONAS Target Companies since 30 June 2021, the date to which the unaudited interim historical financial information of the Exxon Target Companies and the PETRONAS Target Companies included in this document was prepared.

## 15 GENERAL

15.1 The total costs and expenses of, or incidental to, Re-Admission, all of which are payable by the Company, are estimated to be approximately US$4 million (exclusive of value added tax) to the date of this document.

15.2 The Competent Person's reports in respect of the Chad/Cameroon Assets, Nigerian Assets and Nigerien Assets are included, in the form and context in which they are included, with the consent of CGG, which has authorised the contents of its reports for the purposes of the AIM Rules. CGG has also given and not withdrawn its written consent to the inclusion of references in this document to its name in the form and context in which they appear.

15.3 Crowe U.K. LLP has given and has not withdrawn its consent to the inclusion of its Accountant's Reports on the historical financial information of the Exxon Target Companies and the PETRONAS Target Companies in Parts 7A to 8B of this document in the form and context in which it appears and has authorised its report for the purposes of Schedule Two of the AIM Rules for Companies.

15.4 Strand Hanson Limited has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

15.5 Each of the Brokers has given and not withdrawn its written consent to the inclusion in this document of reference to its name in the form and context in which they appear.

15.6 Save as disclosed in this document, the Directors are unaware of any exceptional factors which have influenced the Group's activities.

15.7 Save as otherwise disclosed in this document, no person (other than the Company's professional advisers named in this document and trade suppliers) has at any time within the 12 months preceding the date of this document received, directly or indirectly, from the Company or any other member of the Group or entered into any contractual arrangements to receive, directly or indirectly, from the Company or any other member of the Group on or after Re-Admission any fees, securities in the Company or any other benefit to the value of £10,000 or more.

15.8 Where information has been sourced from a third party, the information has been accurately reproduced and, as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render such information inaccurate or misleading.

15.9 Save as disclosed in this document, so far as the Directors are aware there are no environmental issues that may affect the Company's utilisation of its tangible fixed assets.

15.10 The Directors are not aware of any patents or other intellectual property rights, licences, particular contracts or manufacturing processes on which the Group is dependent.

15.11 There are no provisions in the Articles which would have the effect of delaying, deferring or preventing a change of control of the Company.

15.12 Save as disclosed in this document, the Directors are unaware of:

15.11.1 any significant trends in production, sales and inventory and costs and selling prices since 31 December 2020 to the date of this document; and

15.11.2 any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Group's prospects for at least the current financial year.

15.13 The Articles contain no restriction on the objects of the Company.

## 16 TAXATION

### *Taxation in the United Kingdom*

The following information is based on UK tax law and HM Revenue and Customs ("HMRC") practice currently in force in the UK. Such law and practice (including, without limitation, rates of tax) is in principle subject to change at any time. The information that follows is for guidance purposes only. Any person who is in any doubt about his or her position should contact their professional advisor immediately.

### *Tax treatment of UK investors*

The following information, which relates only to UK taxation, is applicable to persons who are resident in the UK and who beneficially own Ordinary Shares as investments and not as securities to be realised in the course of a trade. It is based on the law and practice currently in force in the UK. The information is not exhaustive and does not apply to potential investors:

- who intend to acquire, or may acquire (either on their own or together with persons with whom they are connected or associated for tax purposes), more than 10 per cent., of any of the classes of shares in the Company; or
- who intend to acquire Ordinary Shares as part of tax avoidance arrangements; or
- who are in any doubt as to their taxation position.

Such Shareholders should consult their professional advisers without delay. Shareholders should note that tax law and interpretation can change and that, in particular, the levels, basis of and reliefs from taxation may change. Such changes may alter the benefits of investment in the Company.

Shareholders who are neither resident nor temporarily non-resident in the UK and who do not carry on a trade, profession or vocation through a branch, agency or permanent establishment in the UK with which the Ordinary Shares are connected, will not normally be liable to UK taxation on dividends paid by the Company or on capital gains arising on the sale or other disposal of Ordinary Shares. Such Shareholders should consult their own tax advisers concerning their tax liabilities.

### *Dividends*

Where the Company pays dividends, no UK withholding taxes are deducted at source. Shareholders who are resident in the UK for tax purposes will, depending on their circumstances, be liable to UK income tax or corporation tax on those dividends.

UK resident individual Shareholders who are domiciled in the UK, and who hold their Ordinary Shares as investments, will be subject to UK income tax on the amount of dividends received from the Company.

Dividend income received by UK tax resident individuals will have a £2,000 per annum dividend tax allowance. Dividend receipts in excess of £2,000 per annum will be taxed at 7.5 per cent. for basic rate taxpayers, 32.5 per cent. for higher rate taxpayers and 38.1 per cent. for additional rate taxpayers. An additional Health & Social Levy of 1.25 per cent. has also been announced that will apply on dividend payments from April 2022.

Shareholders who are subject to UK corporation tax should generally, and subject to certain anti-avoidance provisions, be able to claim exemption from UK corporation tax in respect of any dividend received, but will not be entitled to claim relief in respect of any underlying tax.

### *Disposals of Ordinary Shares*

Any gain arising on the sale, redemption or other disposal of Ordinary Shares will be taxed at the time of such sale, redemption or disposal as a capital gain.

The rate of capital gains tax on disposal of Ordinary Shares by basic rate taxpayers is 10 per cent. and for upper rate and additional rate taxpayers is 20 per cent.

Subject to certain exemptions, the corporation tax rate applicable to a Shareholder's corporate taxable profits is currently 19 per cent. In the Budget on 3 March 2021, it was announced that the rate would increase to 25 per cent. after 1 April 2023.

***Further information for Shareholders subject to UK income tax and capital gains tax***

***"Transactions in securities"***

The attention of Shareholders (whether corporates or individuals) within the scope of UK taxation is drawn to the provisions set out in, respectively, Part 15 of the Corporation Tax Act 2010 and Chapter 1 of Part 13 of the Income Tax Act 2007, which (in each case) give powers to HMRC to raise tax assessments so as to cancel "*tax advantages*" derived from certain prescribed "*transactions in securities*".

***Stamp Duty and Stamp Duty Reserve Tax***

The statements below are intended as a general guide to the current position. They do not apply to certain intermediaries who are not liable to stamp duty or stamp duty reserve tax or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

No stamp duty or stamp duty reserve tax will generally be payable on the issue of Ordinary Shares.

Neither UK stamp duty nor stamp duty reserve tax should arise on transfers of Ordinary Shares on AIM (including instruments transferring Ordinary Shares and agreements to transfer Ordinary Shares) based on the following assumptions:

- the Ordinary Shares are admitted to trading on AIM, but are not listed on any market (with the term "*listed*" being construed in accordance with section 99A of the Finance Act 1986), and this has been certified to Euroclear; and
- AIM continues to be accepted as a "*recognised growth market*" as construed in accordance with section 99A of the Finance Act 1986).

In the event that either of the above assumptions does not apply, stamp duty or stamp duty reserve tax may apply to transfers of Ordinary Shares in certain circumstances.

Any transfer of Ordinary Shares for consideration prior to admission to trading on AIM is likely to be subject to stamp duty or stamp duty reserve tax.

The above comments are intended as a guide to the general stamp duty and stamp duty reserve tax position and may not relate to persons such as charities, market makers, brokers, dealers, intermediaries and persons connected with depositary arrangements or clearance services to whom special rules apply.

**THIS SUMMARY OF UK TAXATION ISSUES CAN ONLY PROVIDE A GENERAL OVERVIEW OF THESE AREAS AND IT IS NOT A DESCRIPTION OF ALL THE TAX CONSIDERATIONS THAT MAY BE RELEVANT TO A DECISION TO INVEST IN THE COMPANY. THE SUMMARY OF CERTAIN UK TAX ISSUES IS BASED ON THE LAWS AND REGULATIONS IN FORCE AS OF THE DATE OF THIS DOCUMENT AND MAY BE SUBJECT TO ANY CHANGES IN UK LAWS OCCURRING AFTER SUCH DATE. LEGAL ADVICE SHOULD BE TAKEN WITH REGARD TO INDIVIDUAL CIRCUMSTANCES. ANY PERSON WHO IS IN ANY DOUBT AS TO HIS OR HER TAX POSITION OR WHERE HE IS RESIDENT, OR OTHERWISE SUBJECT TO TAXATION, IN A JURISDICTION OTHER THAN THE UK, SHOULD CONSULT HIS OR HER PROFESSIONAL ADVISER.**

## 17 MANDATORY BIDS, SQUEEZE OUT AND SELL-OUT RULES RELATING TO THE ORDINARY SHARES

17.1 **Mandatory bid**

The Takeover Code applies to the Company. Under the Takeover Code, if an acquisition of Ordinary Shares were to increase the aggregate holding of the acquiror and its concert parties to shares carrying 30 per cent. or more of the voting rights in the Company, the acquiror and, depending on the circumstances, its concert parties, would be required (except with the consent of the Panel) to make a cash offer for the outstanding shares in the Company at a price not less than the highest price paid for the Ordinary Shares by the acquiror or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of shares by a person holding (together with its concert parties) shares carrying between 30 per cent. and 50 per cent. of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the voting rights.

17.2 **Squeeze-out**

Under the Act, if an offeror were to acquire 90 per cent. of the Ordinary Shares within four months of making its offer, it could then compulsorily acquire the remaining ten per cent. It would do so by sending a notice to outstanding Shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would execute a transfer of the outstanding shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for outstanding Shareholders. The consideration offered to the Shareholders whose shares are compulsorily acquired under the Act must, in general, be the same as the consideration that was available under the takeover offer.

17.3 **Sell-out**

The Act also gives minority Shareholders in the Company a right to be bought out in certain circumstances by an offeror who had made a takeover offer. If a takeover offer related to all the Ordinary Shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90 per cent. of the Ordinary Shares, any holder of shares to which the offer relates who has not accepted the offer can by a written communication to the offeror require it to acquire those shares. The offeror would be required to give any Shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority Shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period. If a Shareholder exercises its rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

## 18 DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents will be available for inspection during usual business hours on any day (Saturdays, Sundays and public holidays excepted) at the offices of Computershare Investor Services plc at the Pavilions, Bridgwater Road, Bristol, BS13 8AE for a period of a month from the date of this document:

18.1 the memorandum and articles of association of the Company; and

18.2 the Accountant's Reports on the Historical Annual Financial Information of the Exxon Target Companies and the PETRONAS Target Companies from Crowe U.K. LLP set out in Parts 7A and 7D, respectively, of this document.

## 19 COPIES OF THIS DOCUMENT

Copies of this document will be available to the public free of charge at the offices of Computershare Investor Services plc at the Pavilions, Bridgwater Road, Bristol, BS13 8AE during normal business hours on any weekday (other than Saturdays, Sundays and public holidays), for a period of at least one month from the date of Re-Admission. This document will also be available for download from the Company's website at www.savannah-energy.com.

## PART 13

## CORPORATE GOVERNANCE

### 1. Introduction

The Board of Directors of Savannah recognises its responsibility for the proper management of the Company and the importance of sound corporate governance, proportionate to the size and nature of the Company and the interests of its shareholders. As an AIM-quoted Company, the Board is committed to maintaining high standards of corporate governance and has adopted the QCA Code as the basis of the Group's governance framework. The Company's statement of compliance with the QCA Code is published and updated at least annually on its website at www.savannah-energy.com.

Set out below is a summary of the Company's current corporate governance structure and practices.

### 2. The Board

The Board is collectively responsible to the shareholders of Savannah for the effective oversight and long term success of the Company. The Board has overall responsibility for the Company's purpose, strategy, business model, performance, capital structure, approval of key contracts and major capital investment plans, the framework for risk management and internal controls, governance matters and engagement with shareholders and the wider stakeholders. The Board remains focused on understanding the needs of shareholders and other stakeholders and considering how the Board's decisions impact them in the longer term. The Board's full responsibilities are detailed in a formal schedule of matters reserved for its decision.

The Board has established a schedule of quarterly meetings, with additional meetings convened when required. The Board addresses several recurring items at each Board meeting, including strategic, operational and financial performance updates, reports from the Board Committees, risk management, investor relations, corporate communications, governance matters, stakeholder engagement and ESG matters.

### 2.1 The roles of the Chair and the Chief Executive

The roles of the Chair and the Chief Executive are separate, with a clear division of responsibilities. The separation of authority enhances the independent oversight of the executive management by the Board and helps to ensure that no one individual on the Board has unfettered authority.

The Board is chaired by Steve Jenkins, a Non-Executive Director who, in accordance with the principles of the QCA Code, is responsible for leading the Board and ensuring that it remains effective in fulfilling its role. Mr. Jenkins is considered to be independent within the meaning of the QCA Code. The Chair is responsible for setting the Board's agenda, ensuring that there is appropriate focus on strategic issues and the monitoring of performance. The Chair promotes a culture of openness and debate within the Board, where Directors can discuss and challenge the actions of the executive management, as well as the views of all Directors, promoting good decision-making and ultimately supporting the Company's long-term, sustainable success. The Committee Chairmen perform the same role for their Committees.

Andrew Knott is the Chief Executive Officer. He is responsible for managing the day to day operations and the implementation of the strategy of the Company on behalf of the Board. The Company's performance and development planning are considered by the Directors in the context of the Company's overall strategy and goals, within the Company's risk and governance frameworks and taking into account their impact on stakeholders in the longer term.

### 2.2 Composition, qualification and independence of the Board

The Board comprises of six Directors: the Non-Executive Chair, the Non-Executive Vice Chair, three Non-Executive Directors and one Executive Director (the CEO). Steve Jenkins, Sir Stephen O'Brien, Mark Iannotti, David Jamison and David Clarkson are all deemed to be independent within the meaning of the QCA Code. Please refer to paragraph 17 of Part 1 for more information in relation to each Director.

The Directors' biographies illustrate the wide range and high calibre of skills and experience that the Directors bring to the Board to help deliver the strategy of the Company for the benefit of the shareholders over the medium to long term. An in-depth review of the skills, capabilities, experience and personal qualities of the Directors was completed in 2020, which demonstrated that the Board as a whole does have the necessary mix of experience, skills, personal qualities and capabilities. These include appropriate industry, strategic, operational, risk management, financial, legal, geopolitical and regulatory experience and, in the case of the Non-Executive Directors, the willingness and ability to provide robust and objective challenge to the views and assumptions of senior management and other Directors. As the size and complexity of the business increases, the composition of the Board will continue to be reviewed, taking into account the Company's circumstances, strategy and goals.

The Board has considered and reviewed the independence and effectiveness of each Non-Executive Director, taking into account any factors that might, or could appear to, affect a Director's judgement and therefore their independence. The Board considers that the performance-related shares and options awarded to certain of the Non-Executive Directors encourage the alignment of their interests with those of the Company's shareholders and are not material enough to compromise their independence, character or judgement. In line with the QCA Code, the Board is, therefore, of the view that Sir Stephen O'Brien, Vice Chair of the Board and current Chair of the Compliance Committee, Mark Iannotti, Chair of the Audit and Risk Committee, David Jamison, Chair of the Remuneration and Nomination Committee, and David Clarkson, Chair of the Health, Safety and Security Committee, were, and continue to be, independent in character and judgement and free from relationships or circumstances that could affect their independence. Steve Jenkins, Chair of the Board, was deemed to have met the criteria for independence set out in the QCA Code upon his appointment and continues to be considered independent.

### 2.3 Board evaluation and appointments to the Board

In line with the recommendations of the QCA Code, the Board undertakes an annual evaluation of its performance, that of the Chair, the Board's Committees and individual Directors. To date, the evaluation has been conducted based on a detailed questionnaire followed by a discussion to assess the effectiveness of the current activities and processes and to identify any possible areas for improvement. The latest questionnaire focused on the following areas:

1. Balance of matters discussed at Board meetings;
2. Communications with shareholders and other stakeholders;
3. Effectiveness of the Chair and individual directors;
4. Work of the Board committees;
5. Relationship between the Non-Executive Directors and the Executive Directors; and
6. Governance arrangements.

The results were anonymised and the findings were presented to the Board for review. The results suggested that despite the constraints imposed by the COVID-19 pandemic, the Board, its Committees and the individual Directors continued to be well briefed by management and to perform effectively. Actions arising from recommendations to further improve the effectiveness of the Board are being implemented, and will include the holding of periodic in-depth reviews of various aspects of strategy and risk, and a continuing focus on succession planning, in particular with a view to increase diversity on the Board.

The Chair also continues to offer the Non-Executive Directors the opportunity to meet regularly, as necessary, in the absence of the CEO, CFO and other members of management.

The Board places value on attracting Directors with diverse outlooks and experience. On the Remuneration and Nomination Committee's recommendation, the Board makes appointments to achieve the balance of skills, experience and knowledge needed, but does so solely on merit. Any Director appointed by the Board must offer himself or herself for election at the first AGM following appointment and for re-election at intervals of three years thereafter.

### 2.4 Directors' Training

The Chair, with the support of the Company's Nominated Adviser, legal advisers and the Company Secretary, is responsible for the induction of new Directors and ongoing development of all Directors. All current Directors of the Company were provided with training in respect of their legal, regulatory and governance responsibilities and obligations in accordance with the UK regulatory regime at the time of their appointment. The comprehensive Board induction programme is tailored to the individual needs and requirements of the Directors, and includes, as necessary, face-to-face meetings with executive management and operational site visits to orientate and familiarise them with the organisation, business, strategy, commercial objectives and key risks.

The Directors also receive regular updates on market and regulatory developments, including legal and governance matters, and are provided with training as required to ensure that their skills and experience are kept up to date.

### 3. Board Committees

The Board delegates certain responsibilities to its Committees, so that it can operate efficiently and give an appropriate level of attention and consideration to relevant matters. The Company has an Audit and Risk Committee and a combined Remuneration and Nomination Committee, a Health, Safety, Security and Environment Committee and a Compliance Committee, all of which operate within a scope and remit defined by specific terms of reference determined by the Board. The composition and role of each Committee is summarised below.

The Board and its Committees are supported by the Company Secretary and a team at Prism Cosec in relation to governance, statutory and compliance matters, as well as with organising Board and Committee meetings and circulating any requisite papers, aiming for information to be provided to the Board members in a timely manner.

### 3.1 The Role of the Audit and Risk Committee

The Audit and Risk Committee is chaired by Mark Iannotti, who, along with its other members, Sir Stephen O'Brien and David Clarkson are considered to be independent Non-Executive Directors of the Company. Mr. Iannotti is considered by the Board to have recent and relevant financial experience and the Committee as a whole has competence relevant to the oil and gas industry. If required, at the request of the Chair of the Committee, the Chief Executive Officer, Interim Chief Financial Officer and other members of the senior management team are also invited to attend meetings.

The terms of reference of the Committee reflect the current statutory requirements and best practice appropriate to a company of Savannah's size, nature and stage of development. Where there is an overlap of responsibilities between the Audit and Risk, Compliance and Health, Safety, Security and Environment Committees, the respective Committee Chairs have the discretion to agree which is the most appropriate Committee to fulfil any obligation.

The role of the Committee is to assist the Board in discharging its oversight responsibilities with regards to: reviewing the financial reporting process, the system of internal controls and management of risk, the audit process and the procedures for monitoring compliance. Any significant finding raised by the external auditors during their review of the half-yearly results of the audit or the full-year results are reviewed and discussed by the Audit and Risk Committee and reported or referred to the Board as appropriate.

The key responsibilities of the Committee are:

- Reviewing the integrity and content of the financial statements, including reviewing and reporting to the Board on significant financial reporting issues and judgements;
- Reviewing the adequacy and effectiveness of the Company's internal controls and risk management policies and systems;
- Reviewing and monitoring compliance policies and systems, including the prevention and detection of fraud and tax evasion;
- Monitoring compliance with applicable regulations;
- Reviewing and approval of the annual audit plan and reviewing the audit findings with the external auditor; and
- Assessing external auditor objectivity and independence and reviewing the performance and remuneration of the external auditor.

The Committee is required to meet at least three times per year.

The terms of reference of the Audit and Risk Committee are available on the Company's website.

### 3.2 The Role of the Remuneration and Nomination Committee

The Remuneration and Nomination Committee is chaired by David Jamison and its other members are Steve Jenkins and Mark Iannotti. All members of the Committee are independent Non-Executive Directors. The Chief Executive Officer and other members of the senior management team are also invited to attend meetings when considered appropriate.

The key responsibilities of the Committee are:

- Determining and reviewing the terms and conditions of service and termination of employment of Executive Directors and senior employees;
- Determining and reviewing the remuneration of Executive Directors and senior employees;
- Reviewing and approving grants of shares or options, from time to time;
- Reviewing and recommending to the Board appointments and re-elections of Directors to the Board; and
- Reviewing the composition of the Board, the membership of the Committees and making recommendations to the Board on any proposed changes.

The Remuneration and Nomination Committee is required to meet at least twice a year. Its terms of reference are available on the Company's website.

### 3.3 The Role of the Health, Safety, Security and Environment Committee

The Health, Safety, Security and Environment Committee is chaired by David Clarkson and its other members are Steve Jenkins and Sir Stephen O'Brien. All of them are considered to be Independent Non-Executive Directors.

The role of the Committee is to oversee the framework of policies, procedures, systems and controls in place in relation to the health, safety, environmental, operational integrity and security risks arising from the operations of the Group. The terms of reference of the Committee outline its key responsibilities and reflect the current statutory requirements and best practice commensurate and proportionate to a company evolving to a full-cycle energy company of Savannah's scale.

The key responsibilities of the Committee are:

- Ensuring that the Company has an appropriate framework of policies, procedures, systems and controls in place in relation to the health, safety, security and environmental risks arising from the operations of the Group;
- Overseeing compliance with, and effectiveness of, the HSSE framework;
- Promoting appropriate behaviours, decisions and culture;
- Communicating the Board's commitment to these matters to the Group's staff, contractors and other stakeholders.
- Receiving reports on an serious accidents and incidents within the Group, including corresponding actions taken by management; and
- Overseeing the quality and integrity of any reporting to external stakeholders regarding health, safety, operational integrity, security and environmental matters.

The Committee is required to meet at least three times a year. Its terms of reference are available on the Company's website.

### 3.4 The Role of the Compliance Committee

The Compliance Committee is chaired by Sir Stephen O'Brien and its other members are David Clarkson, David Jamison and Mark Iannotti. All of them are considered to be Independent Non-Executive Directors.

The role of the Committee is to support the Board in carrying out its duty to promote and oversee compliance with all legal and regulatory obligations. The terms of reference of the Committee outline its key responsibilities and reflect the current statutory requirements and best practice proportionate to a company of Savannah's size, nature and stage of development.

The key responsibilities of the Committee are:

- Reviewing and monitoring compliance controls, policies and systems to identify, assess, manage and report on compliance matters, including;
    - o maintaining adequate compliance procedures, policies and systems;
    - o the prevention of bribery, corruption, money laundering and countering of terrorist financing;
    - o gifts and hospitality, per diem payments, business relationships, including dealings with public officials, agents, intermediaries, consultants, contractors and advisers;
    - o mergers, acquisitions and major new projects;
    - o whistleblowing arrangements and reports;
    - o conflicts of interest; and
    - o legal and regulatory compliance risks.
- Assessing the adequacy and effectiveness of the compliance framework; and
- Communicating the Board's commitment to compliance to the Group's staff, contractors and other stakeholders.

The Committee is required to meet at least four times a year. Its terms of reference are available on the Company's website.

**4. Share Dealing Code**

The Company has adopted a share dealing policy which sets out the requirements and procedures for the Board and applicable employee's dealings in any of its AIM securities in accordance with the provisions of EU Market Abuse Regulations ("MAR") and of the AIM Rules. All Directors have received training on MAR, and this has also been cascaded down to all employees who may come into possession of inside information or become aware of information that could potentially be inside information, to ensure they are aware of how to handle it.

**5. Whistleblowing and anti-bribery and anti-corruption controls**

Savannah is committed to achieving high standards of conduct and accountability. The Company's functional matrix organisation structure allows employees to openly report legitimate concerns regarding any possible improprieties in financial reporting or noncompliance with applicable laws, regulations or Group policies, danger to health and safety, damage to the environment or other matters. The Company has an independently run whistleblowing hotline and other mechanisms that enable the employees to raise any concerns anonymously, without fear of penalty or punishment. The Compliance Committee regularly reviews whether these arrangements continue to function effectively.

The Company has adopted an Anti-Corruption and Bribery policy which applies to the Board and all employees of the Group. It generally sets out their responsibilities in observing and upholding a zero-tolerance position on bribery and corruption in all jurisdictions in which the Group operates, as well as providing guidance on how to recognise and deal with bribery and corruption issues and their potential consequences.

The Group's policy is circulated to all Group employees and is provided to any new joiners and consultants employed by the Group, to ensure it is embedded across the organisation and jurisdictions. All Group employees are required to confirm receipt of the policy and undergo anti-corruption and money laundering training on an annual basis. Management at all levels are responsible for ensuring that those reporting to them, internally and externally, conduct business in compliance with this policy.

## 6. Risk Management and Internal Controls

The Board has overall responsibility for establishing and maintaining the Group's system of internal controls and risk management and reviewing its effectiveness. As with any successful company, delivering the Company's business objectives and overall strategy will involve taking considered risks. The Group's internal controls and risk management framework have been designed to assist the Board in making robust decisions to create and protect shareholder value through sustainable growth over the medium to long term.

The Board recognises that such a system has its limitations. Internal controls can only provide reasonable, not absolute, assurance against material misstatement or loss. The purpose of an effective risk management framework is to assess and manage rather than eliminate risk entirely, which involves Directors and senior management exercising a degree of judgement.

The internal control framework within which the Group operates includes the following key elements:

- Organisational structures (functional matrix organisational structure), delegations of authority and reporting lines
- Group accounting and control procedures to manage the Group consolidation and reporting requirements, including:
  - o Review of monthly management accounts with comparison of actual performance against budget; and consideration of the outturn for the year;
  - o Monthly reconciliation of all key control accounts;
- Budgetary process and monthly monitoring of the annual budget, business performance and deviations from the budget; and
- Operational and strategic review processes for all aspects of the Group's business.

A number of policies and procedures are also in place as part of the Group's internal control framework, which include the Group Anti-Corruption and Money Laundering policy, the Delegation of Authority system, and Travel and Entertainment and Petty Cash policies.

## 7. Conflicts of Interest

Directors have a statutory duty to avoid situations in which they have, or could have, interests that conflict with those of the Company, unless that conflict is first authorised by the Board. The Company's Articles allow the Board to authorise any potential or actual conflict of interest that a Director may have and a process to identify and deal with any such conflicts is in place. Should a Director become aware that they, or their connected parties, have a new potential or actual conflict of interest, they are required to notify the Board. The Board then deals with each conflict on its merits, taking into consideration all the relevant circumstances. All potential and actual conflicts approved by the Board are recorded in a Register of Interests, which is reviewed by the Board at each Board meeting.

## 8. Culture and Stakeholders

Savannah is committed to promoting a healthy and responsible corporate culture. Accordingly, a number of policies and mechanisms are in place to ensure that ethical values and behaviours and fair business practices are embedded in the way the Company operates. The Company expects all employees, suppliers, contractors and consultants to conduct their day-to-day business activities in a fair, honest and ethical manner.

The framework of policies and procedures in place enables the Board to ensure that the Group's employees and those who provide services to it act in accordance with high standards of ethical conduct and the Company only does business with persons who are engaged in legitimate business activities and who use funds from legitimate sources.

# PART 14

# MATERIAL CONTRACTS

## 1 MATERIAL CONTRACTS

The following contracts, not being contracts entered into in the ordinary course of business, have been entered into by the Company or any member of the Group and are or may be material or contain any provision under which any member of the Group has an obligation or entitlement which is material to the Group as at the date of this document.

Defined terms in this Part 14 refer to the same defined terms within the contracts and may or may not be redefined here.

### 1.1 Financial adviser appointments

1.1.1 On 3 December 2020, the Company appointed finnCap Ltd as its Joint Corporate Broker. The Company agreed to pay finnCap Ltd an annual retainer fee in respect of its services.

1.1.2 On 3 December 2020, the Company appointed Panmure Gordon (UK) Limited as its Joint Corporate Broker. The Company agreed to pay Panmure Gordon (UK) Limited an annual retainer fee in respect of its services.

### 1.2 IP Licence Agreement

The Company has received from Andrew Knott (the "Licensor") a non-exclusive, royalty free, transferable, perpetual world-wide right and licence, with the right to sublicense (including to members of the Group), in all intellectual property rights in and relating to "Savannah" and such other intellectual property rights as the Licensor may deliver to the Company (the "IPR"). The license terminates only upon the Company materially breaching the agreement (and leaving such breach unremedied for 30 days), becoming insolvent, or undergoing a change in control. The Company may not use the licensed IPR for any purpose other than in connection with oil and gas exploration and production activities. Other than the initial consideration of £1, paid to obtain the license, there is no fee payable to the Licensor in respect of the license other than to reimburse such costs (eg. trademark fees) as the Licensor may incur in connection therewith. In the event a sub-licensor misuses the licensed IPR, the Company indemnifies the Licensor for any losses suffered thereby.

### 1.3 Placing Agreement

The Company has entered into a placing agreement dated 30 December 2021 with the Directors, Brokers and Strand Hanson pursuant to which the Brokers have been appointed to use their reasonable endeavours to procure the placing of the Placing Shares. The Brokers' obligations are conditional upon Admission taking place on or before 8.00 a.m. on 31 December 2021 or such later date or time as the Company and the Brokers may agree, but in any event being no later than 13 January 2022. Subject to the terms and conditions of the Placing Agreement, the Company has agreed to pay the Brokers a commission on funds raised. Under the terms of the Placing Agreement, the Company and the Directors have given certain customary warranties and indemnities to the Brokers in connection with Admission and other matters relating to the Company and its affairs. The Brokers and Strand Hanson may terminate the Placing Agreement in certain specified circumstances prior to the admission of the Placing Shares to trading on AIM, principally if any of the warranties has ceased to be true and accurate or has become misleading.

### 1.4 Loan facilities

1.4.1 On 20 August 2021, Savannah Niger entered into a facility agreement with Oragroup SA in respect of a FCFA 7,500,000,000 (€11.4 million) revolving loan facility in order to finance its working capital, potential asset acquisitions and general corporate purposes. The Company has guaranteed Savannah Niger's obligations under the facility agreement. The loan agreement is due to terminate on 31 December 2022.

1.4.2 On 16 October 2019, the Company entered into an instrument constituting up to £867,603 of unsecured, non-interest-bearing loan notes, and issued an aggregate £867,603 of loan notes to certain noteholders. The instrument was amended and restated on 30 April 2020, 26 November 2020 and most recently on 26 April 2021. The loan notes are to be redeemed in instalments between 30 June 2021 and 31 January 2022.

1.4.3 On 30 April 2020, the Company entered into a US$15 million finance and investment agreement with Vision Energy Ltd. This was amended and restated on 27 May 2021, and the monies available under the agreement were increased to US$20 million. The finance is available for use in connection with the Group's general corporate and working capital purposes. A redemption fee of 8 per cent. per annum accrues on any amounts of the finance drawn down from time to time on a straight line basis and is payable on the date any amount of the finance is repaid. The finance and investment agreement also provides for an arrangement fee of US$1,000,000 to be payable on the final repayment date under the finance agreement, being the earlier of the date falling: (i) 31 December 2022; or (ii) 15 business days after a qualifying debt or equity fundraising by the Company raising more than US$5 million. The ability to draw down on the finance is dependent on Andrew Knott being CEO of the Company at that time, though any departure of Andrew Knott does not trigger immediate repayment of drawn amounts.

1.4.4 On 9 September 2021, the Company entered into a US$20 million bridge facility agreement with Vitol SA. The facility is available for the purpose of funding transaction costs and paying the deposit related to the PETRONAS Acquisition. Interest of 8 per cent. plus LIBOR accrues on any amounts of the facility drawn from time to time on a straight line basis and is payable on the date any amount of the facility is repaid. The loan agreement and fee letter provide that the Company must pay a utilisation fee of 1.5 per cent. of the amount stated in each utilisation request.

1.5 **The Subscription Letters**

Each Subscriber has entered into a Subscription Letter with the Company to subscribe for their allocation of Subscription Shares at the Issue Price. Each Subscription Letter contains customary certifications and undertakings from the Subscriber as to their identity and level of sophistication. Each Subscriber's obligation to subscribe for Subscription Shares is conditional upon Admission taking place by no later than 13 January 2022. Each Subscription Letter is governed by the laws of England and Wales. The Subscription Letter for Andrew Knott allows for the subscription proceeds to be paid to the Company by no later than 30 April 2022.

## 2 MATERIAL TRANSACTION DOCUMENTS RELATING TO THE EXXON ACQUISITION AND THE PETRONAS ACQUISITION

A summary of each of the material contracts entered into in connection with the Exxon Acquisition and the PETRONAS Acquisition are summarised in Part 2 of this document.

2.1 **Share Sale and Purchase Agreement relating to the Exxon Acquisition**

2.1.1 On 12 December 2021, Savannah Chad and the Exxon Sellers entered into a share sale and purchase agreement in relation to the entire issued share capital of EEPCI and EPIL (the "Exxon Sale Shares") (the "Exxon SPA"). Upon completion of the Exxon SPA, the effective date for the acquisition will be deemed to be the Economic Effective Date.

2.1.2 Pursuant to the terms of the Exxon SPA, Savannah Chad is due to pay the Exxon Sellers an aggregate deposit of US$16.5 million. Savannah Chad (i) paid US$2 million on the date of signature of the Exxon SPA; and (ii) is due to pay US$14.5 million within 5 business days of publication of this document, which will be deducted from the amount of consideration payable by Savannah Chad at Completion.

2.1.3 The Exxon Sellers have the right to retain the deposit in the event:

(a) Savannah Chad fails to deliver evidence of committed funding for the Exxon Acquisition within a certain time period following signature of the Exxon SPA; or

(b) the Exxon Acquisition fails to complete before the date falling 12 months from the date of signing the Exxon SPA (the "Exxon Longstop Date") due to the fault of Savannah Chad.

2.1.4 In accordance with the terms of the Exxon SPA, on 12 December 2021, the Company entered into a parent company guarantee for the benefit of the Exxon Sellers in relation to all of Savannah Chad's payment and performance obligations under the Exxon SPA.

2.1.5 Savannah Chad has agreed to pay the Exxon Sellers the following consideration for the Exxon Sale Shares:

(a) **Completion consideration**:

(i) US$255,600,000 in cash for the entire issued share capital of EEPCI (plus interest); plus

(ii) US$104,400,000 in cash for the entire issued share capital of EPIL (plus interest); plus or less (as applicable)

(iii) the sum of certain completion date adjustments, (plus interest on certain of these adjustments), including: (i) a positive adjustment for EEPCI's underlift position) as at the Economic Effective Date; (ii) a negative adjustment for any leakage from the Exxon Target Group Companies during the interim period; (iii) a positive adjustment for any contributions made to the Exxon Target Group Companies by the Exxon Sellers during the interim period; (iv) a negative adjustment for certain agreed cash amounts extracted from the Exxon Target Group Companies by the Exxon Sellers immediately prior to Completion; and (v) an adjustment to compensate for EEPCI failing to achieve its target production between 1 November 2021 and Completion; plus (vi) to the extent that EEPCI fails to achieve its target production (should the effect of an incident, which affected the water handling system at the Miandoum gathering station, not have been rectified) a negative adjustment at Completion proportionate to the extent to which the then current production falls short of target production, followed by a contingent positive post-Completion non-interest bearing payments payable from the proceeds of EEPCI's crude oil over a four year period post-Completion should the target production be re-achieved; plus

(b) **Contingent consideration:** up to an aggregate of US$50,000,000 of non-interest bearing contingent consideration, by means of payment to Exxon Mobil Corporation of 25 per cent. of the proceeds of sale of EEPCI's entitlement to crude oil (net of any royalty barrels or royalty payments due to Government of Chad and barrels used in operations) received by EEPCI above FOB US$55 per bbl and up to FOB US$80 per bbl, between 1 January 2021 and 31 December 2023. The first of such payments shall be made at Completion.

2.1.6 As mentioned in Part 2 of this document, the Exxon SPA provides that each of Savannah Chad and the Exxon Sellers are under a reasonable endeavours obligation to satisfy (or waive) the various conditions precedent by the Exxon Longstop Date:

(a) obtaining Ministerial Consent;

(b) receipt of waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the indirect transfer of shares in PC Chad in accordance with the PETRONAS SPA;

(c) EEPCI obtaining a settlement between EEPCI and the Government of Chad with respect to certain items, including all taxes or similar levies in relation to the activities of EEPCI prior to the Economic Effective Date;

(d) obtaining Company shareholder approval at the General Meeting;

(e) the issue to the Exxon Sellers of a commitment letter or other evidence (in each case, in a form reasonably satisfactory to the Exxon Sellers) from one or more lenders reasonably satisfactory to the Exxon Sellers confirming committed funding to fund the Exxon Acquisition and the approval of such funding by their respective credit committees;

(f) the submission by EEPCI to HM Revenue and Customs of a Section 18 Corporation Tax Act 2009 election to apply to all foreign establishments;

(g) material completion of the transfer of Exxon's IT systems used in the operation of the Exxon Target Companies and Pipeline Companies to Savannah Chad that have been agreed to be transferred; and

(h) evidence of the transfer of all rights and obligations of Esso Pipeline Services, Inc. ("EPSI") under the COTCo Pipeline Services Agreement (detailed in paragraph 5.11.2(a)(ii) below) to EPIL,

(the "Exxon CPs").

2.1.7 Between the date of signature of the Exxon SPA and completion:

(a) the Exxon Sellers have agreed to comply with a suite of interim covenants, including restrictions relating to the ownership, control and operations of the EEPCI and EPIL;

(b) if a material adverse change were to occur with respect to any of EEPCI and EPIL, depending on whether such material adverse change is remediable or not, the Exxon SPA provides that the Exxon Sellers may elect to remedy the resulting damage, or the parties may agree to reduce the consideration amount or terminate the Exxon SPA; and

(c) the Exxon Sellers shall procure that all existing intercompany agreements between EEPCI and EPIL and the Exxon group are terminated as at completion.

2.1.8 Under the terms of the Exxon SPA, following completion:

(a) Savannah Chad is under certain obligations to ensure that EEPCI and EPIL are de-branded, and no longer use any Exxon trademarks, logos, trade names and any other Exxon identifying features; and

(b) Savannah Chad is responsible for providing all insurance cover for each of EEPCI and EPIL and their businesses, operations and assets.

2.1.9 Under the Exxon SPA:

(a) the Exxon Sellers have given Savannah Chad:

(i) a suite of business related warranties, including in relation to their ownership of EPPCI and EPIL, their title to interests in the Doba Oil Field Development Area and the Pipeline Companies, certain material contracts, environmental issues, employment, tax, abandonment and litigation. The Exxon Sellers have also given certain limited warranties with respect to the Pipeline Companies, and the Chad-Cameroon pipeline business, qualified by the Exxon Sellers' knowledge. The liability of the Exxon Sellers under the Exxon SPA with respect to these warranties is subject to a number of limitations of liability, including: (A) limitations on claim period time, minimum claim size and a cap on the maximum financial liability of the Exxon Sellers; and (B) excluding liability for claims relating to information disclosed by the Exxon Sellers to Savannah Chad.

(ii) subject to completion occurring, certain tax related indemnities and an indemnity with respect to EEPCI's participating interest share of any liabilities arising from certain labour related cases commenced by the ex-employees of a previous contractor (TCC) of the Doba Consortium. The liability of the Exxon Sellers under certain of these indemnities is subject to certain limitations, including a cap on the maximum financial liability of the Exxon Sellers.

(b) Savannah Chad has given the Exxon Sellers:

(i) certain warranties relating to Savannah Chad and its capacity and authority to enter into the Exxon SPA.

(ii) subject to completion occurring and to certain carve outs (mentioned below), a 'clean break' indemnity with respect to any and all liabilities (including environmental, abandonment and safety liabilities) suffered, whether before or after the Effective Date, by the Exxon group or their directors, employees or officers as a result of any liability connected with EEPCI's and EPIL's respective interests in the upstream and midstream businesses in Chad and Cameroon. Under the carve outs from the indemnity, Savannah Chad shall not be liable for: (A) certain taxes which the Exxon Sellers are indemnifying the Company for under the SPA (see paragraph 2.1.9(a)(ii) above); and (B) liabilities arising from the TCC related claims (see paragraph 2.1.9(a)(ii) above).

2.1.10 The Exxon SPA may be terminated:

(a) by mutual agreement between Savannah Chad and the Exxon Sellers;

(b) by the Exxon Sellers if: (i) Savannah Chad fails to deliver evidence of committed funding for the Exxon Acquisition within a certain time period following signature of the Exxon SPA; or (ii) the Exxon CPs are not satisfied or waived by the Exxon Longstop Date and the Exxon Sellers have not breached or failed to comply with its relevant reasonable endeavours obligations with respect to the Exxon CPs;

(c) by Savannah Chad if the Exxon CPs are not satisfied or waived by the Exxon Longstop Date and Savannah Chad has not breached or failed to comply with its relevant reasonable endeavours obligations with respect to the Exxon CPs; or

(d) by either party if:

(i) the other party fails: (i) to comply with certain anti-bribery and corruption obligations set out in the Exxon SPA; (ii) refuses or is unable for any reason not permitted by the Exxon SPA to achieve completion; (iii) to comply with its completion date obligations; or

(ii) a material adverse change occurs as described in paragraph 2.1.7(b) above.

2.1.11 The Exxon SPA is governed by English law. Disputes shall be resolved in the first instance by amicable negotiations between the parties for thirty days, failing which disputes shall be settled by ICC arbitration in English in London by a three-member arbitration panel.

2.2 **Share Sale and Purchase Agreement relating to the PETRONAS Acquisition**

2.2.1 On 2 December 2021, Savannah Chad and PETRONAS entered into a share sale and purchase agreement in relation to the entire issued share capital of PCCEPI (the “PETRONAS Sale Shares”) (the “PETRONAS SPA”). Upon completion of the PETRONAS SPA, the effective date for the acquisition will be deemed to be the Economic Effective Date.

2.2.2 Pursuant to the terms of the PETRONAS SPA, on 2 December 2021 Savannah Chad paid to PETRONAS a deposit of US$5 million, which will be deducted from the amount of consideration payable by Savannah Chad at Completion.

2.2.3 PETRONAS has the right to retain the deposit in the event:

(a) Savannah Chad fails to deliver evidence of committed funding for the PETRONAS Acquisition within a certain time period following signature of the PETRONAS SPA; or

(b) the PETRONAS Acquisition fails to complete before the date falling 12 months from the date of signature of the PETRONAS SPA (the “PETRONAS Longstop Date”) due to the fault of Savannah Chad; or

(c) Savannah Chad fails to obtain the approval of the CEMAC Council for Competition (*Conseil Communautaire de la Concurrence*) prior to the PETRONAS Longstop Date.

2.2.4 In accordance with the terms of the PETRONAS SPA, on 2 December 2021 the Company entered into a parent company guarantee for the benefit of PETRONAS in relation with guaranteeing all of Savannah Chad’s payment and performance obligations under the PETRONAS SPA

2.2.5 Savannah Chad has agreed to pay PETRONAS the following consideration for the PETRONAS Sale Shares:

(a) **Completion consideration**:

(i) US$266,000,000 in cash (plus interest); *plus or less (as applicable)*

(ii) the sum of certain completion date adjustments, including: (A) a positive adjustment for cash as at the Economic Effective Date; (B) a positive adjustment for the working capital balance of the PETRONAS Target Companies as at the Economic Effective Date; (C) a negative adjustment for the value of overlift as at the Economic Effective Date; (D) a negative adjustment for any leakage from the PETRONAS Target Companies during the interim period; (E) a positive adjustment for any contributions made to the PETRONAS Target Companies by PETRONAS during the interim period; and (F) a negative adjustment for certain agreed cash amounts extracted from the PETRONAS Target Companies by PETRONAS immediately prior to Completion.

2.2.6 As mentioned in Part 2 of this document, the PETRONAS SPA provides that each of Savannah Chad and PETRONAS are under a reasonable endeavours obligation to satisfy (or waive) the following conditions precedent by the PETRONAS Longstop Date:

(a) obtaining Ministerial Consent;

(b) receipt of waiver from the other members of the Doba Consortium of their preferential rights under the Doba JOA in relation to the indirect transfer of shares in PC Chad in accordance with the PETRONAS SPA; and

(c) obtaining Company shareholder approval for the PETRONAS Acquisition at the General Meeting,

(the "PETRONAS CPs").

2.2.7 Between the date of signature of the PETRONAS SPA and Completion:

(a) Savannah Chad is under an obligation within certain time periods to:

(i) deliver commitment letters from the relevant Senior Lender entity confirming commitment to fund the Exxon Acquisition and the PETRONAS Acquisition and the unconditional approval of their respective credit committees; and/or

(ii) only where necessary, provide written confirmation that the Company has undertaken an equity fund raise;

(iii) obtain approval from the CEMAC Council for Competition (*Conseil Communautaire de la Concurrence*).

(b) PETRONAS has agreed to comply with a suite of interim covenants, including restrictions relating to the ownership, control and operations of the PETRONAS Target Group Companies;

(c) if a material adverse change were to occur with respect to any of the PETRONAS Target Group Companies, depending on whether such material adverse change is remediable or not, the PETRONAS SPA provides that PETRONAS may elect to remedy the resulting damage, or the parties may agree to reduce the consideration amount or terminate the PETRONAS SPA; and

(d) PETRONAS shall procure that all existing intercompany agreements between the PETRONAS Target Group Companies and the PETRONAS group are terminated as at completion.

2.2.8 Under the terms of the PETRONAS SPA, following completion Savannah Chad is:

(a) under certain obligations to ensure that the PETRONAS Target Group Companies are de-branded, and no longer use any PETRONAS trademarks, logos, trade names and any other PETRONAS identifying features; and

(b) responsible for providing all insurance cover for each of the PETRONAS Target Group Companies and their businesses, operations and assets.

2.2.9 Under the PETRONAS SPA:

(a) PETRONAS has given Savannah Chad a suite of business related warranties, including in relation to the ownership structure of the PETRONAS Target Group Companies, their title to interests in the Doba Oil Field Development Area and TOTCo/COTCo, certain material contracts, environmental issues, employment, tax, abandonment and litigation. PETRONAS has also given certain limited warranties with respect to TOTCo and COTCo, and the Chad-Cameroon pipeline business, qualified by PETRONAS' knowledge. The liability of PETRONAS under the PETRONAS SPA with respect to these warranties is subject to a number of limitations of liability, including: (A) limitations on claim period time, minimum claim size and a cap on the maximum financial liability of PETRONAS; and (B) excluding liability for claims relating to information disclosed by PETRONAS to Savannah Chad.

(b) subject to completion occurring:

(i) certain tax related indemnities, including a pre-Effective Date tax indemnity which is uncapped as regards the financial liability of PETRONAS.

(ii) an indemnity with respect to PC Chad's participating interest share of any liabilities arising from certain labour related cases commenced by the ex-employees of a previous contractor (TCC) of the Doba Consortium.

(c) Savannah Chad has given PETRONAS:

(i) certain warranties relating to Savannah Chad and its capacity and authority to enter into the PETRONAS SPA.

(ii) subject to completion occurring and to certain carve outs (mentioned below), a 'clean break' indemnity with respect to any and all liabilities (including environmental, abandonment and safety liabilities) suffered, whether before or after the Economic Effective Date, by the PETRONAS group or their directors, employees or officers as a result of the PETRONAS Target Group Companies' respective interests in the upstream and midstream businesses in Chad and Cameroon. Under the carve outs from the indemnity, Savannah Chad shall not be liable for: (A) any taxes related losses which the PETRONAS is indemnifying the Company for under the PETRONAS SPA (see paragraph 3.2.9(b)(i) above); (B) any liabilities arising from the TCC related claims (see paragraph 3.2.9(b)(i) above); and (C) any liabilities arising from any ESG claim brought by a State or non-governmental organisation against the PETRONAS group in respect of its and their operations as a global oil and gas company (ie. not specifically relating to the Chad / Cameroon assets).

2.2.10 The PETRONAS SPA may be terminated:

(a) by mutual agreement between Savannah Chad and PETRONAS;

(b) by either PETRONAS or Savannah Chad if the other party: (i) fails, refuses or is unable to complete; (ii) becomes subject to an insolvency event; (iii) breaches certain anti-bribery, corruption or sanctions provisions of the PETRONAS SPA; or (iii) fails to comply with its completion date obligations;

(c) by PETRONAS if: (i) the PETRONAS CPs are not satisfied or waived by the PETRONAS Longstop Date and PETRONAS has not failed to satisfy its relevant reasonable endeavours obligations to satisfy the PETRONAS CPs; (ii) Savannah Chad fails to deliver evidence of committed funding for the PETRONAS Acquisition within a certain time period following signature of the PETRONAS SPA; (iii) Savannah Chad fails to obtain the approval of the CEMAC Council for Competition (*Conseil Communautaire de la Concurrence*) prior to the PETRONAS Longstop Date; or (iv) it elects to terminate due to a material adverse change; or

(d) by Savannah Chad if: (i) the PETRONAS CPs are not satisfied or waived by the PETRONAS Longstop Date and Savannah Chad has not failed to satisfy its relevant reasonable endeavours obligations to satisfy the PETRONAS CPs; (ii) it fails to deliver evidence of committed funding for the PETRONAS Acquisition within a certain time period following signature of the PETRONAS SPA; (iii) Savannah Chad fails to obtain the approval of the CEMAC Council for Competition (*Conseil Communautaire de la Concurrence*) prior to the PETRONAS Longstop Date; or (iv) it elects to terminate due to a material adverse change.

2.2.11 The PETRONAS SPA is governed by English law. Disputes shall be resolved in the first instance by amicable negotiations between the parties for thirty days, failing which disputes shall be settled by ICC arbitration in English in London by a three-member arbitration panel.

2.3 **Transition Services Agreement with Exxon**

2.3.1 Pursuant to the terms of the Exxon SPA, prior to completion Savannah Chad and an appropriate member of the Exxon group shall negotiate and enter into a transitional services agreement under which such member of the Exxon group shall agree to provide (or cause to be provided) certain services for a limited period post-completion and on a transitional and without liability basis.

## 3 MATERIAL FINANCE CONTRACTS RELATING TO THE EXXON ACQUISITION AND THE PETRONAS ACQUISITION

3.1 **Debt Financing**

3.1.1 On 30 December 2021, Savannah Chad entered into a borrowing base facility agreement with the Senior Lender (the "Borrowing Base Facility Agreement").

3.1.2 Pursuant to the terms of the Borrowing Base Facility Agreement, the lenders thereunder (the "Borrowing Base Facility Lenders") will make available to Savannah Chad a revolving credit facility of up to US$400,000,000, subject to an initial maximum of US$300,000,000. The facility will be divided into two tranches; one tranche in an initial amount of US$165,000,000 ("Tranche A") and the other tranche in an initial amount of US$135,000,000 ("Tranche B"). Tranche A may be utilised (among other matters) for the purposes of funding the consideration payable by Savannah Chad under the Exxon SPA and costs and expenses incurred in respect of the Exxon Acquisition. Tranche B may be utilised (among other matters) for the purposes of funding the consideration payable by Savannah Chad under the PETRONAS SPA and costs and expenses incurred in respect of the PETRONAS Acquisition.

3.1.3 The loans advanced under the Borrowing Base Facility Agreement have a final maturity date of 84 months after the date of the Borrowing Base Facility Agreement and interest shall accrue on such loans at a rate which is the sum of the margin (being 7 per cent. per annum) and the compounded reference rate. The interest periods are 3 months in duration and interest is payable on the last day of each interest period. Savannah Chad will pay to the Borrowing Base Facility Lenders: (i) a commitment fee at a rate of 2 per cent. per annum on the amount by which the lower of the Borrowing Base Amount (as defined in paragraph 3.1.5 below) and the Lenders' commitments exceeds the outstanding utilisations and (ii) in relation to the arranging and managing the Debt Financing an advisory fee of up to 5 per cent. of the facility amount.

3.1.4 Semi-annual repayments are due (on each 30 June and 31 December) in accordance with the predetermined reduction profile. The Borrowing Base Facility Agreement contains a number of standard mandatory prepayment events. Savannah Chad may voluntarily prepay any loans outstanding under the Borrowing Base Facility Agreement at any time without penalty or premium.

3.1.5 On each forecast date (being each 30 June and 31 December or more frequently if required (a "Forecast Date")) the parties to the Borrowing Base Facility Agreement shall adopt the latest agreed forecast, including the determination of the net present value of Savannah Chad's interest in the Doba Oil Project and midstream project facilities set out in the forecast (the "Borrowing Base Amount"). On or before each Forecast Date, Savannah Chad shall repay any amount required to ensure that the aggregate outstanding utilisations under the Borrowing Base Facility Agreement do not exceed the lower of the Borrowing Base Amount to be adopted on such Forecast Date and the Borrowing Base Facility Lenders' commitments.

3.1.6 The Borrowing Base Facility Agreement contains certain conditions precedent to the availability of Tranche A and Tranche B. Satisfaction of the conditions precedent is at the discretion of the Borrowing Base Facility Lenders. These conditions precedent include confirmation by the Senior Lender that all required approvals not obtained at date of signing have been obtained, confirmation that the conditions of the Exxon SPA and the PETRONAS SPA are satisfied, technical reports, legal opinions, and execution of an intercreditor agreement between the Borrowing Base Facility Lenders, Savannah Chad and the Junior Loan Facility lender.

3.1.7 The Borrowing Base Facility Agreement contains certain covenants and representations in respect of compliance with anti-corruption laws, environmental laws, sanctions and good industry practice. It also contains standard restrictions on the ability of Savannah Chad, the Exxon Target Companies (following completion of the Exxon Acquisition) and the PETRONAS Target Companies (following completion of the PETRONAS Acquisition) to incur additional financial indebtedness, to grant security over their assets in favour of any person other than the Borrowing Base Facility Lenders and to pay distributions.

3.1.8 Subject to limited exceptions which require the consent of all of the Borrowing Base Facility Lenders, the administrative parties and/or any secured hedging providers, any provision of the Borrowing Base Facility Agreement can be amended or waived with the consent of the majority of the Borrowing Base Facility Lenders (being 66⅔ per cent.).

3.1.9 Following completion of the Exxon Acquisition, each of the Exxon Target Companies is required to accede to the Borrowing Base Facility Agreement as a guarantor and, following completion of the PETRONAS Acquisition, each of the PETRONAS Target Companies is required to accede to the Borrowing Base Facility Agreement as a guarantor. The Borrowing Base Facility Lenders will have the benefit of a comprehensive security package with the loans advanced under the Borrowing Base Facility Agreement being secured against the shares and assets of Savannah Chad, the Exxon Target Companies and the PETRONAS Target Companies. Savannah Chad must also establish and maintain a debt service reserve account which is funded with the higher of $10,000,000 and six months' principal and interest and any unpaid fees. As part of the transaction Andrew Knott has agreed to provide a conditional personal guarantee in relation to the Debt Financing in the period prior to syndication being completed.

3.1.10 On 30 December 2021, Savannah Chad, the Company and the Senior Lender also entered into a mandate letter on standard Loan Market Association terms (including market flex and clear market provisions) which sets out the terms on which the Senior Lender may syndicate its commitment under the Borrowing Base Facility Agreement. It is currently anticipated that syndication will be completed during the first quarter of 2022.

3.2 **Junior Loan Facility**

3.2.1 On 30 December 2021, the Company as borrower, LCP4L as lender and Lothian Capital Partners Holdings Limited as its holding company ("LCPHL HoldCo") entered into the US$32 million Junior Loan Facility. Loans drawn under the Junior Loan Facility (the "Loans") have a 90 month tenor (ie. 7.5 years) and shall accrue interest daily at a rate of: (i) compounded reference rate plus 8 per cent. per annum if paid in cash; or (ii) compounded reference rate plus 10 per cent. per annum if paid-in-kind. An arrangement fee equal to 2 per cent. of the principal amount of each Loan was payable to Lothian Capital Partners 2 Limited (for the account of the LCP4L) upon signing the loan note facility agreement. The Loans and commitment of LCP4L are transferable subject to (i) the consent of the Company (not to be unreasonably withheld or delayed) prior to the occurrence of an event of default under the Junior Loan Facility, and (ii) the accession by the transferee to the intercreditor agreement to be executed in connection with the Exxon Acquisition and the PETRONAS Acquisition.

3.2.2 The Junior Loan Facility shall be subordinated to the Debt Financing and will share on a second-ranking basis the security granted under the Debt Financing. Under the terms of the Junior Loan Facility, the Company has agreed not to grant any security over the assets of the Company other than (i) the security granted to secure the Junior Loan Facility and (ii) the security granted to secure the US$20 million bridge facility agreement under which the Company is a borrower. The Company may voluntarily prepay a Loan, subject to the payment of an early repayment fee of the interest which would have accrued on such Loan for the lesser of: (i) a period of one year from the date of prepayment; and (ii) a period from the date of prepayment to the final maturity date of the Junior Loan Facility. Mandatory prepayment of the Junior Loan Facility will occur in various circumstances, which includes: (i) acceleration under the terms of the Debt Financing: (ii) any refinancing or repayment of the Debt Financing in full, and (iii) the Company incurring more than US$50 million of new debt (in addition to the Junior Loan Facility and the Company's bridge facility).

3.2.3 On 30 December 2021, the Company's Chief Executive Officer, Andrew Knott committed (via LCP4L) to lend: (i) US$17 million to finance the Exxon Acquisition; and (iii) US$15 million to finance the PETRONAS Acquisition. Lothian Capital Partners 3 Limited ("LCP3L") has also committed to subscribe for 11,613,390 new Ordinary Shares as part of the Subscription. At the discretion of Andrew Knott, the Senior Lender may also act as a lender to LCP4L and LCP3L, and in that case the obligations of LCP3L and LCP4L will be cross-guaranteed and secured by Ordinary Shares held by LCP3L in the Company, the Junior Loan Facility advanced by LCP4L and Warrants held by Andrew Knott. LCPHL HoldCo would also grant security over their shares to secure their obligations. Andrew Knott would also provide the Senior Lender with a conditional personal guarantee in relation to certain obligations of LCP3L and LCP4L.

3.3 **Warrant Instrument**

3.3.1 Warrants will be granted to LCP4L as lender under the Junior Loan Facility immediately following the General Meeting, subject to the passing of Resolutions 5 and 9. The number of Warrants to be issued shall be calculated as the total value of the Junior Loan Facility (at the prevailing exchange rate on the date of signature) divided by the Exercise Price. Set out below are the particulars of the principal terms and conditions applying to the Warrants constituted by an instrument entered into by the Company by way of deed poll dated 30 December 2021 (the "Warrant Instrument").

3.3.2 ***Constitution***

The Company has determined by a resolution of the Board to issue up to 101,113,992 Warrants, each Warrant entitling the holder thereof (the "Warrantholder") to subscribe for new Ordinary Shares at the Exercise Price payable in cash in full on subscription.

3.3.3 ***Subscription Rights***

The Warrantholder of each Warrant will have the right ("Subscription Rights"), which may be exercised on any business day from the date of the grant of the Warrants up to (and including) the date falling 90 calendar months after their date of grant (the "Expiry Date") (such period being the "Subscription Period"), to subscribe in cash for one new Ordinary Share (subject to adjustment in accordance with the terms of the Warrant Instrument) in consideration of the payment of the Exercise Price (being 23.5 pence) in full per Warrant, subject to a minimum subscription price of not less than £100,000. The Subscription period shall be extended by a period of three months if the Warrantholder is in possession of relevant price sensitive information or inside information relating to the Company and is thereby precluded from exercising its Subscription Rights on the last day of the Exercise Period. The Warrantholder may elect to pay the subscription price by surrendering to the Company, for cancellation, such number of additional Warrants that have an aggregate value equal to the aggregate subscription price payable (for these purposes, each Warrant shall have a value equal to the prevailing middle market price of one Ordinary Share).

Every Warrant in respect of which Subscription Rights:

(i) have been exercised in full; or

(ii) at the end of the Subscription Period have not been exercised,

shall lapse and be cancelled.

New Ordinary Shares allotted pursuant to the exercise of Warrants in accordance with the terms of the Warrant Instrument shall be issued fully-paid and free from any liens, charges or encumbrances and rights of pre-emption, but shall not rank for any dividends or other distributions declared, made or paid on the Ordinary Shares for which the record date is prior to the date on which the Warrants are exercised (the "Exercise Date") but, subject thereto, shall rank in full for all dividends and other distributions declared, made or paid on the Ordinary Shares on or after the Exercise Date and otherwise *pani passu* in all respects with the Ordinary Shares in issue at that date.

At any time when the Ordinary Shares are admitted to trading on AIM, application will be made by the Company to the London Stock Exchange for the Ordinary Shares allotted pursuant to any exercise of Warrants to be admitted to trading on AIM and the Company will promptly apply for such admission so as to be effective simultaneously with the allotment of the relevant Ordinary Shares pursuant to the exercise of the Warrants in accordance with the terms of the Warrant Instrument becoming effective.

3.3.3 ***Transfer***

The Warrants shall be freely transferable.

3.3.4 ***Undertakings of the Company***

Warrantholders will have made available to them, at the same time and in the same manner as the same are made available to holders of Ordinary Shares, copies of the audited accounts of the Company (with the relevant directors' and auditor's reports) and copies of all other circulars or notices which are made available to holders of Ordinary Shares.

3.3.5 ***Adjustment of Subscription Rights***

The Exercise Price and/or the number of Ordinary Shares for which a Warrantholder is entitled to subscribe shall from time to time be adjusted in accordance with the provisions of the Warrant Instrument to account for, *inter alia*, any sub-division or consolidation of the Ordinary Shares or any issue of Ordinary Shares fully paid by way of capitalisation of profits or reserves, so far as practical to compensate the Warrantholder for the economic effect of such adjustment event.

3.3.6 ***Anti Dilution***

Customary anti-dilution provisions apply for the benefit of Warrantholders including, *inter alia*, where the Company carries out an equity fundraising at a greater than 5 per cent. discount to the prevailing middle market price of the Company's Ordinary Shares.

3.3.7 ***Clawback***

The Warrants cannot be exercised until such time as completion occurs of the Exxon Acquisition or the PETRONAS Acquisition. In the event that the Exxon Acquisition does not complete prior to the Exxon Longstop Date, the Board (save for Andrew Knott) can, at its discretion, cancel the Warrants issued in relation to the Exxon Acquisition (being 53 per cent. of the total Warrants issued), and similarly if the PETRONAS Acquisition does not complete prior to the PETRONAS Longstop Date, the Warrants issued in relation to the PETRONAS Acquisition (being 47 per cent. of the total Warrants issued) can be cancelled at the discretion of the Board (save for Andrew Knott).

## 4 MATERIAL CONTRACTS RELATING TO THE CHAD UPSTREAM ASSETS

### 4.1 1988 Convention

4.1.1 On 19 December 1988, EEPCI entered into a convention covering a portion of the area under an exclusive exploration permit for hydrocarbons ("Permit H") described as "Lake Chad, Chari North, Chari South" (the "1988 Convention"). The original parties were the Republic of Chad, EEPCI, Societe Shell Tchadienne de Recherches et d'Exploitation and Chevron Oil Company of Chad.

4.1.2 The 1988 Convention was amended on 19 May 1993, 12 March 1997, 21 June 2000 and 9 June 2017.

4.1.3 The current parties to the 1988 Convention are the Republic of Chad, EEPCI, PETRONAS Carigali (Chad EP) Inc. ("PETRONAS") and SHT Petroleum Chad Company Limited ("SHT"). For the purpose of this document, EEPCI, PETRONAS and SHT are together referred to as the "Contractor". EEPCI holds a 40 per cent. participating interest, PETRONAS holds a 35 per cent. participating interest and SHT holds a 25 per cent. participating interest.

4.1.4 The purpose of the 1988 Convention is to set out the conditions under which the Contractor shall conduct petroleum operations in the portion of the area of Permit H or concessions which it covers.

4.1.5 The 1988 Convention came into effect on 19 December 1988 and remains in force until 6 September 2050 so long as the Contractor holds Permit H or an exploitation concession granted under the 1988 Convention.

4.1.6 Liability between the Contractor entities is joint and several. No committee or voting rights are established under the 1988 Convention.

4.1.7 The Contractor is required to pay a royalty to the Republic of Chad on total hydrocarbon production at a rate of 12.5 per cent. for crude oil and 5 per cent. for natural gas. The Contractor is also subject to a direct corporate income tax on its profits at a rate to be determined with reference to the Brent reference crude price (subject to indexation) and the ratio of the cumulative upstream net (after tax) revenue divided by cumulative upstream costs (calculated on an annual basis). The rates range from 40 per cent. to 65 per cent. The tax is payable by each Contractor entity to the Republic of Chad by way of quarterly advance payments with annual settlement after declaration of financial results for the year.

4.1.8 If the Republic of Chad cannot meet domestic demand for crude oil, the Contractor must sell to the Republic of Chad on a priority basis the crude oil necessary to meet the domestic demand (subject to specified limits). Crude oil delivered to the Republic of Chad is not subject to any royalty or profits tax.

4.1.9 In accordance with the "Chadian Petroleum Code" (being Ordinance No. 7/PC/TP/MH of 3 February 1962, as well as the Decree of 10 May 1967 specifying the conditions of application of the Ordinance), the Contractor has the right to transport (while retaining ownership therein) any production to the storage, treatment, loading or wholesale consumption points, or the delivery point, in the Republic of Chad.

4.1.10 Prior written approval from the Minister of Petroleum and Energy of the Republic of Chad is required for a transfer of a party's rights and obligations (including any direct or indirect change of control of a Contractor entity) under the 1988 Convention. The Minister has 60 days following notification to grant or deny consent, following which consent is deemed to have been given. Consent may not be unreasonably withheld. Approval is not required for a transfer to an affiliate but the Contractor must inform the Minister within one month of signature of the transfer documents. Any such transfer must not adversely affect the interests of the Republic of Chad, the petroleum operations nor reduce the technical and financial capacity of the Contractor.

4.1.11 The 1988 Convention includes a grandfathering stabilisation regime under which the Republic of Chad will ensure that no government act that will (a) increase the scope of Contractor's obligations or costs under the 1988 Convention (whether directly, indirectly or by application to Contractor's shareholders) or (b) adversely affect the Contractor's (or its shareholders') rights or economic benefits under the 1988 Convention, will apply to the Contractor without its prior agreement. The Republic of Chad will also ensure that no existing or future commitment it has undertaken under the UDEAC treaty or any other treaty which would have the effect of increasing the obligations and charged imposed by the 1988 Convention or which would likely come into conflict with any provision of the 1988 Convention will be implemented into the framework of the 1988 Convention.

4.1.12 In respect of decommissioning, the Contractor is obliged to (a) give the Minister of Petroleum and Energy of the Republic of Chad at least 24 hours' prior notice (or at least 10 days in the case of production wells) before abandoning a well and (b) within 60 days following expiration, relinquishment or withdrawal of a concession, transfer to the Republic of Chad (without compensation) all wells in good working order (normal wear and tear excepted) for the continuance of exploitation, except if the Minister requires their abandonment or if these wells have already been abandoned. Any wells which (by agreement) cannot be used to pursue exploration and exploitation, may be taken by the Republic of Chad without cost and converted into water wells. Contractor is required to leave the tubing in place at the requested level, as well as any wellhead, and to carry out at its expense at the time of the operation of abandoning such well and to the extent possible from a technical and economic point of view, the completion of the well in the water zone as may be requested.

4.1.13 There is no requirement under the 1988 Convention to establish an abandonment security fund.

4.1.14 An event will be considered a force majeure event under the 1988 Convention if (a) it causes non-performance or delayed performance by any party of its contractual obligations, other than in the case of payments for which such party is liable, provided there is a cause and effect link between the failure and the force majeure reason which is relied on and (b) it is unforeseeable and independent of the will of a party, such as natural causes, epidemics, earthquakes, fires, floods, strikes, riots, insurrections, civil disturbances, sabotage, the effects of war or situations attributable to war. The time resulting from any delay due to a force majeure event, increased by the time necessary to repair any damage resulting from such delay or curtailment, shall be added to any time period provided under the 1988 Convention. The term of the 1988 Convention shall also be extended, but only in respect of the area affected by the force majeure event. If a force majeure event lasts for longer than one year, the parties may by mutual agreement agree to terminate the 1988 Convention.

4.1.15 The 1988 Convention can be terminated (without any compensation) in the cases, and in accordance with the procedures provided for, in the Chadian Petroleum Code. The Minister of Petroleum and Energy of the Republic of Chad must give notice to the Contractor of any such termination/procedure by way of registered letter with proof of receipt within the periods provided for in the Chadian Petroleum Code (or within four months if no such periods are provided).

4.1.16 The governing law of the 1988 Convention is stated to be (a) the Convention itself and (b) the Chad Petroleum Code. Disputes shall be resolved in the first instance by amicable settlement between the parties within one month, followed by an optional conciliation, failing which a dispute will be settled by ICC arbitration in Paris by a three-member arbitration panel.

4.2 **2004 Convention**

4.2.1 On 10 May 2004, EEPCI entered into a convention covering a portion of the area under an exclusive exploration permit for hydrocarbons ("Permit H") described as "Chari West, Chari East and Lake Chad" (the "2004 Convention"). The original parties were the Republic of Chad, EEPCI, PETRONAS and Chevron Petroleum Chad Company Limited.

4.2.2 The 2004 Convention was amended on 9 June 2017. The current parties are the Republic of Chad, EEPCI, PETRONAS and SHT. EEPCI, PETRONAS and SHT are together referred to as the "Contractor" for the purpose of this document. EEPCI holds a 40 per cent. participating interest, PETRONAS holds a 35 per cent. participating interest and SHT holds a 25 per cent. participating interest.

4.2.3 The purpose of the 2004 Convention is to set out the conditions under which the Contractor shall conduct petroleum operations in the portion of the area of Permit H or concessions which it covers.

4.2.4 The 2004 Convention came into effect on 10 May 2004 and remains in force until 6 September 2050 so long as the Contractor holds Permit H or an exploitation concession granted under the 2004 Convention.

4.2.5 Liability between the Contractor entities is joint and several. No committee or voting rights are established under the 2004 Convention.

4.2.6 The Contractor is required to pay a royalty to the Republic of Chad on total hydrocarbon production at a rate of 14.25 per cent. for crude oil and 5 per cent. for natural gas. The Contractor is also subject to a direct corporate income tax on its profits at a rate to be determined with reference to the ratio of the cumulative upstream net (after tax) revenue divided by cumulative upstream costs (calculated on an annual basis). The rates range from 42.5 per cent. to 65 per cent. The tax is payable by each Contractor entity to the Republic of Chad by way of quarterly advance payments with annual settlement after declaration of financial results for the year.

4.2.7 If the Republic of Chad cannot meet domestic demand for crude oil, the Contractor must sell to the Republic of Chad on a priority basis the crude oil necessary to meet the domestic demand (subject to specified limits). Crude oil delivered to the Republic of Chad is not subject to any royalty or profits tax.

4.2.8 In accordance with the Chadian Petroleum Code, the Contractor has the right to transport (while retaining ownership therein) any production to the storage, treatment, loading or wholesale consumption points, or the delivery point, in the Republic of Chad.

4.2.9 Prior written approval from the Minister of Petroleum and Energy of the Republic of Chad is required for a transfer of a party's rights and obligations (including any direct or indirect change of control of a Contractor entity) under the 2004 Convention. The Minister has 60 days following notification to grant or deny consent, following which consent is deemed to have been given. Consent may not be unreasonably withheld. Approval is not required for a transfer to an affiliate but the Contractor must inform the Minister within one month of signature of the transfer documents. Any such transfer must not adversely affect the interests of the Republic of Chad, the petroleum operations nor reduce the technical and financial capacity of the Contractor.

4.2.10 The 2004 Convention includes a grandfathering stabilisation regime under which the Republic of Chad will ensure that no government act that will (a) increase the scope of Contractor's obligations or costs under the 2004 Convention (whether directly, indirectly or by application to Contractor's shareholders) or (b) adversely affect the Contractor's (or its shareholders') rights or economic benefits under the 2004 Convention, will apply to the Contractor without its prior agreement. The Republic of Chad will also ensure that no existing or future commitment it has undertaken under the CEMAC treaty or any other treaty which would have the effect of increasing the obligations and charged imposed by the 2004 Convention or which would likely come into conflict with any provision of the 2004 Convention will be implemented into the framework of the 2004 Convention.

4.2.11 In respect of decommissioning, the Contractor is obliged to (a) give the Minister of Petroleum and Energy of the Republic of Chad at least 24 hours' prior notice (or at least 10 days in the case of production wells) before abandoning a well and (b) within 60 days following expiration, relinquishment or withdrawal of a concession, transfer to the Republic of Chad (without compensation) all wells in good working order (normal wear and tear excepted) for the continuance of exploitation, except if the Minister requires their abandonment or if these wells have already been abandoned. Any wells which (by agreement) cannot be used to pursue exploration and exploitation, may be taken by the Republic of Chad without cost and converted into water wells. Contractor is required to leave the tubing in place at the requested level, as well as any wellhead, and to carry out at its expense at the time of the operation of abandoning such well and to the extent possible from a technical and economic point of view, the completion of the well in the water zone as may be requested.

4.2.12 There is no requirement under the 2004 Convention to establish an abandonment security fund.

4.2.13 An event will be considered a force majeure event under the 2004 Convention if (a) it causes non-performance or delayed performance by any party of its contractual obligations, other than in the case of payments for which such party is liable, provided there is a cause and effect link between the failure and the force majeure reason which is relied on and (b) it is unforeseeable and independent of the will of a party, such as natural causes, epidemics, earthquakes, fires, floods, strikes, riots, insurrections, civil disturbances, sabotage, the effects of war or situations attributable to war. The time resulting from any delay due to a force majeure event, increased by the time necessary to repair any damage resulting from such delay or curtailment, shall be added to any time period provided under the 2004 Convention. The term of the 2004 Convention shall also be extended, but only in respect of the area affected by the force majeure event. If a force majeure event lasts for longer than one year, the parties may by mutual agreement agree to terminate the 2004 Convention.

4.2.14 The 2004 Convention can be terminated (without any compensation) in the cases, and in accordance with the procedures provided for, in the Chadian Petroleum Code. The Minister of Petroleum and Energy of the Republic of Chad must give notice to the Contractor of any such termination/procedure by way of registered letter with proof of receipt within the periods provided for in the Chadian Petroleum Code (or within four months if no such periods are provided).

4.2.15 The governing law of the 2004 Convention is stated to be (a) the Convention itself and (b) the Chadian Petroleum Code. Disputes shall be resolved in the first instance by amicable settlement between the parties within one month, followed by an optional conciliation, failing which a dispute will be settled by ICC arbitration in Paris by a three-member arbitration panel. The parties may also agree to submit a dispute to an expert.

4.3 **Doba JOA**

4.3.1 On 7 April 2000, EEPCI entered into a joint operating agreement with PETRONAS and Chevron Petroleum Chad Company Limited (the "Doba JOA"). The Doba JOA was amended on 1 September 2009 and 11 June 2014.

4.3.2 The current parties to the Doba JOA are EEPCI, PETRONAS and SHT. EEPCI holds a 40 per cent. participating interest, PETRONAS holds a 35 per cent. participating interest and SHT holds a 25 per cent. participating interest.

4.3.3 The purpose of the Doba JOA is to further define the rights and obligations of the parties with respect to petroleum operations under the 1988 Convention and the 2004 Convention.

4.3.4 The Doba JOA came into effect on 7 April 2000 and continues in effect for as long as the 1988 Convention and the 2004 Convention or any concession thereunder are in force or, if later, until all materials, equipment and personal property used in connection with the joint operations have been removed and disposed of and final settlement has been made between the parties.

4.3.5 EEPCI is designated as the operator under the Doba JOA. In its capacity as operator, EEPCI (and its affiliates) shall not be liable to the non-operators for (except in respect of their participating interest share of) any damage, loss, cost, expense or liability in connection with the performance of the duties and functions of operator in relation to joint operations, except for that arising from the operator's gross negligence (which is limited to acts or omissions by operator's corporate officers or senior and intermediate supervisory employees with significant responsibility for conducting joint operations). In no event shall EEPCI in its capacity as operator be liable to the non-operators for consequential loss or damage (including but not limited to pollution or inability to produce hydrocarbons).

4.3.6 An operating committee, consisting of one representative of each party, is established under the Doba JOA. As EEPCI is operator, its representative is also the chairperson of the operating committee. Decisions are made by the affirmative vote of at least two parties holding at least 60 per cent. of the total participating interests entitled to vote on the matter, other than certain decisions which require a unanimous vote. The decisions requiring a unanimous vote include those relating to drilling (once minimum work obligations have been satisfied), relinquishment, determination of the commerciality of a field and approval of a development and exploitation plan.

4.3.7 Any transfer of all or part of a party's participating interest (including a change of control scenario) is subject to the pre-emptive rights of the other parties. Following notification, the parties have a 30 day period in which to exercise their pre-emption rights. If the transfer is not effected within 120 days after the expiration of the 30 day option period, the option to purchase will again attach to the interest specified in the original notice. A party may not transfer, assign or sell an interest in the exploitation concessions granted under the 1988 Convention and the 2004 Convention unless that party's affiliate transfers, assigns or sells an equivalent proportionate amount of its shares in COTCo and TOTCo and a like interest in the 1988 Convention, 2004 Convention, Doba JOA and any associated agreements. A disposal by way of mortgage or other security arrangement is not considered a "transfer" for the purposes of the pre-emption procedure.

4.3.8 Prior to cessation of production from any field, the operator must submit a decommissioning plan to the operating committee for review and approval. Abandonment costs shall be charged to the joint account. Once abandonment of a well is approved under the Doba JOA, it must be plugged and abandoned in accordance with the 1988 Convention or the 2004 Convention (as applicable), the exploitation concession(s) granted thereunder and applicable law and regulations. All buried field related pipelines shall be either (a) purged and decommissioned in place or (b) where desirable and practical, excavated, dismantled and individual segments hauled away for disposal, salvage or reuse.

4.3.9 If a party fails to pay its share of costs under the Doba JOA, it shall be a defaulting party and the amount due shall bear interest at a rate of LIBOR plus 3 per cent. The operator shall give a defaulting party written notice of its default (with copies to the other parties). The defaulting party has 10 days to provide funds to cover the default. If it fails to do so, the non-defaulting parties shall provide a share of the amount in default (proportionate to its participating interest) to the operator within 20 days. Such parties then have a lien on the defaulting party's participating interest and jointly owned assets under the 1988 Convention and the 2004 Convention (including production). The operator is authorised to sell the production entitlement of the defaulting party (over which the non-defaulting parties have a lien) in an arm's-length sale on commercially reasonably terms and (after deducting costs associated with such sale) pay the net proceeds to the non-defaulting parties. If remuneration under the 1988 Convention and the 2004 Convention (including the production entitlement attribute to defaulting party's participating interest) is not sufficient to recover the amounts due, each non-defaulting party (including operator) has the option to require the defaulting party to assign to it a share of the defaulting party's participating interest.

4.3.10 An event will be considered a force majeure event under the Doba JOA if (a) it is unforeseeable and independent of the will of the party, such as natural causes, epidemics, earthquakes, fires, floods, strikes, riots, insurrections, civil disturbances, sabotage, the effects of war or situations attributable to war and (b) there is a cause and effect link between the failure and the force majeure reason which is relied on. The intention of the parties is that the term force majeure shall be interpreted in accordance with the principles and practices of international law.

4.3.11 Under the Doba JOA, each party is required to provide to the Republic of Chad the parent company guarantee required under the 1988 Convention and the 2004 Convention. Under the provisions setting out the exploration work obligations in the 1988 Convention and the 2004 Convention, the contractor entities are required to provide acceptable parent company guarantees upon request from the Republic of Chad during the exploration phase.

4.3.12 The Doba JOA is governed by English law. Disputes shall be referred to ICC arbitration in English in London by a single arbitrator. Each party agrees to waive sovereign immunity against the validity and enforcement of any award or judgment.

## 5 MATERIAL CONTRACTS RELATING TO THE CHAD AND CAMEROON MIDSTREAM ASSETS

### 5.1 Intergovernmental Agreement

5.1.1 On 8 February 1996, the governments of the Republic of Chad and the Republic of Cameroon entered into an inter-governmental agreement (as between themselves) (the "Intergovernmental Agreement").

5.1.2 The Intergovernmental Agreement sets out the terms for transporting hydrocarbons through the Chad-Cameroon Pipeline.

5.1.3 The Republic of Cameroon granted to the Republic of Chad, and to any entity shipping hydrocarbons through the Chad-Cameroon Pipeline, a right of access to the sea and free transit for the export by pipeline of hydrocarbons extracted in the Republic of Chad.

5.1.4 The Republic of Cameroon is to take the relevant measures to avoid delays and difficulties, especially technical or administrative delays in the operation and maintenance of the Chad-Cameroon Pipeline and the moving of goods in transit.

5.1.5 The states shall cooperate to avoid double taxation of all individuals involved in the activities relating to the operation, use and maintenance of the Chad-Cameroon Pipeline.

5.1.6 The Intergovernmental Agreement provides that profits of COTCo are subject to tax only in the Republic of Cameroon and profits of TOTCo are subject to tax only in the Republic of Chad. The tax administrations of Chad and Cameroon cooperate with one another in order to properly allocate and collect taxes arising in connection with the construction, operation and maintenance of the Chad-Cameroon Pipeline.

5.1.7 Shippers using the Chad-Cameroon Pipeline to transport hydrocarbons extracted in the Republic of Chad ("Shippers") are not liable for any Cameroonian duties, taxes, fees, royalties or other costs relating to the import or export of hydrocarbons.

5.1.8 The Intergovernmental Agreement does not specify a governing law but disputes shall be settled in accordance with the rules of the United Nations Commission on International Trade Law (UNCITRAL) before three arbitrators, conducted and shall take place in Paris, France.

5.2 **TOTCo Convention**

5.2.1 On 10 July 1998, TOTCo entered into the TOTCo Convention with the Republic of Chad (as amended on 19 December 1998 and 18 November 2013) which granted TOTCo the rights to construct, own, operate and maintain the portion of the Chad-Cameroon Pipeline located in the Republic of Chad (the "Chad Transportation System") for the purpose of transporting hydrocarbons (the "TOTCo Convention").

5.2.2 The TOTCo Convention came into effect on 17 August 1998 and expires on 6 September 2050 (in line with the expiration of the last of the concessions exploited under the 1988 Convention and 2004 Convention).

5.2.3 The TOTCo Convention may be terminated before its expiry date:

(a) by agreement of the parties; or

(b) subject to applicable grace periods, the Republic of Chad for a breach by TOTCo of: (i) certain regulatory provisions, (ii) certain conditions of the TOTCo Convention; and (iii) of sections 45, 46, 49 or 50 of the Chadian Petroleum Code.

5.2.4 Under the terms of the TOTCo Convention, TOTCo pays an access levy to the Republic of Chad in relation to third party shippers (other than EEPCI, PETRONAS and SHT (together being members of the "Consortium")) that transport crude oil through the Chad Transportation System.

5.2.5 TOTCo shall give priority to crude oil produced by the Consortium members but may also transport crude oil from operations other than those of the Consortium, provided that any third party shippers agree to pay for: (i) any cost required to modify the Chad Transportation System; and (ii) the applicable commercial tariff calculated in accordance with the terms of the TOTCo Convention. TOTCo must submit all contracts with third party shippers to the minister responsible for petroleum operations for prior approval.

5.2.6 Under the TOTCo Convention, TOTCo is subject to a direct tax of 50 per cent. on its net profits. Except for such direct profits tax, TOTCo, its shareholders and affiliates are exempt from all other tax on revenue imposed upon the results of the transportation activities, the profits, and distribution of profits, and from all taxes, duties and contributions of any nature whatsoever in relation to the transportation activities.

5.2.7 The Republic of Chad provides certain fiscal, legislative, customs and foreign exchange guarantees, including a guarantee that no governmental act taken after 19 December 1988 will be applied to TOTCo which would have the effect of increasing the obligations of TOTCo, or that would adversely affect the economic rights and benefits of TOTCo, as provided for under the TOTCo Convention. TOTCo is also entitled to exemptions including in relation to certain import duties and taxes on goods necessary to carry out transportation activities.

5.2.8 The terms of the TOTCo Convention grant TOTCo the following key rights:

(a) right to carry out the works relating to the operation, maintenance and works necessary for the transportation activities in relation to the Chad Transportation System;

(b) rights to transport other Chadian crude oil (other than the Kome, Bolobo and Miandoum fields (the "Three Fields") crude oil);

(c) rights to transport crude oil originating from a third country, provided an international agreement is entered into between the Republic of Chad and said third country;

(d) right to transport hydrocarbons for the account of any Shipper through the Chad Transportation System;

(e) right for TOTCo to transport its own hydrocarbons and to sell or transfer such hydrocarbons, to the extent such operations are carried out as enforcement of security over the hydrocarbons of defaulting Shippers; and

(f) right to use public installations, water and other natural resource materials for transportation activity.

5.2.9 TOTCo may at any time renounce in whole or in part the Chad Transportation System. TOTCo is required to specify the effective date of renunciation which is to be no less than:

(a) six months from the date of notice of renunciation in relation to a part of the Chad Transportation System; and

(b) 24 months from the date of notice of renunciation in relation to the whole Chad Transportation System.

For any sections of the Chad Transportation System subject to renunciation by TOTCo but not utilised by the Republic of Chad, TOTCo will, at its own expense, undertake certain abandonment obligations.

5.2.10 TOTCo is to comply with the laws and regulations of the Republic of Chad. Activities undertaken within the framework of the TOTCo Convention are governed by the terms of the TOTCo Convention, the Chadian Petroleum Code and the Upstream Conventions (as defined below).

5.2.11 In case of a dispute, if the parties fail to reach agreement after one month, the dispute may be settled under the Rules of Arbitration and Conciliation of the International Chamber of Commerce. Any arbitration will be before three arbitrators, conducted and shall take place in Paris, France.

## 5.3 **COTCo Convention**

5.3.1 On 20 March 1998, COTCo entered into the COTCo Convention with the Republic of Cameroon (as amended on 21 February 2001, 19 October 2013 and 12 February 2014) which granted COTCo the rights to construct, own, operate and maintain the portion of the Chad-Cameroon Pipeline located in the Republic of Cameroon (the "Cameroon Transportation System") for the purpose of transporting hydrocarbons (the "COTCo Convention").

5.3.2 The COTCo Convention came into effect on the date of first lifting (which the Company understands took place in 2003). The 25 year initial period expires in 2028. The term is automatically extended on the same terms for a further 25 years upon notification by COTCo to the Republic of Cameroon no less than five years prior to the end of the initial period.

5.3.3 The COTCo Convention may be terminated before its expiry date by:

(a) the agreement of the parties;

(b) COTCo's renunciation of the authorisation for transportation by pipeline; or

(c) the Republic of Cameroon, following a suspension of the authorisation for transportation by pipeline that COTCo has failed to cure within 180 days, for COTCo's: (i) failure to comply with local payment requirements; (ii) refusal to make connections to the Cameroon Transportation System; or (iii) failure to pay the transit fee.

5.3.4 The COTCo Convention provides the Republic of Cameroon with a right to suspend COTCo's authorisation for transportation by pipeline for up to 180 days if, subject to certain grace periods, COTCo fails to remedy its: (i) failure to comply with local payment requirements; (ii) refusal to make connections to the Cameroon Transportation System; or (iii) failure to pay the transit fee.

5.3.5 Under the terms of the COTCo Convention, COTCo pays a transit fee to the Republic of Cameroon based on the quantity of crude oil transported through the Cameroon Transportation System.

5.3.6 COTCo shall give priority to crude oil produced by the Consortium members but may also transport crude oil from operations other than those of the Consortium, provided any third party shippers agree to pay: (i) for any cost to modify the Cameroon Transportation System; and (ii) the commercial tariff calculated in accordance with the terms of the COTCo Convention.

5.3.7 Under the COTCo Convention, COTCo is subject to a company tax of five per cent. calculated in accordance with the general tax code of the Republic of Cameroon in force as of 31 December 1994. The COTCo Convention also provides COTCo with certain other tax exemptions.

5.3.8 The Republic of Cameroon provides certain elements of the fiscal, legal, tax and exchange control guarantees, including guarantees not to modify such regimes in a way that would adversely affect COTCo's rights or economic benefits. COTCo is also entitled to exemptions including in relation to certain import duties and taxes on goods necessary to carry out transportation activities.

5.3.9 The COTCo Convention grants COTCo the following key rights:

(a) rights to certain land easements for the construction, operation and maintenance of the Cameroon Transportation System; and

(b) rights to construct, maintain and operate the Cameroon Transportation System, including the right to transport hydrocarbons.

5.3.10 COTCo may, before the expiry of the authorisation for transportation by pipeline, renounce the operation of all or part of the Cameroon Transportation System by providing no less than:

(a) six months' notice for the renunciation of part of the Cameroon Transportation System; or

(b) 24 months' notice for the renunciation of the whole of the Cameroon Transportation System.

5.3.11 Following the notice of renunciation the Republic of Cameroon has the option to purchase the parts subject to renunciation. For any part of the Cameroon Transportation System subject to renunciation but not otherwise acquired by the Republic of Cameroon, COTCo is required to undertake certain abandonment obligations.

5.3.12 The COTCo Convention is governed by Cameroonian Law, the general principles of international law and common practices widely used in the international petroleum industry.

5.3.13 Disputes shall be settled by arbitration before the International Centre for the Settlement of Disputes relating to Investments (ICSID), in accordance with the Convention for Settlement of Disputes relating to Investments between States and Nationals of other States (ICSID Convention).

5.3.14 If the dispute does not fall within the ICSID, a dispute will be submitted to arbitration under the International Chamber of Commerce (ICC). Any arbitration will be before three arbitrators, conducted in both the French and English languages and shall take place in Paris, France.

5.3.15 Any arbitration taking place under the COTCo Convention is subject to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958.

5.4 **Co-operation Agreement**

5.4.1 On 10 July 1998, TOTCo and COTCo entered into a co-operation agreement in relation to the Chad-Cameroon Pipeline (the "Co-operation Agreement").

5.4.2 The Co-operation Agreement shall end upon the date of permanent abandonment of the operation of either the: (i) Cameroon Transportation System by COTCo; or (ii) Chad Transportation System by TOTCo.

5.4.3 The Co-operation Agreement regulates the operation of the Chad-Cameroon Pipeline by COTCo and TOTCo as one integrated transportation system.

5.4.4 Each party is to:

(a) operate and maintain its portion of the Chad-Cameroon Pipeline in accordance with the applicable laws of its country, the provisions of the TOTCo Convention or the COTCo Convention (as applicable) and internationally accepted standards and practices;

(b) not unreasonably interfere with the other party's operation of its portion of the Chad-Cameroon Pipeline, and shall act with diligence to mitigate any consequences adversely affecting the operation of the Chad-Cameroon Pipeline; and

(c) provide to the other party the services, materials and equipment that may be required or requested by the other party for the construction, operation and maintenance of its portion of the Chad-Cameroon Pipeline. Such services are to be provided at cost.

5.4.5 With respect to cost allocation:

(a) costs exclusively incurred in connection with the Cameroon Transportation System or relating exclusive to assets belonging to COTCo shall be allocated to COTCo;

(b) costs exclusively incurred in connection with the Chad Transportation System or relating exclusive to assets belonging to TOTCo shall be allocated to TOTCo;

(c) infrastructure costs will also be allocated on the basis of the location of the infrastructure; and

(d) all other costs shall be allocated according to the ratio of other costs allocated to TOTCo and COTCo over the same period.

5.4.6 If a Shipper fails to pay its tariff under a transportation agreement, each of TOTCo and COTCo must notify the other if it elects to exercise its remedies under the relevant transportation agreement. If such remedy involves lifting and selling the defaulting Shipper's crude oil, COTCo shall arrange for the lifting and sale of said crude oil. The Co-operation Agreement sets out how any proceeds of sale from such crude oil shall be allocated between TOTCo and COTCo.

5.4.7 The Co-operation Agreement is governed by English law and disputes will be referred to arbitration under the International Chamber of Commerce Rules before three arbitrators, to be conducted in both the French and English languages and held in Paris.

## 5.5 Agreements with the Consortium

### 5.5.1 *Consortium-TOTCo Transportation Agreement*

(a) On 21 June 2000, the Consortium members entered into a transportation agreement with TOTCo which regulates the transportation services provided by TOTCo to the Consortium members on the Chad Transportation System (the "Consortium-TOTCo Transportation Agreement").

(b) Under the Consortium-TOTCo Transportation Agreement, the Consortium has first priority over capacity in the Chad Transportation System.

(c) The Consortium-TOTCo Transportation Agreement remains in force until all Consortium members have withdrawn from the 1988 Convention and 2004 Convention (together the "Upstream Conventions"), and will terminate at the end of a period of 24 months from the date the Consortium members provide notice to TOTCo of such withdrawal or when TOTCo has abandoned the Chad Transportation System in accordance with the TOTCo Convention.

(d) The Consortium members each pay a tariff to TOTCo based on the usage and throughput rate of the respective Consortium member.

(e) The agreement incorporates a set of general terms and conditions (the "GTTs"), a summary of which is provided in section 5.5.4 below.

(f) A failure to lift is governed by the GTTs. For further details see section 5.5.4 below.

### 5.5.2 *Consortium-COTCo Transportation Agreement*

(a) On 19 June 2000, the Consortium members entered into a transportation agreement with COTCo which regulates the transportation services provided by COTCo to the

Consortium members on the Cameroon Transportation System (the "Consortium-COTCo Transportation Agreement").

(b) Under the Consortium-COTCo Transportation Agreement, the Consortium has first priority over capacity in the Cameroon Transportation System.

(c) The Consortium-COTCo Transportation Agreement remains in force until terminated by all Consortium members providing their respective notice of withdrawal to COTCo and when the Republic of Cameroon has given notice of termination to COTCo, or when COTCo has abandoned the Cameroon Transportation System.

(d) The Consortium members each pay a tariff to COTCo based on the usage and throughput rate of the respective Consortium member.

(e) The Consortium-COTCo Transportation Agreement incorporates the GTTs. Please see section 5.5.4 below for a summary of the key terms of the GTTs.

(f) A failure to lift is governed by the GTTs. For further details see section 5.5.4 below.

5.5.3 ***Abandonment under the Consortium transportation contracts (see sections 5.5.1 and 5.5.2 above)***

(a) Where the "Transporter" (being COTCo or TOTCo (as applicable)): (i) continues to operate its respective section of the Chad-Cameroon Pipeline after the Consortium members' withdrawal from the Upstream Conventions; and (ii) continues to provide services to the other Shippers, the Consortium members will not be liable for abandonment costs.

(b) The Consortium members shall be responsible for their pro rata share of abandonment costs (based on their share of the total quantity transported by all Shippers over the previous 36 months) if a Transporter decides to cease operating its respective section of the Chad-Cameroon Pipeline as a result of (i) the Consortium members' withdrawal from the Upstream Conventions, or (ii) future crude oil production forecasts from the Shippers.

(c) Third party Shippers are charged an abandonment fee as part of the tariff charged by the relevant Transporter under their respective transportation agreement.

5.5.4 ***General terms and conditions (applicable to Consortium transportation agreements in sections 5.5.1 and 5.5.2 above)***

(a) The Consortium's transportation agreements with each of TOTCo and COTCo incorporate the GTTs, which govern matters including scheduling, cargo nominations, lifting, nomination of tankers, and the following key terms as summarised below.

(b) *Failure to lift*

(i) If COTCo determines that a lifting for a given Shipper is delayed or shall not be carried out, COTCo shall seek to arrange for such cargo to be lifted by another Shipper.

(ii) The Shipper who lifts such cargo will be an overlifter and will be required to make restitution to the defaulting lifter within 12 months.

(c) *Crude commingling*

(i) Crude is commingled in the Chad-Cameroon Pipeline and no Shipper is entitled to receive out of the Chad-Cameroon Pipeline the identical crude that was delivered on behalf of the Shipper into the Chad-Cameroon Pipeline.

(d) *Failure to pay tariff*

(i) When a Shipper fails to make a tariff payment, the Owners are entitled to cease shipments and sell such Shipper's crude.

(ii) The defaulting Shipper's crude may be sold by another Shipper who shall pay the sales proceeds to the defaulting Shipper less any reasonable expenses incurred and an administration fee.

5.6 **Agreements with Glencore**

5.6.1 ***Glencore-TOTCo Transportation Agreement***

(a) On 11 October 2013, Glencore Exploration (DOB/DOI) Limited ("Glencore"), Petrochad (Mangara) Limited ("PCM") and SHT (together, the "Glencore Group") entered into a transportation agreement with TOTCo for the transportation of crude oil produced under the Production Sharing Contract dated 18 March 2011 between the Republic of Chad, Glencore, PCM and SHT (the "Glencore PSC") through the Chad Transportation System (the "Glencore-TOTCo Transportation Agreement").

(b) Under the Glencore-TOTCo Transportation Agreement, the Glencore Group has second ranking priority over capacity in the Chad Transportation System behind the Consortium.

(c) There are no minimum nomination requirements for the Glencore Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The Glencore-TOTCo Transportation Agreement remains in force until the earlier of: (i) the termination of TOTCo's operatorship of the Chad Transportation System; (ii) the termination of the Glencore PSC; (iii) TOTCo exercising its termination rights under the agreement (see section 5.6.1(h) below); or (iv) termination by the mutual written consent of TOTCo and the Glencore Group.

(e) The Glencore Group each pay a tariff to TOTCo based on the usage and throughput rate of the Glencore Group (including an abandonment fee).

(f) The Glencore-TOTCo Transportation Agreement incorporates a set of general terms and conditions (the "JGTTs"), a summary of which is provided in section 5.9 below.

(f) In order to guarantee the tariff payments due under the Glencore-TOTCo Transportation Agreement PCM shall provide a letter of credit and Glencore shall provide a parent company guarantee.

(h) TOTCo has the right to terminate the Glencore-TOTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

5.6.2 ***Glencore-COTCo Transportation Agreement***

(a) On 21 October 2013, the Glencore Group entered into a transportation agreement with COTCo for the transportation of crude oil produced under the Glencore PSC through the Cameroon Transportation System (the "Glencore-COTCo Transportation Agreement").

(b) Under the Glencore-COTCo Transportation Agreement, the Glencore Group has second ranking priority over capacity in the Cameroon Transportation System behind the Consortium.

(c) There is no minimum nomination requirement for the Glencore Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The Glencore-COTCo Transportation Agreement remains in force until the earlier of: (i) the termination of COTCo's operatorship of the Cameroon Transportation System; (ii) the termination of the Glencore PSC; (iii) COTCo exercising its termination rights under the agreement (see section 5.6.2(h) below); or (iv) termination by the mutual written consent of COTCo and the Glencore Group.

(e) The Glencore Group each pay a tariff to COTCo based on the usage and throughput rate of the Glencore Group (including an abandonment fee).

(f) The Glencore-COTCo Transportation Agreement incorporates the JGTTs. See section 5.9 below for a summary.

(g) In order to guarantee the tariff payments due under the agreement PCM shall provide a letter of credit and Glencore shall provide a parent company guarantee.

(h) COTCo has the right to terminate the Glencore-COTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

#### 5.6.3 *Glencore Interconnection Agreement (Chad Transportation System)*

(a) On 25 October 2012, PCM entered into an interconnection agreement with TOTCo in relation to the Chad Transportation System (the "Glencore Interconnection Agreement").

(b) The Glencore Interconnection Agreement regulates: (i) how the PCM connecting pipeline is connected to the Chad Transportation System; and (ii) the continuing operational and maintenance requirements in respect thereof.

(c) TOTCo shall be responsible for the removal and abandonment of the tie-in facilities. TOTCo has the right to charge PCM for such abandonment and removal of such tie-in facilities at cost. PCM shall be responsible for the removal and abandonment of the connecting party facilities including the connecting pipeline and ancillary equipment.

#### 5.6.4 *Glencore Facilities Modification Agreement (Cameroon Transportation System)*

(a) On 18 March 2013, PCM entered into a facilities modification agreement with COTCo in relation to the Cameroon Transportation System (the "Glencore Facilities Modification Agreement").

(b) The Glencore Facilities Modification Agreement regulates: (i) how the PCM connecting pipeline is connected to the Cameroon Transportation System; and (ii) the continuing operational and maintenance requirements in respect thereof.

(c) COTCo shall be responsible for the abandonment of the modified facilities and has the right to charge such amount to PCM at cost.

### 5.7 Agreements with CNPCI

#### 5.7.1 *CNPCI-TOTCo Transportation Agreement*

(a) On 22 November 2013, CNPCI, Cliveden and the Republic of Chad (together, the "CNPCI Group") entered into a transportation agreement (the "CNPCI-TOTCo Transportation Agreement") with TOTCo for the transportation of crude oil produced under the Convention for Exploration, Exploitation and Transportation of Hydrocarbons between the Republic of Chad, CNPCI and Cliveden dated 23 February 1999 (the "CNPCI Convention") through the Chad Transportation System.

(b) Under the CNPCI-TOTCo Transportation Agreement, the CNPCI, Cliveden and the Republic of Chad (the "CNPCI Group") has second ranking priority over capacity in the Chad Transportation System behind the Consortium.

(c) There are no minimum nomination requirements for the CNPCI Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The CNPCI-TOTCo Transportation Agreement remains in force until the earlier of: (i) the termination of TOTCo's operatorship of the Chad Transportation System; (ii) the termination of the CNPCI Convention; (iii) TOTCo exercising its termination rights under the CNPCI-TOTCo Transportation Agreement (see section 5.7.1(h) below); or (iv) termination by the mutual written consent of TOTCo and the CNPCI Group.

(e) The CNPCI Group each pay a tariff to TOTCo based on the usage and throughput rate of the CNPCI Group (including an abandonment fee).

(f) The CNPCI-TOTCo Transportation Agreement incorporates the JGTTs. See section 5.9 below for a summary of the key terms of the JGTTs.

(g) In order to guarantee the tariff payments due under the CNPCI-TOTCo Transportation Agreement CNPCI and Cliveden are to provide a parent company guarantee.

(h) TOTCo also has the right to terminate the CNPCI-TOTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

5.7.2 ***CNPCI-COTCo Transportation Agreement***

(a) On 22 November 2013, the CNPCI Group entered into a transportation agreement with COTCo for the transportation of crude oil producing under the CNPCI Convention through the Cameroon Transportation System (the "CNPCI-COTCo Transportation Agreement").

(b) Under the CNPCI-COTCo Transportation Agreement, the CNPCI Group has second ranking priority over capacity in the Cameroon Transportation System behind the Consortium.

(c) There is no minimum nomination requirement for the CNPCI Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The CNPCI-COTCo Transportation Agreement remains in force until the earlier of: (i) the termination of COTCo's operatorship of the Cameroon Transportation System; (ii) the termination of the CNPCI Convention; (iii) COTCo exercising its termination rights under the CNPCI-COTCo Transportation Agreement (see section 5.7.2(h) below); or (iv) termination by the mutual written consent of COTCo and the CNPCI Group.

(e) The CNPCI Group each pay a tariff to COTCo based on the usage and throughput rate of the CNPCI Group (including an abandonment fee).

(f) The CNPCI-COTCo Transportation Agreement incorporates the JGTTs. See section 5.9 below for a summary of the key terms of the JGTTs.

(g) In order to guarantee the tariff payments due under the agreement CNPCI and Cliveden are to provide a parent company guarantee.

(h) COTCo has the right to terminate the CNPCI-COTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

5.7.3 ***CNPCI Interconnection Agreement (Chad Transportation System)***

(a) On 14 August 2012, CNPCI entered into an interconnection agreement with TOTCo in relation to the Chad Transportation System (the "CNPCI Interconnection Agreement").

(b) The CNPCI Interconnection Agreement regulates (i) how the CNPCI connecting pipeline is connected to the Chad Transportation System; and (ii) the continuing operational and maintenance requirements in respect thereof.

(c) TOTCo shall be responsible for the removal and abandonment of the tie-in facilities. TOTCo has the right to charge CNPCI for such abandonment and removal of such tie-in facilities at cost. CNPCI shall be responsible for the removal and abandonment of the connecting party facilities including the connecting pipeline and ancillary equipment.

5.7.4 ***CNPCI Facilities Modification Agreement (Cameroon Transportation System)***

(a) On 18 March 2013, CNPCI entered into a facilities modification agreement with COTCo in relation to the Cameroon Transportation System (the "CNPCI Facilities Modification Agreement").

(b) The CNPCI Facilities Modification Agreement regulates (i) how the CNPCI connecting pipeline is connected to the Cameroon Transportation System; and (ii) the continuing operational and maintenance requirements in respect thereof.

(c) COTCo is responsible for the abandonment of the modified facilities and has the right to charge such amount back to CNPCI at cost.

### 5.8 Agreements with OPIC

#### 5.8.1 *OPIC-TOTCo Transportation Agreement*

(a) On 28 January 2020, OPIC Africa Corporation ("OPIC"), CEFC Hainan International (HK) Limited ("CEFC") and SHT (together, the "OPIC Group") entered into a transportation agreement with TOTCo for the transportation of crude oil produced under the Convention for Exploration, Exploitation and Transportation of Hydrocarbons dated 25 January 2006 between the Republic of Chad and the OPIC Group ("OPIC Convention") through the Chad Transportation System (the "OPIC-TOTCo Transportation Agreement").

(b) Under the OPIC-TOTCo Transportation Agreement, the OPIC Group has second ranking priority over capacity in the Chad Transportation System behind the Consortium.

(c) There are no minimum nomination requirements for the OPIC Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The OPIC-TOTCo Transportation Agreement remains in force until the earlier of: (i) the termination of TOTCo's operatorship of the Chad Transportation System; (ii) the termination of the OPIC PSC; (iii) TOTCo exercising its termination rights under the agreement (see section 5.8.1(h) below); or (iv) termination by the mutual written consent of TOTCo and the OPIC Group.

(e) The OPIC Group each pay a tariff to TOTCo based on the usage and throughput rate of the OPIC Group (including an abandonment fee).

(f) The OPIC-TOTCo Transportation Agreement incorporates a set of general terms and conditions (the "JGTTs"), a summary of which is provided in section 5.9 below.

(g) In order to guarantee the tariff payments due under the OPIC-TOTCo Transportation Agreement CEFC shall provide a letter of credit and OPIC shall provide a parent company guarantee.

(h) TOTCo has the right to terminate the OPIC-TOTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

#### 5.8.2 *OPIC-COTCo Transportation Agreement*

(a) On 28 January 2020, the OPIC Group entered into a transportation agreement with COTCo for the transportation of crude oil produced under the OPIC Convention through the Cameroon Transportation System (the "OPIC-COTCo Transportation Agreement").

(b) Under the OPIC-COTCo Transportation Agreement, the OPIC Group has second ranking priority over capacity in the Cameroon Transportation System behind the Consortium.

(c) There is no minimum nomination requirement for the OPIC Group, nor is there a send-or-pay regime in place for volumes of crude oil nominated.

(d) The OPIC-COTCo Transportation Agreement remains in force until the earlier of: (i) the termination of COTCo's operatorship of the Cameroon Transportation System; (ii) the termination of the OPIC Convention; (iii) COTCo exercising its termination rights under the OPIC-COTCo Transportation Agreement (see section 5.8.2(h) below); or (iv) termination by the mutual written consent of COTCo and the OPIC Group.

(e) The OPIC Group each pay a tariff to COTCo based on the usage and throughput rate of the OPIC Group (including an abandonment fee).

(f) The OPIC-COTCo Transportation Agreement incorporates the JGTTs. See section 5.9 below for a summary of the key terms of the JGTTs.

(g) In order to guarantee the tariff payments due under the agreement CEFC shall provide a letter of credit and OPIC shall provide a parent company guarantee.

(h) COTCo has the right to terminate the OPIC-COTCo Transportation Agreement (in respect of an individual Shipper) immediately in the event that such Shipper undergoes an insolvency or bankruptcy event.

5.8.3 ***OPIC Interconnection Agreement (Chad Transportation System)***

On 27 September 2018, the OPIC Group entered into an interconnection agreement with TOTCo in relation to the Chad Transportation System.

5.8.4 ***OPIC Facilities Modification Agreement (Cameroon Transportation System)***

On 10 September 2019, the OPIC Group entered into an interconnection agreement with TOTCo in relation to the Chad Transportation System.

## 5.9 Joint general terms and conditions (applicable to Glencore and CNPCI transportation agreements)

5.9.1 The Glencore-TOTCo, Glencore-COTCo, OPIC-TOTCo, OPIC-COTCo, CNPCI-TOTCo and CNPCI-COTCo transportation agreements each incorporate the JGTTs, which governs matters including scheduling, cargo, nominations, lifting, nomination of tankers, and the following key terms as summarised below.

5.9.2 ***Failure to lift***

(a) Upon a failure to lift, the Transporter has the authority to take all actions concerning the respective Shipper's cargo, including:

(i) exchanging cargos and lifting sequences with other Shippers;

(ii) chartering a vessel in order to place the respective Shipper's cargo in floating storage;

(iii) reducing or curtailing the respective Shipper's input into the system; or

(iv) selling the cargo for the respective Shipper's account.

(b) The Transporter is to release funds from the sale of the defaulting Shipper's cargo net of all costs and fees attributable to the Shipper.

5.9.3 ***Failure to pay tariff***

(a) When a Shipper fails to make a tariff payment, the Owners are entitled to cease shipments and retain or sell such Shipper's crude and the same rights apply as for a failure to lift described above.

## 5.10 TOTCo and COTCo bylaws

5.10.1 ***TOTCo bylaws***

(a) The governance of TOTCo is regulated by the TOTCo bylaws dated 26 April 2016.

(b) TOTCo's share capital is split between "A" shares that are held by members of the Consortium, and "B" shares that are held by the Republic of Chad. Each of the "A" shares and “B” shares carry equivalent rights and all shares are subject to a pre-emption right in favour of the existing shareholders on a proposed transfer by a shareholder to a third party transferee. The “B” shares give the Republic of Chad a blocking right over certain matters to be voted on by the shareholders.

(c) Board meetings are to be held at least twice per year and each meeting has a quorum of one half of the directors. Decisions are made by a simple majority of the directors present and the chairman has a casting vote if the vote is equal. The chairman of the board is also the general manager of TOTCo.

(d) EPIL has the right to nominate up to four directors to the board, PETRONAS may nominate up to three directors, SHT may nominate up to two directors and the Republic of Chad may nominate up to two directors.

(e) Powers of the board include:

  (i) appointment of a general manager and the deputy general manager of TOTCo;

  (ii) examination and adoption of work programs and budget submitted by the general manager;

  (iii) examination of activity reports submitted by the general manager;

  (iv) approval of the transportation contracts;

  (v) delegation for additional powers to the general manager;

  (vi) making of cash calls for payment of share capital;

  (vii) the sale, leasing or any other transfer of materials and equipment of a value between \$50,000 and \$10,000,000; and

  (viii) the appointment of persons nominated by the general manager to other positions of responsibility at the level of manager of TOTCo.

(f) An ordinary general meeting of the shareholders takes place at least once every accounting year. Any shareholder with at least one director may request the chairman to convene a general meeting. A general meeting may also be convened extraordinarily by the board of directors.

(g) The quorum for any general meeting is shareholder(s) holding at least one half of the issued TOTCo share capital to be present at the time of the meeting. If the quorum is not met the meeting shall be reconvened. At the second meeting there shall be no quorum requirement, other than for an extraordinary general meeting, which requires shareholder(s) holding at least one quarter of the issued TOTCo share capital present to be quorate.

(h) At general meetings and extraordinary general meetings, each shareholder is entitled to cast one vote for each share in TOTCo that it holds.

(i) The following decisions will be passed at an ordinary general meeting of the shareholders by a simple majority of the votes cast:

  (i) appointment of directors to the board of directors;

  (ii) payment of dividends;

  (iii) approval of the accounts, the balance sheets and the annual reports of TOTCo;

  (iv) appointment and replacement of TOTCo’s auditors and approval of remuneration of TOTCo’s auditors; and

  (v) approval of any agreement between TOTCo and its directors.

(j) The following matters require two thirds approval of the total votes cast at an extraordinary general meeting:

  (i) extending the duration of or dissolving TOTCo;

(ii) any modification to the capital of TOTCo; and

(iii) authorisation for loans or other borrowings and for any security interest over TOTCo's assets in connection with the construction or extension of the Cameroon Transportation System.

(k) The following matters require a majority representing at least 90 per cent. of the votes cast by holders of "A" shares and at least at least 90 per cent. of the votes cast by holders of "B" shares at an extraordinary general meeting to be passed:

(i) approval of the TOTCo services agreement with EEPCI and any amendments thereto;

(ii) any amendment to the TOTCo bylaws;

(iii) approval of the use of net profits to finance investments in relation to the Chad Transportation System;

(iv) approval of the Co-operation Agreement and any amendment thereto;

(v) approval of the TOTCo Convention and any amendments thereto;

(vi) merger of TOTCo with any other company;

(vii) the termination to the operation of the Chad Transportation System, when such termination occurs during the period of production of hydrocarbons by the Consortium under the TOTCo Convention;

(viii) the establishment of foreign branches or agencies of TOTCo;

(ix) the increase of the capital of TOTCo by increase of the nominal value of the existing shares, except when it is carried out by way of conversion of reserves; and

(x) the sale, lease or transfer of the Chad Transportation System or any part thereof essential to its operation.

(l) Five per cent. of the net profits of TOTCo shall be allocated to the statutory reserve until such reserve is equal to one tenth of the capital of TOTCo at any given time.

(m) The shareholders may approve the payment of dividends in a general meeting, unless they adopt a special resolution (requiring at least 90 per cent. of the votes cast by holders of "A" shares and at least at least 90 per cent. of the votes cast by holders of "B" shares) to use net profits to finance capital expenditures.

(n) The TOTCo board will appoint a general manager as proposed by EEPCI as the services company. If the TOTCo board fails to approve a general manager, EEPCI will continue to nominate candidates until the general manager nomination is approved.

(o) If any shareholder wishes to transfer its shares, it must first notify the other shareholders of any proposed transfer (including the number of shares to be transferred and the price). The other shareholders then have a period of 60 days to exercise their pre-emption rights.

(p) Any transfer of shares is subject to the approval of the board of directors. If such approval is not obtained, TOTCo shall purchase such shares.

(q) There are no restrictions or requirements in respect of a change of control of a TOTCo shareholder.

### 5.10.2 ***COTCo bylaws***

(a) The governance of COTCo is regulated by the COTCo bylaws dated 25 April 2016.

(b) All of the shares in COTCo carry equivalent rights and all shares are subject a pre-emption right in favour of the existing shareholders on a proposed transfer to a third party transferee.

(c) Board meetings are to be held at least twice per year and each meeting has a quorum of two thirds of the directors. In case the required quorum is not met, a new meeting may be called where the required quorum shall be one half of the directors present or represented. If a third meeting is called, the board meeting shall be held and the directors present or represented will be deemed a valid quorum.

(d) EPIL has the right to nominate four directors to the board, the other shareholders may nominate two directors each.

(e) Decisions are made by directors representing a majority of the members present. In case of a tie the Chairman has a casting vote. The chairman of the board is also the general manager of COTCo.

(f) Powers of the board include:

  (i) appointment of persons proposed by the general manager to the position of manager;

  (ii) examination and approval of work programs and budget submitted by the general manager;

  (iii) examination of activity reports submitted by the general manager;

  (iv) approval of all contracts for the use of the Cameroon Transportation System;

  (v) delegation for additional powers to the general manager;

  (vi) making of cash calls for payment of share capital; and

  (vii) the sale, lease or any other transfer of materials and equipment of a value exceeding $50,000.

(g) An ordinary general meeting of the shareholders takes place at least once every accounting year. Any of the current shareholders may request the chairman to convene a general meeting. A general meeting may also be convened extraordinarily by the board of directors.

(h) The quorum for any general meeting is shareholder(s) holding at least one half of the issued COTCo share capital to be present at the time of the meeting. If the quorum is not met the meeting shall be reconvened and no quorum shall be required at the reconvened meeting for an ordinary general meeting. A reconvened extraordinary general meeting shall require at least one fourth of the share capital of COTCo to be quorate.

(i) The following decisions will be passed at an ordinary general meeting if approved by shareholders representing a simple majority of total shares held by the shareholders present or represented at the general meeting:

  (i) appointment of directors to the board of directors;

  (ii) approval of the accounts, the balance sheets and the annual reports of COTCo;

  (iii) approval of the payment of dividends;

  (iv) appointment and replacement of COTCo's auditors and approval of remuneration of COTCo's auditors;

  (v) decisions in respect of the depreciation of capital; and

  (vi) approval of any agreements between COTCo and its directors.

(j) The following matters require an affirmative vote of shareholders holding at least two thirds of the total shares of COTCo:

  (i) extending the duration of or dissolving COTCo;

  (ii) any modification to the capital of COTCo;

  (iii) authorisation for loans or other borrowings and for any security interest over COTCo's assets in connection with the construction or extension of the Cameroon Transportation System;

(iv) conferring on the board of directors any authorisations or powers in addition to those granted by the COTCo bylaws; and

(v) the abandonment of the Cameroon Transportation System resulting from the non-renewal of the COTCo Convention or from the renunciation of COTCo's authorisation for transportation by pipeline, and any sale or transfer of all or part of the Cameroon Transportation System to the Republic of Cameroon which could result therefrom, when such abandonment occurs after the end of the period of production of hydrocarbons by the Consortium in the Permit H zone.

(k) The following require an affirmative vote of all COTCo shareholders:

(i) approval of the EPSI-COTCo services agreement and any amendments thereto;

(ii) any amendment to the COTCo bylaws;

(iii) approval of the use of net profits to finance investments in relation to the Cameroon Transportation System;

(iv) merger of COTCo with any other company;

(v) the sale, lease or transfer of the Cameroon Transportation System, unless such transfers are carried out in execution of guarantees; and,

(vi) during the period of production of hydrocarbons by the Consortium in the Permit H zone, the abandonment of the Cameroon Transportation System resulting from the non-renewal of the COTCo Convention or from the termination of COTCo's authorisation for transportation by pipeline (being the authorisation provided for in Law No. 96/14 granted by decree by the Republic of Cameroon to COTCo allowing it to carry out activities relating to the construction, operation and maintenance of the Cameroon Transportation System within the territory of the Republic of Cameroon).

(l) Ten per cent. of the net profits of COTCo shall be allocated to the statutory reserve until such reserve is equal to one fifth of the capital of COTCo at any given time.

(m) The shareholders in a general meeting may decide to pay dividends that, in their opinion, appear justified by the net profits of COTCo unless the shareholders instead pass a resolution to use the net profits of COTCo for capital expenditure.

(n) The COTCo board will appoint a General Manager as proposed by Esso Pipeline Services Inc. ("EPSI") as the current services company (which will be EPIL following Completion of the Exxon Acquisition). If the COTCo board fails to approve a general manager, EPSI (or EPIL following Completion of the Exxon Acquisition) will continue to nominate candidates until the general manager nomination is approved.

(o) Following 10 December 2025, if any shareholder wishes to transfer its shares, it must first notify the other shareholders of any proposed transfer (including the number of shares to be transferred and the price). The other shareholders then have a period of 60 days to exercise their pre-emption rights.

(p) There are no restrictions or requirements in respect of a change of control of a COTCo shareholder.

5.11 **Services Agreements**

5.11.1 ***TOTCo and COTCo Services Agreement***

(a) On 20 December 2014, COTCo and TOTCo entered into a services agreement to provide each other with services including the provision of personnel, equipment and any other services required to ensure the efficient operation of both the Chad Transportation System and Cameroon Transportation System.

(b) The services provided under the agreement are on an "at cost" basis and the agreement will remain in effect so long as the COTCo Convention and TOTCo Convention remain in force.

(c) Either party may terminate the agreement if the other party defaults in any material way, in its duties or obligations and does not commence and diligently pursue the curing of such default within 30 days after written notice from the other party specifying the default and requesting the defaulting party to remedy the same.

(d) The agreement is governed by the laws of the Organization for the Harmonization of Business Law in Africa ("OHADA"). Where OHADA has not legislated, the agreement will be governed by French law.

(e) Disputes will be referred to arbitration under the International Chamber of Commerce Rules before three arbitrators, such arbitration shall be held in Paris and conducted in English.

5.11.2 ***Exxon Services Agreements***

(a) Esso Pipeline Services Inc. ("EPSI") provides services to both COTCo and TOTCo as follows:

(i) COTCo and EPSI entered into a services agreement dated 1 September 1998 for the supply of pipeline services to COTCo by EPSI. As part of the Exxon Acquisition, this services agreement shall be assigned from EPSI to EPIL.

(ii) TOTCo and EEPCI entered into a services agreement dated 10 July 1998 for the supply of pipeline services to TOTCo by EEPCI. Under this agreement EEPCI has the right to provide services through an affiliate and subsequently nominated EPSI as the supplier of services to TOTCo in a side letter dated 16 January 2014.

(iii) The services referred to in (i) and (ii) above are provided on a third party basis under the ExxonMobil global master services agreement and include the provision of personnel, materials, equipment and other services to ensure the maintenance of the Cameroon Transportation System and Chad Transportation System, as applicable.

(iv) EEPCI also provides information technology, procurement, real estate and facilities services on the same basis as described above.

## 6 MATERIAL FINANCE CONTRACTS RELATING TO THE NIGERIAN ASSETS

### 6.1 Accugas Term Facility

6.1.1 On 23 June 2015, Accugas Limited entered into a term facility agreement between, amongst others, certain financial institutions as lenders and FBNQuest Capital Limited as facility agent (the "Term Facility Agent") (as amended on 28 November 2016, as amended and restated on 29 December 2016, and as further amended on 1 August 2019) (the "Original Term Facility Agreement").

6.1.2 The Original Term Facility Agreement was further amended and restated pursuant to an amendment and restatement agreement dated 7 November 2019 between, amongst others, Accugas Limited as borrower, certain financial institutions as lenders (the "Term Facility Lenders") and the Term Facility Agent (the "Amended and Restated Term Facility Agreement"). Pursuant to the terms of the Amended and Restated Term Facility Agreement, the Term Facility Lenders made available to Accugas Limited a term facility in an amount of US$382,055,000 for the purpose of refinancing certain existing loan agreements to which Accugas Limited was a party and funding Accugas Limited's general corporate and working capital requirements.

6.1.3 The loans advanced under the Amended and Restated Term Facility Agreement have a final maturity date of 31 December 2025 and interest shall accrue on such loans at a rate which is the sum of the applicable margin and 3 month USD LIBOR. For each Term Facility Lender other than GuarantCo Ltd. the applicable margin is 10.43 per cent. per annum whereas for GuarantCo Ltd. the applicable margin is 12.43 per cent. per annum. Interest periods are quarterly ending on 31 March, 30 June, 30 September and 31 December of each year. The

Amended and Restated Term Facility Agreement has semi-annual repayment dates (falling on 30 June and 31 December of each year) and an amortising repayment profile with a final bullet repayment. The Amended and Restated Term Facility Agreement contains a number of standard mandatory prepayment events and excess cashflow will be applied on each repayment date to repay any outstanding loans. In addition, Accugas Limited can voluntarily prepay any loans outstanding under the Amended and Restated Term Facility Agreement at any time without penalty or premium.

6.1.4 The Amended and Restated Term Facility Agreement contains financial covenants which test the historic debt service cover ratio, the forecast debt service cover ratio and the forecast interest cover ratio at the end of each quarter (being 31 March, 30 June, 30 September and 31 December of each year). The Amended and Restated Term Facility Agreement also contains standard covenants and representations in respect of compliance with anti-money laundering and anti-corruption laws, environmental laws and social standards, health and safety laws and sanctions. It also contains restrictions on Accugas Limited's ability to incur additional financial indebtedness, to grant security over its assets in favour of any person other than the Term Facility Lenders and to pay distributions.

6.1.5 Subject to limited exceptions which require the consent of all of the Term Facility Lenders, any provision of the Amended and Restated Term Facility Agreement can be amended or waived with the consent of the majority of the Term Facility Lenders (being 66.66 per cent.).

6.1.6 The Term Facility Lenders have the benefit of a comprehensive security package with the loans advanced under the Amended and Restated Term Facility Agreement being secured against the shares and assets of Accugas Limited. Accugas Limited must also establish and maintain a debt service reserve account which is funded with six months' principal and interest.

6.1.7 On 23 June 2015, Accugas Limited entered into an accounts bank agreement between, amongst others, Accugas Limited, the Term Facility Agent and certain account banks (the "Existing Accounts Bank Agreement"). The Existing Accounts Bank Agreement has been further amended and restated pursuant to an amendment and restatement agreement dated 7 November 2019 between, amongst others, Accugas Limited, the Term Facility Agent and certain account banks (the "Amended and Restated Accounts Bank Agreement"). The Amended and Restated Accounts Bank Agreement governs the account arrangements of Accugas Limited, including in relation to withdrawals from, lock-up and set-off of accounts, the waterfall of payments from the collection accounts and arrangements in respect of the gas prepayment accounts.

6.2 **Working Capital Facility**

6.2.1 On 2 October 2015, SEUGL entered into a working capital facility agreement between, amongst others, certain financial institutions as lenders and FBNQuest Capital Limited as facility agent (the "Working Capital Facility Agent") (the "Original Working Capital Facility").

6.2.2 The Original Working Capital Facility has been amended and restated pursuant to an amendment and restatement agreement dated 7 November 2019 between, amongst others, SEUGL as borrower, certain financial institutions as lenders (the "Working Capital Facility Lenders") and the Working Capital Facility Agent (the "Amended and Restated Working Capital Facility Agreement"). Pursuant to the terms of the Amended and Restated Working Capital Facility Agreement, the Working Capital Facility Lenders made available to SEUGL a working capital facility in an amount of NGN 4,800,000,000 for the purpose of funding SEUGL's general corporate and working capital requirements.

6.2.3 The loans advanced under the Amended and Restated Working Capital Facility Agreement have a final maturity date of 31 December 2026 and interest shall accrue on such loans at a rate which is the sum of the applicable margin (being 5 per cent. per annum) and 90 day NIBOR *provided that* if the interest rate is less than 17 per cent. per annum, the interest rate is deemed to be 17 per cent. per annum. Interest periods are semi-annual ending on 30 June and 31 December of each year. In addition, SEUGL will pay to each Working Capital Facility Lender an annual management fee of 0.50 per cent. of such Working Capital Facility Lender's participation in any outstanding loans under the Amended and Restated Working Capital Facility Agreement.

6.2.4 The Amended and Restated Working Capital Facility Agreement has semi-annual repayment dates (falling on 30 June and 31 December of each year) and an amortising repayment profile with a final bullet repayment. The Amended and Restated Working Capital Facility Agreement contains a number of standard mandatory prepayment events and SEUGL may voluntarily prepay any loans outstanding under the Amended and Restated Working Capital Facility Agreement at any time without penalty or premium.

6.2.5 The Amended and Restated Term Facility Agreement contains standard representations in respect of compliance with anti-money laundering and anti-corruption laws, environmental laws and social standards, and sanctions. It also contains restrictions on SEUGL's ability to incur additional financial indebtedness, to grant security over its assets in favour of any person other than the Working Capital Facility Lenders and to pay distributions.

6.2.6 Subject to limited exceptions which require the consent of all of the Working Capital Facility Lenders, any provision of the Amended and Restated Working Capital Facility Agreement can be amended or waived with the consent of the majority of the Working Capital Facility Lenders (being 66.66 per cent.).

6.2.7 The loans advanced under the Amended and Restated Term Facility Agreement are secured against the shares of Savannah Energy Nigeria Limited's subsidiaries as well as the assets of Savannah Energy Nigeria Limited and its subsidiaries, including the interests the Group owns in the Uquo Field and the Stubb Creek Field, and benefits from guarantees from Savannah Energy Nigeria Limited and its subsidiaries. Such security and guarantees rank *pari passu* with those granted in favour of the holders of the SEUGL Notes (as defined below). In addition, SEUGL must also establish and maintain a debt service reserve account which is funded with six months' principal and interest.

6.3 **Promissory Note**

6.3.1 On 21 July 2015, Seven Energy Finance Limited as outgoing payor (the "Outgoing Payor") and FBNQuest Capital Limited as the payee (the "Payee") entered into a deed of novation and variation in relation to a US$12,000,000 promissory note originally issued by Seven Energy International Limited to the benefit of GEC Petroleum Development Company Limited on 12 December 2014 and which was subsequently novated on 12 December 2014, such that the Payee was the payee thereunder and the Outgoing Payor was the payor thereunder (the "Original Promissory Note").

6.3.2 The Original Promissory Note was novated and amended and restated pursuant to a deed of novation and amendment dated 7 November 2019 between the Outgoing Payor, Accugas HoldCo, as payor (the "Payor"), the Payee and Accugas MidCo, as guarantor (the "Amended and Restated Promissory Note"). The Amended and Restated Promissory Note is a US$11,500,000 promissory note with a maturity date of 31 December 2025. Interest will accrue at a cash interest rate of eight per cent. per annum unless the Payor elects to pay PIK interest at a rate of 10 per cent. per annum. Interest periods are semi-annual ending on 30 June and 31 December of each year. The Amended and Restated Promissory Note has semi-annual repayment dates (falling on 30 June and 31 December of each year) starting on 30 June 2021 with US$500,000 instalments due on each such repayment date. The Payor may voluntarily prepay the Amended and Restated Promissory Note at any time (without penalty).

6.3.3 The Amended and Restated Promissory Note is secured against the shares of Accugas HoldCo, Accugas MidCo and Exoro as well as the assets of Accugas HoldCo and Accugas MidCo, but not (for the avoidance of doubt) against the shares or assets of Accugas Limited. The Payee also benefits from a guarantee from Accugas MidCo. Such security and guarantees rank *pari passu* with those granted in favour of the Accugas HoldCo Senior Secured Notes (as defined below).

6.3.4 The Amended and Restated Promissory Note is additionally secured against the shares of Savannah Energy Nigeria Limited's subsidiaries as well as the assets of Savannah Energy Nigeria Limited and its subsidiaries, although such security ranks behind that granted in favour of the SEUGL Notes (as defined below) and the Amended and Restated Working Capital Facility Agreement.

6.3.5 The Payee also benefits from guarantees from Savannah Energy Nigeria Limited and its subsidiaries from the date on which the SEUGL Notes and the Amended and Restated Working Capital Facility Agreement are discharged.

6.4 **Accugas HoldCo Senior Secured Notes**

6.4.1 On 14 November 2019, Accugas HoldCo entered into an indenture between, amongst others, GLAS Trustees Limited as trustee and Accugas MidCo as guarantor (the "Indenture") pursuant to which Accugas HoldCo issued senior secured notes in an amount of US$20,000,000 (the "Accugas HoldCo Senior Secured Notes") with a maturity date of 15 November 2025.

6.4.2 Cash interest on the Accugas HoldCo Senior Secured Notes accrues at a rate of six per cent. per annum and PIK interest accrues at a rate of eight per cent. per annum. Interest periods are semi-annual ending on 15 May and 15 November of each year.

6.4.3 Accugas HoldCo may voluntarily redeem the Accugas HoldCo Senior Secured Notes at any time. The redemption price will depend upon the year in which the Accugas HoldCo Senior Secured Notes are redeemed with such redemption price in 2019 being 50 per cent. and increasing by 10 per cent. each year until 2024 when the redemption price will be (and will remain thereafter) 100 per cent. The Indenture also contains certain standard mandatory redemption events.

6.4.4 The Indenture contains restrictions on Accugas HoldCo's ability to incur additional financial indebtedness, to grant security over its assets in favour of any person other than the holders of the Accugas HoldCo Senior Secured Notes and to pay distributions.

6.4.5 Subject to limited exceptions which require the consent of at least 90 per cent. of the holders of the Accugas HoldCo Senior Secured Notes, any provision of the Indenture can be amended or waived with the consent of more than 75 per cent. of the holders of the Accugas HoldCo Senior Secured Notes.

6.4.6 The Accugas HoldCo Senior Secured Notes are secured against the shares of Accugas HoldCo, Accugas MidCo and Exoro as well as the assets of Accugas HoldCo and Accugas MidCo, but not (for the avoidance of doubt) against the shares or assets of Accugas Limited. The Accugas HoldCo Senior Secured Notes also benefit from a guarantee from Accugas MidCo. Such security and guarantees rank *pari passu* with those granted in favour of the Amended and Restated Promissory Note.

6.5 **SEUGL Notes**

6.5.1 On 14 November 2019, SEUGL entered into a note purchase agreement with the Nigeria Sovereign Investment Authority (the "Note Purchase Agreement") pursuant to which SEUGL issued senior secured notes in an amount of US$105,000,000 with a maturity date of 31 December 2026 (the "SEUGL Notes").

6.5.2 Interest will accrue on the SEUGL Notes at a cash interest rate of 8 per cent. per annum. Interest periods are semi-annual ending on 30 June and 31 December of each year.

6.5.3 The Note Purchase Agreement contains certain mandatory redemption events including an obligation to redeem US$5,000,000 of the principal amount of the SEUGL Notes within 30 calendar days of the date of their issuance. In addition, on each interest payment date occurring on or around 30 June of each year (starting on the interest payment date occurring on or around 30 June 2020) until the maturity of the SEUGL Notes, SEUGL must make a redemption of US$4,200,000 (or, if lower, the aggregate principal amount of the SEUGL Notes outstanding at such time) less the aggregate principal amount of any optional redemption in the period from the immediately preceding interest payment date to the current interest payment date.

6.5.4 Furthermore, on each interest payment date occurring on or around 31 December of each year (following the interest payment date occurring on or around 30 June 2020) until the maturity of the SEUGL Notes, SEUGL must make a redemption of US$8,400,000 (or, if lower, the aggregate principal amount of the SEUGL Notes outstanding at such time) less the aggregate principal amount of any optional redemption in the period from the interest payment date that occurred on or around 31 December of the previous year to the current interest payment date. SEUGL may voluntarily redeem the SEUGL Notes at any time at a redemption price equal to 100 per cent. of the notes to be redeemed (plus accrued and unpaid interest).

6.5.5 The Note Purchase Agreement contains standard representations in respect of compliance with anti-money laundering and anti-corruption laws, environmental laws and sanctions. It also contains restrictions on SEUGL's ability to incur additional financial indebtedness, to grant security over its assets in favour of any person other than the holders of the SEUGL Notes and to pay distributions. It also contains extensive reporting requirements in relation to the financial condition of SEUGL and the guarantors. Subject to certain exceptions, any provision of the Note Purchase Agreement may be amended or waived with the consent of the holder of the SEUGL Notes.

6.5.6 The SEUGL Notes are secured against the shares of Savannah Energy Nigeria Limited's subsidiaries as well as the assets of Savannah Energy Nigeria Limited and its subsidiaries, including the interests the group owns in the Uquo Field and the Stubb Creek Field, and benefit from guarantees from Savannah Energy Nigeria Limited and its subsidiaries. Such security and guarantees rank *pari passu* with those granted in favour of the Working Capital Facility Lenders. In addition, SEUGL shall maintain a debt service reserve account with a minimum balance of not less than US$2,000,000.

## 7 MATERIAL CONTRACTS RELATING TO THE UQUO FIELD

### 7.1 Uquo HoldCo Shareholders' Agreement

7.1.1 On 14 November 2019, African Upstream Holdings Mauritius ("AIIM Uquo"), Savannah Energy (Uquo) Jersey Limited ("Uquo TopCo") and Savannah Energy (Uquo) Limited ("Uquo HoldCo") entered into a shareholders' agreement relating to Uquo HoldCo (the "Uquo SHA"). Each shareholder in Uquo HoldCo shall exercise its voting rights and other rights as a member of Uquo HoldCo, and procure that any director appointed by it from time to time exercise their voting rights, and power and authorities to ensure compliance with the Uquo SHA, the articles of association, business plan and budget of Uquo Holdco. Each shareholder shall procure that no action is taken by Uquo HoldCo or any group company, and that no resolution is passed by Uquo HoldCo in respect of any shareholder reserved matters (listed in paragraph 7.1.6 below) without the written approval of the shareholders representing 85% of the issued shares.

7.1.2 There shall be no more than five directors on the board of Uquo Holdco. The Uquo TopCo shall have the right to nominate three persons and AIIM Uquo shall have the right to nominate two persons, for appointment as directors in the board of Uquo Holdco. The CEO of Uquo Holdco shall be a director nominated by Uquo TopCo by written notice to AIIM Uquo and copy to the company. The CEO shall chair the board meetings of Uquo HoldCo at which he/she is present, but he/she shall not have a casting vote. Uquo Topco shall propose candidates for the role of chief executive officer of SEUGL for approval by AIIM Uquo (acting reasonably). Uquo TopCo and AIIM Uquo shall give joint written notice to the board of SEUGL to appoint the CEO. The boards of other subsidiaries within the group shall have the same director composition as in Uquo Holdco.

7.1.3 Except for shareholder reserved matters and any delegation of authority to the CEO or any other executive or committees of the SEUGL Board, the SEUGL Board shall be responsible for the day-to-day operations and management of the business of the Group in accordance with the business plan and budget. The initial rolling five-year business plan and rolling annual budget has been approved by Uquo TopCo and AIIM Uquo. Each subsequent business plan and budget shall be prepared by the CEO and senior management of SEUGL and submitted annually to the board of Uquo Holdco for approval. The board of Uquo HoldCo shall consult with, and reasonably consider the comments of, the shareholders.

7.1.4 Shareholders are not obliged to provide any capital to Uquo HoldCo by way of subscription for further shares or by way of a loan. Subject to the approval of the board of Uquo HoldCo and the terms of any third party financing agreements, Uquo HoldCo may request further funding from the shareholders. Each shareholder may provide to Uquo HoldCo its proportion of any additional funding in cash by way of a shareholder loan on certain agreed commercial terms (an "Uquo Additional Shareholder Loan"). If a shareholder elects not to provide an Uquo Additional Shareholder Loan, the other shareholders may elect to provide all or part of the funding shortfall by providing an additional shareholder loan on certain agreed commercial terms (an "Uquo Additional Shortfall Loan"). If any employees join any employee share scheme of the Company or its affiliates, the corresponding amount of such employee share scheme shall be deemed an interest free shareholder loan between Uquo HoldCo and Uquo TopCo (an "Uquo Employee Share Scheme Loan").

7.1.5 Subject to: (i) the terms of any third party financing agreements; (ii) applicable law and insolvency legislation; (iii) maintaining a minimum US$10 million cash reserve; and (iv) making appropriate provision for working capital and liabilities of the group as the board of Uquo HoldCo deems appropriate; the board of Uquo HoldCo shall resolve (and procure that the group companies resolve) to distribute all distributable cash to the shareholders on a quarterly basis or as soon as possible after a capital event. Such distributable cash shall be allocated and distributed in the following priority: (i) repayment of interest and principal amounts outstanding under all Uquo Additional Shortfall Loans; (ii) repayment of interest and principal amounts outstanding under all Uquo Additional Shareholder Loans; (iii) repayment to Uquo TopCo of the amounts outstanding under all Uquo Employee Share Scheme Loans; and (iv) the remainder to the shareholders as a dividend *pro rata* the number of shares in Uquo HoldCo held at the time.

7.1.6 The following reserved matters (applicable to Uquo HoldCo, Savannah Energy (BVI) Limited and SEUGL) shall require an 85 per cent. majority vote of the shareholders:

(a) any change to the articles of Uquo Holdco, the business, the auditors, the distribution policy, the share capital or share rights;

(b) any material amendment to, or withdrawal or relinquishment from, the Uquo JOA;

(c) any transfer of SEUGL's participating interest under the Uquo JOA;

(d) sale of any fixed assets with a value greater than US$20 million or which are a material part of the infrastructure of the Uquo business;

(e) change to the business plan and budget (other than due to inflation or the undertaking of a new revenue generating activity) that may result in an increase of the aggregate of total operating and administrative costs in a financial year by more than fifty per cent. when compared against the amount budgeted for that financial year;

(f) SEUGL undertaking an Exploration Operation (described below);

(g) settlement of disputes with a value of over US$5 million or relating to the material assets;

(h) winding up, proposing any arrangement or composition with creditors of Uquo HoldCo, applying for an administration order or appointing a receiver or administrator in respect of Uquo HoldCo;

(i) any material transaction with a shareholder or any of its affiliates, or any guarantee or indemnity not in the ordinary course of business and on arm's length terms;

(j) any material amendment to the Uquo Services Agreement;

(k) mergers and acquisitions, or the entry into of any partnership, joint venture or consortium agreement not included in the business plan and budget;

(l) acquiring or disposing of any material undertaking of company or closing down any material business operation;

(m) any issue of share capital other than to a group company which is wholly owned by Uquo HoldCo; and

(n) sale of shares in Savannah Energy (BVI) Limited or SEUGL.

7.1.7 Save for a permitted transfer, shareholder consent is required for a shareholder to transfer any shares. Permitted transfers are:

(a) Where Uquo TopCo wishes to transfer all or part of its shares in Uquo HoldCo to a third party purchaser on arm's length terms, Uquo TopCo must procure that the third party purchaser, subject to certain conditions, makes a written offer to AIIM Uquo to purchase a *pro rata* amount of its shares in Uquo HoldCo.

(b) Where Uquo TopCo wishes to transfer all (but no part only) of its shares in Uquo HoldCo to a *bona fide* third party purchaser on arm's length terms, subject to certain conditions, Uquo TopCo shall have the option to require the other shareholders to sell their shares to the third party purchaser. If the proposed purchase price of the shares held by AIIM Uquo is less than the higher of: (i) 20 per cent. IRR on AIIM Uquo's total investment expenditure in Uquo HoldCo at such date; or (ii) 2.5 times AIIM Uquo's total investment expenditure in Uquo HoldCo at such date, AIIM Uquo has the right to decline to sell its shares in Uquo HoldCo. If AIIM Uquo declines the third party purchaser's offer, it shall no longer have the right to exercise the Uquo Exit Option (described below).

(c) Save if the transferee is a restricted person, where a shareholder wishes to transfer to an affiliate.

(d) Where a shareholder wishes to sell all or part of its shareholding (the "Uquo Sale Shares") in Uquo Holdco the selling shareholder shall notify the other shareholders in writing of its intention to sell the Uquo Sale Shares, and each remaining shareholder may notify the selling shareholder in writing of the cash price (the "Uquo Offer Price") at which it would be willing to purchase the Uquo Sale Shares and the key terms of such purchase (the "Uquo Offer Terms"). If the selling shareholder does not accept any Uquo Offer Terms or Uquo Offer Price submitted by a remaining shareholder then the selling shareholder shall be entitled to sell the sale shares at a price that is more than the Uquo Offer Price and on materially the same terms as the Uquo Offer Terms. Where the proposed purchaser is a Uquo Matching-Right Transferee (which is a company which is controlled or majority managed by one or more Nigerian national(s) or entity(ies), or which Uquo TopCo considers, acting reasonably, would restrict or prevent Uquo TopCo or SEUGL from achieving its long-term objectives as a result of such investors' reputation or the leverage in their capital structure) then the remaining shareholders shall have the right to acquire the Uquo Sale Shares for the same price and on the same terms as offered by such Uquo Matching-Right Transferee.

7.1.8 Under the Uquo SHA, AIIM Uquo has a non-transferable option to require Uquo TopCo to purchase all of AIIM Uquo's shares in Uquo HoldCo on any date falling within 30 calendar days of 14 November 2023 ("Uquo Exit Option"). The consideration for such shares (the "Uquo Exit Consideration") is to be calculated in accordance with an agreed Uquo Exit Consideration formulae at the date AIIM Uquo serves notice on Uquo TopCo to exercise its option. If prior to the date the Uquo Exit Option arises the Company is taken over by a third party, the Exit Consideration shall be calculated in accordance with the Uquo Exit Consideration formulae and capped at an amount equal to 18 per cent. IRR on AIIM Uquo's total investment expenditure at such date in Uquo HoldCo.

7.1.9 Uquo Topco or any of the directors of SEUGL nominated by Uquo TopCo may propose that it undertakes the acquisition or licensing of seismic data for exploration purposes and/or the drilling of any exploration well in accordance with the terms of the Uquo JOA (an "Exploration Operation"). A decision to pursue an Exploration Operation is a shareholder reserved matter. If the shareholders elect not to approve the Exploration Operation, then Uquo TopCo or its affiliate shall have the right to pursue the unapproved Exploration Operation through an affiliate of SEUGL under the Uquo JOA (a "SEUGL Exploration Affiliate"). The shareholders shall procure that SEUGL transfers the minimum percentage of its participating interest under the Uquo JOA to the relevant SEUGL Exploration Associate as is necessary for the same to undertake the unapproved Exploration Operation as a sole risk operation in accordance with the Uquo JOA. The SEUGL Exploration Affiliate shall bear the entire cost of the unapproved Exploration Operation sole risk operations, and be entitled to 100 per cent. of any hydrocarbons produced therefrom. If, during the unapproved Exploration Operations, a discovery of previously unproven hydrocarbons is made, subject to certain conditions (including the payment of a back-in premium amount), AIIM Uquo shall have the right to elect to back-in and participate in such Exploration Operations.

7.2 **Uquo Field Farm-Out Agreement**

7.2.1 On 25 February 2003, the DPR granted Frontier the right to operate the Uquo Field as a marginal field. Pursuant to the Marginal Field Guidelines, at this time, the area also became independent of OML 13 for operational purposes. On 27 April 2004, NNPC, SPDC, Elf Petroleum Nigeria Limited, and AGIP, as a joint venture and the holders of OML 13 at this time, agreed to terms of a farm-out agreement under which the Uquo Field would be developed by Frontier (the "Uquo FOA"). As at the date of this document, Nigerian Petroleum Development Company ("NPDC"), a wholly owned subsidiary of NNPC, is the holder of OML 13 (ie. the farmor). The term of the Uquo FOA was for an initial period of sixty months and subsequently renewed. The NUPRC confirmed in a letter dated 16 November 2021 that the FOA is valid until 10 March 2026.

7.2.2 Pursuant to a deed of assignment dated 15 May 2006, Frontier assigned a 40 per cent. legal interest in the Uquo Field to Red Rock Energy Limited ("Red Rock"). This assignment was approved by the MPR on 4 October 2006. Red Rock then assigned the interest to SEUGL, itself an affiliate of Red Rock. This assignment was approved by the MPR on 3 October 2007.

7.2.3 The Uquo FOA requires Frontier to pay to the Uquo FOA farmor an overriding royalty on crude oil production at the following rates: (i) 2.5 per cent. of the value of daily production up to 2,000 bopd; (ii) 3 per cent. of the value of daily production from 2,001 to 5,000 bopd; (iii) 5.5 per cent. of the value of daily production from 5,001 to 10,000 bopd; (iv) 7.5 per cent. of the value of daily production from 10,001 to 15,000 bopd; and (v) the parties are to negotiate and agree the overriding royalty rate to be paid on production in excess of 15,000 bopd. For the production of natural gas, Frontier pays an overriding royalty of: (i) 0 per cent. of the value of daily production below 20 MMscfpd; and (ii) the parties are to negotiate and agree the overriding royalty rate to be paid on daily production above 20 MMscfpd. At the date of this document, daily production of natural gas from the Gas Project has exceeded 20 MMscfpd, but no agreement has been made between the parties as to the level of the overriding royalty rate. The farmor can lift its crude oil entitlement from the field or elect to receive its royalty in US$ equivalent at the prevailing market prices for the crude oil on the date of payment. In the event the government asserts any right it may have to acquire an interest in the Uquo Field, Frontier has a best endeavours obligation to ensure the government assumes a corresponding part of Frontier's obligations and liabilities under the Uquo FOA.

7.2.4 Under the Uquo FOA if Frontier owes money to the farmor for a continuous period of three months, Frontier will be in default. If Frontier is deemed to be in default it is deemed to have granted to the farmor a lien on all crude oil produced from the Uquo Field and the proceeds from such production to secure discharge of the owed amounts plus interest. During any period of default, Frontier is not entitled to its production from the Uquo Field, which will vest in and be the property of the farmor. The farmor is entitled to sell the production and, after deducting all costs incurred during the sale, is entitled to recover from the remaining proceeds all amounts owed to the farmor by Frontier.

7.2.5 The Uquo FOA may be terminated immediately if: (i) Frontier becomes bankrupt and is forced to make restitution to its creditors or insolvent or wilfully violates Nigerian laws and regulations governing petroleum operations, financial transactions and/or commercial operations; (ii) the Commission determines that Frontier is not complying with Nigerian petroleum laws, regulations or environmental health and safety standards with respect to operations undertaken in respect of the Uquo Field (after a 90 day cure period); (iii) Frontier assigns its rights and interests in the Uquo Field without the written consent of the Nigerian Government; (iv) Frontier intentionally extracts or produces petroleum outside the farm-out area; or (v) Frontier fails to remedy or remove a material breach (as defined in the agreement which may include a substantial breach of the Uquo FOA, breaches of health/environmental standards, confidentiality obligations, abandonment security obligations, insurance obligations, creation of encumbrances contrary to the agreement, intentional submission of false information to the Nigerian Government or where the DPR notify that the Uquo Field operations are interfering with the farmor's operations) of the Uquo FOA within a 90 day cure period. The Uquo FOA farmor can also terminate on 30 days' notice if Frontier ceases operations for more than 90 days without acceptable cause or justification.

7.2.6 The Uquo FOA requires farmees to provide security funds to satisfy abandonment obligations with such security funds being reduced or released as the underlying obligations and liabilities are met, reduced or released. Upon commencement of operations and prior to submission of its first work programme to the DPR, the farmees and farmor were required to enter into an abandonment security agreement. By the provisions of the PIA which came into force in August 2021, it is now a statutory obligation for farmees to make adequate provisions for, and establish, a Decommissioning and Abandonment Fund, with funds to be set aside in escrow and funded on a straight-line basis over the remaining economic life of the Uquo Field. The PIA mandates farmees to submit their decommissioning plans to the regulator within 12 months of the PIA becoming effective. As at the date of this document, an abandonment security agreement has not been agreed by the parties and there has been no attempt to enforce this obligation or enter into an abandonment security agreement with the farmees.

7.2.7 A party must give the other party notice of a force majeure situation within 24 hours of such a situation occurring along with an estimate of how long its resolution might take. The obligations of the party giving notice of force majeure (other than payments of amounts due or furnishing security) will then be suspended. There is a reasonable endeavours obligation on the party giving notice to remove or overcome the force majeure situation as quickly as possible in an economic manner.

7.3 **Uquo Field Joint Operating Agreement**

7.3.1 On 9 January 2007, Frontier and SEUGL entered into a joint operating agreement to set out the parties' obligations with respect to the conduct of petroleum operations in the Uquo Field (the "Uquo JOA"). The Uquo JOA has been amended from time to time to reflect the changes in the parties' interests, and was most recently amended and restated on 30 September 2019. Unless otherwise terminated in accordance with its terms, the term of the Uquo JOA runs concurrently with the term of the Uquo FOA, therefore, once the Uquo FOA terminates or expires, the Uquo JOA shall also terminate or expire (subject to final settlement being made).

7.3.2 The terms of the Uquo JOA provide that, save for certain joint operations retained by the parties (mentioned below), with effect from 31 August 2018 (the "Economic Effective Date") Frontier and SEUGL have separated the operations at the Uquo Field such that:

(a) SEUGL has 100 per cent. of the economic benefit of, shall retain all gas produced and gross proceeds from (including associated natural gas produced from the Oil Project), shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the gas project (being the exploration, appraisal, development and production of gas reservoirs at the Uquo Field) (the "Gas Project");

(b) Frontier has 100 per cent. of the economic benefit of, shall retain all crude oil produced and gross proceeds from, shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the oil project (being the exploration, appraisal, development and production of oil reservoirs and drilling and completion of the water-reinjection well at the Uquo Field) (the "Oil Project"); and

(c) Frontier and SEUGL have maintained certain joint operations (detailed below), from which Frontier and SEUGL shall own, take in kind and separately dispose of all hydrocarbons produced from the same *pro rata* to their participating interest share.

7.3.3 Frontier is the operator of the Uquo Field and responsible for undertaking all oil and gas operations on behalf of the parties (save with respect to the drilling and completion of new gas wells, which Frontier delegates responsibility for undertaking to SEUGL until completion). The operations are conducted by a Field Operations Team, led by an operations director (appointed by Frontier). The Field Operations Team is comprised of: (i) a Gas Team (headed by the Head of Gas Operations), composed of SEUGL secondees, which is responsible for managing and operating the Gas Project; and (ii) an Oil Team (headed by the Head of Oil Operations), composed of Frontier secondees, which is responsible for managing and operating the Oil Project.

7.3.4 Decisions in respect of the Uquo Field's operations are taken by a joint operating committee which has the power to authorise, direct and supervise Frontier, acting as operator, in its conduct of operations at the Uquo Field. The joint operating committee is made up of four members, two of whom are appointed by Frontier ("Frontier Representatives") and two of whom are appointed by SEUGL ("SEUGL Representatives"). All decisions of the joint operating committee require the unanimous vote of Frontier and SEUGL. Save with respect to matters where a representative has a *bona fide* belief that it will result in a breach of compliance policies, applicable law or may lead to an operations conflict between the Oil Project and Gas Project, with respect to matters relating to:

(a) the Gas Project, the Frontier representatives must vote in accordance with the SEUGL Representatives;

(b) the Oil Project, the SEUGL representatives must vote in accordance with the Frontier Representatives;

(c) the joint operations and other matters which are non-specific to the Oil Project and Gas Project, the Frontier and SEUGL Representatives may freely exercise their votes.

7.3.5 With respect to the Oil Project and Gas Project operations, the Uquo JOA provides for certain circumstances where a party can elect to have a well from the other party's project transferred to its own project.

7.3.6 In addition, if a party obtains all necessary approvals to drill for hydrocarbons deeper than the Uquo Field farm-out area (ie. below 10,350 feet TVDSS) (a "Deep Well"), the other party shall, subject to certain conditions, have the right to elect to participate in the proposed Deep Well as a joint operation. If a Deep Well is conducted as a joint operation in accordance with the terms of the Uquo JOA, each party shall: (i) bear their participating interest share of costs and liabilities of conducting such exploration; and (ii) shall own, take in kind and separately dispose of all hydrocarbons produced from the same *pro rata* to their participating interest share.

7.3.7 Other joint operations include shared services, as agreed between the parties (including maintenance of joint property, asset protection and logistics), carried out by Frontier (as operator) on behalf of the parties. Between 31 December 2019 and 31 December 2020, SEUGL was obliged to carry Frontier's share of shared services costs and expenses. From 31 December 2020, Frontier is obliged to bear SEUGL's shared services costs and expenses until it has paid an amount on SEUGL's behalf equal to the carried amount paid by SEUGL. The basis on which the allocation of the costs and expenses of the shared services shall be borne between the parties shall be agreed every two years between the parties.

7.3.8 The Uquo JOA includes a number of events of default, including where: (i) a party fails to pay certain payments to the other party relating to Deep Wells and the transfer of wells between parties; (ii) a party fails to perform its indemnity obligations under the Uquo FOA or Uquo JOA; (iii) an order is made by a court or an effective resolution is passed for the dissolution, liquidation or winding up of a party, or a party dissolves, liquidates or is wound up, or a receiver is appointed for a substantial portion of the party's assets; (limbs (i) to (iii) being "Financial Defaults"); and (iv) a party is responsible for an act or omission, contrary to the standard of a reasonable and prudent operator, which if not cured could be expected to result in a material risk to the non-defaulting party's title to its participating interest (a "Title Risk Default").

7.3.9 During any such event of default, subject to certain notice and cure periods, the defaulting party shall be restricted from taking certain actions and exercising certain of its rights under the Uquo JOA, including no rights to: (i) vote on joint operating committee decisions relating to joint operations; (ii) consent to or reject to another party's transfer of participating interest or take assignment of any portion of another party's participating interest; (iii) receive any entitlement for joint operations; and (iv) submit a proposal to drill a Deep Well to the joint operating committee. If a Financial Default is not remedied by the 180th day following the default, or, subject to certain exceptions, a Title Risk Default by the 30th day following notice of the default, the non-defaulting party may require the defaulting party to withdraw from the Uquo JOA.

7.3.10 If, as a result of force majeure, either party is rendered unable, wholly or in part, to carry out its obligations under the Uquo JOA then following the issuance of a notice of force majeure (which shall be provided within a reasonable time of such event occurring) such obligations shall be suspended until the force majeure event ceases to impact the party's ability to carry out its obligations and such reasonable period of time to allow the party to put itself into the position it was in prior to the force majeure event. If a party remains unable to perform its obligations under the Uquo JOA due to force majeure event for a period of six months (following the issuance of a force majeure notice) then the other party may, at its sole discretion issue a notice of termination which will be deemed to have taken effect when issued. If the Uquo JOA is terminated pursuant to an event of force majeure neither party shall remain liable to the other except where payments have been paid for performance which has not been delivered and where obligations for payment existed prior to termination.

7.4 **Uquo Upstream GSA**

7.4.1 On 6 November 2019, SEUGL and Accugas Limited entered into a natural gas sales agreement relating to the sale of unprocessed gas produced by SEUGL to Accugas Limited ("Uquo GSA") for onward supply by Accugas Limited to its downstream customers under the Calabar PRG GSA, the Ibom Power GSA, Unicem GSA, FIPL GSA and the Mulak GSA. The Uquo GSA became effective on 14 November 2019. The previous gas sales arrangements between Accugas Limited, SEUGL and Frontier were terminated on such date.

7.4.2 The term of the initial period of the Uquo GSA is until 31 December 2028, thereafter the Uquo GSA shall continue until the expiry of 12 months' written notice from SEUGL that it is no longer technically possible to produce commercial quantities of gas from the Uquo Field.

7.4.3 The Uquo GSA is on a pay when paid basis. Accugas Limited is obliged to pay SEUGL for the quantities of gas supplied within five business days following the date on which Accugas Limited receives payment from the relevant downstream customer with respect to such quantities of gas (the "Due Date").

7.4.4 The source of the gas to be sold and delivered under the Uquo GSA shall be sourced at SEUGL's discretion. Until 31 December 2028, the daily contract quantity shall be 195 MMscfpd. Thereafter, SEUGL and Accugas Limited shall agree the daily contract quantity. The annual contract quantity shall be the daily contract quantity multiplied by number of days in a contract year. Subject to the terms of the Uquo GSA, SEUGL shall have the right to temporarily and/or permanently reduce the daily contract quantity by a rateable amount in the event Accugas Limited fails to pay for gas delivered within certain time periods irrespective of whether Accugas Limited has received payment from the existing downstream gas sales customers for such quantities of gas. SEUGL also has the right to suspend deliveries of gas on ten days' notice in the event Accugas Limited does not pay SEUGL for such gas on the Due Date.

7.4.5 Accugas Limited has committed, subject to certain deductions, to a take or pay quantity per month equal to eighty per cent. of 1/12$^{th}$ of the annual contract quantity. Each quarter Accugas Limited shall be obliged to pay (at the applicable contract price) for the aggregate amount of gas it failed to take under the take or pay quantity. Subject to certain conditions, Accugas Limited is entitled to the part of the take or pay quantity which is not taken during a quarter, but which has been paid for by making a take or pay payment.

7.4.6 The contract price is a set base price ((unindexed) in \$/Mscf) for the relevant contract year multiplied by a weighted average adjustment to reflect the inflation provisions Accugas Limited receives under the existing downstream gas sales agreements. The base price for each contract year is set out in a schedule to the Uquo GSA, and increases on the later of: (i) the date of the monthly invoice under which SEUGL has delivered an aggregate of 110 Bscf of gas under the Uquo GSA; and (ii) 14 November 2021. Either party is entitled to seek a review of the contract price if, as a result of a change in law or any hindrance of government or other act or failure to act by any government claiming jurisdiction over the agreement, that party suffers a material adverse financial impact in any contract year.

7.4.7 Subject to the satisfaction of the certain conditions precedent, Accugas Limited was obliged to pre-pay for natural gas for a value of up to US$40 million, such pre-payment to be applied:

(a) up to US$8.4 million to the holder of the SEUGL 10.50 per cent. senior secure notes due 2026 with an aggregate principal amount of US$105 million;

(b) up to US$22.5 million (or US$18 million if SEUGL is required to make a 20 per cent. payment contribution) towards drilling the next well at the Uquo Field;

(c) up to US$3.1 million towards SEUGL's working capital requirements in line with an agreed working capital budget; and

(d) up to US$6 million towards funding SEUGL's cost of repairing the Uquo-7 well.

7.4.8 From 1 July 2020, repayment of the expended prepayment amount by SEUGL commenced through applying a discount to the price of gas delivered to Accugas Limited until repaid. The applicable discount to be applied per contract year is set out in a schedule to the Uquo GSA.

7.4.9 SEUGL may terminate the Uquo GSA:

(a) on 180 days' notice if: (i) Accugas Limited abandons its operations at the CPF; (ii) Accugas Limited breaches certain of the covenants it gives under the Uquo GSA and such breach is not remedied within 90 days; (iii) due to reasons of force majeure, Accugas Limited has not taken delivery of a quantity of gas equal to at least 75 per cent. of the annual contract quantity for a continuous period of 24 months; (iv) Accugas Limited fails to take delivery of at least 50 per cent. of the aggregate of the properly nominated quantities in any contract year and any take or pay payments remain outstanding on the last day of such contract year (regardless of whether the payment date for such take or pay payments have arisen under the terms of the Uquo GSA); and (v) for reasons other than force majeure, Accugas Limited nominates zero quantities of gas for 45 day continuously, or for 90 days in aggregate, during any contract year.

(b) on 30 days' notice if Accugas Limited does not pay certain prepayment amounts to SEUGL when due.

(c) with immediate effect if: (i) SEUGL's right to suspend deliveries of natural gas to Accugas Limited has arisen and not ceased within 60 days; (ii) in accordance with the terms of the Uquo GSA, SEUGL issues a notice to permanently reduce the daily contract quantity resulting in a reduced daily contract quantity of zero; (iii) Accugas Limited diverts gas to customers other than the existing downstream customers without SEUGL's written consent and does not within 60 days: (a) pay for the quantity of gas diverted; and (b) provide evidence that it is under no further obligation to supply such gas; (iv) an act of insolvency in relation to Accugas Limited occurs and continues for ten business days; (v) Accugas Limited fails to give notice of the occurrence of an acceleration event under certain Accugas Limited third party financing arrangements within five business days of such event; (vi) Accugas Limited does not provide to SEUGL, after an acceleration event under certain Accugas Limited third party financing arrangements, with specific information relating to payments made by downstream customers within five business days from the due date of the same; (vii) after an acceleration event under certain Accugas Limited third party financing arrangements, Accugas Limited does not pay any amount to SEUGL under a monthly invoice when due and payable; (viii) all of the existing downstream gas sales agreement terminate or expire; (ix) Accugas Limited does not pay certain prepayment amounts within ten business days; and (x) Accugas Limited breaches certain covenants and does not remedy the same within ten business days.

7.4.10 Accugas Limited may terminate the Uquo GSA:

(a) on 180 days' notice if: (i) SEUGL abandons its operations at the Uquo Field; (ii) SEUGL breaches certain of the covenants it gives under the Uquo GSA and such breach is not remedied within 90 days; (iii) for reasons of force majeure, SEUGL has been unable to make available for delivery a quantity of gas equal to at least 75 per cent. of the annual contract quantity for a continuous period of 24 months, provided that during each contract year of such 24 month period the quantities of gas properly nominated by Accugas Limited exceed 75 per cent. of the annual contract quantity; and (iv) SEUGL fails to make available in any contract year at least: (a) 50 per cent. of the annual contract quantity, provided Accugas Limited properly nominates quantities of gas which exceed 50 per cent. of the annual contract quantity during such time: or (b) 50 per cent. of the aggregate properly nominated quantities in such time;

(b) with immediate effect if: (i) all of the existing downstream gas sales agreements terminate or expire; or (ii) an act of insolvency effects SEUGL.

7.4.11 Force majeure under the Uquo GSA includes force majeure which primarily affects a third party where that force majeure prevents, impedes or delays SEUGL or Accugas Limited's performance under the agreement.

7.4.12 Except in relation to permitted assignments to affiliates, neither party shall assign all or any part of their rights and obligations under the Uquo GSA without the prior written consent of the other party. The parties may assign their rights by way of security for the purpose of or in connection with financing or re-financing their respective operations. SEUGL is required to assign *pro-rata* its rights and obligations to any purchaser of SEUGL's interests in the Uquo Field. To the extent of any partial assignment, SEUGL and the purchaser shall be jointly and severally liable.

7.4.13 Accugas Limited is required to pay to SEUGL an annual fixed administration fee and management fee. Each fee is paid in two equal instalments per contract year.

7.5 **SEUGL Services Agreement**

7.5.1 On 14 November 2019, the Company and SEUGL entered into the SEUGL Services Agreement which sets out the terms on which each entity can provide from time to time certain services to the other. The Company can also request that SEUGL provides services to an affiliate of the Company (other than Seven Energy (BVI) Limited, Savannah Energy (Uquo) Limited, Accugas Holdings UK plc, Accugas UK Limited, Exoro Holding BV and Accugas Limited) (the "SAVE Group Companies"). The Company may perform any requested services itself, or procure that one of the SAVE Group Companies performs such service. The services are to be performed to the highest level of care, skill and diligence in accordance with best practice in the service provider's industry, profession or trade.

7.5.2 Subject to certain exclusions, the services provided are charged on a pass through basis in accordance with an accounting procedure scheduled thereto, save that the Company may charge an indirect charge for the cost of indirect services and related office costs of the Company and the SAVE Group Companies not otherwise set out in the accounting procedure. This indirect charge is based on a sliding scale of five per cent. to one per cent. of total expenditure depending on the amount of total expenditure per annum (the higher the total expenditure, the lower the percentage of indirect charge), with a minimum charge of US$200,000 per calendar year. If the estimated cost of a major project is estimated to be more than US$10 million, the Company can charge a separate indirect charge for such project if approved by the parties at the time of approval of the project.

7.5.3 The services to be provided under the agreement include: (i) sub-surface activities; (ii) upstream asset management; (iii) executive management functions: (iv) QHSE; (v) HR; (vi) security and transport; (vii) finance; (viii) legal; (ix) administrative; (x) IT; and (xi) such other services as may be agreed between the parties. Any services provided to SEUGL will only be those necessary for the running of its business in a manner consistent with its business plan and budget from time to time.

7.5.4 The party requesting the services may immediately terminate the SEUGL Services Agreement if the services provider commits a material breach which cannot be cured, or if it can be cured, has not been cured within seven days of being notified. Either party may immediately terminate if the other party takes any step or action in connection with entering bankruptcy, administration, provisional liquidation or any composition or arrangement with creditors (other than a solvent restructuring), being wound up, having a receiver appointed to any of its assets or ceasing to carry on its business.

7.6 **Transportation Services Agreement**

7.6.1 On 30 September 2019, SEUGL and Frontier entered into the Transportation Services Agreement (the "Uquo TSA") which sets out the terms on which Frontier shall transport SEUGL's quantities of crude oil (if any) and condensate through a system of pipelines from the CPF to QIT for onward sale to ExxonMobil International Holdings Inc. ("ExxonMobil") under the terms of the ExxonMobil COSA. The Uquo TSA became effective on 31 December 2019.

7.6.2 The Uquo TSA provides that it shall remain in full force and effect until the earlier of: (i) the date SEUGL permanently stops producing hydrocarbons at the Uquo Field; (ii) the date that Frontier stops transporting crude oil and condensate through the relevant pipeline system; (iii) on 180 days' written notice by SEUGL that it intends to stop delivering crude oil and condensate under the Uquo TSA; and (iv) 29 November 2022, save that if the ExxonMobil COSA and the CHA are extended beyond this date, or replaced with new contracts, the Uquo TSA shall be effective until such new termination date.

7.6.3 Subject to certain conditions, Frontier is obliged to accept quantities of SEUGL's crude and condensate, meeting the delivery specifications, not exceeding 1,000 bopd. All crude oil delivered under the Uquo TSA shall originate from the Uquo Field, unless such crude from a field other than the Uquo Field would not cause Frontier to be in breach of its obligations under the ExxonMobil COSA and/or CHA. Frontier shall sell the quantities of SEUGL's crude oil and condensate delivered by SEUGL pursuant to the terms of the ExxonMobil COSA. The quantities sold are calculated under the ExxonMobil COSA taking account of pipeline losses, shrinkage and all other physical losses.

7.6.4 The Uquo TSA provides that Frontier shall pay to SEUGL any payment made by ExxonMobil to Frontier with respect to SEUGL's crude oil and condensate (less certain costs incurred by Frontier under the CHA). Frontier is not required to pay any such amounts to SEUGL unless and until Frontier receives valid payment from ExxonMobil. For the transportation services, SEUGL is required to pay Frontier, on a monthly basis, the following costs incurred by Frontier on a pass through basis: (i) 20 per cent. of the operating expenditures relating to the FUN Manifold Pipeline; (ii) 50 per cent. of the costs of maintaining the right of way associated with the FUN Manifold Pipeline; (iii) 20 per cent. of the remedial capital expenditures (not including any expansion capital expenditures) relating to the FUN Manifold and QIT Pipeline; (iv) a share of the operating expenditures of the FUN Manifold and QIT Pipeline in accordance with the cost allocation regime agreed under the FUN JOA; and (iv) a share of the costs incurred by Frontier under the CHA.

7.6.5 Frontier has the right to suspend and/or reduce the quantity of SEUGL's crude oil and condensate accepted for delivery and suspend the transportation services in certain circumstances, including: (i) subject to Frontier's obligation to use reasonable endeavours to accept such crude oil and condensate, where SEUGL's crude oil and condensate does not meet delivery specifications; (ii) there is a scheduled outage; (iii) Frontier receives an instruction under the CHA requiring the suspension or reduction of deliveries at QIT; (iv) SEUGL fails to meet its metering obligations under the Uquo TSA such that it prevents the performance of transportation services by Frontier; (v) any payment due by SEUGL under the Uquo TSA has not been made within 60 days of its due date; and (vi) a force majeure event. Frontier is obliged to use its reasonable endeavours to restore the transportation services as soon as reasonably practicable.

7.6.6 The Uquo TSA provides that either party may terminate by written notice: (i) after failing to remedy/provide a proposal for remedying (reasonably satisfactory to the non-defaulting party) such breach within 45 days from the non-defaulting party delivering a notice of the breach, upon giving 60 days' written notice in the event the defaulting party materially fails to perform or comply with any of its material obligations; (ii) upon 60 days' notice for failure to pay any amounts due under the Uquo TSA; (iii) if an order is made or resolution passed for the winding up of the other party; (iv) if a receiver, administrator or administrative receiver is appointed over the whole or any material part of the assets of the other party, or the other party ceases to carry on the whole or a substantial part of its business; (v) breach of any anti-bribery and corruption warranties set out in the Uquo TSA; and (vi) upon 30 days' notice if the other party is excused from the performance of any material obligation under the Uquo TSA for a continuous period of 18 months due to a force majeure event.

7.6.7 Pursuant to the Uquo TSA, a party shall be excused from the performance of any obligation under the Uquo TSA if such failure is attributable to an event of force majeure and obligations are notified to the other party as soon as reasonably practicable of the circumstances constituting the force majeure. The affected party is required to do all such things a reasonable and prudent operation would do to continue to perform its obligations under the Uquo TSA and to minimise the effect of the force majeure event.

## 8 MATERIAL CONTRACTS RELATING TO THE NIGERIAN MIDSTREAM ASSETS

### 8.1 Accugas SHA

8.1.1 On 14 November 2019, African Midstream Holdings Mauritius ("AIIM Accugas"), Savannah Energy Nigeria Midstream Limited ("Accugas TopCo") and Accugas Holdings UK plc ("Accugas HoldCo") entered into a shareholders' agreement relating to Accugas HoldCo (the "Accugas SHA"). Each shareholder in Accugas HoldCo shall exercise its voting rights and other rights as a member of Accugas HoldCo and procure that any director appointed by it from time to time exercise their voting rights, and power and authorities to ensure compliance with the Accugas SHA, the articles of association, business plan and budget of Accugas HoldCo. Each shareholder shall procure that no action is taken by Accugas HoldCo or any Group company, and that no resolution is passed by Accugas HoldCo in respect of any shareholder reserved matters (listed in paragraph 8.1.6 below) without the written approval of the shareholders representing 85 per cent. of the issued shares.

8.1.2 There shall be no more than five directors on the board of Accugas Holdco. The Accugas TopCo shall have the right to nominate three persons and AIIM Accugas shall have the right to nominate two persons for appointment as directors in the board of Accugas HoldCo. The CEO of Accugas HoldCo shall be a director nominated by Accugas TopCo by written notice to AIIM Accugas and copied to Accugas HoldCo. The CEO shall chair the board meetings of Accugas HoldCo at which he/she is present, but he/she shall not have a casting vote. Accugas Topco shall propose candidates for the role of chief executive officer of Accugas Limited for approval by AIIM Accugas (acting reasonably). Accugas TopCo and AIIM Uquo shall give joint written notice to the board of Accugas Limited to appoint the CEO.

8.1.3 Except for shareholder reserved matters and any delegation of authority to the CEO or any other executive or committees of the Accugas Limited board, the Accugas Limited board shall be responsible for the day-to-day operations and management of the business of the group in accordance with the business plan and budget. The initial rolling five year business plan and rolling annual budget has been approved by Accugas TopCo and AIIM Accugas. Each subsequent business plan and budget shall be prepared by the CEO and senior management of Accugas Limited and submitted annually to the board of Accugas Holdco for approval. The board of Accugas HoldCo shall consult with, and reasonably consider the comments of, the shareholders.

8.1.4 Shareholders are not obliged to provide any capital to Accugas HoldCo by way of subscription for further shares or by way of a loan. Subject to the approval of the board of Accugas HoldCo and the terms of any third party financing agreements, Accugas HoldCo may request further funding from the shareholders. Each shareholder may provide to Accugas HoldCo its proportion of any additional funding in cash by way of a shareholder loan on certain agreed commercial terms (an "Accugas Additional Shareholder Loan"). If a shareholder elects not to provide an Accugas Additional Shareholder Loan, the other shareholders may elect to provide all or part of the funding shortfall by providing an additional shareholder loan on certain agreed commercial terms (an "Accugas Additional Shortfall Loan"). If any employees join any employee share scheme of the Company or its affiliates, the corresponding amount of such employee share scheme shall be deemed an interest free shareholder loan between Accugas HoldCo and Accugas TopCo (an "Accugas Employee Share Scheme Loan").

8.1.5 Subject to: (i) the terms of any third party financing agreements; (ii) applicable law and insolvency legislation; (iii) maintaining a minimum US$10 million cash reserve; and (iv) making appropriate provision for working capital and liabilities of the group as the board of Accugas HoldCo deems appropriate; the board of Accugas HoldCo shall resolve (and procure that the group companies resolve) to distribute all distributable cash to the shareholders on a quarterly basis or as soon as possible after a capital event. As soon as possible after a cash is resolved to be distributable, such cash shall be allocated and distributed in the following priority: (i) repayment of interest and principal amounts outstanding under all Accugas Additional Shortfall Loans; (ii) repayment of interest and principal amounts outstanding under all Accugas Additional Shareholder Loans; (iii) repayment to Accugas TopCo of the amounts outstanding under all Accugas Employee Share Scheme Loans; and (iv) the remainder to the shareholders as a dividend *pro rata* to the number of shares in Accugas HoldCo held at the time.

8.1.6 The following reserved matters (applicable to Accugas HoldCo, Accugas MidCo, Exoro and Accugas Limited) shall require an 85 per cent. majority vote of the shareholders:

(a) any change to the articles of Accugas Holdco, the business, the auditors, the distribution policy, the share capital or share rights;

(b) the execution of any new agreement or contract relating to any downstream supply contracts under which gas is supplied by a group company to a downstream customer; and any material amendment, consent or waiver of a material term of any new or existing downstream contract;

(c) any material amendment of any of the existing downstream supply contracts, and any material amendment, consent or waiver or any decision not to enforce a term thereunder;

(d) sale of any fixed assets with a value greater than US$20 million or which are a material part of the infrastructure of the Accugas Limited's business;

(e) change to the business plan and budget (other than due to inflation or the undertaking of a new revenue generating activity) that may result in an increase of the aggregate of total operating and administrative costs in a financial year by more than fifty per cent. when compared against the amount budgeted for that financial year;

(f) approval of any New Project (details below)

(g) settlement of disputes with a value of over US$5 million or relating to the material assets;

(h) winding up, proposing any arrangement or composition with creditors of Accugas HoldCo, applying for an administration order or appointing a receiver or administrator in respect of Accugas HoldCo;

(i) any material transaction with a shareholder or any of its affiliates, or any guarantee or indemnity not in the ordinary course of business and on arm's length terms;

(j) any material amendment to the Accugas Services Agreement;

(k) mergers and acquisitions, or the entry into of any partnership, joint venture or consortium agreement not included in the business plan and budget;

(l) acquiring or disposing of any material undertaking of the company or closing down any material business operation;

(m) any issue of share capital other than to a group company which is wholly owned by Accugas HoldCo; and

(n) sale of shares in Accugas MidCo, Exoro or Accugas Limited.

8.1.7 Save for a permitted transfer, shareholder consent is required for a shareholder to transfer any shares. Permitted transfers are:

(a) Where Accugas TopCo wishes to transfer all or part of its shares in Accugas HoldCo to a third party purchaser on arm's length terms, Accugas TopCo must procure that the third party purchaser, subject to certain conditions, makes a written offer to AIIM Accugas to purchase a *pro rata* amount of its shares in Accugas HoldCo.

(b) Where Accugas TopCo wishes to transfer all (but no part only) of its shares in Accugas HoldCo to a *bona fide* third party purchaser on arm's length terms, subject to certain conditions, Accugas TopCo shall have the option to require the other shareholders to sell their shares to the third party purchaser. If the proposed purchase price of the shares held by AIIM Accugas is less than the higher of: (i) 20 per cent. IRR on AIIM Accugas's total investment expenditure in Accugas HoldCo at such date; or (ii) 2.5 times AIIM Accugas's total investment expenditure in Accugas HoldCo at such date, AIIM Accugas has the right to decline to sell its shares in Accugas HoldCo. If AIIM Accugas declines the third party purchaser's offer, it shall no longer have the right to exercise the Accugas Exit Option (details below).

(c) Save if the transferee is a restricted person, where a shareholder wishes to transfer to an affiliate.

(d) Where a shareholder wishes to sell all or part of its shareholding (the "Accugas Sale Shares") in Accugas Holdco the selling shareholder shall notify the other shareholders in writing of its intention to sell the Accugas Sale Shares, and each remaining shareholder may notify the selling shareholder in writing of the cash price (the "Accugas Offer Price") at which it would be willing to purchase the Accugas Sale Shares and the key terms of such purchase (the "Accugas Offer Terms"). If the selling shareholder does not accept any Accugas Offer Terms or Accugas Offer Price submitted by a remaining shareholder then the selling shareholder shall be entitled to sell the sale shares at a price that is more than the Accugas Offer Price and on materially the same terms as the Accugas Offer Terms. Where the proposed purchaser is an Accugas Matching-Right Transferee (which is a company which is controlled or majority managed by one or more Nigerian national(s) or entity(ies), or which Accugas TopCo considers, acting reasonably, would restrict or prevent Accugas TopCo or Accugas Limited from achieving its long-term objectives as a result of such investors' reputation or the leverage in their capital structure) then the remaining shareholders shall have the right to acquire the Accugas Sale Shares for the same price and on the same terms as offered by such Accugas Matching-Right Transferee.

8.1.8 Under the Accugas SHA, AIIM Accugas has a non-transferable option to require Accugas TopCo to purchase all of AIIM Accugas's shares in Accugas HoldCo on any date falling within 30 calendar days of 14 November 2023 ("Accugas Exit Option"). The consideration for such shares (the "Accugas Exit Consideration") is to be calculated in accordance with an agreed Accugas Exit Consideration formulae at the date AIIM Accugas serves notice on Accugas TopCo to exercise its option. If prior to the date the Accugas Exit Option arises the Company is taken over by a third party, the Accugas Exit Consideration shall be calculated in accordance with the Accugas Exit Consideration formulae and capped at an amount equal to 18 per cent. IRR on AIIM Accugas's total investment expenditure at such date in Accugas HoldCo.

8.1.9 Any shareholder or any of its directors on the board of Accugas Limited may propose that a group company undertakes a new project to build, own or operate infrastructure for the purpose of processing and/or transporting gas in an area within a radius of 30 km from the CPF ("New Project"). A decision to pursue a New Project is a shareholder reserved matter. If the shareholders elect not to approve the New Project, the proposing shareholder or its affiliates shall have the right to pursue the unapproved New Project outside the group companies. With respect to an unapproved New Project, Accugas HoldCo and Accugas Limited shall provide reasonable assistance on reasonable commercial terms to the proposing shareholder to implement such unapproved New Project by: (i) providing reasonable access to Accugas Limited's infrastructure (subject to Accugas Limited determining such access is technically feasible, and acting reasonably and in good faith in agreeing reasonable commercial terms for the assistance, and provided that such assistance does not unduly interfere with Accugas Limited's business operations); (ii) allowing facilities relating to the unapproved New Project to be constructed on land owned, leased or licenced by Accugas Limited (provided always that doing so does not constitute a breach by Accugas Limited of any lease, sub-lease or certificate of occupancy to which it is a party); and (iii) charging an access tariff to use any Accugas

Limited pipelines to be agreed between the proposing shareholder and Accugas Limited acting reasonably and in good faith.

8.1.10 The Accugas SHA provides that if the joint venture parties to the Stubb Creek Field make a final investment decision to develop the Stubb Creek gas field and the joint venture parties give notice that they wish to supply gas to Accugas Limited's facilities, the shareholders are obliged to procure that Accugas Limited enters promptly into a gas sales agreement in relation to the 2C resources included in the CPR for the Stubb Creek Field at the date of the Accugas SHA (the "Stubb Creek GSA").

8.1.11 The terms of the Stubb Creek GSA and any new gas sales agreement between Accugas Limited and the Company and its affiliates shall be on substantially similar terms as the Upstream GSA save that the contract price per Mscf pursuant to such new GSA shall be equal to the sum of:

(a) US$1.70; and

(b) the weighted average percentage increase in achieved price pursuant to Accugas Limited's downstream contracts (where weighting shall be allocated proportionally on the daily contract quantity of the relevant downstream contracts out of the aggregate daily contract quantity under all downstream contracts) since 14 November 2019; plus

(c) an amount equal to 50 per cent. of the amount by which the price agreed for the sale of gas by Accugas Limited to its buyers under a new downstream GSA is in excess of US$3.40 per Mscf.

8.1.12 Pursuant to the terms of the Accugas SHA, in the event there is insufficient capacity in the Accugas Limited facilities to accept all contracted gas, Accugas Limited shall allocate available capacity in the following priority: (i) gas supplied under the Upstream GSA and Stubb Creek GSA; (ii) other gas supplied from the Uquo Field or Stubb Creek Field and gas from any other field in which SEUGL, UERL or any affiliates hold an interest; and (ii) any other source. Any gas sales, transportation and processing or other agreement at Accugas Limited's facilities entered into by Accugas Limited in relation to any other source of gas shall be on an interruptible basis in order to make capacity available in such priority. This order of priority and contracting basis shall also apply to any other processing facilities owned by Accugas Limited or its affiliates, provided that the price paid by Accugas Limited for gas under the SEUGL GSA and Stubb Creek GSA is not higher than the price payable in respect of any other source.

8.2 **Accugas Services Agreement**

8.2.1 On 14 November 2019, the Company and Accugas Limited entered into the Accugas Services Agreement which sets out the terms on which each entity can provide from time to time certain services to the other, the Company can also request that Accugas Limited provides services to the one of the SAVE Group Companies. The Company may perform any requested services itself, or procure that one of the SAVE Group Companies performs such service. The services are to be performed to the highest level of care, skill and diligence in accordance with best practice in the service provider's industry, profession or trade.

8.2.2 Subject to certain exclusions, the services provided are charged on a pass through basis in accordance with an accounting procedure scheduled thereto, save that the Company may charge an indirect charge for the cost of indirect services and related office costs of the Company and the SAVE Group Companies not otherwise set out in the accounting procedure. This indirect charge is based on a sliding scale of five per cent. to one per cent. of total expenditure depending on the amount of total expenditure per annum (the higher the total expenditure, the lower the percentage of indirect charge), with a minimum charge of US$200,000 per calendar year. If the estimated cost of a major project is estimated to be more than US$10 million, the Company can charge a separate indirect charge for such project if approved by the parties at the time of approval of the project.

8.2.3 The services to be provided under the agreement include: (i) executive management functions: (ii) QHS; (iii) HR; (iv) security and transport; (v) Lagos finance; (vi) legal; (vii) administrative; (viii)

IT; and (ix) such other services as may be agreed between the parties. Any services provided to Accugas Limited will only be those necessary for the running of its business in a manner consistent with its business plan and budget from time to time.

8.2.4 The party requesting the services may immediately terminate the Accugas Services Agreement if the services provider commits a material breach which cannot be cured, or if it can be cured, has not been cured within seven days of being notified. Either party may immediately terminate if the other party takes any step or action in connection with entering bankruptcy, administration, provisional liquidation or any composition or arrangement with creditors (other than a solvent restructuring), being wound up, having a receiver appointed to any of its assets or ceasing to carry on its business.

## 9 GAS SALE AND PURCHASE AGREEMENTS

### 9.1 Calabar PRG GSA

9.1.1 On 8 December 2011, Accugas Limited entered into a GSA with Calabar Electricity Generation Company Limited (now Calabar Generation Company Limited ("CGCL"), the Calabar NIPP power station's owner and operator, and CGCL's parent company, Niger Delta Power Holding Company Limited ("NDPHC"), to supply natural gas to CGCL ("Calabar PRG GSA"). The Calabar PRG GSA was amended on 20 February 2013 via a side letter and became effective on 22 September 2017.

9.1.2 On 10 November 2014, the parties entered into an interim GSA for Accugas Limited to supply natural gas to CGCL via the East Horizon Pipeline until the facilities required to supply gas to CGCL under the Calabar PRG GSA could be built. On 12 May 2017, the parties executed an amendment and restatement of the Calabar PRG GSA, pursuant to which NDPHC is no longer a party to the agreement. The conditions precedent for this agreement were satisfied on 15 September 2017.

9.1.3 The term of the Calabar PRG GSA is 20 years from the start date. Provided Accugas Limited's facilities were constructed, tested, commissioned and ready to deliver quantities of natural gas to the delivery point when all conditions precedent were satisfied, the start date occurred five business days later, being 22 September 2017. First deliveries under the Calabar PRG GSA occurred on 22 September 2017.

9.1.4 Under the Calabar PRG GSA, the daily contract quantity is 131 MMscfpd and the annual contract quantity is 131 MMscfpd multiplied by the number of days in the relevant year ("ACQ"). Accugas Limited is contracted to supply the gas volumes nominated, being between zero and 150 MMscfpd, capped at a maximum of 150 MMscfpd multiplied by 365 in any given year. CGCL has committed to a take-or-pay obligation equivalent to 80 per cent. of 1/12$^{th}$ of the ACQ for the relevant year, less certain deductions set forth in the Calabar PRG GSA. Subject to the terms of the Calabar PRG GSA, CGCL can require any gas paid for but not received to be supplied as make-up gas at a later date, for which purpose CGCL may extend the term of the Calabar PRG GSA for a further 18 months.

9.1.5 The contract price is US$3.16 per MMBtu for the first year, to be increased progressively over the first seven years of the contract to US$4.74 per MMBtu (indexed annually by reference to US CPI). Either party is entitled to seek a review of the contract price if, as a result of a change in law or any hindrance of government or other act or failure to act by any government claiming jurisdiction over the agreement, that party suffers a material adverse financial impact in any contract year.

9.1.6 All payments under the agreement are to be made: (a) in the Naira currency using the applicable sell rate for the conversion of US$ to Naira published by the Central Bank of Nigeria on the business day immediately prior to the date of payment, or in the event that such rate is not published by the Central Bank of Nigeria, the interbank rate published on the FMDQ's website; or (b) at the option of CGCL, provided no laws prohibit this, in US$.

9.1.7 The Calabar PRG GSA can be terminated by CGCL by 30 days' notice to Accugas Limited if given prior to the start date, or by 180 days' notice thereafter if Accugas Limited, among other things: (i) abandons construction or operation of the facilities required to deliver gas to the delivery point; (ii) due to a force majeure event, fails to make available for delivery 75 per cent. of the ACQ over a continuous 24 month period (provided that the volumes properly nominated by the buyer during each contract year of that period exceed 75 per cent. of the ACQ); (iii) fails to make available for delivery in any contract year 50 per cent. of the ACQ (provided that during that contract year the quantities of gas that are properly nominated by CGCL exceed 50 per cent. of the ACQ or 50 per cent. of the aggregate of the properly nominated quantities in such contract year); or (iv) suffers an insolvency event which is defined to include an assignment or general arrangement for the benefit of creditors. The agreement can also be terminated with immediate effect by CGCL where CGCL's power purchase agreement is terminated due to an event of force majeure.

9.1.8 Accugas Limited may terminate the Calabar PRG GSA by 30 days' notice to CGCL if given prior to the start date, or by 180 days' notice thereafter, if CGCL, among other things: (i) abandons construction or operation of the Calabar NIPP power station and the connecting pipeline; (ii) due to a force majeure event, is unable to take delivery of at least 75 per cent. of the ACQ over a 24 month period; (iii) fails to take delivery in any contract year of 50 per cent. of the aggregate of properly nominated quantities of gas; (iv) nominates zero quantities of natural gas for a period of 45 continuous days or 90 days in aggregate during any contract year, for reasons other than force majeure (and without Accugas Limited's consent); (v) suffers an insolvency event; or (vi) diverts the natural gas to facilities other than the Calabar NIPP power station, without the consent of Accugas Limited.

9.1.9 Force majeure under the Calabar PRG GSA includes force majeure which primarily affects a third party where that force majeure prevents, impedes or delays CGCL or Accugas Limited's performance under the agreement.

9.1.10 Where CGCL fails to pay amounts due pursuant to the Calabar PRG GSA, interest at five per cent. plus three month LIBOR is applicable on all amounts due, and Accugas Limited is entitled to make a claim under the letter of credit provided in accordance with the terms of the Support Agreement (see "PRG Agreements" section below). If the amount remains unpaid by either CGCL or the provider of the credit support, Accugas Limited is entitled to suspend deliveries under the agreement on ten days' notice until such time as payment is made. If deliveries remain suspended in this manner for 60 consecutive days, Accugas Limited shall have the right to terminate the agreement.

9.1.11 Except in relation to permitted assignments to affiliates, the parties shall not assign all or any part of their rights and obligations under the Calabar PRG GSA without the prior written consent of the other parties. CGCL and Accugas Limited may assign their rights under the agreement to a bank or other financial entity for the purpose of providing financing in connection with their respective facilities subject to the terms of the Support Agreement (see "PRG Agreements" section below).

9.1.12 CGCL must provide a letter of credit from an acceptable financial institution and as supported by the International Development Association's partial risk guarantee throughout the term of the agreement, in accordance with the terms of the Support Agreement (see "PRG Agreements" section below).

9.1.13 The Calabar PRG GSA can be terminated by Accugas Limited in the event of an insolvency event affecting whichever of NDPHC or Nigerian Bulk Electricity Trading Plc ("NBET"). NBET is the party providing credit support for the agreement in accordance with the terms of the Support Agreement (see "PRG Agreements" section below).

9.1.14 Any change of control of CGCL requires Accugas Limited's prior written consent; prior to any change of control, alternative credit support must be provided to Accugas Limited to Accugas Limited's satisfaction determined at its sole discretion. However, it is recognised that CGCL and NDPHC are engaged in a process of privatisation, for which consent is explicitly given; credit support in the context of the privatisation is dealt with pursuant to the Support

Agreement (see "PRG Agreements" section below). The Calabar PRG GSA can be terminated by Accugas Limited in the event of a change of control of CGCL in breach of the terms of the agreement.

9.1.15 The Calabar PRG GSA is governed by the laws of the Federal Republic of Nigeria.

9.2 **PRG Agreements**

9.2.1 The Calabar PRG GSA is ultimately supported by a partial risk guarantee from the International Development Association; however, this is not triggered immediately and a network of contracts has been put in place as set out below.

9.2.2 Pursuant to the support agreement between NDPHC, CGCL, Accugas Limited and NBET dated 12 May 2017 ("Support Agreement"), NDPHC is to procure a letter of credit for Accugas Limited in relation to the amounts payable by CGCL under the Calabar PRG GSA, which letter of credit will be supported by the International Development Association's partial risk guarantee pursuant to the guarantee agreement (see below). The Support Agreement specifies that when NDPHC is privatised, NBET will replace NDPHC as the guarantor for CGCL under the Calabar PRG GSA, being the party required to provide credit support for the Calabar PRG GSA. This is to ensure that the International Development Association's partial risk guarantee is always linked to credit support provided by a state owned entity. The fees for the letter of credit issued pursuant to the Support Agreement are to be paid by Accugas Limited.

9.2.3 There is a 90 day moratorium period from the effective date of the letter of credit during which and in respect of which Accugas Limited will not be able to make demands for payment pursuant to the letter of credit. The letter of credit is provided by JP Morgan Chase Bank N.A., London Branch, or a substitute bank which must be a bank meeting the eligibility criteria, including a minimum of a "Long Term Issues Rating" of A2 by Moody's Investor Services, Inc, a "Foreign Company Long Term Issuer Default Rating" of "A" from Fitch Ratings Ltd and a "Foreign Long Term Issuer Credit Rating" of "A" by Standard and Poor's Financial Services LLC. The Support Agreement cannot be assigned, by the parties except for: (i) Accugas Limited assigning its rights under the Support Agreement by way of security which does not require consent of the other parties; and (ii) concurrently with the assignment of the Calabar PRG GSA and subject to the written consent of the other parties and the International Development Association.

9.2.4 Pursuant to the project agreement between Accugas Limited and the International Development Association dated 14 June 2017, Accugas Limited agrees to pay the International Development Association's fees relating to the provision of the partial risk guarantee, being an annual fee of 0.75 per cent. of the maximum amount of the letter of credit applicable for the relevant period, together with one-off fees of 0.15 per cent. and 0.50 per cent. of the maximum amount of the letter of credit as initiation and processing fees.

9.2.5 In order to monitor Accugas Limited's compliance with its obligation under the project agreement, Accugas Limited agrees to allow inspections of its pipelines and facilities by the International Development Association on reasonable notice. Accugas Limited must also keep (and allow the International Development Association access to) reports and information relating to gas deliveries pursuant to the Calabar PRG GSA, monthly invoices in relation to the same, information on payments made and defaults pursuant to the Calabar PRG GSA and demands under the Calabar PRG GSA.

9.2.6 Accugas Limited also makes the following covenants to the International Development Association:

(a) no material change to the letter of credit or any other agreement related to the Support Agreement or Calabar PRG GSA without the International Development Association's prior written consent;

(b) not to bring claims during a moratorium period;

(c) deliver a notice of credit support;

(d) co-operate in good faith with the International Development Association in relation to any breaches notified by the International Development Association;

(e) not engage in sanctionable practices (being corrupt practices, collusive practices, coercive practices or obstructive practices, each as defined in the agreement) in relation to the supply of gas pursuant to the Calabar PRG GSA;

(f) not engage or enter into contracts with debarred persons, being a person or entity which is ineligible to be awarded a World Bank financed contract;

(g) to execute, operate and maintain the project with due diligence and efficiency and comply with its material obligations under the agreements relating to the Calabar PRG GSA;

(h) to implement and maintain policies and procedures to monitor compliance with environmental and social laws, a resettlement action plan and environmental impact assessments;

(i) keep the International Development Association informed of payment and default notices or demands pursuant to the Calabar PRG GSA and Support Agreement;

(j) not assign its rights, interests, covenants or obligations under this agreement, the Support Agreement or the letter of credit without the International Development Association's prior written consent (not to be unreasonably delayed);

9.2.7 to notify the International Development Association of its application for or receipt of permits or licences for new oil wells or gas gathering or treatment facilities in the Uquo Field area and develop any such new wells or facilities in compliance with environmental and social laws; and

9.2.8 to ensure compliance by its employees, agents, contractors and sub-contractors with environmental and social laws in relation to the supply of gas for the Calabar PRG GSA.

9.2.9 In the event Accugas Limited breaches its representations, covenants or other obligations, the International Development Association can suspend its guarantee's coverage of the letter of credit on 45 days' notice. In the event Accugas Limited fails to make payments due within six business days, breaches its obligations relating to sanctionable practices, debarred persons, or in the event the guarantee of the letter of credit is suspended for a period of 180 days or longer, the International Development Association is entitled to terminate its guarantee.

9.2.10 Accugas Limited has agreed to indemnify the International Development Association for, *inter alia*, any claims or liabilities incurred as a result of a representation, warranty, covenant or obligation of Accugas Limited under the agreement and all reasonable costs and expenses incurred in the enforcement of its rights or the enforcement of the letter of credit bank's rights, or the amendment of or a waiver or consent under the agreement.

9.2.11 There is a guarantee agreement between the International Development Association and JP Morgan dated 14 June 2017 under which the International Development Association guarantees any amounts outstanding under the letter of credit to be issued by JP Morgan to NDPHC or NBET, as applicable, pursuant to the Support Agreement.

9.2.12 By an indemnity agreement between the State of Nigeria and the International Development Association, the State of Nigeria agrees to indemnify the International Development Association for payments made pursuant to the guarantee agreement above.

9.2.13 Pursuant to a cooperation agreement between the International Development Association and NDPHC dated 14 June 2017, NDPHC gives a number of warranties and covenants for the benefit of International Development Association and agrees to indemnify International Development Association for its losses pursuant to this agreement.

9.2.14 Pursuant to a cooperation agreement between the International Development Association and NBET dated 14 June 2017, NBET gives a number of warranties and covenants for the benefit of International Development Association and agrees to indemnify International Development Association for its losses pursuant to this agreement.

9.2.15 Pursuant to a reimbursement and credit agreement dated 15 May 2017 between NDPHC and JP Morgan and NBET, NDPHC and NBET, as applicable, agree to reimburse JP Morgan for amounts advanced under the credit support provided under the Calabar PRG GSA, with interest.

9.3 **Ibom Power GSA**

9.3.1 On 15 May 2009, Seven Exploration & Production Limited ("SEPL") (as seller) and Ibom Power (as buyer) entered into a gas purchase and sales agreement, whereby SEPL agreed to supply processed gas to Ibom Power, as operator of the Ibom Power station (the "Ibom Power GSA"). On 4 June 2010, SEPL transferred its rights, liabilities, duties and obligations under the Ibom Power GSA to Accugas Limited via a deed of amendment, replacement and novation, and the Ibom Power GSA was amended and restated on the same day. The term of the Ibom Power GSA is ten years from the date of first commercial supply of gas (which occurred on 1 January 2014), subject to any extension mutually agreed between the parties.

9.3.2 Delivery was initially on a take or pay basis for 100 per cent. of the ACQ being 43,500 MMBtu multiplied by the number of days in the contract year, less certain deductions set out in the Ibom Power GSA. The Minimum and Maximum Daily Quantities were both 43,000 MMBtupd. Under an addendum to the Ibom Power GSA executed on 26 April 2016, the Daily Contract Quantity was reduced to 20,000 MMBtu and the Maximum Daily Quantity ("MDQ") became 27,000 MMBtu. Under the Ibom Power GSA, Ibom Power agrees to accept and pay for, or to pay for if not taken, the monthly equivalent of 80 per cent. of the daily contract quantity, less certain deductions set forth in the Ibom Power GSA (including an Ibom Power force majeure and up to twelve days of Ibom Power outages). Ibom Power has an option to increase the daily contract quantity to 43,500 MMBtu ("Increased DCQ") with a take-or-pay obligation of 80 per cent. of the Increased DCQ. The parties agree to discuss in good faith increasing the DCQ and MDQ to meet Ibom Power's requirements in Phase 2 of its developments, which will occur when the power generation capacity of Ibom Power's facilities reaches 685MW. Initially, the contract price for the gas was the higher of: (i) the fixed price, being a price of US$0.40 per MMBtu plus a subsidy of US$1.60 per MMBtu payable by the Akwa Ibom State Government to deliver to Accugas Limited a price of US$2.00 per MMBtu (converted to Naira at the buying rate published on the Central Bank of Nigeria website for the invoice date); or, (ii) the last price, being the fixed price adjusted annually on the anniversary of the first supply date by the movement in US CPI for the preceding 12 months. By an addendum dated 1 August 2016, the parties agreed a new price of US$3.30 per MMBtu, however, this price increase has yet to come into force, and is only expected to do so once regulatory approval from the Nigerian Electricity Regulatory Commission has been granted.

9.3.3 The Ibom Power GSA provides that Ibom Power pay an advance of US$63.5 million for future gas deliveries. Accugas Limited repays the advance payment to Ibom Power by the provision of gas by way of credit in respect of the full amount invoiced for each month following the first supply date until the value of gas invoiced to Ibom Power equals 50 per cent. of the advance payment, and thereafter by way of credit of a Naira amount equal to US$294,028 in respect of each invoice for each month until the aggregate credits invoiced to Ibom Power from Accugas Limited, during the contract period, shall equal the advance payment.

9.3.4 The Ibom Power GSA requires Ibom Power to provide a guarantee from the Akwa Ibom State Government in respect of its obligations under the agreement and in accordance with the provisions set out therein. Ibom Power provided an executed guarantee from the Akwa Ibom State Government dated 24 June 2010 (the "Akwa Guarantee"), for the Naira equivalent of US$2.4 million to be set aside in an escrow account for 60 days, each month. Accugas has advised that the Akwa Guarantee has now fallen away.

9.3.5 The Ibom Power GSA can be terminated by Accugas Limited upon ten days' written notice in the case of an event of default, as defined in the agreement, by Ibom Power or by the Akwa Ibom State government under its Akwa Guarantee. There are no reciprocal termination rights for Ibom Power. Save for permitted affiliates, the parties are not permitted to assign all or any part of their rights and obligations under the agreement without the prior written consent of the other parties. However, Ibom Power is not required to obtain the prior written consent of

Accugas Limited in the event of a full or partial assignment of the agreement by Ibom Power for the purposes of obtaining financing for the construction of the Ibom Power station in Akwa Ibom State.

9.3.6 The Ibom Power GSA is governed by the laws of the Federal Republic of Nigeria.

9.4 **Unicem GSA**

9.4.1 By a gas sale agreement dated 18 April 2007 (as amended on 5 January 2012 and 28 November 2016, and amended and restated on 21 December 2020) between EHGC (as seller) and Lafarge Africa PLC ("Unicem", previously United Cement Company of Nigeria Limited) (as buyer) (the "Unicem GSA"), EHGC agreed to sell and Unicem agreed to purchase gas for Unicem's cement plant in Cross River State, Nigeria. The term of the agreement is until 7 January 2037, subject to Unicem's right to elect to extend the term of the agreement for delivery of make-up gas by up to a further 24 months (the "GSA Extension Period"). As at 20 November 2021, the outstanding balance of make-up gas paid for by Unicem but not taken was 18,301,069.64 Mscf.

9.4.2 Pursuant to the terms of the 21 December 2020 amendment and restatement of the Unicem GSA, Unicem was obliged to make an advance payment of US$20 million. Unicem had the right to elect to pay the advance payment amount in US Dollars or NGN (at the Nigerian Autonomous Foreign Exchange fixing rate for US Dollar to NGN conversions on 21 December 2020). Upon receipt of the advance payment by Accugas Limited, the outstanding balance of make-up gas at such time was to be credited by an amount of gas equal to the advance payment amount (based on the then applicable contract price). Accugas Limited shall be deemed to settle the advance payment amount through delivery of make-up gas to Unicem.

9.4.3 From 1 January 2020 Unicem has agreed to take and/or pay for a minimum of 80 per cent. of the monthly contract quantity (subject to certain deductions set out in the Unicem GSA) (the "Take-or-Pay Quantity"). The monthly contract quantity is calculated by multiplying the daily contract quantity of 24.19 MMscf by the number of days in such month. During the GSA Extension Period the Take-or-Pay Quantity shall reduce to 50 per cent. of monthly contract quantity.

9.4.4 From 1 January 2020, the daily nominations limit for Unicem is 125 per cent. of daily contract quantity for the purpose of utilising make up gas in accordance with the terms of the agreement. With Accugas Limited's written consent (not to be unreasonably withheld), Unicem can nominate up to a maximum of 42.57 MMscf per day above the daily nomination limit ("Overrun Gas").

9.4.5 From 1 January 2020 until 30 April 2027, the contract price for gas delivered shall be US$5.00 per Mscf. From 1 May 2027 the contract price for gas delivered shall be US$5.10 per Mscf subject to an annual (upward) US CPI related escalation. From 1 January 2020 until 30 April 2027, Unicem shall make a pre-payment on the Take-or-Pay Quantity of US$2.50 per Mscf. This prepayment shall be deemed to be settled by Accugas Limited by delivery of make-up gas. Unicem has the option to elect to pay in US Dollars or NGN (applying the Central Bank of Nigeria US Dollar to NGN exchange rate on the date of payment).

9.4.6 If a party considers that there has been a significant change in law or regulation, with the direct consequence that: (i) the applicable contract price creates economic hardship for a party; and (ii) the contract price is uncompetitive when compared to other fuels that are available in sufficient quantities at the delivery point, then the affected party can request a price review. They shall carry out the price review within three months of the request. If the parties are unable to agree an amendment to the contract price within five months of the request, either party may refer the matter for expert determination.

9.4.7 The Unicem GSA may be terminated, by either party by notice in writing with immediate effect if any act of insolvency occurs in relation to the other party. Unicem may also terminate, *inter alios*, for convenience on three months' notice. However, where Unicem terminates for convenience, Unicem shall be liable to pay the seller a termination fee in the sum of US$500 million, which sum shall be reduced by: (i) US$5 million for each contract year which has elapsed since 21 December 2020 prior to such termination; (ii) US$13,700 for each day that has elapsed since the anniversary of 21 December 2020 immediately preceding the effective date of the termination; and (iii) the aggregate of any outstanding payments due from Unicem to Accugas Limited under the agreement at the date of termination. Unicem has the right to elect to pay the advance payment amount in US Dollars or NGN (at the Central Bank of Nigeria US Dollar to NGN conversion rate applicable on the date of payment).

9.4.8 Unicem's obligations under the Unicem GSA are guaranteed to a value of NGN 1,654,596,000 billion (approximately US$680 million) under a bank guarantee in favour of Accugas Limited executed by Standard Chartered Bank Nigeria Limited and dated 27 April 2021. The guaranteed sum is payable upon written demand signed by an authorised representative of Accugas Limited stating that the customer has failed to make any due payments under the contract. The guarantee expires on 26 April 2022. The guarantee cannot be transferred or assigned.

9.4.9 The Unicem GSA is governed by the laws of the Federal Republic of Nigeria.

9.5 **FIPL GSA**

9.5.1 The agreement (the "FIPL GSA") came into effect on 28 January 2020, with a contractual start date from the date that First Independent Power Limited provides security to Accugas Limited in the form of a US$1.5 million letter of credit, representing 30 days' gas supply of 20 MMscfpd (which the Company has confirmed is not in place as at the date of this document). Unless extended in accordance with its terms, the agreement will terminate on the first anniversary of the contractual start date.

9.5.2 The FIPL GSA provides that First Independent Power Limited may nominate an amount of gas up to a maximum of 35 MMscfpd for delivery on the following day, of which Accugas Limited may choose to accept, vary or reject. For accepted nominations, First Independent Power Limited will pay to Accugas Limited a gas sales price of US$2.50 per MMBtu and will pay an additional transportation tariff to transport the gas from the Uquo CPF to the Ikot Abasi Gas Receiving Facility at a rate specified in the gas transportation agreement which is yet to be agreed.

9.5.3 If First Independent Power Limited takes either (i) less than 80 per cent., or (ii) more than 120 per cent. of the daily nominated quantity, First Independent Power Limited will pay a ten per cent. premium on the price for amounts of gas falling below or above such thresholds. If Accugas Limited delivers less than 80 per cent. of the daily nominated quantity, First Independent Power Limited will be entitled to a ten per cent. discount on any amount under the 80 per cent. threshold.

9.5.4 The FIPL GSA can be terminated by Accugas Limited by giving ten days' notice to First Independent Power Limited for certain events of default as defined in the agreement. There is a reciprocal right for First Power Independent Limited to terminate by serving notice on Accugas Limited for Accugas Limited's insolvency or breach of their material obligations under the agreement.

9.5.5 The FIPL GSA is governed by the laws of the Federal Republic of Nigeria.

9.6 **Mulak GSA**

9.6.1 On 5 February 2021, Accugas Limited (as seller) and Mulak Energy Limited ("Mulak") (as buyer) entered into a gas sales and purchase agreement, whereby Accugas Limited agreed to supply natural gas to Mulak as operator of the compressed natural gas production facility being developed by Mulak at Ikot Abasi, Akwa Ibom State (the "Mulak GSA").

9.6.2 The main terms of the Mulak GSA only become effective on the satisfaction of certain conditions, including: (i) the execution of a direct agreement between the parties, (ii) the acquisition by Mulak of the land, licences and permissions to commence construction and operation of its facilities, and (iii) the agreement by the parties of insurance to be maintained by Mulak. The agreement has a longstop date of 31 July 2021 (unless extended by the parties) by which time if the parties have not satisfied the conditions, either party may terminate the agreement. On the date the conditions are satisfied (or waived) the Mulak GSA will commence ("Commencement Date").

9.6.3 Following the Commencement Date, Accugas Limited will begin construction on the interconnection works necessary to connect the Accugas facilities to the Mulak facilities, the cost of which is for Mulak. Once Accugas Limited has completed the interconnection works it will issue to Mulak a "Seller Ready Notice" signalling its readiness to supply gas to Mulak.

9.6.4 Following the Commencement Date, Mulak will begin construction of its own facilities in order to receive gas from Accugas Limited. Once Mulak has completed its facilities it will issue to Accugas Limited a "Buyer Ready Notice" signalling its readiness to receive gas from Accugas Limited. In the Buyer Ready Notice Mulak will notify Accugas Limited of a "First Gas Date" being the date on which Mulak wishes to receive the first gas.

9.6.5 Simultaneously with the issuance of the Buyer Ready Notice, Mulak will pay to Accugas Limited the Naira equivalent of $700,000 ("Advance Payment") to be held by Accugas Limited as prepayment by Mulak to cover invoices for the supply of natural gas for the first period of delivery following the First Gas Date.

9.6.6 If either party fails to complete their respective construction works (and provide a Buyer Ready Notice or Seller Ready Notice, as applicable) within 12 months from the Commencement Date, the other party may terminate the Mulak GSA immediately.

9.6.7 The term of the agreement shall run for seven years from the First Gas Date unless otherwise extended by the parties. Mulak may extend the contract period for a further fixed period of five years by serving notice on Accugas Limited 12 months prior to the end of the seven year contract period.

9.6.8 Accugas Limited will supply natural gas to Mulak on an interruptible basis for a period of 24 months from the Commencement Date ("Interruptible Gas Delivery Period"). During the Interruptible Gas Delivery Period, Mulak shall, by the twenty fifth day of each month, provide Accugas Limited with a daily contract quantity ("DCQ") nomination for the following month between zero and 2.5MMscf subject to acceptance by Accugas Limited. Upon acceptance by Accugas Limited the interruptible DCQ nomination will be fixed for that month ("Confirmed Interruptible Gas DCQ"). If the parties cannot agree an acceptable interruptible DCQ nomination then the interruptible DCQ nomination for that month shall be zero.

9.6.9 For each quarter during the Interruptible Gas Delivery Period, the quarterly contract quantity shall be calculated as the sum of the Confirmed Interruptible Gas DCQs multiplied by the number of days in that quarter.

9.6.10 During the Interruptible Gas Delivery Period, Mulak shall be obliged to take and pay for (or pay for if not taken) a quantity of natural gas equal to 80 per cent. of the quarterly contract quantity as calculated in accordance with section 9.6.9 above.

9.6.11 Following the end of the Interruptible Gas Delivery Period, Accugas Limited will supply natural gas to Mulak for the remainder of the contract period on a firm basis ("Firm Delivery Period"). Mulak shall notify Accugas Limited in writing no later than seven months before the end of the Interruptible Gas Delivery Period of its DCQ nomination for the Firm Delivery Period.

9.6.12 The nominated DCQ for the Firm Delivery Period is to be between zero and 2.5MMscf, however if Mulak nominates less than 1.5MMscf as the Firm Delivery Period DCQ nomination, Accugas Limited has the right to terminate the Mulak GSA by providing 60 days' notice to Mulak following its nomination.

9.6.13 No later than four months prior to the end of a contract year, Mulak may request an increase in the Firm Delivery Period DCQ for the following contract year. Accugas Limited will have discretion to accept or reject a Firm Delivery Period DCQ nomination of less than 1.5MMscf. If the Firm Delivery Period DCQ nomination is equal to or greater than 1.5MMscf, Mulak may issue an increase request for: (i) up to 120 per cent. of the Firm Delivery Period DCQ (which will not require Accugas Limited approval), or (ii) an amount above 120 per cent. of the Firm Delivery Period DCQ nomination (which will require Accugas Limited approval).

9.6.14 If Mulak fails to make a nomination for the Firm Delivery Period DCQ, the fall-back DCQ nomination shall be 2.5MMscf ("Fall-back DCQ").

9.6.15 For each quarter during the Firm Delivery Period, the quarterly contract quantity shall be calculated as either the Firm Delivery Period DCQ nomination or the Fall-back DCQ (as applicable) multiplied by the number of days in such quarter.

9.6.16 During the Firm Delivery Period, Mulak shall be obliged to take and pay for (or pay for if not taken) a quantity of natural gas equal to 80 per cent. of the quarterly contract quantity as calculated in accordance with section 9.6.15 directly above.

9.6.17 The contract price for natural gas under the agreement for the first contract year shall be $5.15/MMBtu and for each successive contract year shall be adjusted in proportion to the US CPI index, calculated by reference to a formula contained in the Mulak GSA.

9.6.18 By the date falling one month after the First Gas Date, Mulak shall establish and maintain credit support throughout the remainder of the Interruptible Gas Delivery Period in the amount of $390,000, and during the Firm Delivery Period (up until three months after termination of the Mulak GSA) credit support in the amount of $1,170,000.

9.6.19 Mulak's remedies under the agreement include a shortfall gas and liquidated damages regime. Where at the end of any quarter following the quarter in which a shortfall gas aggregate arose Mulak has not taken an amount equal to the shortfall gas balance, Mulak will invoice Accugas Limited for an amount equal to the product of the shortfall gas balance remaining at the end of the quarter multiplied by ten per cent. of the contract price applicable at the time that such quantity of shortfall gas arose. Upon payment of the amount, the shortfall gas balance to which it relates shall be extinguished.

9.6.20 All payments under the agreement are to be made in US Dollars but Mulak may opt to pay any Dollar amounts due under the agreement in the Naira currency using the Nigerian Autonomous Foreign Exchange Rate (NAFEX) for Dollar to Naira conversions published by the FMDQ OTC PLC on FMDQ's website on the business day immediately preceding the date of payment.

9.6.21 The Mulak GSA can be terminated by Mulak giving 90 days' notice to Accugas Limited if any of the following has occurred and has not been cured to the satisfaction of Mulak by the end of such 90 day period: (i) Accugas Limited abandons operation of its facilities required to deliver gas to the delivery point or abandons construction of the interconnection works; (ii) for reasons other than Accugas Limited's force majeure, by the date falling 30 days after the start of the Firm Delivery Period Accugas Limited is unable to make the take or pay quantities available on a sustained basis; or (iii) an act of insolvency affects Accugas Limited. The Mulak GSA can also be terminated with immediate effect by Mulak if: (i) for reasons other than the Accugas Limited's force majeure, during the Firm Delivery Period, Accugas Limited has been unable to make available for delivery volumes of gas to Mulak of at least 80 per cent. of the aggregate quarterly contract quantity in any 12 month period, or 50 per cent. of the aggregate of the quarterly contract quantity in any six month period; (ii) the conditions to the Mulak GSA have not been satisfied prior to the longstop date; (iii) Accugas Limited has not issued the Seller Ready Notice within 12 months of the Commencement Date; or (iv) Accugas Limited breaches its anti-bribery and corruption related undertakings.

9.6.22 The agreement can be terminated by Accugas Limited giving 90 days' notice to Mulak if any of the following has occurred and has not been cured to the satisfaction of Accugas Limited:

(i) following the Commencement Date, Mulak abandons the construction or operation of its facilities; (ii) Accugas Limited reasonably believes that the Mulak facilities pose a risk of personal injury to Accugas Limited directors, officers, employees, agents or contractors, or damage to or loss of property of Accugas Limited or its affiliates; or (iii) an act of insolvency affects Mulak. The agreement can also be terminated with immediate effect by Accugas Limited if: (i) Mulak fails to establish or maintain the credit support up to $390,000 during the Interruptible Gas Delivery Period and $1,170,000 during the Firm Delivery Period (and such failure is not remedied within 14 days of from the date the credit support was supposed to be established or maintained; (ii) Accugas Limited has issued Mulak a notice of non-payment and such non-payment has not been remedied within fourteen days from the date of the notice of non-payment; (iii) for reasons other than the Accugas Limited's fault or Mulak's force majeure, during the Firm Delivery Period, Mulak does not take delivery of at least 80 per cent. of the aggregate quarterly contract quantity in any 12 month period, or 50 per cent. of the aggregate of the quarterly contract quantity in any six month period; (iv) without the prior written consent of Accugas Limited, Mulak diverts uncompressed natural gas to facilities other than its own facilities; (v) Accugas Limited's right to suspend deliveries under the agreement has arisen and has not ceased within 90 days of the notice of suspension; (vi) there is a change in control of Mulak in breach of the terms of the Mulak GSA; (vii) Mulak breaches its anti-bribery and corruption related undertakings; (viii) the conditions to the Mulak GSA have not been satisfied prior to the longstop date; or (ix) Mulak has not issued the Buyer Ready Notice within 12 months of the Commencement Date.

9.6.23 Force majeure under the Mulak GSA includes force majeure which primarily affects a third party where that force majeure prevents, impedes or delays Mulak or Accugas Limited's performance under the agreement.

9.6.24 Where Mulak fails to pay amounts due pursuant to the agreement, interest at four per cent. plus three month LIBOR is applicable on all amounts due, and Accugas Limited is entitled to make a claim on the Advance Payment ($700,000) or the credit support (during the Interruptible Gas Delivery Period an amount of $390,000 and the Firm Delivery Period an amount of $1,170,000). If the amount remains unpaid by either Mulak or the provider of the credit support, Accugas Limited may immediately suspend deliveries of natural gas to Mulak.

9.6.25 Except in relation to permitted assignments to affiliates, the parties shall not assign all or any part of their rights and obligations under the agreement without the prior written consent of the other party. Mulak and Accugas Limited may assign their rights under the agreement to a bank or other financial entity for the purpose of providing financing in connection with their respective facilities.

9.6.26 Any change of control of Mulak requires the prior written consent of Accugas Limited, such consent is not to be unreasonably withheld provided that the new proposed owner of Mulak is a reputable business and has the requisite technical and financial capabilities to satisfy Mulak's obligations under the Mulak GSA. The agreement can be terminated by Accugas Limited in the event that a change of control of Mulak breaches the terms of the Mulak GSA.

9.6.27 The Mulak GSA is governed by the laws of the Federal Republic of Nigeria.

## 10 MATERIAL CONTRACTS RELATING TO THE STUBB CREEK FIELD

### 10.1 Stubb Creek Field Farm-out Agreement

10.1.1 On 25 February 2003, the MPR granted Universal the right to operate the Stubb Creek Field as a marginal field. Pursuant to the Marginal Field Guidelines, at this time, the area also became independent of OML 14 (now OPL 276) for operational purposes. On 22 December 2003, NNPC, SPDC, Elf Petroleum Nigeria Limited and AGIP, as a joint venture, agreed to terms of a farm-out agreement under which the Stubb Creek Field would be developed by Universal as operator (the "Stubb Creek FOA"). The term of the Stubb Creek FOA was for an initial period of 60 months.

10.1.2 A DPR letter dated 12 April 2016 to Universal approved the renewal of the Stubb Creek Field licence for a period of 10 years effective from 1 May 2016. This was confirmed in a letter of good standing from NUPRC dated 16 November 2021

10.1.3 The Stubb Creek FOA requires Universal to pay to the Stubb Creek FOA farmors an overriding royalty on crude oil production at the following rates: (i) 2.5 per cent. of the value of daily production up to 2,000 bopd; (ii) 3 per cent. of the value of daily production from 2,001 to 5,000 bopd; (iii) 5.5 per cent. of the value of daily production from 5,001 to 10,000 bopd; (iv) 7.5 per cent. of the value of daily production from 10,001 to 15,000 bopd; and (v) the parties are to negotiate and agree the overriding royalty rate to be paid on production in excess of 15,000 bopd. At the date of this document, daily production has not exceeded 15,000 bopd. For the production of natural gas, Universal pays an overriding royalty of: (i) 0 per cent. of the value of daily production below 20 MMscfpd; and (ii) the parties are to agree the overriding royalty rate to be paid on daily production above 20 MMscfpd. At the date of this document, no gas royalty is paid for the Stubb Creek Field as the field is not producing more than 20 MMscfpd. The farmors can lift their crude oil entitlement from the field or elect to receive their royalty in US$ equivalent at the prevailing market prices for the crude oil on the date of payment. In the event the government asserts any right it may have to acquire an interest in the Stubb Creek Field, Universal has a best endeavours obligation to ensure the government assumes a corresponding part of Universal's obligations and liabilities under the Stubb Creek FOA.

10.1.4 Under the Stubb Creek FOA, if Universal owes money to the farmors for a continuous period of three months, Universal will be in default. If Universal is deemed to be in default it is deemed to have granted to the farmors a lien on all crude oil produced from the Stubb Creek Field and the proceeds from such production to secure discharge of the owed amounts plus interest. During any period of default, Universal is not entitled to its production from the Stubb Creek Field, which will vest in and be the property of the farmors. The farmors are entitled to sell the production and, after deducting all costs incurred during the sale, are entitled to recover from the remaining proceeds all amounts owed to the farmors by Universal.

10.1.5 The Stubb Creek FOA may be terminated immediately if: (i) Universal becomes bankrupt and is forced to make restitution to its creditors or insolvent or wilfully violates Nigerian laws and regulations governing petroleum operations, financial transactions and/or commercial operations; (ii) the DPR determines that Universal is not complying with Nigerian petroleum laws, regulations or environmental health and safety standards with respect to operations undertaken in respect of the Stubb Creek Field (after a 90 day cure period); (iii) Universal assigns its rights and interests in the Stubb Creek Field without the written consent of the Nigerian Government; (iv) Universal intentionally extracts or produces petroleum outside the farm-out area; or (v) Universal fails to remedy or remove a material breach (as defined in the agreement to include a substantial breach of the Stubb Creek FOA which may include breaches of health/environmental standards, confidentiality obligations, abandonment security obligations, insurance obligations, creation of encumbrances contrary to the agreement, intentional submission of false information to the Nigerian Government or where the DPR notify that the Stubb Creek Field operations are interfering with the farmor's operations) of the Stubb Creek FOA within a 90 day cure period. The Stubb Creek farmors can also terminate on 30 days' notice if Universal ceases operations for more than 90 days without acceptable cause or justification.

10.1.6 The Stubb Creek FOA requires farmees to provide security funds to satisfy abandonment obligations with such security funds being reduced or released as the underlying obligations and liabilities are met, reduced or released. Upon commencement of operations and prior to submission of its first work programme to the DPR, the farmees and farmors are required to enter into an abandonment security agreement. To date, an abandonment security agreement has not been agreed by the parties, however, NNPC (the only remaining farmor) has not attempted to enforce this obligation or enter into an abandonment security agreement with the farmees. However, under the terms of the PIA which came into force in August 2021, it is now a statutory obligation for farmees to make adequate provision for, and establish, a Decommissioning and Abandonment Fund with funds to be set aside in escrow and funded on a straight-line basis over the remaining economic life of the Uquo Field. The PIA mandates farmees to submit their decommissioning plans to the regulator within 12 months of the PIA becoming effective.

10.1.7 A party must give the other party notice of a force majeure situation within 24 hours of such a situation occurring along with an estimate of how long its resolution might take. The obligations of the party giving notice of force majeure (other than payments of amount due or furnishing security) will then be suspended. There is a reasonable endeavours obligation on the party giving notice to remove or overcome the force majeure situation as quickly as possible in an economic manner.

10.2 **Stubb Creek Funding Agreement and Joint Operating Agreement**

10.2.1 On 11 August 2010, Universal and Sinopec entered into a joint operating agreement to set out the parties' obligations with respect to the conduct of petroleum operations in the Stubb Creek Field ("Stubb Creek JOA"). The Stubb Creek JOA designates Universal as the operator and Sinopec as the funding partner and technical advisor of the Stubb Creek Field.

10.2.2 Pursuant to the Stubb Creek JOA, Universal agreed to assign an undivided 49 per cent. legal interest in the Stubb Creek Field to Sinopec. The assignment of Universal's 49 per cent. legal interest in the Stubb Creek Field to Sinopec was approved by the MPR on 8 June 2015.

10.2.3 On 11 August 2010, Universal and Sinopec also entered into a funding agreement which set out the parties' respective funding obligations and profit allocations with respect to exploration, development and production of the Stubb Creek Field (the "Stubb Creek FA"). The terms of the Stubb Creek JOA and Stubb Creek FA run concurrently with the term of the Stubb Creek FOA. Therefore, once the Stubb Creek FOA terminates or expires, the Stubb Creek JOA and Stubb Creek FA shall also terminate or expire.

10.2.4 Pursuant to the Stubb Creek FA and Stubb Creek JOA, Universal is required to provide 20 per cent. and Sinopec 80 per cent. of funding for crude oil and associated natural gas developments and Universal is entitled to 35 per cent. and Sinopec 65 per cent. of profits from crude oil and associated natural gas developments. Universal is required to provide 50 per cent. and Sinopec 50 per cent. of funding for non-associated natural gas developments and Universal is entitled to 60 per cent. and Sinopec 40 per cent. of profits from non-associated natural gas developments. Universal is responsible for all royalties, taxes, rates and assessments that may be imposed under the Stubb Creek FOA and must make all payments due to the farmors under the Stubb Creek FOA.

10.2.5 If Universal or Sinopec fails to pay a cash call, that party is in default under the Stubb Creek JOA and the other party is authorised to sell the defaulting party's share of petroleum. If the defaulting party fails to pay over three consecutive cash calls, a penalty of 20 per cent. of the total amounts owed is added to the sum due by the defaulting party (in addition to compound interest and taxes). If Sinopec fails to pay five consecutive cash calls, its profit oil allocation is decreased to nil per cent. and if Universal fails to pay five consecutive cash calls, its profit oil allocation is decreased to 15 per cent.

10.2.6 The Stubb Creek JOA provides that decision-making in relation to all matters pertaining to the conduct of petroleum operations and preparation of the field development plan of the Stubb Creek Field is conducted through a project management committee. The project management committee consists of eight members: four appointed by each of Universal (one to be the project manager) and Sinopec (one to be the deputy project manager). Universal also appoints the project management committee Chairman and Sinopec appoints the project management committee Secretary.

10.2.7 Pursuant to the Stubb Creek JOA, decisions in respect of production and the development of the Stubb Creek Field require the joint consent of Universal and Sinopec. In the event of a deadlock:

(a) in respect of crude oil and associated natural gas developments, the dispute resolution provisions in the Stubb Creek JOA will be initiated; and

(b) in respect of non-associated natural gas development, Universal, as operator, has a casting vote and the decision of the operator will be adopted.

10.2.8 Pursuant to the Stubb Creek JOA, no party shall be liable for the failure to perform, or for delays in performing any obligations to the extent that such failure or delay in performance was attributed to an event of force majeure. In the event of force majeure, a party affected by such an event must give notice to the other party as soon as reasonably possible, stating the date, cause and extent of such event. Any party whose obligations have been suspended by the event of force majeure shall resume the performance of such obligations as soon as reasonably possible after the force majeure event has ended/been removed.

10.2.9 Either party may terminate the Stubb Creek JOA if any of the following events occur: (i) default of a material obligation by the other party (that is not remedied within a 30 day cure period); (ii) assignment of the Stubb Creek JOA without the prior written notice and consent of the other party; (iii) a party is adjudged insolvent, bankrupt or to have made restitution to its creditors by a court of competent jurisdiction in Nigeria; or (iv) a party liquidates or terminates its corporate existence. Sinopec also has a right (as a major financial contributor) to withdraw with immediate effect if it is found that the proven reserves cannot be economically produced, and additionally Sinopec may reassign its rights to Universal on three months' notice.

10.3 **Mobil Crude Handling Agreement**

10.3.1 On 30 November 2012, MPN in its capacity as operator of the QIT, entered into a crude handling agreement with Frontier Oil Nigeria Limited, Universal and Network Exploration & Production Company Nigeria Limited (together, the "FUN Group") with respect to this paragraph 10.3) ("CHA"). The term of the CHA was for five years from the date of execution, expiring at the end of November 2017, however, the CHA was extended pursuant to an amendment agreement dated January 2018 extending the term to 29 November 2022.

10.3.2 The CHA provides that oil ("Qua Iboe Crude") produced by the FUN Group will be shipped through the oil infrastructure of the QIT. In consideration, the FUN Group must pay MPN monthly tariffs as recalculated and adjusted annually based on actual cash and non-cash operating costs. The FUN Group first delivered Qua Iboe Crude to MPN on 31 January 2015. There is a send or pay obligation allowing the FUN Group to either deliver the required quantity of crude oil each year or make payments (as calculated by a formula in the agreement) for such quantity.

10.3.3 The CHA provides that MPN may terminate the agreement: (i) upon termination of the ExxonMobil COSA (as defined below), (ii) upon cessation of MPN operating the QIT, (iii) due to the FUN Group's failure to deliver by reason of force majeure for a period of six consecutive months, (iv) due to the FUN Group's failure to deliver crude which fails to meet the agreed specification for a period of 12 consecutive months or (v) there is a change to the FUN Group's financial circumstances.

10.3.4 The CHA provides that the FUN Group may terminate the agreement: (i) if a FUN Group marginal field ceases to be a producing field, (ii) where MPN fails to accept Qua Iboe Crude for a period of six consecutive months or fails to deliver Qua Iboe Crude at the delivery point, (iii) the FUN Group are (having used reasonable endeavours to do so) unable to deliver crude or deliver crude at the agreed specification for a period of 12 consecutive months.

10.3.5 Either party may terminate the CHA if there is a payment default, prolonged force majeure or a change in financial circumstances. A payment default is defined in the agreement as when a party fails to pay any sum 30 days after the payment date. A prolonged force majeure is where either party is excused from its obligations due to a force majeure event for a period of 24 consecutive months. A change in financial circumstances is defined in the agreement as when MPN has reasonable grounds to believe that the FUN Group will cease to have the financial resources to meet its obligations under the CHA.

10.3.6 Pursuant to the CHA, a party shall be excused from failing to perform its obligations in whole or part if such failure is attributed to an event of force majeure other than to the extent that a party is required from making timely payments of any monies due which became payable prior to the event of force majeure. A party claiming force majeure shall promptly notify the other parties of the nature and extent of the force majeure and shall keep the other parties informed of steps being taken in relation to such event.

10.3.7 By a separate and concurrent agreement described in paragraph 10.4 below, MPN's affiliate, ExxonMobil Sales and Supply LLC ("ExxonMobil S&S"), committed to purchase all volumes of Qua Iboe Crude stored and transferred by MPN.

10.4 **Exxon Mobil Crude Oil Sales Agreement**

10.4.1 On 30 November 2012, ExxonMobil S&S and the FUN Group entered into an agreement pursuant to which the FUN Group have agreed to sell Qua Iboe Crude to ExxonMobil S&S (the "ExxonMobil COSA").

10.4.2 The term of the ExxonMobil COSA commenced on the effective date of the CHA and continues throughout the term of the CHA. As noted above, the CHA was extended to 29 November 2022 and consequently the term of the ExxonMobil COSA will also expire once the termination conditions in the agreement have been met. The ExxonMobil COSA states that in the event that the CHA is terminated, the ExxonMobil COSA will automatically terminate on the earlier of: (i) the end of the third full month following the date of termination of the CHA; and (ii) the date of ExxonMobil S&S's payment for the purchase of the remaining inventory of the FUN Group in the QIT.

10.4.3 The ExxonMobil COSA specifies the quantity of Qua Iboe Crude to be sold under the agreement, which is determined at monthly production curtailment and lifting schedule meetings with NNPC and MPN. However, the FUN Group reserves the right to deliver a quantity less than that shown in the lifting schedule in the event of production changes, weather, operational reasons or any other matters beyond the control of the FUN Group.

10.4.4 The contract price per barrel for a particular month of lifting is determined in accordance with the following formula: the average of the dated Brent quotations published in Platts in the month of lifting plus the average of the differential for Qua Iboe Crude to dated Brent published in the period starting on the twentieth day of the second month prior to the month of lifting through the nineteenth day of the first month prior to the month of lifting; less a logistics margin of 0.125 per cent. of the price component determined as described above (subject to the logistics margin not being less than US$0.11 per barrel). In the pricing formula, where available, the differential for Qua Iboe Crude to dated Brent is calculated on a 50/50 basis using information published in Platts and Argus Media. There is no take-or-pay obligation on ExxonMobil S&S and title to and risk of loss passes from the FUN Group to ExxonMobil S&S as the cargo passes the permanent inlet flange of the vessel at the load port.

10.4.5 Pursuant to the ExxonMobil S&S General Terms and Conditions (March 1997 edition) ("GTC") (which are incorporated by reference into the terms of the ExxonMobil COSA), neither party shall be liable for loss or damage, including indirect or consequential damage, under the terms of the agreement due to a force majeure event which is beyond its reasonable control. Pursuant to the GTCs, ExxonMobil S&S is not obligated to purchase additional crude oil during a period of force majeure to make up deliveries omitted during the period of disruption nor will the term of the ExxonMobil COSA be automatically extended due to such an event. The party affected by the force majeure is required to give prompt notice to the other party providing sufficient details relating to the event and the estimated scope of disability caused by such an event.

10.5 **FUN JOA**

10.5.1 On 28 August 2014, the FUN Group (as operators of the Uquo, Stubb Creek and Qua Iboe marginal fields) entered into a joint operating agreement with respect to certain facilities which connect to the QIT through which they export processed crude oil ("FUN JOA").

10.5.2 The FUN JOA became effective upon its date of execution and has effect until all materials, equipment and personal property used in connection with the operations envisaged by the

FUN JOA have been removed and disposed of and final settlement has been made among the parties.

10.5.3 Frontier is the designated operator of the FUN JOA and each member of the FUN Group has an equal one third participating interest in the FUN JOA. All rights and interests in the joint property are held by the FUN Group in trust for the members of their respective field's joint venture in accordance with their respective participating interest in the FUN JOA.

10.5.4 All capital expenditure and all liabilities incurred by the operator in connection with the joint operations are shared in accordance with the parties' participating interests. The cost of fixed operating expenditures is shared by the parties in accordance with their participating interests. The cost of variable operating expenditures is shared by the parties in accordance with the volumes of crude oil they each deliver under the FUN JOA. Each party pays its share of variable operating expenditure based upon the ratio of crude oil it delivers against the total volume of crude oil delivered by the parties.

10.5.5 Each party is entitled to use its participating interest share in the capacity of the facilities. In the event of a shutdown or constraint affecting the facilities the parties shall share rateably in the constraint and reduced volume. Each party has the right to permit the other parties to utilise its spare capacity on such terms as the parties may agree.

10.5.6 The FUN JOA was amended and restated on 24 February 2020, but no material changes were made.

10.6 **Savannah Energy (Stubb Creek) Limited SHA**

10.6.1 On 23 January 2019, Savannah Energy Nigeria Limited ("SEN"), STC Joint Venture Limited ("STC") and Savannah Energy (Stubb Creek) Limited ("SESCL") entered into a shareholders' agreement relating to SESCL (the "SESCL SHA").

10.6.2 SESCL has 100 shares in issue and the shares are divided into two classes (A shares and B shares). STC holds 75A Shares and SEN holds 25 B shares.

10.6.3 STC's A shares have no right to receive any dividends, interest, bonuses or distributions or other payments whereas SEN's B shares hold the right to all economic benefit.

10.6.4 SESCL shall have a minimum of two directors on the board of which STC is entitled to appoint one director and SEN is entitled to appoint four directors. The chairperson shall be an SEN board member and will not have a casting vote. The quorum for any director meeting requires at least two SEN directors.

10.6.5 STC cannot transfer or dispose of its shares without the prior written consent of SEN.

10.6.6 The agreement will terminate when one party ceases to hold any shares in SESCL.

10.6.7 The agreement is governed by the laws of England and Wales and any disputes will be resolved exclusively by the English courts.

10.7 **Universal Shareholders Agreement**

10.7.1 On 13 January 2013, Universal Energy Resources Limited ("Universal") and its 25 shareholders as at that date, entered into a shareholders' agreement relating to Universal (the "UERL SHA"). The shareholders agreed to develop an employee share ownership option plan intended to provide that up to 0.5 per cent. of the issued shares of Universal be issued to employees based upon financial performance of Universal ("Employee Share Option"). The terms of such Employee Share Option shall be as agreed by the board.

10.7.2 As at the date of the UERL SHA until November 2019, Seven Exploration and Production Limited held majority shares amounting to 62.5 per cent. of the issued shares in Universal and the balance minority shares amounting to 37.5 per cent. of issued shares of Universal were held by the other 24 shareholders. As part of the restructuring of Universal's former parent company, the minority shareholders transferred their cumulative 37.5 per cent. shares in Universal to Stubb Creek HoldCo Limited ("SCH"). At Completion of the restructuring, SEPL transferred all of its shares (less one share) in Universal to SCH and transferred one share to Savannah Energy Nigeria Limited. By a Deed of Adherence executed on or about the date of completion of the restructuring, SCH acceded to the UERL SHA.

10.7.3 The UERL SHA provides that the Board of Universal shall consist of 10 members who shall be appointed by the shareholders (holding not less than 10 per cent. of the issued shares), in accordance with their respective shareholding in Universal. Given that SCH currently holds all the shares (less 1 share) in Universal, it is entitled to nominate for appointment all the directors in Universal. The Board shall have the full power and responsibility for the management of the Company including the power to appoint and revoke the appointment of management as well as to approve Universal's annual business plans, operations, and annual budget.

10.7.4 *Matter requiring Supermajority Vote of the Board:* The following actions shall require at least 75 per cent. majority vote of the members of the board:

(a) changes in the company's name, domicile, or head office;

(b) any change in the capital structure of the Company;

(c) borrowings, authorisation, issuance, or redemption of debt (including guarantees) or granting of security interests in the assets of the company in line with the agreed thresholds set by the Board from time to time;

(d) change in the company's fiscal year or accounting reference period;

(e) any profit-sharing scheme designed to enhance the performance of the company's employees;

(f) approval of the business plan of the company or any material variations therefrom, including but not limited to restricted to new business development with regards to scope, location and strategy;

(g) approval of the annual or periodic budgets and capital expenditure budget, and any material variations therefrom;

(h) approval of the annual balance sheet and profit and loss statement;

(i) any appointment or changes in auditors for the company and any changes to the accounting policies of the company or any key subsidiary, other than changes consistent with or which continue to result in accounting policies which are consistent with IFRS;

(j) related-party transactions between the company on the one hand and entities in which any of the shareholders and members of the company or the company's management team ("Interested Parties") or persons having familiar relationship with the Interested Persons have an economic interest, where such transactions during any given year exceeds the sum of 10 million Naira and is not specified in the approved business plan and/or annual budget of the company;

(k) commencement or settlement of legal or arbitral proceedings where the amount in dispute or the value of the matter in dispute is not defined in monetary terms is assessed by the managing director to be greater than N50 million Naira;

(l) the conclusion of any agreement relating to supplies, asset acquisition, professional services and/or any other contractual commitment involving amounts in excess of limits to be fixed by the board from time to time;

10.7.5 *Matter requiring Supermajority Vote of Shareholders:* The following actions shall require at least 75 per cent. majority vote of the shareholders:

(a) changes in equity capital structure of the Company such as including but not limited to, amongst others, increase in share capital by creation of new shares and/or classes of shares, changes in nominal value of each share, creation of equity securities including debentures, the issuance of equity securities or securities convertible or exchangeable into equity, redemption of shares or equity securities, granting of options or similar rights to purchase any equity, changes in the nature of the company's shares (but excluding Employee Share Option);

(b) any change in the Constitutional Documents (Memorandum and Articles of Association) of the company or any action that may directly or indirectly alter or change the rights, privileges or preferences attached to the shares in the share capital of the company and changes to the rules of procedure of any governing body of the company;

(c) the creation of new subsidiaries and expansion or development of the business of the company through any means other than the company or a wholly owned subsidiary of the company;

(d) enlisting the company in any capital market whatsoever and making any public offering of shares in the company;

(e) any liquidation, winding up or bankruptcy, reorganization or other analogous insolvency proceeding of the company; or

(f) changing the nature of the primary business of the company in a material way.

## 11 MATERIAL CONTRACTS RELATING TO THE EAST HORIZON PIPELINE

Pursuant to a share purchase and sale agreement dated 24 December 2013, SEIL purchased EHGC from Oando Plc and Ayotola Jagun ("EHGC Sellers") for US$250 million less estimated net liabilities. Completion was subject to a number of conditions precedent, including entry by Accugas Limited, as an affiliate of SEIL, into a facility agreement to fund the acquisition. As part of its post-closing covenants, SEIL agreed to indemnify the EHGC Sellers against any damages incurred by them or any of their affiliates in respect of a parent company guarantee, until such time as the Sellers could obtain full and final release from the parent company guarantee.

By court order dated 14 December 2016 the Federal High Court at Lagos approved the scheme of merger dated 27 October 2017 between EHGC and Accugas Limited. Under the scheme of merger, all assets, liabilities and undertakings, including contractual rights, real property, tax losses and unutilised capital allowances and intellectual property of EHGC would merge with those of Accugas Limited under the sanction of the court without any further act or deed. In consideration for the transfer, Accugas Limited issued additional shares to Exoro, and Exoro issued additional shares to SEIL. The effective date of the merger was agreed by the parties and declared in a joint declaration of the shareholders as 31 August 2017. As a result of the merger Accugas Limited has inherited EHGC's position in all agreements to which it had previously been party.

### 11.1 **Pipeline MOU**

11.1.1 A binding memorandum of understanding was entered into on 18 November 2014 between Nigerian Gas Company Limited ("NGC"), EHGC, Oando PLC and SEIL in relation to the East Horizon Pipeline (the "Pipeline MOU").

11.1.2 Pursuant to the Pipeline MOU, NGC, EHGC and SEIL agreed that EHGC would transfer 15 per cent. ownership of the East Horizon Pipeline to NGC in part satisfaction of a debt owed by EHGC to NGC under the terms of a gas sale and purchase agreement entered into on 30 December 2008 ("NGC GSA") by NGC and Unicem, and which Unicem assigned to EHGC (and making EHGC the gas supplier) by deed of assignment dated 29 March 2007. The NGC GSA was ratified by a deed of ratification dated 16 December 2013 between NGC, Unicem and EHGC. The NGC GSA has subsequently been terminated.

11.1.3 The original intent of the NGC GSA parties was that Unicem would construct the East Horizon Pipeline to transport gas purchased from NGC to Unicem. However, it was subsequently agreed that EHGC would construct the pipeline and supply gas to Unicem hence the reason for the assignment of the NGC GSA from Unicem to EHGC and the entry into the Unicem GSA between EHGC and Unicem.

11.1.4 At the date of the Pipeline MOU, an amount of NGN 7,332,021,301.06 was agreed to be owed by EHGC to NGC in respect of the value of gas delivered by NGC to EHGC under the NGC

GSA net of the amortised East Horizon Pipeline construction capex amount owed by NGC to EHGC (the "Outstanding NGC Amount").

11.1.5 Under the Pipeline MOU, the parties agreed that the transfer of a 15 per cent. interest in the East Horizon Pipeline from EHGC to NGC would discharge an amount of NGN 5,801,250,000.00 out of the Outstanding NGC Amount.

11.1.6 The parties agreed that a further amount of NGN 991,413,138 of the Outstanding NGC Amount would be paid to NGC by Oando and an amount of NGN 539,358,163 of the Outstanding NGC Amount would be paid to NGC by SEIL, in satisfaction of EHGC's payment obligations to NGC under the NGC GSA.

11.1.7 Pursuant to the Pipeline MOU, all claims that NGC, EHGC and SEIL may have against each other relating to the acquisition by SEIL of EHGC or relating to the East Horizon Pipeline will be resolved by the proposed transfer by EHGC to NGC of 15 per cent. ownership in the East Horizon Pipeline pursuant to the Ownership Agreement (as defined below). However, the Pipeline MOU and the Ownership Agreement does not in any way prejudice EHGC's or NGC's rights under the NGC GSA, whether accruing before, on or after 31 August 2014, including (except to the extent expressly settled in the Ownership Agreement) NGC's rights to recover any outstanding payments that may be due to NGC in relation to the supply of gas under the NGC GSA.

11.2 **Ownership Agreement**

11.2.1 Pursuant to the terms of the Pipeline MOU, an ownership agreement was entered into between EHGC, NGC and SEIL on 18 November 2014 (the "Ownership Agreement"), to give effect to the transfer of the 15 per cent. ownership interest in the East Horizon Pipeline agreed under the Pipeline MOU.

11.2.2 The consideration for this transfer will be the release by NGC of its entitlement to recover NGN 5,801,250,000.00 of the NGC Outstanding Amount. EHGC is required to account for and pay to NGC all amounts received by EHGC in the period between signing the Ownership Agreement and completion which relate to the ownership interest to be transferred. In addition EHGC is required to indemnify NGC for any actual loss suffered as a result of environmental liability arising under or in connection with such interest prior to completion (capped at US$18.75 million).

11.2.3 Completion under the Ownership Agreement is subject to a number of conditions which have not yet been satisfied. In particular, completion under the Ownership Agreement is subject to the execution of a pipeline maintenance agreement between EHGC, NGC and SEIL in relation to the East Horizon Pipeline (the "PMA"), together with the consent of the Minster of Petroleum Resources; the Company has confirmed that negotiations between NGC and EHGC (now Accugas Limited) with respect to the PMA remain ongoing and EHGC is working with NGC to seek satisfaction of the conditions precedent. The long stop date for the satisfaction of the Ownership Agreement conditions has expired, and Accugas Limited is in discussions with NGC for a possible collaboration to enable the parties to realise optimum value from the East Horizon Pipeline, maximise the flow of gas across the Eastern markets and facilitate the development of new gas infrastructure in the region.

11.2.4 In the period between signing the Ownership Agreement and completion, EHGC and SEIL are not permitted to sell, trade, relinquish, assign or otherwise create or agree to create any encumbrance over the NGC's interest, the pipeline or any part thereof.

11.2.5 No party may trade, sell, assign or otherwise dispose of its participating interests in the pipeline under the Ownership Agreement pending completion. If a party (transferor) desires to transfer all or a portion of its participating interests in the pipeline, the transferor must give the other party (offeree) written notice of their intention to transfer (offer notice). The offeree shall have 20 business days following the date on which the offer notice is sent to provide an offer to purchase all of the transfer interest at a purchase price and on terms and conditions no less favourable than in the offer notice (purchase notice). If the transferor does not receive a purchase notice within 20 business days of the offer notice, the offeree is deemed to have declined to purchase the transfer interest and the transferor shall be entitled to transfer all (but not less than all) of the transfer interest to a third party purchaser.

## 12 NIGERIEN PSC R1234

***R1234 PSC***

### 1. Exploration and Exploitation Process and Timelines

Below is a description of the process and timelines under the R1234 PSC for the exploration and exploitation of the area governed by the R1234 PSC. The R1234 PSC shall be subject to the Petroleum Code 2017 (Law n°2017-63 dated 14 August 2017, which replaces the Petroleum Code dated 2007).

***Stage 1 – Exploration phase***

The Niger Government shall issue the Contractor an Exclusive Exploration Authorisation via an order by the Minister responsible for Hydrocarbons 30 days following the signature of the R1234 PSC. Pursuant to Article 8.1 of the R1234 PSC, the term of the Exclusive Exploration Authorisation shall be four years from the date of issuance, being the date of Official Gazette publication (the "Initial Period"). Article 8.1.4 of the R1234 PSC requires the Contractor to undertake Exploration Operations within 180 days from the date of the award of the Exclusive Exploration Authorisation. Failure to comply with such deadline may constitute a default under the R1234 PSC and may result in the withdrawal of the Exclusive Exploration Authorisation.

The Exclusive Exploration Authorisation shall be renewed on request of the Contractor, two times only, and for a period requested by the Contractor in its renewal application, provided that each renewal period does not exceed two years and the whole duration of the Exclusive Exploration Authorisation (including the Initial Period and the renewal periods) does not exceed eight years (without prejudice to any two year extension requested by the Contractor in accordance with Article 10.3 of the R1234 PSC).

The Contractor's renewal application shall indicate the area that the Contractor wishes to retain, which shall not exceed 50 per cent. of the surface area defined for the current Exclusive Exploration Authorisation at the date of the renewal application.

During the Initial Period, the Contractor undertakes to execute the following Minimum Works Program: (i) acquisition, processing and interpretation of 250 $km^2$ of new 3D seismic profiles; and (ii) drilling of two Exploration Wells to a minimum depth of 2,000 metres, with at least one exploration well on R1, R2 or R4.

If a renewal exploration period is granted (each of which is up to two years in length) in respect of R1234 PSC, the Contractor shall implement the following Minimum Works Program:

- For the first renewal period: drilling of two Exploration Wells of a minimum depth of 2,000 metres, with at least one exploration well on R1, R2 or R4.
- For the second renewal period: the drilling of one Exploration Well of a minimum depth of 2,000 metres.

If the Contractor fails to satisfy the Minimum Works Program obligation either during the Initial Period or any of the renewal periods, or if due to the total renunciation or the withdrawal of the Exclusive Exploration Authorisation during these periods, the works have not achieved the minimum undertakings required for that period, the Contractor shall pay the Niger Government, as a lump sum payment, within 30 days after the end of the period concerned, being the effective date of the total renunciation or the date of the withdrawal of the Exclusive Exploration Authorisation, a penalty equivalent to: (i) US$1,000,000 for each undrilled well; (ii) US$800 per kilometre of 2D seismic profiles not acquired, processed or interpreted and (iii) US$2,500 per square kilometre of 3D seismic profiles not acquired, processed or interpreted.

With respect to undertaking Exploration Operations, the Government acknowledges that a number of environmental studies and environmental compliance certificates previously obtained with respect to the R1, R2, R3 and R4 blocks remain valid for the term of the R1234 PSC.

***Stage 2 – Discovery/Feasibility phase***

The Contractor must notify the Niger Government as soon as possible of any discovery made within the Contractual Exploration Area and no later than seven days from this discovery. Within 30 days of the discovery, the Contractor shall send a report concerning this discovery to the Minister responsible for Hydrocarbons containing all available information about this discovery. If the Contractor fails to notify the Niger Government within the seven-day period of a Discovery estimated to exceed five million discoverable barrels, the Contractor shall incur a penalty of US$1,000,000.

No later than 90 days after the notification of the discovery and if the Contractor considers that the discovery indicates the existence of a Commercial Oilfield, the Contractor must undertake a Feasibility Study to confirm the existence of the Commercial Oilfield.

The Contractor can make an application to the Minister responsible for Hydrocarbons to extend the Exclusive Exploration Authorisation for up to an additional two-year period in order to enable the Contractor to finalise either: (i) a Feasibility Study for a discovery; or (ii) a Feasibility Study for the operations of construction and exploitation of a Pipeline Transport System for Hydrocarbons.

***Stage 3 – Exploitation phase***

If the Contractor concludes that an Oilfield is a Commercial Oilfield, or that several oilfields are Commercial Oilfields, it may request an Exclusive Exploitation Authorisation and shall be entitled to obtain a separate Exclusive Exploitation Authorisation for each Commercial Oilfield or a joint one for more than one of these Commercial Oilfields, at the Contractor's choice. Pursuant to Article 12.4 of the R1234 PSC, the Exclusive Exploitation Authorisation shall be issued by a decree of the Council of Ministers, for the period requested by the Contractor, and this period cannot exceed 25 years with respect to the exploitation of crude oil, and 30 years with respect to the exploitation of natural gas.

The Contractor is entitled to apply for a maximum ten-year renewal of the period of each Exclusive Exploitation Authorisation. This application for renewal must be submitted at least two years prior to the expiration of the initial period of the Exclusive Exploitation Authorisation. If the renewal application is deemed admissible by the Minister responsible for Hydrocarbons, the Minister responsible for Hydrocarbons and the Contractor shall negotiate and agree an amendment to the PSC. Such amendment shall be presented to the Council of Ministers for approval by decree.

***Government of Niger participation***

On the issuance of any Exclusive Exploitation Authorisation, the Niger Government shall be entitled to require that a participation in the rights and obligations arising from such Exclusive Exploitation Authorisation is assigned to it either directly or via a Public Body, for a maximum of 20 per cent. (the "Public Participating Interest").

If the Niger Government decides to take such a participating interest in the Exclusive Exploitation Authorisation, the Niger Government must carry out the following acts to the extent of its participating interest in the Exclusive Exploitation Authorisation:

- reimburse immediately without interest, its proportional share of the Petroleum Costs relating to the Exploration Operations; and
- contribute an equivalent amount with the other Joint Holders of the Exclusive Exploitation Authorisation to the financing of the Petroleum Costs relating to the Exploitation Operations from the date of the issuance of the Exclusive Exploitation Authorisation.

Until the commencement date of commercial production, the Government or National Operator shall be carried by the Advances of the other Joint Holders of the Exclusive Exploitation Authorisation up to the Public Participation Interests of 15 per cent. (the "Carried Participation"). Such Advances shall not be interest bearing. The Niger Government or National Operator shall be responsible for the proportion of costs of the Public Participation Interest which exceed the Carried Participation. From the commencement date of commercial production until complete reimbursement of the Advances, the Government or National Operator shall remit to the Joint Holders the volumes of Hydrocarbons to which it is entitled to the delivery of by way of Cost Oil relating to the Carried Interest.

## 2. Economics of the R1234 PSC

### 2.1 *Signature bonus*

The Contractor must pay to the Government a Signature Bonus amounting to US$1,000,000. According to Section 37.4 of the R1234 PSC, the Signature Bonus and its payment shall be exempt from all taxes (including turnover tax) and fees in Niger. Pursuant to Section 37.4.2, the Signature Bonus shall constitute a recoverable Petroleum Cost.

The Contractor undertakes to pay eight per cent. of the amount of the Signature Bonus (US$80,000) no later than the due date of the Signature Bonus in order to enable the Government to fulfil its payment obligations in relation to the tax and financial assistance for the promotion, development and follow up of petroleum activities in Niger provided by the State's counsels; this payment shall not constitute a recoverable Petroleum Cost[1].

### 2.2 *Ad Valorem Tax (i.e. Royalty)*

Once commercial production has begun, the Contractor is required to pay the Government an Ad Valorem Tax at a rate of 12.5 per cent. for crude oil and 2.5 per cent. for natural gas (following the subtraction of transportation costs to market). The Ad Valorem Tax shall be wholly or partly paid either in cash or in.

### 2.3 *Cost Recovery*

A portion of the Net Production of Hydrocarbons, net of Ad Valorem Tax and originating from each Contractual Exploitation Area during the Calendar Quarter shall be allocated to the reimbursement of: (i) the Petroleum Costs related to Exploitation and Development Operations actually borne by the Contractor in relation to the Contractual Exploitation Area concerned, and (ii) Petroleum Costs related to Exploration Operations, within the limit of the Cost Stop that represents 70 per cent. of the Net Production of Hydrocarbons, net of Ad Valorem Tax.

Unrecovered Petroleum Costs in each Calendar Quarter are carried forward to the subsequent Calendar Year until total recovery or expiry of the Contract.

The recoverable Petroleum Costs related to Exploration Operations include the following costs:

- geophysical, geochemical, paleontological, geological, topographic and seismic surveys and interpretations thereof;
- personnel, equipment, supplies and services used in the coring, drilling of Exploration and Evaluation Wells not completed as Production Wells, and the completion of wells for water supply;
- the equipment used to achieve the objectives referred to in subparagraphs (a) and (b) of the paragraph 11.2.1, including access roads; and
- the share of overhead costs attributable to the costs of the Exploration Operations in proportion to the share of the costs of the Exploration Operations in the total Petroleum Costs, excluding overhead costs.

The recoverable Petroleum Costs related to development Operations are the following:

- the drilling of Development and Production Wells, including wells drilled for the injection of water and Natural Gas to increase the recovery rate of Hydrocarbons;
- wells completed by the installation of casing or equipment after a well has been drilled with the intention of completing it as a Production Well or a Water or Natural Gas Injection Well to increase the recovery of Hydrocarbons;

1 Pursuant to the R1234 PSC, "Petroleum Costs" refers to all costs, charges and expenses incurred by the Contractor with a view to or as part of the execution of the Petroleum Operations. The R1234 PSC determines the type of Petroleum cost that can be recoverable. In such, pursuant to Section 37.4.2 of the R1234 PSC, the signature bonus constitutes a recoverable petroleum cost. Pursuant to Section 41.2 of the R1234 PSC, the Contractor shall start recovering its share of the Petroleum Costs relating to this area by receiving a quantity of Hydrocarbons called 'Cost Oil" each Calendar Year. (Please refer to the point on "Cost Oil" hereafter).

- production, transportation and storage related equipment, such as pipelines, processing and production units, wellhead equipment, enhanced recovery systems, storage units, and other related equipment, as well as access roads related to production activities;
- engineering related to Development Operations and Transport Operations; and
- the share of overheads attributable to Development Operations costs in proportion to the share of Development Operations costs in total Petroleum Costs, excluding overheads.

The recoverable Petroleum Costs related to Production Operations are all the Petroleum Costs incurred from the start of the commercial production of Hydrocarbons, excluding (i) the costs of the Exploration Operations, (ii) the costs of the Development Operations and (iii) the costs of Abandonment Works. The costs of Production Operations also include provisions made to deal with losses or charges other than those relating to Abandonment Works.

The costs of Abandonment Works include all costs, charges and expenses incurred by the Contractor in order to carry out or in connection with the execution of the Abandonment Works provided for in the Contract. They shall consist exclusively of the provisions made in accordance with the provisions of Clause 36.3 of the R1234 PSC and of that part of the costs relating to the Abandonment Works which exceeds the amount of the said provisions.

2.4 ***Profit sharing***

The Net Production of Hydrocarbons from each Contractual Exploitation Area, less the Ad Valorem Tax and the portion deducted as Cost Oil, is referred to as “Profit Oil” and is allocated between the Government of Niger and the Contractor in accordance with an “R-Factor” determined each quarter for each Exclusive Exploration Authorisation using the following formula:

$$\text{R-Factor} = \frac{W(1) - X(2)}{Y(3) + Z(4)}$$

Notes:

(1) “**W**” means the total of the amount of the share of Crude Oil at the Ex-Field Market Price applicable for each Quarter from the start of production, and, where applicable, of the share of Natural Gas to which the Contractor is entitled as Cost Oil and Profit Oil for the Quarter in question, from the date of the issue of the Exclusive Exploitation Authorisation up till the last Day of the Quarter preceding the Quarter for which the R-Factor is determined.

(2) “**X**” means the total of the costs of the Exploitation Operations, with the exception of the costs of Development Operations, incurred by the Contractor from the date of the issue of the Exclusive Exploitation Authorisation until the last Day of the Quarter preceding the Quarter for which the R- Factor is determined.

(3) “**Y**” means the total of the costs of the Development Operations for the Contractual Exploitation Area concerned incurred by the Contractor from the date of the issue of the Exclusive Exploitation Authorisation up till the last Day of the Quarter preceding the Quarter for which the R-Factor is Determined.

(4) “**Z**” means the total of the Exploration Costs allocated to this Contractual Exploitation Area in accordance with Article 41 mentioned above.

Profit Oil is shared between the Government of Niger and the Contractor according to the following scale, depending on R-factor:

| *R-factor* | *Percentage of Profit Oil to the benefit of the Contractor* | *Percentage of Profit Oil to the benefit of the Government of Niger* |
|---|---|---|
| Less than or equal to 1 | 60% | 40% |
| Between 1 and 1.5 | 55% | 45% |
| Between 1.5 and 2 | 50% | 50% |
| Greater than 2 | 45% | 55% |

For the first Quarter from the commencement of commercial production, the R-Factor shall be deemed to be less than or equal to 1.

2.5 ***Infrastructure***

The Contractor is entitled to use the public installations required for the Petroleum Operations, including airports, roads, building sites and other similar installations, subject to the payment of fees due for such use, where applicable.

In addition, the Contractor is entitled to execute or have executed on these lands, all construction works and infrastructure required or necessary for the Petroleum Operations, including the setup of markers and boundary markers, the construction of the installations required for the storage of materials, equipment, products and waste, and for ballasting and the elimination of pollution and the transport of materials, equipment and extracted products, without prejudice to the observance of the rules relating to the execution of construction works and infrastructure applicable in the protection areas that may be established around built-up areas, cultivated areas, plantations, water points, archaeological sites, cultural sites and burial sites, by the Nigerien authorities.

2.6 ***Access to pipelines and rights for the construction of pipelines***

The Exclusive Exploitation Authorisation(s) issued to the Contractor shall entitle it to transport, within the territory of Niger, its share of the products to the storage, processing, loading, major consumption or delivery points or have it so transported.

If the Contractor determines that such transport requires the construction and operation of one or more pipeline transport systems for hydrocarbons, the Government shall, subject to the compliance by the Transport Contractor with the formalities and conditions provided to this effect by Petroleum Legislation: (1) sign a transport agreement with; and (2) issue an Internal Transport Authorisation to, the Transport Contractor.

The Contractor may also request to be authorised to transport the Hydrocarbons from the Contractual Exploitation Area by a pipeline transport system constructed by another person and in which the Hydrocarbons extracted by the Contractor shall not have priority. The granting of such authorisation shall be automatic if all the conditions required by Petroleum Legislation are met.

The transport tariff relating to a pipeline transport system for Hydrocarbons must be agreed between the Transport Contractor and the Minister responsible for Hydrocarbons. In particular, this tariff must: (a) include and use coefficient for the installations; (b) take into account the operating costs of this pipelines transport system; (c) take into account the depreciation of installations and pipelines; and (d) enable the Transport Contractor to achieve an internal rate of return (IRR) not exceeding 12.5 per cent. over the whole duration of the related Transport Operations.

The State shall facilitate the Contractor to use existing pipeline transport systems for Hydrocarbons or pipelines to be constructed for the evacuation of Hydrocarbons from any exploitation contractual area to the international market. The State shall ensure that the transport tariff applied to the Contractor in such pipeline transport systems is fair, and is not discriminatory compared to the rate applied to other users on comparable terms relating to quality, frequency and flow. In principle, the maximum IRR usually granted by the State to any transport contractor is 12.5 per cent.

Concerning international transportation of hydrocarbons produced, the Government and Savannah Niger will cooperate mutually so as to negotiate and bring to finalisation international transport agreements with the foreign states concerned. The Government will make its best efforts so that the Transport Contractor can obtain all authorisations or licences required by the related foreign State relative to the export transport system.

2.7 ***Abandonment***

On the earlier of:

- when the parties estimate that 50 per cent. of the initial recoverable reserves of an Exclusive Exploitation Authorisation will have been produced at the end of the next Calendar Year; and
- the fifteenth anniversary of the date of granting the Exclusive Exploitation Authorisation,

the Contractor shall submit to the Minister responsible for Hydrocarbons, no later than 31 August of the current Calendar Year, an abandonment plan. The abandonment plan shall include the

Abandonment Operations that the Contractor proposes to execute within the Contractual Exploitation Area relating to the Exclusive Exploitation Authorisation, a plan for the restoration of the site, a programme of the proposed works, and a detailed estimate of all costs associated with the Abandonment Operations. The Contractor shall submit a budget for the abandonment plan, which shall not exceed US$400,000 and shall be deemed a Petroleum Cost.

Under Article 36.3 of the R1234 PSC, from the date which is the earlier of:

- the Calendar Year which 50 per cent. of the initial recoverable reserves of an Exclusive Exploitation Authorisation will be produced; and
- the 16th anniversary of the granting of the Exclusive Exploitation Authorisation,

the Contractor shall constitute an annual provision for Abandonment Operations in an account with the Central Bank of West African States, in accordance with the terms of an escrow agreement. The annual provision for the Abandonment Operations to be made by the Contractor at the end of a Calendar Year for each Contractual Exploitation Area shall be calculated as follows:

$$\text{Contribution to Abandonment Fund} = \frac{(\text{ECAO}(1) - \text{TPAO}(2)) \times \text{TPH}(3)}{\text{TPR}(4)}$$

Notes:

(1) "**ECAO**" means the estimated costs of the Abandonment Operations.

(2) "**TPAO**" means the total provisions made for Abandonment Operations related to the same Exclusive Exploitation Authorisation and effected during the Calendar Years preceding the one for which the provision is calculated.

(3) "**TPH**" means the total production of Hydrocarbons from the Contractual Exploitation Area for this Calendar Year.

(4) "**TPR**" means the total of the proven reserves developed and still to be produced during the Exclusive Exploitation Authorisation at the beginning of this Calendar Year within the Contractual Exploitation Area in question.

### 2.8 *Taxes*

- *Land royalties*

  The Contractor must pay annual land royalties calculated in accordance with the following schedule (in XOF):

  (a) Exclusive Exploration Authorisation: Initial Period: 500F/km$^2$/year

  First Renewal Period: 1,500F/km$^2$/year Second Renewal Period: 2,500F/km$^2$/year Extension period: 5,000F/km$^2$/year

  (b) Exclusive Exploitation Authorisation: Initial Period: 1,500,000F/km$^2$/year Renewal Period: 2,000,000F/km$^2$/year

- *Capital gains tax on Assets Transfer*

  Pursuant to Article 48.1 of the R1234 PSC, the capital gains resulting from the transfer of an Authorisation or a participation in any such Authorisation realised by the Contractor or any of its constituent entities shall be subject to an exceptional 25 per cent. tax payable by the Assignor.

  Under Article 48.1.2 of the R1234 PSC, the provisions of Article 48.1.1 shall not apply to capital gains on the transfer of materials, equipment and other items used for the execution of the Petroleum Operations. As provided under Article 48.2 of the R1234 PSC, the basis for the capital gains tax shall be the difference between:

  – the transfer price for the assets concerned; and

  – the cost price of the assets concerned.

  The transfer price is made up of the price actually received, in cash or in kind, less any repayment of advances made by the Assignee in relation to the Authorisation concerned (a "Payment in Kind"). Pursuant to Article 48.2.3 of the R1234 PSC, and notwithstanding the provisions above, the financial valuation of the Exploration Operations that the Assignee agrees to perform on behalf of the Contractor is not included in the sale price of the assets, provided that the relevant Exploration Operations are conducted after the date of the transfer. Consequently, the financing of such costs by the Assignee shall not be subject to capital gains tax.

The cost price of the assets concerned shall be constituted by the aggregate Petroleum Costs relating to these assets not yet recovered but actually incurred by the Contractor as at the date of transfer. For the purpose of calculating the cost price, such Petroleum Costs shall be deemed to include costs directly incurred in relation to the Petroleum Operations before the date of entry into the PSC, including costs incurred for the purpose of negotiating and signing the PSC and the signature bonus amount.

Pursuant to Article 48.3 of the R1234 PSC, the capital gains tax shall be paid by the Assignor:

- if the sale price is paid entirely by any mean other than a Payment in Kind, within thirty days of the issue of the transfer authorisation;
- if the sale price is paid partly by cash and partly by Payment in Kind and;
- the difference between the cash payment and the cost price of the transferred Authorisation or participation in an Authorisation or participation in an Authorisation results in a positive balance:
  - the capital gains tax on the positive balance shall be paid within thirty days of the issue of the transfer authorisation; and
  - the remaining balance of capital gains shall be payable no later than 31 March of the Calendar Year following the Calendar Year in which the Cost Oil corresponding to the Petroleum Costs (the "Cost Oil Nature Payment") is paid to the Contractor, up to a limit of 25 per cent. of the amount of Cost Oil, until full repayment of the capital gain tax amount.
- the difference between the cash payment and the cost price of the transferred Authorisation or participation in an Authorisation results in a negative or net zero balance, the capital gains tax shall be payable from the first year which the Cost Oil Nature Payment is made to the Contractor, up to a limit of 25 per cent. of the amount of Cost Oil, until full repayment of the capital gain tax amount.

The transfer of the Authorisation or participation in an Authorisation concerned shall only take effect from the submission of a declaration by the Contractor concerning the capital gain on the disposal, validated by the tax authorities of the Republic of Niger, and of the payment of the tax due.

Under Article 48.4 of the R1234 PSC, any capital gains realised on the disposal of an Authorisation or a Participation in an Authorisation to an affiliated company shall benefit from the deferment of the capital gains tax until any subsequent disposal by the affiliate entity to a third party (including the capital gain tax due on such disposal to the third party).

- *General tax exemption*

  Pursuant to Article 49.1.1 of the R1234 PSC, apart from the fees stipulated in Article 90 of the Petroleum Code, the exceptional capital gains tax on disposals under Article 48, the Ad Valorem Tax, the land royalties, the Government's share of Profit Oil, stamp duties and registration fees (except where an exception is stipulated in the PSC), the tree cutting tax and the provisions of Paragraph 49.4 of the R1234 PSC related to withholdings, each of the Contractor's constituent entities shall be exempt from all taxes, deductions, charges, imposts and other obligatory contributions:

  - either by virtue of the activities executed in application of the R1234 PSC; or
  - by virtue of the payments received or effected as part of the execution of the R1234 PSC.
  - Tax scheme for Transport Operations

  Annex D of the R1234 PSC provides that, in addition to the tax advantages provided under the Petroleum Code, the Transport Contractor will be classified under the regime of free zones or free points provided for under Article 31 of the Investment Code and therefore will benefit from tax and customs exemptions, including the following:

  I during the establishment phase:

- total exemption from duties and taxes collected by the State including value-added tax on services, works and services directly related to Transport Operations; and
- total exemption from customs duties and taxes, including value-added tax, excluding the Statistical Tax, the Community Levy, the Solidarity Community Levy on imported materials, equipment and tools directly related to Transport Operations.

I during the exploitation phase:

- total exemption from customs duties and taxes, excluding the Statistical Tax, the Community Levy, the Solidarity Community Levy and the value-added tax on imported raw materials and packaging in case of unavailability of locally produced equivalent products; and
- total exemption from the minimum tax, the professional tax and the property tax.

2.9 ***Exchange regulations***

The Contractor is subject to the exchange control regime under ordinary law in force in the Republic of Niger, which shall include the Western Africa Economic Monetary Union Foreign Exchange Regulation n°09/2010/CM/UEMOA (the "WAEMU FOREX Regulation"). The Contractor shall not benefit from the derogations and exceptions to the Republic of Niger's exchange control regime provided under the R1/R2 PSC and R3/R4 PSC. Under applicable law, Savannah Niger shall be entitled to receive abroad the proceeds of Hydrocarbons effected in the Republic of Niger, but such proceeds must be repatriated to Niger within 30 days from the payment due date under the relevant sales agreement.

Post-repatriation, Savannah Niger shall have the right to transfer funds abroad in accordance with the framework provided under the WAEMU FOREX Regulation, which includes by way of dividend payments and interest payments.

2.10 ***Other fees***

Under the terms of the R1234 PSC, the Contractor is obliged to pay the following:

- **Training and Development fees** – the Contractor shall contribute the following towards the training and upgrading of the employees of the Ministry responsible for Hydrocarbons:
  - for each Calendar Year until the end of the Exclusive Exploration Authorisation: €500,000; and
  - for each Calendar Year upon the granting of the Exclusive Exploitation Authorisation (and for each Exclusive Exploitation Authorisation): €300,000.
- **Legal and financial assistance fees** – the Contractor shall contribute the following towards the financing of legal and financial assistance for the Ministry responsible for Hydrocarbons:
  - for each Calendar Year until the end of the Exclusive Exploration Authorisation: €250,000; and
  - for each Calendar Year upon the granting of the Exclusive Exploitation Authorisation (and for each Exclusive Exploitation Authorisation): €300,000.
- **Social program fees** – for assistance to local populations, for each year during the exploration phase, the Contractor shall contribute US$30,000.
- **Municipal Development Petroleum Program ("MDPP")** – Prior to submitting an application for an Exclusive Exploitation Authorisation, the Contractor must submit to the mayor of each municipality concerned, and gain the approval of the municipal council, of a MDPP setting out the Contractor's proposals for financial and technical support for the implementation of the Municipal Development Plan. The amount due from the Contractor for all MDPP (to be distributed equally) shall be:
  - US$150,000 per year, for production volumes less than or equal to 10,000 barrels per day;
  - US$300,000 per year for production volumes greater than 10,000 barrels per day and less than or equal to 50,000 barrels per day; and

– US$1,000,000 per year for production greater than 50,000 barrels per day.

- Regional Development Petroleum Program ("RDPP") – Prior to submitting an application for an Exclusive Exploitation Authorisation, the Contractor must submit to the president of each municipality concerned, and gain the approval of the municipal council, of a RDPP setting out the Contractor's proposals for financial and technical support for the implementation of the Municipal Development Plan. The amount due from the Contractor for all RDPP (to be distributed equally) shall be:
  – US$100,000 per year, for production volumes less than or equal to 10,000 barrels per day;
  – US$200,000 per year for production volumes greater than 10,000 barrels per day and less than or equal to 50,000 barrels per day; and
  – US$500,000 per year for production greater than 50,000 barrels per day.

2.11 ***Liability***

Within the limits of and in accordance with the modalities stipulated by the R1234 PSC relating to the Contractor's liability and to the settlement of disputes, the Contractor must indemnify the Government for any direct damage caused to the Government imputable to the Contractor, its managers, employees or agents and the persons that it has substituted for the execution of the R1234 PSC.

The Contractor shall be solely liable for direct damage caused to Third Parties due to the Petroleum Operations or by the acts of its agents, employees or any other person that it may have substituted in the execution of the Contract. For the purpose of this Article, the Government shall be deemed to be a Third Party in relation to the damage caused to public works, buildings and other public property. This Article shall also apply to direct damage to the environment as soon as the damage exceeds the environmental impact level generally accepted in the international petroleum industry and by Current Legislation.

2.12 ***Applicable Law***

The Petroleum Legislation, Current Legislation (which includes any law or Act with the same legal value, derived from an international treaty or agreement properly ratified by the State) and the PSC as well as principles of international law shall constitute the law of the Parties subject to: (i) with respect to the conventional rules of international law, that they are not the result of international agreements that have not been duly ratified by the State and taking into account the reservations expressed by the State in the implementation of the said international agreement; and (ii) with respect to the other rules and principles of international law, the State has not demonstrated in one way or other, before the conclusion of the PSC, its intention not to be bound by these rules.

The Nigerien Government guarantees that the Contractor shall not be subject, without its prior consent, to a Change in Law[2] where the Change Law will result in a Change of Contractual Conditions. According to the R1234 PSC, a Change in Law will Change the Contractual Conditions if it:

- Aggravates, directly or consequently, immediately or in the long term, the obligations and burdens imposed on the Contractor by the provisions of the Petroleum Legislation, the Stabilized Laws in Force or the provisions of the Contract; and/or
- Infringes upon the Contractor's economic and fiscal rights and advantages resulting from the Petroleum Legislation, the Stabilized Laws in Force and the Contract.

If the Government modifies the current Legislation whose application to the Contract would have the effect of modifying its economic and financial conditions, obligations and responsibilities and rights and advantages, the Parties shall agree on the modifications to be made to this Contract to preserve its economy. Amendments to this Contract shall in no event diminish the rights nor increase the obligations of the Contractor as agreed at the Effective Date.

2 "Change in Law" is defined under the R1234 as it follows: (i) any modification made, after the Signature Date, to a Stabilized Law in Force or to an International Act not falling under the Social and Environmental Laws or ii) any provision resulting from an International Act not falling under the Social and Environmental Laws, which entered into force in the territory of the Republic of Niger after the Signature Date".

In the absence of agreement between the Parties within 90 days from the date of the commencement of negotiations for the adoption of the amendments necessitated by the changes:

– the Change in Law will not apply to the Contractor if it results from an amendment to the Stabilized Laws[3] in Force; and

– the Change in Law will apply to the Contractor if it results from an International Act.

3 "Stabilized Laws in Force" is defined under the R1234 as it follows: "all the laws in force with the exception of those under Social and Environmental Laws". "Social and Environmental Laws" are defined as "any International Act and any Law in force relating to labour law, social law, environmental protection, protection of cultural heritage, as well as the provisions of petroleum legislation that deal with these matters".

## PART 15

## NOTICE OF GENERAL MEETING

# SAVANNAH ENERGY PLC

*(Incorporated and registered in England and Wales under the Companies Act 2006 with registered number 09115262)*

NOTICE IS HEREBY GIVEN THAT a general meeting (the "GM") of Savannah Energy PLC (the "Company") will be held at the offices of the Company at 40 Bank Street, London E14 5NR at 10.30 a.m. on 24 January 2022 to consider and, if thought fit, pass the following resolutions of which resolutions 1 to 6 (inclusive) will be proposed as ordinary resolutions of the Company and resolutions 7 to 10 will be proposed as special resolutions of the Company:

**ORDINARY RESOLUTIONS**

1. THAT the Exxon Acquisition (as defined in this Admission Document) be and is hereby approved for all purposes, including, without limitation, for the purposes of Rule 14 of the AIM Rules for Companies published by the London Stock Exchange plc and that the directors of the Company (the "Directors") be and are hereby authorised to take all steps necessary or, in the opinion of the Directors, desirable, to give effect to the Exxon Acquisition, including without limitation, waiving, amending, varying or extending any of the conditions and terms of the Exxon Acquisition.

2. THAT the PETRONAS Acquisition (as defined in this Admission Document) be and is hereby approved for all purposes, including, without limitation, for the purposes of Rule 14 of the AIM Rules for Companies published by the London Stock Exchange plc and that the Directors be and are hereby authorised to take all steps necessary or, in the opinion of the Directors, desirable, to give effect to the PETRONAS Acquisition, including without limitation, waiving, amending, varying or extending any of the conditions and terms of the PETRONAS Acquisition.

3. THAT the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Companies Act 2006 (the "Act"), in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £416,010.62, such authority to expire at the next annual general meeting of the Company, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked).

4. THAT the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £58,066.96, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked).

5. THAT the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £101,114, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity

securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked).

6. THAT the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £23,853.46, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked).

**SPECIAL RESOLUTIONS**

7. THAT the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by resolution 3 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by resolution 3 above. This power shall cease to have effect when the authority conferred by resolution 3 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired.

8. THAT the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by resolution 4 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by resolution 4 above. This power shall cease to have effect when the authority conferred by resolution 4 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired.

9. THAT the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by resolution 5 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by resolution 5 above. This power shall cease to have effect when the authority conferred by resolution 5 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired.

10. THAT the Directors be and they are hereby empowered pursuant to Section 571 of the Act to allot equity securities (within the meaning of Section 560 of the Act) pursuant to the authority conferred by resolution 6 above as if Section 561(1) of the Act does not apply to such an allotment, on the basis that this power shall be limited to any allotment made pursuant to the authority conferred on the Directors by resolution 6 above. This power shall cease to have effect when the authority conferred by resolution 6 above is revoked or (if not revoked) expires but the Company may make an offer or agreement which would or might require equity securities to be allotted after expiry of this power and the Directors may allot equity securities in pursuance of that offer or agreement as if this power had not expired.

By order of the Board

**Andrew Knott**

Chief Executive Officer, on behalf of Savannah Energy PLC

Registered office: 40 Bank Street, London E14 5NR

Dated: 30 December 2021

## Important Notes

The following notes explain your general rights as a shareholder and your right to vote at this GM or appoint someone else on your behalf. Shareholders are strongly encouraged to submit a proxy vote in advance of the GM and to appoint the Chair of the Meeting as their proxy.

1. To be entitled to attend and vote at the GM (and for the purpose of the determination by the Company of the votes you may cast), you must be registered in the Register of Members of the Company at close of trading on 20 January 2022 (or, in the event of any adjournment, close of business on the date which is 48 hours before the time of the adjourned meeting). Changes to the Register of Members after the relevant deadline shall be disregarded in determining the rights of any person to attend and vote at the GM. There are no other procedures or requirements for Members to comply with in order to attend and vote at the GM.
2. It is the current intention that voting at the GM will be conducted by way of a poll and not by a show of hands. The Company believes that a poll is more representative of shareholders' voting intentions because shareholder votes are counted according to the number of Ordinary Shares held and all votes tendered are taken into account.
3. If you are a Member at the time set out in Note 1 above, you are entitled to appoint a proxy to exercise all or part of your rights to attend, speak and vote at the GM and you should have received a Form of Proxy with this Notice. You can only appoint a proxy using the procedures set out in these notes and the notes to the Form of Proxy. If you do not have a Form of Proxy and believe that you should have one, or if you require additional forms, please contact the Company's Registrar using the contact details set out in Note 22 below. A proxy need not be a Member but must attend the GM to represent you. If you wish your proxy to speak on your behalf at the GM you will need to appoint your own choice of proxy (not the Chair) and give your instructions directly to them.
4. You may appoint more than one proxy provided that each proxy is appointed to exercise the rights attached to different Ordinary Shares. You may not appoint more than one proxy to exercise the rights attached to any one Ordinary Share. To appoint more than one proxy, please contact the Company's Registrar using the contact details set out in Note 22 below.
5. In the case of joint holders, where more than one of the joint holders purports to appoint a proxy, only the appointment submitted by the most senior holder will be accepted. Seniority is determined by the order in which the names of the joint holders appear in the Company's Register of Members in respect of the joint holding (the first named being the most senior).
6. Any person to whom this Notice is sent who is a person nominated under Section 146 of the Companies Act 2006 (the "Act") to enjoy information rights (a "Nominated Person") may, under an agreement between him/her and the Member by whom he/she was nominated, have a right to be appointed (or to have someone else appointed) as a proxy for the GM. If a Nominated Person has no such proxy appointment right or does not wish to exercise it, he/she may, under any such agreement, have a right to give instructions to the Member as to the exercise of voting rights.
7. The statement of the rights of shareholders in relation to the appointment of proxies in Notes 3, 5 and 10 do not apply to Nominated Persons. The rights described in these paragraphs can only be exercised by Members of the Company.
8. The notes to the Form of Proxy explain how to direct your proxy on how to vote on each resolution or withhold their vote. A vote withheld is not a vote in law, which means that the vote will not be counted in the calculation of votes for or against the resolution. If no voting indication is given, your proxy will vote or abstain from voting at his or her discretion. Your proxy will vote (or abstain from voting) as he or she thinks fit in relation to any other matter which is put before the GM.
9. The return of a completed form of proxy, other such instrument or any CREST Proxy Instruction (as described in Note 13 below) will not prevent a shareholder attending the GM and voting in person if he/she wishes to do so.
10. In order to be valid, a proxy appointment must be made and returned by one of the following methods:
    (a) by completion of the Form of Proxy, in hard copy form by post, or by courier to the registrar, Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol BS99 6ZY ("the Registrar");
    (b) in the case of CREST members, by utilising the CREST electronic proxy appointment service in accordance with the procedures set out below; or
    (c) by appointing your proxy electronically via the Registrar's website at www.investorcentre.co.uk/eproxy. You will need your Control Number, SRN & PIN which can be found on your Form of Proxy,

    and in each case, the appointment must be received not less than 48 hours before the time for holding of the General Meeting. In calculating such 48-hour period, no account shall be taken of any part of a day that is not a working day. A Member that appoints a person to act on its behalf under any power of attorney or other authority and wishes to use method (a), (b) or (c) must return such power of attorney or other authority to Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol BS99 6ZY prior to using such method and in any event not less than 48 hours before the time of the General Meeting. If you hold your ordinary shares in uncertificated form (that is, in CREST) you may appoint a proxy by completing and transmitting a CREST message (a "CREST Proxy Instruction") in accordance with the procedures set out in the CREST manual so that it is received by the Registrar by no later than 10.30 a.m. on 20 January 2022. Electronic communication facilities are open to all Members and those who use them will not be disadvantaged. If you return more than one proxy appointment, either by paper or electronic communication, the proxy appointment received last by the Company's Registrar before the latest time for the receipt of proxies will take precedence.
11. CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the GM (and any adjournment of the GM) by using the procedures described in the CREST Manual (available from https://www.euroclear.com). CREST Personal Members or other CREST sponsored members, and those CREST members who have appointed a service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

12. In order for a proxy appointment made by means of CREST to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear UK & Ireland Limited's specifications and must contain the information required for such instructions, as described in the CREST Manual. The message must be transmitted so as to be received by the issuers' agent (ID 3RA50) by 10.30 a.m. on 20 January 2022. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST application host) from which the issuers' agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time, any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

13. CREST members and, where applicable, their CREST sponsors, or voting service providers should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular message. Normal system timings and limitations will, therefore, apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member, or sponsored member, or has appointed a voting service provider(s), to procure that his CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting system providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings. The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5) (a) of the Uncertificated Securities Regulations 2001.

14. In the case of a Member which is a company, the Form of Proxy must be executed under its common seal or signed on its behalf by an officer of the company or an attorney of the company. Any power of attorney or any other authority under which the Form of Proxy is signed (or a duly certified copy of such power or authority) must be included with the Form of Proxy.

15. Any corporation which is a Member may, by resolution of its directors or other governing body appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that no more than one corporate representative exercises powers in relation to the same shares. Corporate representatives should bring with them either an original or certified copy of the appropriate board resolution or an original letter confirming the appointment, provided it is on the corporation's letterhead and is signed by an authorised signatory and accompanied by evidence of the signatory's authority.

16. Under Section 527 of the Act, shareholders meeting the threshold requirements set out in that section have the right to require the Company to publish on a website a statement setting out any matter relating to: (i) the audit of the Company's accounts (including the Auditor's Report and the conduct of the audit); or (ii) any circumstances connected with an auditor of the Company ceasing to hold office since the previous meeting at which annual accounts and reports were laid in accordance with Section 437 of the Act. The Company may not require the shareholders requesting any such website publication to pay its expenses in complying with Sections 527 or 528 of the Act. Where the Company is required to place a statement on a website under Section 527 of the Act, it must forward the statement to the Company's auditor not later than the time when it makes the statement available on the website. The business which may be dealt with at the GM includes any statement that the Company has been required under Section 527 of the Act to publish on a website.

17. Any shareholder attending the GM has the right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the GM but no such answer need be given if (a) to do so would interfere unduly with the preparation for the GM or involve the disclosure of confidential information, (b) the answer has already been given on a website in the form of an answer to a question, or (c) it is undesirable in the interests of the Company or the good order of the GM that the question be answered.

18. Copies of the service contracts of the Executive Directors and the letters of appointment of the Chair and Non-Executive Directors are available for inspection during normal business hours at the registered office of the Company and may also be inspected at the GM venue for 15 minutes prior to and during the GM.

19. As at 29 December 2021 (being the last practicable business day prior to the publication of this Notice), the Company's ordinary issued share capital consists of (being the last practicable business day prior to the publication of this Notice), the Company's ordinary issued share capital consists of 996,408,412 Ordinary Shares, carrying one vote each. No shares were held in treasury. Therefore, the total voting rights in the Company as at 29 December 2021 were 996,408,412.

20. Information regarding the Company's GM can be found at www.savannah-energy.com

21. You may not use any electronic address provided in either this Notice or any related documents (including the Form of Proxy) to communicate with the Company for any purposes other than those expressly stated.

22. Members who have general queries about the GM should call the Company's Registrar, Computershare Investor Services PLC on 0370 707 1133 (or, if calling from outside the UK, on +44 (0) 370 707 1133). Calls are charged at the current national rate from within the UK plus network extras, lines are open 8.30 a.m.-5.30 p.m., Monday to Friday. Calls from outside the UK will be charged at the applicable international rate. Different charges may apply to calls made from mobile telephones and calls may be recorded and randomly monitored for security and training purposes. Please note that Computershare Investor Services PLC cannot provide investment advice, nor advise you how to cast your vote on the resolutions.

# APPENDIX A

# OVERVIEW OF NIGERIA'S NATIONAL LEGISLATIVE FRAMEWORK

## 1 CONSTITUTION OF THE FEDERAL REPUBLIC OF NIGERIA 1999 (AS AMENDED), CAP C23, LFN 2004

The Constitution vests the entire property and control of all minerals, mineral oils and natural gas in, under or upon any land in Nigeria, its territorial waters and the exclusive economic zone of Nigeria in the Federal Government of Nigeria.

## 2 THE PETROLEUM INDUSTRY ACT, 2021

2.1 The Petroleum Industry Act (the "PIA") was enacted in August 2021 and provides a legal, governance, regulatory and fiscal framework for the Nigerian petroleum industry. The PIA formally segments the Nigerian petroleum industry into the upstream sector on the one hand and the midstream and downstream sectors on the other hand. The upstream sector is regulated by the Nigerian Upstream Regulatory Commission (the "Commission") while the midstream and downstream sector is regulated by the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the "Authority"). The PIA vests general oversight power over the industry sector in the minister of petroleum (the "Minister").

### The Nigerian Upstream Regulatory Commission

2.2 Under the PIA, the Minister is empowered to formulate, monitor and administer the Federal Government of Nigeria's policy over the petroleum industry. Although the Minister is empowered by the PIA to grant, revoke, or assign prospecting and exploration licenses and mining leases to applying persons, the exercise of this power is subject to the recommendation of the Commission. The Commission exercises regulatory powers and oversight over the technical and commercial activities of the upstream petroleum industry. The Commission is charged with the responsibilities of ensuring and enforcing compliance with the terms and condition of all permits, leases and licenses granted within the upstream sector. The Commission is also empowered by the PIA to enforce the provisions of any laws or regulations or policies which were formerly regulated or administered by the Department of Petroleum Resources (the "DPR") as it concerns the upstream petroleum operations in Nigeria. This thus divests the DPR of its regulatory powers over the upstream petroleum sector.

### The Nigerian Midstream and Downstream Petroleum Regulatory Authority

2.3 The Authority, as one of the regulatory bodies under the PIA, is empowered to have technical and commercial regulation of midstream and downstream petroleum operations in the midstream and downstream segments of the petroleum industry. The Authority's functions include the regulation of petroleum liquid operations, domestic natural gas operations and export natural gas operations. It is also empowered to determine the appropriate tariff methodology for the processing of natural gas, transportation and transmission of natural gas, transportation of crude oil, bulk storage of crude oil and monitoring the quality of service provided. The Authority is empowered to issue regulations in pursuance of its regulatory oversight powers. The power to grant, issue, modify, cancel, or terminate all licences, permits and authorisations for midstream and downstream petroleum operations, is vested in the Authority.

### The Petroleum Industry Fiscal Framework

2.4 The PIA introduces the Petroleum Industry Fiscal Framework. The PIA provides for the current petroleum profits tax to be split into two, namely: (1) Hydrocarbon Tax ("HT"); and (2) Companies Income Tax ("CIT"). The HT, together with CIT, will apply to companies engaged in upstream petroleum operations. HT does not apply to AG, NAG or condensate from NAG. The fiscal and tax amendments in the PIA will apply upon the:

(a) conversion of existing Oil Prospecting Licences ("OPLs") and Oil Mining Leases ("OMLs") to Petroleum Prospecting Licences ("PPLs") and Petroleum Mining Licences ("PMLs");

(b) conversion of producing marginal field licences to PMLs within 18 months from the effective date of the PIA;

(c) termination or expiration of unconverted licenses; and/or

(d) renewal of OMLs.

2.5 Consequently, holders of OPLs and OMLs that do not convert their licences to PPLs and PMLs (respectively) will continue to be taxed under the current Petroleum Profit Tax Act pending the expiration of their licences.

2.6 In Section 310, the PIA repeals several laws that previously regulated specific aspects of the petroleum industry. Certain of these laws include:

(a) Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003;

(b) Associated Gas Reinjection Act, 1979;

(c) Nigerian National Petroleum Corporation Act ("NNPC Act"), 1977 (as amended), which will, in accordance with Section 53 of the PIA, be repealed upon the incorporation of NNPC Limited and the transfer of NNPC's assets and liabilities to entities designated by the PIA. NNPC Limited will be a private company that will maintain the role of NNPC for the Federal Government. The PIA does not provide NNPC Limited with any powers to make policy or regulation governing the petroleum sector;

(d) The Petroleum Profit Tax Act, Cap P13, LFN 2004; and

(e) Deep Offshore and Inland Basin Production Sharing Contract Act ("DOIBPSCA"), 1993 CAP D3, LFN 2004 (as amended in 2019), which will no longer regulate the petroleum industry once all existing permits, licenses and leases granted pursuant to the DOIBPSCA either expire or are terminated.

## 3 THE PETROLEUM ACT 1969 (AS AMENDED) CHAPTER P10 LFN 2004 ("PA")

Under Section 311 of the PIA, the PA will continue to apply until the termination or expiration of all existing OPLs and OMLs held by holders that do not wish to voluntarily convert the OPLs and OMLs to PPLs and PMLs (respectively).

## 4 THE PETROLEUM PROFIT TAX ACT 1959 (AS AMENDED) CAP P13 LFN 2004 (the "PPTA")

4.1 Section 310 of the PIA repeals the PPTA. However, the PPTA will continue to apply to those companies which hold OPLs and OMLs issued under the PA and: (1) have not converted such licenses and leases to the new model of the licenses and leases under the PIA; or (2) such leases and/or licenses have not expired, or been terminated or renewed under the PIA. Thus, for these companies, the PPTA will continue to regulate the taxation of their operations.

4.2 The PPTA imposes tax upon the profit of companies engaged in petroleum operations, realised from the extraction of petroleum in Nigeria and also regulates the collection of imposed tax by the Federal Inland Revenue Services. This includes companies engaged in the operation and production (including sale thereof) of crude oil and liquefied and associated natural gas operation.

## 5 NIGERIAN NATIONAL PETROLEUM CORPORATION ACT 1977, CAP N123, LFN 2004

5.1 As mentioned at paragraph 2.6c above, pursuant to Section 310 of the PIA, the NNPC Act shall be repealed upon NNPC ceasing to exist. Section 54 of the PIA mandates that the assets, interest and liabilities of NNPC are to be transferred to a new entity to be incorporated and called NNPC Limited (or its subsidiaries). NNPC shall cease to exist after its remaining assets, interests and liabilities (other than those transferred to NNPC Limited or its subsidiaries) shall have been extinguished or transferred to the government.

5.2 NNPC is the state oil corporation in Nigeria (established on 1 April 1977). NNPC had broad ranging operational interests in refining, petrochemicals and products transportation as well as marketing. It was authorised to engage in commercial activities pertaining to the petroleum industry and also to enforce general control over the sector. The Minister of State for Petroleum Resources was the chairman of NNPC and charged with overseeing the affairs of the NNPC. The duties of NNPC included: (a) exploration and prospecting for, working, winning or otherwise acquiring, possessing and disposing of petroleum; (b) purchasing and marketing petroleum, its products and by-products; and (c) engaging in activities that enhance the petroleum industry in the overall interest of Nigeria.

## 6 NIGERIAN OIL AND GAS INDUSTRY CONTENT DEVELOPMENT ACT, 2010 (the "LOCAL CONTENT ACT")

The Local Content Act provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry. The Local Content Act promotes the use of local goods, services and manpower in the development of projects within the oil and gas industry. The Local Content Act prescribes minimum thresholds for Nigerian participation in oil and gas activities and also impacts the day to day management of companies operating in the oil and gas industry by imposing requirements concerning, among others, the use and involvement of Nigerian labour in their operations. The Schedule to the Local Content Act provides various types of goods and services or man-hours that must be quantified as Nigerian. It mandates preference for Nigerian companies undertaking projects in the oil and gas industry. It imposes a number of reporting obligations in respect of project development and general operations, which allow the Nigerian Content Development Monitoring Board to assess a company's compliance with the local content rules. The Act also deals with employment of Nigerians, technology transfer and the patronage of financial, insurance and legal service providers.

## 7 OIL TERMINAL DUES ACT ("OTD ACT")

The OTD Act regulates the establishment of Oil Terminals, including terminals established on FPSOs, and imposes terminal dues on ships evacuating liquefied petroleum gas ("LPG") or liquefied natural gas ("LNG") for services provided by the terminal operator. The OTD Act, also in tandem with the Oil in Navigable Waters Act (the "ONWA"), regulates the discharge of LPG or LNG from ships and extends the application of the ONWA regime to all oil terminals even where they are located outside the area regulated by the ONWA.

## 8 OIL PIPELINE ACT CAP 07, LFN 2004 ("OP ACT")

The OP Act regulates, through the granting of licences and permits, the laying and use of pipelines to transport mineral oils, natural gas and any of their derivatives or components, and also any substance (including steam and water) used or intended to be used in the production or refining or conveying of mineral oils, natural gas, and any of their derivatives or components. Section 311(9) of the PIA maintains the OP Act pending the termination, expiration or conversion of OMLs and OPLs. Section 311(9)(c) of the PIA provides that the OP Act and any legislation enacted pursuant to it shall remain in operation and be deemed to have been made under the PIA as long as it is not inconsistent with the terms of the PIA.

## 9 OIL IN NAVIGABLE WATERS ACT

The ONWA and the regulations made pursuant thereto regulate the discharge of oil in prohibited areas of the sea, i.e., within 50 miles of the shore. However, the Oil Terminals Dues Act extends the application of the restrictions under the ONWA regime to oil terminals wherever they are located and to the discharge of LPG and LNG. Therefore, the ONWA prohibits discharge of LPG from any FPSO into the water; it also prohibits discharges into other vessels at night.

## 10 MERCHANT SHIPPING ACT

The Merchant Shipping Act regulates the shipping industry generally. It deals extensively with the flagging, registration, deregistration, transfer and mortgage of ships. The Merchant Shipping Act also regulates seafarers and provides detailed rules on diverse issues, touching on safety at sea, cargoes, surveys, pollution, shipwrecks etc. the Act applies to all ships including FPSOs.

## 11 COASTAL AND INLAND SHIPPING (CABOTAGE) ACT

11.1 The Cabotage Act reserves coastal trade for vessels owned and manned by Nigerians, which are built and flagged as Nigerian vessel. This Act prevents foreign vessels from participating in coastal trade unless they obtain a waiver from the Minister of Transport. To ensure compliance with Cabotage rules, all vessels intending to participate in local trade are required to register for the Cabotage trade.

11.2 The Minister of Transportation had in exercise of his powers under Section 46 of the Cabotage Act, issued the Guidelines for the Implementation of the Cabotage Act wherein the Drilling Rigs was included as vessels.

11.3 In 2019, the Federal High Court (**"**FHC**"**) in the case of Seadrill Mobile Units Nigeria Ltd V, the Honourable Minister of Transportation & 2 Ors. held that Rigs fall within the scope of the definition of vessels under the Cabotage Act. A few days after the judgment was passed, the Court of Appeal in the case of Transocean Support Services Nigeria Limited & 3Ors V. NIMASA and Minister of Transport, overruled the decision of the FHC in the Seadrill case. The Court of Appeal stated *inter alia* that a Rig was not expressly listed as one of the vessels eligible for registration under the Cabotage Act, thus the attempt by the Minister of Transport to list Rigs in the Cabotage Guidelines is improper.

## 12 THE ENVIRONMENTAL IMPACT ASSESSMENT ACT 1992 (N0. 68) (the "EIA ACT")

12.1 The EIA Act deals with the consideration of environmental impact in respect of public and private projects. The application of the EIA Act to the oil and gas industry is seen in its schedule where it makes provisions for specific activities requiring an environmental impact assessment. These activities include, oil and gas development, construction of off-shore pipeline in excess of 50 kilometers' in length, construction of refineries, etc.

12.2 The PIA empowers the Commission to play a regulatory role of monitoring and ensuring compliance with the PIA with respect to environmental sustainability and environmental degradation that may result from petroleum operations of licensees and lessees. A licensee or lessee, who engages in upstream petroleum operations, is required by the Commission to submit for approval an environmental management plan in respect of projects which require environmental impact assessment within one year of the effective date of the PIA or six months after the grant of the applicable licence or lease. The Commission shall give its approval for such plan, provided it is in compliance with regulations issued under the EIA Act and the applicant has the capacity or has provided for the capacity to rehabilitate and manage negative impacts on the environment.

## APPENDIX B

## OVERVIEW OF NIGER'S NATIONAL LEGISLATIVE FRAMEWORK

The national legislative framework of petroleum activities in Niger is greatly influenced by the evolution of the local industry. The law pertaining to the Niger petroleum code was amended several times in 2004, 2006, 2007 (Law n°2007-01 dated 31 January 2007, which implementation modalities are provided for in Decree n°2007-082/PRN/MME dated 28 March 2007) and 2017 (Law n°2017-63 dated 14 August 2017, which replaces the Petroleum Code dated 2007; the draft Decree to implement the application of the Petroleum Code dated 2017 was examined and adopted by the Council of Ministers on 25 September 2018).

The Nigerien oil industry is governed by the Ministry of Petroleum, Energy and Renewable Energy, which also implements the policies. The Ministry represents the government in all upstream oil and gas industry dealings and investments.

The Petroleum Nigerien Company (*"SONIDEP"*) is the National Oil Company which mission is notably to ensure the purchase, storage and proper distribution of refined products to all parts of the Nigerien territory and export any excess refined production from the Soraz refinery. SONIDEP also aims to ensure the continuity and security of supplies of Niger in hydrocarbons and derived products, in particular the constitution and management of security reserves.

The Petroleum Code is enforced by the agents of the General Direction of Hydrocarbons of the Ministry of Petroleum, Energy and Renewable Energy. The General Direction of Hydrocarbons is divided into three Directions:

1. Direction of Exploration and Production of Hydrocarbons;
2. Direction of Refining, Transport and Distribution of Hydrocarbons;
3. Direction of Economy, Taxation and Petroleum Investments.

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