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 independent 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 outside of the United Kingdom ("**UK**"), you should seek advice from a person duly qualified in your jurisdiction who specialises in advising on the acquisition of shares and other securities.

This document, which comprises an AIM admission document drawn up in accordance with the AIM Rules for Companies ("**AIM Rules**"), has been issued in connection with an application for admission to trading on AIM of the entire issued share capital of United Oil & Gas PLC (the "**Company**"). This document does not constitute an offer or any part of any offer of transferable securities to the public within the meaning of section 102B of FSMA or otherwise. Accordingly, this document does not constitute a prospectus for the purposes of section 85 of FSMA or otherwise, and has not been drawn up in accordance with the Prospectus Regulation Rules or filed with or approved by the Financial Conduct Authority ("**FCA**") or any other competent authority.

The Company and the Directors, whose names appear on page 8 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 (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. 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.

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 United Kingdom Listing Authority (the "Official List") and the AIM Rules are less demanding than those of the Official List. It is emphasised that no application is being made for admission of the Shares to trading on the Official List. A prospective investor should be aware of the risks of investing in such 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 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.

INVESTMENT IN THE COMPANY IS SPECULATIVE AND INVOLVES A HIGH DEGREE OF RISK. THE WHOLE OF THIS DOCUMENT SHOULD BE READ AND IN PARTICULAR YOUR ATTENTION IS DRAWN TO THE SECTION ENTITLED "RISK FACTORS" SET OUT IN PART III OF THIS DOCUMENT, WHICH DESCRIBES CERTAIN RISKS ASSOCIATED WITH AN INVESTMENT IN THE COMPANY.

UNITED OIL & GAS PLC

(Incorporated and Registered in England and Wales under the Companies Act 2006 with registered number 09624969)

Proposed acquisition of Rockhopper (Egypt) Pty Limited

Conditional Placing of 150,616,669 new Ordinary Shares of 1 pence each at 3 pence per Ordinary Share

Conditional Subscription of 8,419,498 new Ordinary Shares of 1 pence each at 3 pence per Ordinary Share

Admission of the Enlarged Ordinary Share Capital to trading on AIM

and

Notice of General Meeting

Nominated Adviser	***Joint Broker***	***Joint Broker***
BEAUMONT CORNISH Limited	CENKOS	OPTIVA SECURITIES THE GLOBAL INVESTOR

The Placing and the Subscription is conditional, *inter alia*, on Admission taking place on or before 6 January 2020 (or such later date as the Company, Beaumont Cornish Limited, Optiva Securities Limited and Cenkos Securities PLC may agree, but in any event not later than 31 January 2020. The Placing Shares and Subscription Shares will, on Admission, rank *pari passu* in all respects with the Existing Ordinary Shares including the right to receive all dividends or other distributions declared, made or paid after Admission.

A notice convening the General Meeting to be held at 200 Strand, London WC2R 1DJ at 10.00 a.m. on 23 December 2019 is set out at the end of this document. The enclosed Form of Proxy for use at the General Meeting should be completed and returned to the Company's registrars, Share Registrars Limited, The Courtyard, 17 West Street, Farnham, Surrey GU9 7DR, as soon as possible and to be valid must arrive on or before 10.00 a.m. on 19 December 2019 (or 48 hours before the time fixed for any adjourned meeting excluding non-business days). Completion and return of a Form of Proxy will not preclude Shareholders from attending and voting in person at the General Meeting should they wish.

Beaumont Cornish Limited ("**BCL**"), a firm which is authorised and regulated in the United Kingdom by the FCA, is acting exclusively for the Company and no one else in connection with the proposed Placing and Admission. BCL's responsibilities as the Company's nominated adviser under the AIM Rules for Companies and the AIM Rules for Nominated Advisers will be owed solely to the London Stock Exchange and not to the Company, the Directors or to any other person in respect of such person's decision to subscribe for or acquire Shares in reliance on any part of this document. Apart from the responsibilities and liabilities, if any, which may be imposed on BCL by FSMA or the regulatory regime established under it, BCL does not accept any responsibility whatsoever for the contents of this document. BCL has not authorised the contents of this document and no representation or warranty, express or implied, is made by it as to the accuracy or contents of this document or the opinions contained herein. The information contained in this document is not intended to inform or be relied upon by any subsequent purchasers of Shares (whether on or off market) and accordingly no duty of care is accepted by BCL 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.

Optiva Securities Limited ("**Optiva**"), a firm which is authorised and regulated in the United Kingdom by the FCA, is acting exclusively for the Company as joint broker in connection with the Placing and Admission, and will not be responsible for any other person for providing the protections afforded to the clients of Optiva or advising any other person in connection with the Placing and Admission. Apart from the responsibilities and liabilities, if any, which may be imposed on Optiva by FSMA or the regulatory regime established under it, Optiva does not accept any responsibility whatsoever for the contents of this document or any part of it.

Cenkos Securities PLC ("**Cenkos**"), a firm which is authorised and regulated in the United Kingdom by the FCA, is acting exclusively for the Company as joint broker in connection with the Placing and Admission, and will not be responsible for any other person for providing the protections afforded to the clients of Cenkos or advising any other person in connection with the Placing and Admission. Apart from the responsibilities and liabilities, if any, which may be imposed on Cenkos by FSMA or the regulatory regime established under it, Cenkos does not accept any responsibility whatsoever for the contents of this document or any part of it.

This document does not constitute an offer to sell, or a solicitation to buy or subscribe for, securities 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, this document is not for publication or distribution in or into the United States, Canada, Australia, New Zealand, the Republic of South Africa or Japan, nor in any other country or territory where to do so would contravene local securities laws or regulations. The distribution of this document in other jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restriction. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdictions. The Shares have not been, nor will they be, registered under the securities laws of any State of the United States or any province or territory of Canada, Australia, New Zealand, the Republic of South Africa or Japan. Accordingly, the Shares may not be offered or sold, directly or indirectly, in or into the United States, Canada, Australia, New Zealand, the Republic of South Africa or Japan.

Holding Ordinary Shares may have implications for overseas shareholders under the laws of the relevant overseas jurisdictions. Overseas investors should inform themselves about and observe any applicable legal requirements. It is the responsibility of each overseas shareholder to satisfy themselves as to the full observance of the laws of the relevant jurisdiction in connection therewith, including the obtaining of any governmental, exchange control or other consents which may be required, or the compliance with other necessary formalities which are required to be observed and the payment of any issue, transfer or other taxes due in such jurisdiction.

Copies of this 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 Admission at the registered office of the Company at Kerman & Co., 200 Strand, London WC2R 1DJ. This document is also available on the Company's website: www.uogplc.com.

Forward looking statements Advisory

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 "**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 are based on 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 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 Group, or the industry in which the Group operates, to be materially different from any future results, achievements or performance expressed or implied by such forward looking statements. These risks and factors include, but are not limited to, risks relating to the Company's ability to execute its exploration and development programme, drilling and operating risks, dependence on key personnel, compliance with environmental regulations and competition. Any forward looking statement in this document speaks only as of the date it is made.

Forward looking statements and other information contained herein concerning the oil and natural gas industry in the countries in which the Company operates and the Company's general expectations concerning this industry are based on estimates prepared by the Company's management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Actual results, performance or achievement could differ materially from that expressed in, or implied by any forward looking statements or information in this document, and accordingly, investors should not place undue reliance on any such forward looking statements or information. Further, any forward looking statement or information speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward looking statements or information to reflect information, events, results, circumstances or otherwise after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law including securities laws and/or the AIM Rules for Companies. All forward looking statements and information contained in this document and other documents of the Company are qualified by such cautionary statements. New factors emerge from time to time, and it is not possible for the Company's management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statements.

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IMPORTANT INFORMATION

Investment Considerations

In making an investment decision, prospective investors must rely on their own examination, analysis and enquiry of the Group, this Document and the terms of the Admission, including the merits and risks involved. The contents of this Document are not to be construed as advice relating to legal, financial, taxation, investment decisions or any other matter. Investors should inform themselves as to:

- the legal requirements within their own countries for the purchase, holding, transfer or other disposal of the Ordinary Shares;
- any foreign exchange restrictions applicable to the purchase, holding, transfer or other disposal of the
- Ordinary Shares which they might encounter; and the income and other tax consequences which may apply in their own countries as a result of the purchase, holding, transfer or other disposal of the Ordinary Shares or distributions by the Company, either on a liquidation and distribution or otherwise. Prospective investors must rely upon their own representatives, including their own legal advisers and accountants, as to legal, tax, investment or any other related matters concerning the Company and an investment therein.

An investment in the Company should be regarded as a long-term investment. There can be no assurance that the Group's objectives will be achieved.

It should be remembered that the price of the Ordinary Shares and any income from such Ordinary Shares can go down as well as up.

This Document should be read in its entirety before making any investment in the Ordinary Shares. All Shareholders are entitled to the benefit of, are bound by, and are deemed to have notice of, the provisions of the Articles, which investors should review.

Data Protection

The Company may delegate certain administrative functions to third parties and will require such third parties to comply with data protection and regulatory requirements of any jurisdiction in which data processing occurs. Such information will be held and processed by the Company (or any third party, functionary or agent appointed by the Company) for the following purposes:

verifying the identity of the prospective investor to comply with statutory and regulatory requirements in relation to anti-money laundering procedures;

carrying out the business of the Group and the administering of interests in the Group;

meeting the legal, regulatory, reporting and/or financial obligations of the Group in the United Kingdom or elsewhere; and

disclosing personal data to other functionaries of, or advisers to, the Group to operate and/or administer the Company.

Where appropriate it may be necessary for the Company (or any third party, functionary or agent appointed by the Company) to:

- disclose personal data to third party service providers, agents or functionaries appointed by the Company to provide services to prospective investors; and
- transfer personal data outside of the EEA to countries or territories which do not offer the same level of protection for the rights and freedoms of prospective investors as the United Kingdom.

If the Company (or any third party, functionary or agent appointed by the Company) discloses personal data to such a third party, agent or functionary and/or makes such a transfer of personal data, it will use reasonable endeavours to ensure that any third party, agent or functionary to whom the relevant personal data is disclosed or transferred is contractually bound to provide an adequate level of protection in respect of such personal data.

In providing such personal data, investors will be deemed to have agreed to the processing of such personal data in the manner described above. Prospective investors are responsible for informing any third party individual to whom the personal data relates of the disclosure and use of such data in accordance with these provisions.

Extraction of Information from the Competent Person's Reports

This Document contains cross-references to information contained in the Competent Person's Reports set out in Parts VIII, IX and X of this Document. The Company confirms that the information which has been extracted from the Competent Person's Reports has been accurately reproduced and that so far as the Company is aware and is able to ascertain from the Competent Person's Reports, no facts have been omitted which would render the extracts inaccurate or misleading. Each Competent Person has reviewed the information contained in this Document which relates to information contained in the respective Competent Person's Report and has confirmed in writing to the Company, Beaumont Cornish, Optiva, Cenkos, that the information presented is accurate, balanced and complete and not inconsistent with the Competent Person's Report.

References to "development licence" and "development lease" are used interchangeably throughout this Document.

Third Party Data

This Document includes certain market, economic and industry data, which was obtained by the Company from industry publications, data and reports, compiled by professional organisations and analysts' data from other external sources conducted by or on behalf of the Company. Where information contained in this Document originates from a third party source, it is identified where it appears in this Document together with the name of its source. The Company confirms that data sourced from third parties used to prepare the disclosures in this Document has been accurately reproduced and, so far as the Company and the Directors are aware, and able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. All third party information is identified alongside where it is used.

Certain of the aforementioned third party sources may state that the information they contain has been obtained from sources believed to be reliable. However, such third party sources may also state that the accuracy and completeness of such information is not guaranteed and that the projections they contain are based on significant assumptions. As the Company does not have access to the facts and assumptions underlying such market data, statistical information and economic indicators included in these third party sources, the Company is unable to verify such information.

Currency Presentation

Unless otherwise indicated, all references in this Document to "**UK Sterling**", "**pound sterling**", "**sterling**", "**£**", or "**pounds**" or "**pence**" or "**GBP**" are to the lawful currency of the UK, all references to "**EUR**", "**€**" or "euro cents" are to the lawful currency of the EU. In addition, all references to "**USD**", "**US$**", "**US dollar**" or "**cents**" are to the lawful currency of the United States and all references to "**Egyptian Pounds**" are to the lawful currency of Egypt.

Change in Reporting Currency

The Company has changed its presentation currency from UK Sterling (GBP) to United States dollars (US$), to better reflect the Group's expanding and international business activities and to improve investors' ability to compare the Group's financial results with other publicly traded businesses in the international oil and gas industry. Previously the Group reported its interim and annual reports, consolidated balance sheets, related consolidated income statements and cash flows (etc.) in GBP. The change in presentational currency for the period beginning on 1 January 2019 is appropriate based on the fact that following completion of the Rockhopper Acquisition, the cash flow position reported in US$ will be substantially greater and will create uniform financial reporting across the Enlarged Group's future fundraisings (if any) and operational transactions. In making this change in presentation currency, the Company followed the requirements set out in IAS 21, The Effects of Change in Foreign Exchange Rates. In accordance with IAS 21, the change in presentational currency is applied retrospectively and financial statements for the last three financial years have therefore been translated into the new presentation currency. Under this method, the consolidated income statement and cash flow statement items have been translated into the presentation currency using the average exchange rates prevailing during each reporting period. All assets and liabilities over the last three financial years have been translated using the exchange rate prevailing at the consolidated balance sheets dates. The equity balances over the last three financial years are translated into the presentational currency using the prevailing exchange rate at the date of the transaction. The foreign exchange gains and losses that arise on the translation into the presentational currency are recorded in the statement of comprehensive income. All financial references in this Document are in United States Dollars unless otherwise noted.

No Incorporation of Website

The contents of any website of the Company or any other person do not form part of this Document.

Definitions and Glossary of Technical Terms

A list of defined terms used in this Document is set out in 'Definitions' and a list of technical terms and their meanings used in this Document is set out in the glossaries of technical terms contained in Parts VIII, IX and X.

Conversion

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To convert from	*To*	*Multiply by*
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbl	cubic metres	0.159
cubic metres	Bbl	6.292
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621

Governing Law

Unless otherwise stated, statements made in this Document or documents incorporated herein by reference are based on the law and practice currently in force in England and Wales and are subject to changes therein.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Date of this Document	6 December 2019
Resumption of trading in the Existing Ordinary Shares on AIM	on or about 9 December 2019
Latest time for return of the Form of Proxy	10.00 a.m. on 19 December 2019
General Meeting	10.00 a.m. on 23 December 2019
Completion of the Rockhopper Acquisition	on or about 6 January 2020
Admission to trading effective and Commencement of dealings in the Enlarged Ordinary Share Capital on AIM	on or about 6 January 2020

Note: All references to time in this Document are to London time unless otherwise stated and each of the times and dates are indicative only and may be subject to change (based on the Company's current expectations). If any of the above times or dates should change, the revised times and/or dates will be notified to Shareholders by an announcement on a regulatory information service.

PLACING, SUBSCRIPTION AND ROCKHOPPER ACQUISITION STATISTICS

Number of Existing Ordinary Shares as at the date of this Document	345,613,985
Number of Warrants in issue as at the date of this Document	82,212,206
Number of Options in issue as at the date of this Document	11,117,648
Placing Price per Ordinary Share	3 pence
Number of Placing Shares to be issued pursuant to the Placing	150,616,669
Subscription Price per Ordinary Share	3 pence
Number of Subscription Shares to be issued pursuant to the Subscription	8,419,498
Number of Consideration Shares	114,503,817
Enlarged Ordinary Share Capital on Admission	619,153,969
Percentage of Enlarged Ordinary Share Capital on Admission represented by the Placing Shares and the Subscription Shares	25.7 per cent.
Consideration Shares as a percentage of the Enlarged Ordinary Share Capital	18.5 per cent.
Market capitalisation of the Company at the Placing Price on Admission	£18.6 million
Gross proceeds of the Placing and the Subscription	£4.8 million
Proceeds of the Placing (net of expenses)	£4.3 million
ISIN	GB00BYX0MB92
SEDOL	BYX0MB9
LEI	213800WZWERBFYBQ9J17Q9J17
TIDM	UOG

Note: Figures are calculated based on USD:GBP exchange rate of £1:$1.31 as at 4 December 2019

DIRECTORS, SECRETARY AND ADVISERS

Directors:	Alan Graham Martin, *Non-Executive Chairman* Brian Edward Andrew Larkin, *Chief Executive Officer* Jonathan James Leather, *Chief Operating Officer* David Thomas Patrick Quirke, *Chief Financial Officer* Alberto Cattaruzza, *Non-Executive Director* *all of the Company's registered office below.*
Business Address	9 Upper Pembroke Street Dublin 2 Ireland Telephone: +353 1 905 3557
Registered Office	200 Strand London WC2R 1DJ United Kingdom
Company Secretary	David Thomas Patrick Quirke
Nominated Adviser	Beaumont Cornish Limited 10th Floor 30 Crown Place London EC2A 4EB United Kingdom
Joint Broker	Optiva Securities Limited 49 Berkeley Square Mayfair London W1J 5AZ United Kingdom
Joint Broker	Cenkos Securities plc 6.7.8 Tokenhouse Yard London EC2R 7AS United Kingdom
Legal advisers to the Company (as to English law)	Kerman & Co 200 Strand London WC2R 1DJ United Kingdom
Legal advisers to the Company (as to Australian law)	Maddocks Angel Place Level 27 123 Pitt Street Sydney, NSW 2000 Australia
Legal advisers to the Company (as to Egyptian law)	Sharkawy & Sarhan Law Firm Arabella Plaza Building 2 Gamal Abdel Nasser Axis Fifth District, New Cairo Cairo, Egypt

Reporting Accountants and Auditors	UHY Hacker Young LLP Quadrant House 4 Thomas More Square London E1W 1YW United Kingdom
Legal advisers to the Nominated Adviser and Joint Brokers	DMH Stallard LLP 6 New Street Square New Fetter Lane London EC4A 3BF United Kingdom
Competent Person	ERC Equipoise Ltd 6th Floor Stephenson House 2 Cherry Orchard Road Croydon CR0 6BA United Kingdom
Competent Person	CGG Services (UK) Limited Crompton Way Manor Royal Estate Crawley West Sussex RH10 9QN United Kingdom
Competent Person	Gaffney, Cline & Associates Bentley Hall Blacknest Road Alton Hampshire GU34 4PU United Kingdom
Registrars	Share Registrars Limited 17 West Street Farnham Surrey GU9 7SR United Kingdom
Website	www.uogplc.com

DEFINITIONS

The following definitions apply throughout this Document, unless the context requires otherwise.

£ or **UK Sterling**	Pound Sterling, the lawful currency of the UK
Abu Sennan Concession	the concession agreement for petroleum exploration and exploitation in the Abu Sennan Area, Western Desert, Egypt dated 5 June 2007, as amended by way of an amendment agreement dated 10 September 2018
Abu Sennan JOA	the joint operating agreement dated 14 January 2008 as amended by a deed of amendment dated 24 October 2010
Act	the UK Companies Act 2006, as amended
Admission	admission of the Company's entire issued, and to be issued, ordinary share capital to trading on AIM and such admission becoming effective in accordance with the AIM Rules
Affiliate(s)	in relation to any person, any entity controlled, directly or indirectly, by the person, any entity that controls, directly or indirectly, the person or any entity directly or indirectly under common control with the person.
AIM	the market of that name operated by the London Stock Exchange
AIM Rules or **AIM Rules for Companies**	the AIM Rules for Companies published by the London Stock Exchange from time to time (including, without limitation, any guidance notes or statements of practice) and those other rules of the London Stock Exchange which govern the admission of securities to trading on, and the regulation of, AIM from time to time
Articles	the articles of the Company, a summary of which is set out in paragraph 6 of Part VII of this Document
Assigned Interest	an undivided legal and beneficial twenty per cent. (20 per cent.) interest in the production sharing agreement between Tullow Jamaica and the PCJ dated 16 October 2014 relating to the Walton Basin and Morant Basin consisting of blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a portion of block 1, offshore Jamaica from 1 November 2017
Assets	(a) Rockhopper's entire undivided twenty-two per cent (22 per cent.) interest in, and in relation to, the Abu Sennan Concession; (b) Rockhopper's entire undivided interest in, and in relation to, the development leases; (c) Rockhopper's twenty-two per cent (22 per cent.) participating interest in the Abu Sennan JOA; and (d) Rockhopper's eleven per cent (11 per cent.) shareholding in EASPC represented by 550 ordinary issued shares, and (for the avoidance of doubt) the definition of Assets shall specifically exclude any interest held by Rockhopper PLC in the El Qa'a Plain Area

Aurora	Aurora Production (UK) Limited, a company incorporated and registered in Scotland with company number SC301743
Baron	Baron Oil PLC, a company incorporated and registered in England and Wales with company number 05098776
Beaumont Cornish	Beaumont Cornish Limited, a member of the London Stock Exchange and authorised and regulated in the conduct of investment business by the FCA
Beaumont Cornish Warrants	warrants created pursuant to the Beaumont Cornish Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Beaumont Cornish Warrant Instrument
Beaumont Cornish Warrant Instrument	the warrant instrument executed by the Company constituting the Beaumont Cornish Warrants, details of which are set out in paragraph 12.11 of Part VII of this Document
Bénin	Republic of Bénin
Board or Directors	the board of directors of the Company set out on pages 66-67 of this Document (or from time to time)
BPO	BP Oil International Limited
Bribery Act	the Bribery Act 2010
BTL	Britannic Trading Limited, a company incorporated in England and Wales under the Act with company number 00871912
BTL Facility	the pre-payment financing structure agreement dated 22 July 2019 between BTL and the Company and made under a 2002 ISDA Master Agreement, together with all Credit Support Documents as defined and set out therein
Cenkos	Cenkos Securities PLC, joint broker to the Company, who are authorised and regulated by the FCA
Cenkos December 2019 Warrants	warrants created pursuant to the Cenkos December 2019 Warrant Agreement to subscribe for new Ordinary Shares on the terms and conditions set out in the Cenkos December 2019 Warrant Agreement
Cenkos December 2019 Warrant Agreement	the warrant agreement made between the Company and Cenkos details of which are set out in paragraph 12.51 of Part VII of this Document
Certificated or in Certificated Form	an Ordinary Share which is not in uncertificated form
Change of Control	the acquisition of Control of the Company by any person or party (or any group of persons or parties who are acting in concert)
City Code or Takeover Code	the UK City Code on Takeovers and Mergers
Closely Associated Person	● a spouse, or a partner considered to be equivalent to a spouse in accordance with national law; ● a dependent child, in accordance with national law;

- a relative who has shared the same household for at least one year on the date of the transaction concerned; or
- a legal person, trust or partnership, the managerial responsibilities of which are discharged by a person discharging managerial responsibilities or by a person referred to in point (a), (b) or (c), which is directly or indirectly controlled by such a person, which is set up for the benefit of such a person, or the economic interests of which are substantially equivalent to those of such a person

Company or **United Oil & Gas** or **UOG** or **United**	United Oil & Gas PLC (formerly known as Senterra Energy PLC), a company incorporated in England and Wales under the Act with company number 09624969
Competent Person(s)	ERC Equipoise Limited, CGG Services (UK) Limited and Gaffney, Cline & Associates (individually and collectively)
Completion	completion of the Rockhopper Acquisition
Connected Persons	has the meaning set out in section 252 of the Act and includes a spouse, children under 18 and any company in which the relevant person is interested in shares comprising at least one-fifth of the share capital of that company
Consideration	the purchase price to be paid in accordance with the terms of the Rockhopper Acquisition Agreement
Consideration Shares	114,503,817 new Ordinary Shares to be issued with a deemed issue price equivalent to the Placing Price with a deemed aggregate value of approx. US$4.5 million as part of the payment of the Consideration to Rockhopper PLC pursuant to the terms of the Rockhopper Acquisition Agreement
Contract	a farm out agreement dated 24 November 2017 between Tullow Jamaica and UOG Jamaica pursuant to which Tullow Jamaica agreed to transfer the Assigned Interest to UOG Jamaica
Contractors or **Contractor Group**	Kuwait Energy Egypt, GlobalConnect, Rockhopper Egypt, and Dover
Control	an interest, or interests, in Ordinary Shares carrying in aggregate 30 per cent. or more of the Voting Rights of a company, irrespective of whether such interest or interests give de facto control
Corallian	Corallian Energy Limited, a company incorporated and registered in England and Wales under the Act with company number 09835991
Corallian Licences	together, the P1918 Licence, PEDL 330 Licence and the PEDL 345 Licence
Corfe	Corfe Energy Limited, a company incorporated and registered in England and Wales under the Act with company number 06030678
CREST Regulations	the Uncertificated Securities Regulations 2001 of the UK (SI 2001/3755) (as amended)
CREST	the relevant system (as defined in the CREST Regulations) for paperless settlement of share transfers and holding shares in uncertificated form which is administered by Euroclear

Deferred Shares	the 30,000 redeemable deferred shares of £1 each in the capital of the Company
Deposit	a deposit of US$0.3 million paid to Rockhopper PLC pursuant to the terms of the Rockhopper Acquisition Agreement
Directors	the directors of the Company as at the date of this Document, whose names are set out on page 8 of this Document
Disclosure Guidance and **Transparency Rules or DTR**	the Disclosure Guidance and Transparency Rules made by the FCA pursuant to section 73A of the FSMA, as amended from time to time
Document	this AIM admission document
Dorset	Dorset Exploration Limited, a company which was incorporated and registered in England and Wales with company number 04982511
Dover	Dover Investments Limited
EASPC or **Operating Company**	East Abu Sennan Petroleum Company
EGAS	EGAS was established in August 2001 as an entity mandated to focus on the natural gas activities in Egypt
EGPC	Egyptian General Petroleum Company
Egdon	Edgon Resources U.K. Limited, a company incorporated and registered in England and Wales under the Act with company number 03424561
Egypt	The Arab Republic of Egypt
Egyptian Government	the government of Egypt
Enlarged Group	the Company and its Subsidiaries following Completion and Admission
Enlarged Ordinary Share Capital	the issued ordinary share capital of the Company on Admission comprising the Existing Ordinary Shares, the Consideration Shares, the Subscription Shares and the Placing Shares
ENI	the Italian oil and gas multinational
Euroclear	Euroclear UK & Ireland Limited, a company incorporated and registered in England and Wales under the Companies Act 1985 with company number 02878738
Existing Group	the Company and its Subsidiaries at the date of this Document
Existing Ordinary Shares	the 345,613,985 Ordinary Shares in issue as at the date of this Document, being the entire issued share capital of the Company
Existing Share Capital	the issued ordinary share capital of the Company as at the date of this Document
Exploration PL090 Licence	the exploration licence block of the PL090 Licence
FCA	the UK Financial Conduct Authority

First Oil or FOEL	First Oil Expro Limited (in Administration) Limited, a company incorporated and registered in England and Wales under the Act with company number 01021486
Form of Proxy	the form of proxy accompanying this document for use by Shareholders at the General Meeting
FSMA	the Financial Services and Markets Act 2000
Fundraising	the Subscription and the Placing
General Meeting	the general meeting of the Company to be held at 10.00 a.m. on 23 December 2019 (and any adjournment of such meeting) at 200 Strand, London WC2R 1DJ, notice of which is set out at the end of this Document
GANOPE	GANOPE is a public entity operating in the petroleum sector in Egypt. According to GANOPE's available by-laws, it is wholly owned by EGPC. GANOPE was established in Aswan (in the South of Egypt) by virtue of Ministerial Decree no. (1755) for 2002. It works as a holding Company, and operates exclusively in a specified area in Egypt, which is the Southern Valley, "**Ganoub el Wadi**" field
GlobalConnect	GlobalConnect Limited
Group	the Company and its Subsidiaries from time to time
Hibiscus	Anasuria Hibiscus UK Limited, a company incorporated and registered in England and Wales under the Act with company number 09696268
HMRC	HM Revenue and Customs
IFRS	International Financial Reporting Standards as adopted by the European Union
IMF	International Monetary Fund
Independent Directors	the Directors who are not participating in the Subscription, namely, Messrs Larkin, Leather and Cattaruzza
Infrastrata	Infrastrata PLC, a company incorporated in England and Wales under the Act with company number 06409712
ISAs	Individual Savings Accounts
Jamaica JOA	a joint operating agreement dated 1 March 2018 executed by Tullow Jamaica and UOG Jamaica relating to the Assigned Interest and defined the respective rights and obligations of the parties concerning operations and activities under the Contract
Kuwait Energy Egypt	Kuwait Energy Egypt Limited
London Stock Exchange or LSE	London Stock Exchange plc
Main Market	the regulated market of the London Stock Exchange for officially listed securities
MAR	the Market Abuse Regulation (EU) No 596/2014
Net Proceeds	the net proceeds of the Placing and Subscription

NPI Agreement	an agreement dated 23 February 2017 between Corallian and Infrastrata plc pursuant to which Corallian undertook to pay to Infrastrata sums in respect of profits made as a result of the production of petroleum from the P1918 Licence
Official List	the Official List of the UK Listing Authority
OGA	the Oil and Gas Authority, an independent government company established by the UK Government in its current form on 1 October 2016
Options	option to subscribe for Ordinary Shares
Optiva or Optiva Securities	Optiva Securities Limited, joint broker to the Company, who are authorised and regulated by the FCA
Optiva December 2019 Warrant Agreement	the warrant agreement made between the Company and Optiva details of which are set out in paragraph 12.50 of Part VII of this Document
Optiva December 2019 Warrants	warrants created pursuant to the Optiva December 2019 Warrant Agreement, to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva December 2019 Warrant Agreement
Optiva April 2018 Warrant Instrument	the warrant instrument executed by the Company constituting the Optiva March 2018 Warrants, details of which are set out in paragraph 12.26 of Part VII of this Document
Optiva April 2018 Warrants	warrants created pursuant to the Optiva April 2018 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva April 2018 Warrant Instrument
Optiva December 2017 Warrant Instrument	the warrant instrument executed by the Company constituting the Optiva December 2017 Warrants, details of which are set out in paragraph 12.16 of Part VII of this Document
Optiva December 2017 Warrants	warrants created pursuant to the Optiva December 2017 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva December 2017 Warrant Instrument
Optiva July 2017 Warrants	warrants created pursuant to the Optiva July 2017 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva July 2017 Warrant Instrument
Optiva July 2017 Warrant Instrument	the warrant instrument executed by the Company constituting the Optiva July 2017 Warrants, details of which are set out in paragraph 12.12 of Part VII of this Document
Ordinary Shares	ordinary shares of 1 pence each in the capital of the Company
Panel	The Panel on Takeovers and Mergers in the UK
PCJ	Petroleum Corporation of Jamaica
P2264 Licence	United Kingdom Offshore Licence No. P2264 dated 1 December 2014 (executed 4 March 2015)

P2366 Licence	United Kingdom Offshore Licence No. P2366 dated 20 September 2018 (executed 20 September 2018)
PEDL 330 Licence	United Kingdom Onshore Licence No. PEDL 330 dated 21 July 2016 (executed 15 September 2016)
PEDL 345 Licence	United Kingdom Onshore Licence No. PEDL 345 dated 21 July 2016 (executed 15 September 2016)
PDMR	a person within the Company who is: ● a member of the administrative, management or supervisory body of the Company; or ● a person who acts as a director of the Company whether or not officially appointed to such position; or ● a senior executive who is not a member of the Board who has regular access to inside information relating directly or indirectly to that entity and power to take managerial decisions affecting the future developments and business prospects of the Company
P1918 Licence	United Kingdom Offshore Licence No. P1918 dated 1 February 2012 (executed 14 June 2012)
PL090 Licence	United Kingdom Petroleum Production Licence No. PL090 dated 30 May 1968
Placees	those persons who have agreed to subscribe for the Placing Shares
Placing	the conditional placing by Cenkos and Optiva on behalf of the Company of the Placing Shares pursuant to the Placing Agreement
Placing Agreement	the conditional agreement dated 6 December 2019 between (1) the Company, (2) the Directors, (3) Cenkos, (4) Optiva and (5) BCL relating to the Placing, details of which are set out in paragraph 12.49 of Part VII of this Document
Placing Price	3 pence per Placing Share
Placing Shares	150,616,669 new Ordinary Shares to be issued at the Placing Price by the Company pursuant to the Placing
Podere Gallina Farm-In Agreement	the farm-in agreement entered into on 4 May 2017 between UOG UK and PVO
Production Sharing Agreement	the production sharing agreement dated 16 October 2014, originally entered into between Tullow Jamaica and the PCJ relating to the Walton Basin and Morant Basin licence consisting of Blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a Portion of Block 1, offshore Jamaica
Proposals	the Rockhopper Acquisition, the Fundraising and Admission, in each case as described in this Document
Prospectus Regulation Rules	the prospectus regulation rules made by the FCA pursuant to the Financial Services and Markets Act 2000 (Prospectus) Regulations 2019, as amended from time to time
Prospex	Prospex Oil and Gas Plc, a company incorporated and registered in England and Wales under the Act with company number 03896382

Public Party	any of EGPC, EGAS and GANOPE and **Public Parties** shall mean all of them
PVEL	Po Valley Energy Limited, a company incorporated and registered in Australia
PVO	Po Valley Operations Pty Ltd, a company incorporated and registered in Australia
QCA Code	the Corporate Governance Code for small and mid-size Quoted Companies published by the Quoted Companies Alliance in 2018 (as amended from time to time)
Registrar	Share Registrars Limited, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 4715037
Resolutions	the resolutions to be put to the Shareholders at the General Meeting as detailed in paragraph 13 of Part I of this Document
RIS	regulatory information service
Rockhopper Acquisition	the proposed acquisition by the Company of the entire issued share capital of Rockhopper Egypt pursuant to the terms of the Rockhopper Acquisition Agreement
Rockhopper Acquisition Agreement	the conditional agreement dated 22 July 2019 between (1) Rockhopper PLC and (2) the Company (and supplemented by a side letter dated on or about 5 December 2019) relating to the Rockhopper Acquisition, details of which are set out in paragraph 12.44 of Part VII of this Document
Rockhopper Egypt Assets CPR or **GCA CPR**	the competent person's report prepared by Gaffney Cline & Associates, as set out in Part VIII of this Document
Rockhopper Egypt	Rockhopper (Egypt) Pty Limited, a limited liability company incorporated in Australia under ACN 1 30 573 796
Rockhopper PLC	Rockhopper Exploration PLC, a company incorporated in England and Wales under the Act with company number 05250250
Securities Act	United States Securities Act of 1933
September 2018 Placing Warrants	warrants created pursuant to the September 2018 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the September 2018 Warrant Instrument
September 2018 Warrant Instrument	the warrant instrument executed by the Company constituting the September 2018 Placing Warrants, details of which are set out in paragraph 12.27 of Part VII of this Document
Shard	Shard Capital Partners LLP, a limited liability partnership registered in England and Wales with number OC360394
Shareholders	holders of Ordinary Shares
Side Letter Agreement	a side letter agreement dated 22 July 2019 executed by Company, BTL and BPO in relation to crude oil and natural gas entitlements, on the terms set out therein

Stelinmatvic	Stelinmatvic Industries Ltd, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 5123578
Subscribers	those persons who have agreed to subscribe for Subscription Shares
Subscription	the conditional subscription for new Ordinary Shares in the Company pursuant to the terms of the Subscription Agreements
Subscription Agreements	the conditional subscription agreements dated December 2019 between the Subscribers and the Company relating to the Subscription, details of which are set out in paragraph 12.48 of Part VII of this Document
Subscription Price	3 pence per Subscription Share
Subscription Shares	8,419,498 new Ordinary Shares to be issued at the Subscription Price by the Company pursuant to the Subscription
Subsidiary or **Subsidiaries**	a subsidiary undertaking (as defined by section 1159 of the Act)
Swift	Swift Exploration Limited, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 4736197
TIDM	Tradable Instrument Display Mnemonic
Tullow Jamaica	Tullow Jamaica Limited, a company incorporated and registered in England and Wales under the Act with company number 09162755
UK or **United Kingdom**	the United Kingdom of Great Britain and Northern Ireland
UK Companies Act 1985	the UK Companies Act 1985, as amended
UK Government	the government of the UK
UKLA or **UK Listing Authority**	the FCA acting in its capacity as the competent authority for listing in the UK pursuant to Part VI of FSMA
Uncertificated or **in Uncertificated Form**	a share or other security recorded on the relevant register of the relevant company 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
United States or **US**	has the meaning given to the term "**United States**" in Regulation S of the Securities Act
UOG Colter	UOG Colter Limited, a company incorporated and registered in England and Wales under the Act and with company number 11143916
UOG CPRs	the competent person's reports prepared by CGG Services (UK) Limited and ERC Equipoise Ltd as set out respectively in Part IX and Part X of this Document
UOG Ireland	UOG Ireland Limited (formerly known as United Oil and Gas Limited), a company incorporated in Ireland under company number 559743

UOG Italy	UOG Italia S.r.l., a company incorporated in Italy and with company number 14361161004
UOG Jamaica	UOG Jamaica Limited, a company incorporated and registered in England and Wales under the Act and with company number 11066439
UOG PL090	UOG PL090 Limited, a company incorporated and registered in England and Wales under the Act and with company number 10164996
UOG UK	UOG Holdings PLC, a company incorporated and registered in England and Wales under the Act and with company number 10358067
UOG Warrant Instrument	the warrant instrument executed by the Company constituting the UOG Warrants, details of which are set out in paragraph 12.13 of Part VII of this Document
UOG Warrants	warrants created pursuant to the UOG Warrant Instrument and granted by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the UOG Warrant Instrument
USD or **US$**	United States dollars, the lawful currency of the United States
VAT	UK value added tax
Voting Rights	all the voting rights attributable to the capital of the Company which are currently exercisable at a general meeting of shareholders of the Company
Waddock Cross PL090 Licence	the Waddock Cross licence block of the PL090 Licence
Walton-Morant Licence	The Walton Basin and Morant Basin licence consisting of Blocks 6, 7, 9, 10,11, 12, 17, 25,26, 27 and a portion of Block 1, offshore Jamaica
Warrants	warrants to subscribe for new Ordinary Shares, further details of which are set out in Part VII of this Document

PART I

LETTER FROM THE CHAIRMAN OF UNITED OIL & GAS PLC

(incorporated in England and Wales with registered number 09624969)

Directors:	Registered Office:
Alan Graham Martin, Non-Executive Chairman	200 Strand
Brian Edward Andrew Larkin, Chief Executive Officer	London
Jonathan James Leather, Chief Operating Officer	WC2R 1DJ
David Thomas Patrick Quirke, Chief Financial Officer	
Alberto Cattaruzza, Non-Executive Director	

6 December 2019

To Shareholders and, for information only, to holders of Options and Warrants

Dear Shareholder,

Proposed acquisition of Rockhopper Egypt Pty Limited
Conditional Placing of 150,616,669 new Ordinary Shares of 1 pence each at 3 pence per Ordinary Share
Conditional Subscription of 8,419,498 new Ordinary Shares of 1 pence each at 3 pence per Ordinary Share
Admission of the Enlarged Ordinary Share Capital to trading on AIM
and
Notice of General Meeting

1 Introduction

The Company announced on 23 July 2019 that it had entered into a binding conditional sale and purchase agreement with Rockhopper PLC to acquire the entire issued share capital of Rockhopper Egypt, which owns a 22 per cent. non-operated working interest in the Abu Sennan Concession and associated development leases in Egypt, with an effective date of 1 January 2019.

As the Rockhopper Acquisition constitutes a "**reverse takeover**" under Rule 14 of the AIM Rules, it is conditional upon, amongst other things, the approval of Shareholders at a general meeting. The Existing Ordinary Shares were suspended from trading on AIM on 23 July 2019, pending publication of this Document. Trading in the Existing Ordinary Shares is expected to be restored following publication of this Document. A reverse takeover also involves the cancellation of the Existing Ordinary Shares from trading on AIM and a new application for the Enlarged Ordinary Share Capital to be admitted to trading on AIM.

The consideration for the Rockhopper Acquisition is US$16 million (approximately £12.2 million) in accordance with the terms of the Rockhopper Acquisition Agreement. A deposit of US$0.3 million has been paid on signing and the balance of US$15.7 million is to be satisfied in cash and shares at Completion conditional on, *inter alia,* Shareholder approval.

Further details of the Rockhopper Acquisition Agreement are set out in the section headed "**Principal Terms of the Rockhopper Acquisition**" in this Part I and paragraph 12.44 of Part VII of this Document. Information on the Rockhopper Egypt Assets is set out in this Part I, Part II and the Rockhopper Egypt Assets CPR set out in Part VIII of this Document.

The Rockhopper Acquisition will be funded through the BTL Facility, the Fundraising to raise a gross amount of approximately £4.8 million and Consideration Shares in the Company with a deemed issue price equivalent to the Placing Price.

BTL has agreed to provide the Company with a pre-payment financing structure of up to US$8 million, transacted under a 2002 ISDA Master Agreement. Pursuant to the terms of the BTL Facility, the Company will make repayments over 30 calendar months based upon dated Brent market prices for an agreed volume, capped at an agreed level. The financing structure will generate an upfront payment to the Company that will be used to fund part of the Rockhopper Acquisition and in addition, will hedge a portion of the Company's production during the term of the pre-payment while allowing the Company to benefit from market prices above the capped price for the pre-payment volume.

The Company intends to draw down the full amount under the BTL Facility (US$8 million), on or prior to Completion, to fund the Rockhopper Acquisition. Further details of the BTL Facility are set out in paragraph 12.45 of Part VII of this Document.

In addition, the Company has conditionally raised:

- £252,585 by the proposed issue of 8,419,498 new Ordinary Shares pursuant to the Subscription at 3 pence per Subscription Share; and
- £4.5 million (before expenses) by the proposed issue of 150,616,669 new Ordinary Shares pursuant to the Placing at 3 pence per Placing Share.

The Placing Price and the Subscription Price represents a discount of approximately 26 per cent. to the Company's closing mid-market price of 4.05p on 22 July 2019 being the date prior to which the Existing Ordinary Shares were suspended from trading on AIM, pending publication of this Document.

The purpose of this Document is to provide Shareholders with information regarding the Rockhopper Acquisition and the Fundraising, and to convene a general meeting at which the Resolutions seeking Shareholder authority to approve the Rockhopper Acquisition and for the issue of the Consideration Shares, Placing Shares and the Subscription Shares. If the appropriate Resolutions are not passed, the Company will be unable to issue the Placing Shares, Subscription Shares and the Consideration Shares and the Company will not be able to proceed with the Rockhopper Acquisition. The general meeting of the Company at which the Resolutions will be proposed has been convened for 10.00 a.m. on 23 December 2019 at 200 Strand, London WC2R 1DJ. A Form of Proxy for use at the General Meeting is enclosed with this Document.

Further information about the Rockhopper Acquisition, the Fundraising and the Company's current trading and prospects is set out below. **You are recommended to read the whole of this Document and not to rely on the information contained in this letter. In particular, you are advised to consider carefully the "Risk Factors" set out in Part III (Risk Factors) of this Document.**

2 Background to, and Reasons for, the Rockhopper Acquisition

The Rockhopper Acquisition is considered by the Directors to be an important step in achieving the Company's stated strategy to build a balanced full-cycle portfolio of assets with the potential to significantly increase shareholder value. The Rockhopper Acquisition accelerates the Company's transformation from a company with a portfolio of exploration, development and appraisal assets to a portfolio which includes producing assets, generating operating cashflow to fund the business. The Directors consider the underlying asset to contain significant low-risk exploration and appraisal potential to grow reserves and extend field life.

Some of the reasons why the Rockhopper Acquisition is particularly attractive to the Company are:

- Fits with the Company's stated strategy to build a balanced full cycle portfolio of assets to increase shareholder value
- Provides the Company's first production of c. 1,100 boepd
- Adds 2.66 million boe of net working interest 2P reserves at mid-2019 – the effective date of the Rockhopper Acquisition being 1 January 2019 (2P reserves split of 87 per cent. oil and 13 per cent. gas)
- Good quality crude with average discount to Brent of ~ US$2/bbl
- Low cost entry with implied acquisition cost of US$6 per boe
- PSC terms reduce cash flow impact of lower oil prices

- Low cash operating costs (US$6.5 per boe in 2018) and limited capital commitments
- Excellent projected return on investment with projected IRR of 27 per cent. at US$65/bbl*
- With projected NPV10 of US$26.6 million *(Source: GCA CPR Executive Summary)*

* UOG calculations based on 2P reserves included in the GCA CPR

The Directors believe that completion of the Rockhopper Acquisition will advance and enhance the Company's future ability to complete further acquisitions which together with advancing its existing portfolio will transform it into a cashflow generating company with an enhanced growth profile.

3 Principal Terms of the Rockhopper Acquisition

The Company entered into the Rockhopper Acquisition Agreement pursuant to which it conditionally agreed to acquire the entire issued ordinary share capital of Rockhopper Egypt which owns the Assets, with an effective date of 1 January 2019. The consideration payable by the Company for the Rockhopper Acquisition is US$16 million (approximately £12.2 million) in accordance with terms of the Rockhopper Acquisition Agreement. A deposit of US$0.3 million has been paid on signing the Rockhopper Acquisition Agreement and the balance of US$15.7 million is to be satisfied in cash and Consideration Shares at Completion.

Completion of the Rockhopper Acquisition Agreement is conditional, amongst other matters, on:

- the written waiver, or non-exercise of EGPC's pre-emptive rights under the Abu Sennan Concession*;
- EGPC and the Minister of Petroleum and Mineral Resources of Egypt providing written consent to the Rockhopper Acquisition;
- the written waiver, or non-exercise, in accordance with the terms of the Abu Sennan JOA of the pre-emptive rights by each party to the Abu Sennan JOA (other than Rockhopper Egypt)*;
- the release of the security granted in favour of the Falkland Islands Government over the shares in Target and its assets by way of debentures;
- the BTL Facility becoming unconditional in all respects save for any conditions relating to the Rockhopper Acquisition Agreement and Admission;
- passing of the Resolutions by Shareholders at the General Meeting; and
- Admission occurring.

* satisfied as at the date of this Document.

The Rockhopper Acquisition Agreement is subject to reciprocal termination rights and permits each party to terminate if a breach of a fundamental warranty occurs prior to the date of submission of a deed of assignment to EGPC and the Minister of Petroleum & Mining Resources. The Rockhopper Acquisition Agreement contains an automatic termination provision if any of the Conditions has not been fulfilled on or before the date falling six months after the date of the Rockhopper Acquisition Agreement (or such other date as the parties may agree in writing) (the "**Backstop Date**").

If Completion does not occur by the Backstop Date, due to (i) Rockhopper PLC's breach of a fundamental warranty at Completion; (ii) the exercise of pre-emption rights of a joint-venture party under the Abu Sennan JOA; (iii) Rockhopper PLC's failure to obtain the release and discharge of an encumbrance over the assets of Rockhopper Egypt by the Backstop Date; or (iv) because the Company is the non-defaulting party, the Deposit will be returned to the Company in full. Rockhopper PLC has a right to retain the Deposit in all other circumstances.

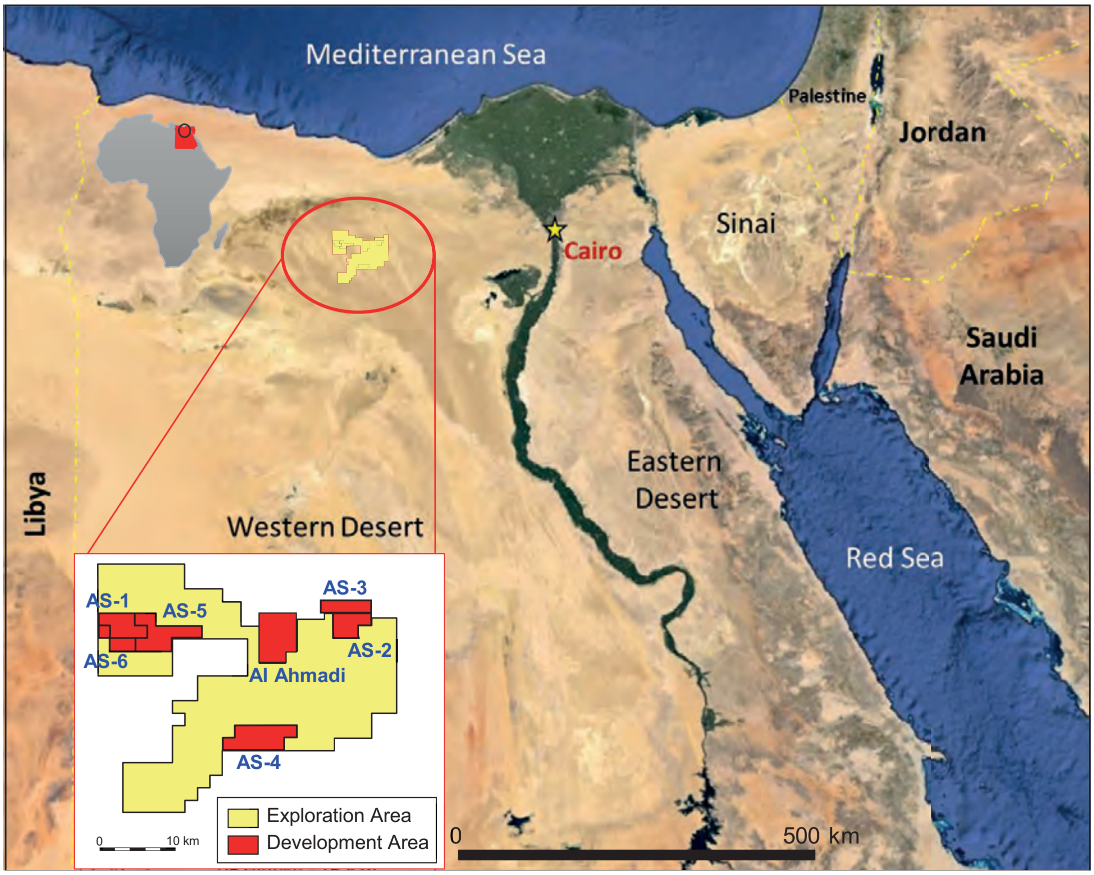
For as long as Rockhopper PLC holds 10 per cent. or more of the entire issued ordinary share capital of the Company it is entitled to appoint a director to the Board subject to the regulatory approval of the Company's nominated adviser.

Further details of the Rockhopper Acquisition Agreement are set out in paragraph 12.44 of Part VII of this Document.

4 Information on the Rockhopper Egypt Assets

The Abu Sennan Concession is located in the Western Desert of Egypt (Figure 1). The Western Desert is one of Egypt's most productive hydrocarbon regions. Despite its maturity, the Western Desert continues to be a very prospective region with Wood Mackenzie estimating the basin still holds one billion boe (83 per cent. oil) of risked prospective resources. Furthermore, the Western Desert is renowned as a low cost exploration region, with Wood Mackenzie estimating the average well cost over the last 10 years to be US$3.8 million per well and with wells often being drilled for less than US$1 million.

Figure 1: Location of Abu Sennan



(Source: GCA CPR Introduction)

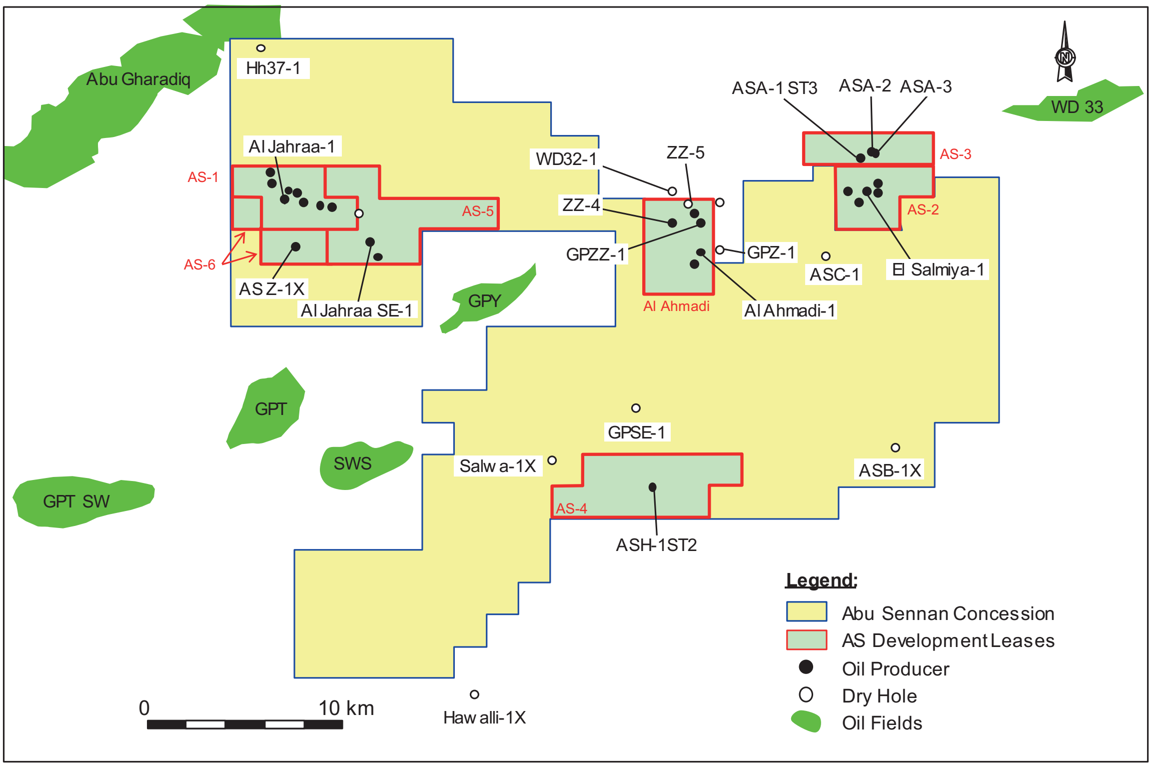
As at the date of this Document, the respective interests in the Abu Sennan Concession are held as follows:

Rockhopper Egypt	22 per cent.
Kuwait Energy Egypt	25 per cent.
GlobalConnect	25 per cent.
Dover	28 per cent.

The Abu Sennan Concession has been in production since 2012, with produced oil being exported by truck and gas being transmitted via pipeline to a nearby facility belonging to the General Petroleum Company. As at 30 June 2019, seven development leases (Figure 2) have been awarded covering the eight fields that have been discovered and put into production. The development leases are operated by the East Abu Sennan Petroleum Company, which is a joint venture between EGPC and the Contractor Group. The Contractor Group is represented by Kuwait Energy Egypt and thus, Kuwait Energy Egypt is effectively the operator.

Ongoing infill drilling campaign has had considerable success to date as gross production levels have increased from 4,000 boepd at the start of the year to c. 5,000 boepd at present. Recent drilling results from the Bahariya reservoir of the Al Jahraa Field highlight the infill potential across the seven production concessions. The successful well at Al Jahraa-7 has been put into production and in late August was producing at >600 bopd.

Figure 2: Map of Wells and Development Areas



(Source: GCA CPR Discussion, 1 Background)

Further details of the Rockhopper Assets are set out in section A of Part II and the GCA CPR set out in Part VIII of this Document.

5 Rockhopper Acquisition Financing, details of Fundraising and Use of Proceeds

5.1 *BTL Facility*

BTL has agreed to provide the Company with a pre-payment financing structure of up to US$8 million, transacted under a 2002 ISDA Master Agreement. Pursuant to the terms of the BTL Facility, the Company will make repayments over 30 calendar months based upon dated Brent market prices for an agreed volume, capped at an agreed level. The financing structure will generate an upfront payment to the Company that will be used to fund part of the Rockhopper Acquisition and in addition, will hedge a portion of the Company's production during the term of the pre-payment while allowing the Company to benefit from market prices above the capped price for the pre-payment volume.

The Company has agreed to pay a non-refundable execution fee of 3 per cent. of the pre-payment amount to BTL in consideration of the BTL Facility. This fee will be deducted and withheld from the proceeds of the final agreed pre-payment amount.

The execution of the Side Letter Agreement was a condition precedent to the execution of the BTL Facility entered into between the Company, BTL and BPO. The Side Letter Agreement contains certain acknowledgments and agreements amongst the parties in relation to crude oil and natural gas entitlements.

As a condition precedent to drawdown of the BTL Facility, the Company is required to grant first ranking security over the shares in Rockhopper Egypt and over certain bank accounts of the Company and Rockhopper Egypt. Certain other deliverables are required to be satisfied by the Company as condition precedents to drawdown.

The 2002 ISDA Master Agreement contains standard representations, warranties and events of default (including payment default) and undertakings as to the performance of the obligations of the Company in relation to the pre-paid swap arrangement.

Further details of the BTL Facility are set out in paragraph 12.45 of Part VII of this Document.

5.2 ***Placing***

The Company has conditionally raised £4.5 million (approximately US$5.9 million) before expenses (£4.3 million (approximately (US$5.6 million) net of Placing expenses) through the Placing being undertaken by Cenkos and Optiva of 150,616,669 Placing Shares at 3 pence per Placing Share, from certain existing and new investors to include both institutional and retail investors.

The issue of the Placing Shares is conditional, *inter alia,* on the passing of the Resolutions at the General Meeting.

The Placing Price represents a discount of approximately 26 per cent. to the Company's mid-market price of 4.05p on 22 July 2019 being the date prior to which the Existing Ordinary Shares were suspended from trading on AIM pending publication of this Document. At the Placing Price, the Company is valued at approximately £18.6 million on Admission. The Placing Shares will represent approximately 24 per cent. of the Enlarged Ordinary Share Capital on Admission.

On 6 December 2019, the Company, Beaumont Cornish, the Directors, Cenkos and Optiva entered into the Placing Agreement pursuant to which each of Cenkos and Optiva agreed, subject to certain conditions, to use its reasonable endeavours to procure subscribers for the Placing Shares pursuant to the Placing.

The Placing of the Placing Shares is conditional, *inter alia,* on:

- the passing of the Resolutions to be proposed at the General Meeting;
- compliance by the Company in all material respects with its obligations under the Placing Agreement;
- the Rockhopper Acquisition Agreement becoming unconditional save for Admission; and
- Admission having occurred by no later than 8.00 a.m. on or about 6 January 2020 or such later time as agreed between Beaumont Cornish, Cenkos and Optiva not being later than 4.00 p.m. on 31 January 2020.

Under the Placing Agreement, which may be terminated by Beaumont Cornish, Cenkos and Optiva in certain circumstances (including force majeure) prior to Admission, the Company and the Directors have given certain warranties and indemnities to Beaumont Cornish, Cenkos, and Optiva concerning, *inter alia,* the accuracy of information contained in this Document.

Dealings in the Existing Ordinary Shares are expected to recommence on or around 9 December 2019 following on the publication of this Document.

The Placing Shares will rank, on issue, *pari passu,* in all respects with the Existing Ordinary Shares including the right to receive dividends and distributions paid or made in respect of the Ordinary Shares after Admission. The Placing Shares will be issued free from all liens, charges and encumbrances.

Further details of the Placing Agreement are set out in paragraph 12.49 of Part VII of this Document.

5.3 ***Subscription***

Certain existing shareholders of the Company and two Directors, Graham Martin and David Quirke have agreed to subscribe for an aggregate amount of 8,419,498 Subscription Shares at the Subscription Price which is equal to the Placing Price.

Graham Martin and David Quirke have each subscribed for 2 million Subscription Shares and 833,333 Subscription Shares respectively at the Subscription Price on the same terms as the other Subscribers as part of the Subscription.

The Subscription is conditional, *inter alia,* on:

- the passing of the Resolutions to be proposed at the General Meeting;
- the Rockhopper Acquisition Agreement becoming unconditional save for Admission; and
- Admission having occurred by no later than the long stop date as defined in the Rockhopper Acquisition Agreement.

Further details of the Subscription are set out at paragraph 12.48 of Part VII of this Document.

Together, the Placing and the Subscription are expected to raise approximately £4.8 million (before expenses).

5.4 ***Use of Proceeds***

The net proceeds of the Placing and the Subscription together with the drawdown under the BTL Facility, totalling approximately US$13.7 million (approximately £10.4 million), will be used to fund the cash element of the Consideration for the Rockhopper Acquisition, costs of the Rockhopper Acquisition, Admission and working capital requirements of the Enlarged Group, as follows:

	£ million	*US$ million*
Consideration for Rockhopper Acquisition (cash element)	8.7	11.5
Costs of the Rockhopper Acquisition and Admission	0.6	0.8
General working capital	1.1	1.4
Total	**10.4**	**13.7**

6 Information on the Group

6.1 United Oil & Gas PLC is an AIM-quoted company with licence interests in the UK, Jamaica and Italy. The Group has an experienced management team and has grown significantly since its establishment in 2015 through its acquisition of exploration, appraisal and development assets. The Directors have a proven track record of successfully evaluating and recommending farm-in deals and actively seeking attractive opportunities to acquire assets in which full value is not currently being realised.

6.2 ***Company Strategy***

The Company's stated strategy is to build a portfolio of production, development and low-risk appraisal/exploration oil and gas assets in Europe and the Greater Mediterranean area, whilst remaining alert for exceptional growth opportunities on a global basis – primarily in the Caribbean, Latin America and Africa.

The Board is continuously looking at potential acquisition, joint venture or other business opportunities which may achieve capital growth for the Company and its Shareholders.

The Rockhopper Acquisition is an ideal fit for the Company's strategy of building a portfolio of production, development and low-risk appraisal/exploration oil and gas assets. The cash flow stream of the Assets coupled with the near term revenues from the Selva gas field in Italy will position the Company to seek further growth opportunities of scale.

The Board considers the Rockhopper Acquisition as the first in a series of acquisitions planned over the medium-term which coupled with the advancement of our existing portfolio will continue the Company's growth trajectory.

6.3 ***UOG's assets***

Overview

As at the date of this Document, the Company has a number of directly held oil and gas assets located in the UK, Italy and Jamaica in development of which it is actively involved and an option to farm in to Block B onshore acreage in Bénin. These are outlined in the "UOG Current Portfolio Overview" table and their geographic spread is presented in the UOG Current Portfolio Overview figure below.

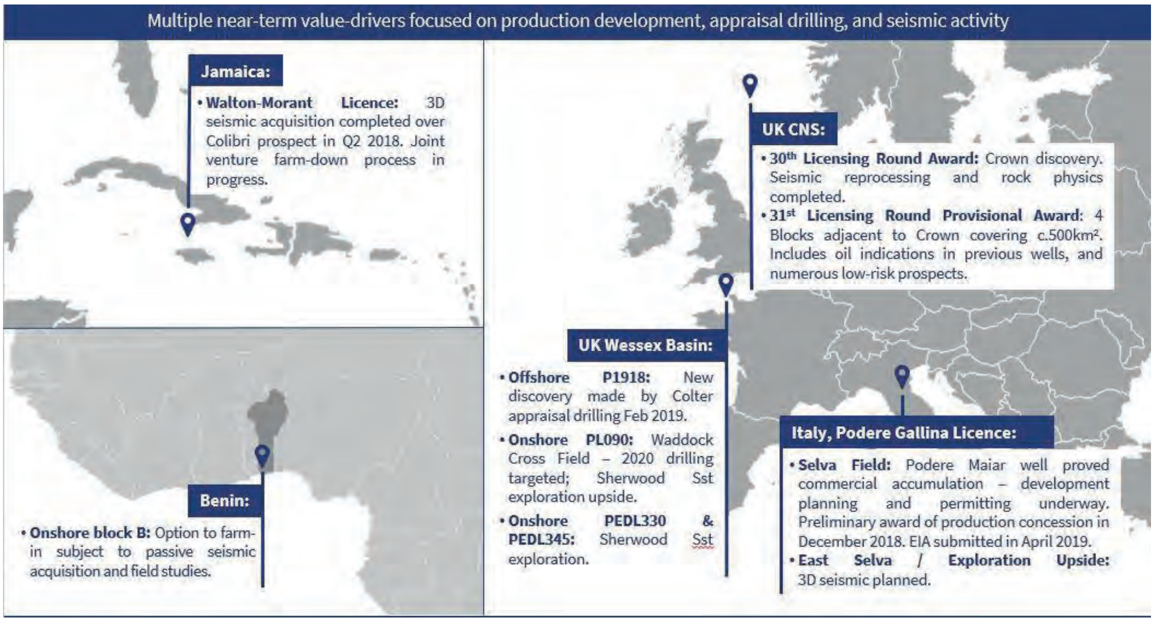
UOG Current Assets:

Country	*Licence*	*Operator/ Administrator*	*UOG's Interest*	*Status*
Italy	Podere Gallina Licence	Po Valley Operations Pty Ltd	20.00%	Production from Podere Maiar well expected in 2020 Evaluation of exploration opportunities continuing
UK	PL090 (Waddock Cross)	Egdon Resources UK Limited	26.25%	Development well drilling targeted in 2020
UK	PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	18.95%	Seismic interpretation continuing
UK	P1918* (Colter)	Corallian Energy Limited	10.00%	Colter well completed Post-well evaluation continuing
UK	PEDL330	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing
UK	PEDL345	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing
UK	P2366* (Crown)	United Oil & Gas Plc	95.00%	Divestment process underway – SPA signed with Hibiscus, subject, *inter alia*, to OGA approval
UK	P2480*	United Oil & Gas Plc	100.00%	Seismic data purchase and geological/ geophysical studies to be completed by July 2022
Jamaica	Walton-Morant*	Tullow Jamaica Limited	20%	Farm-down process underway, drill or drop decision Q1 2020
Bénin	Bénin Onshore Block B**	Elephant Oil Ltd	20%	Discussions continuing on option execution

* Offshore

** UOG's interest in Bénin Onshore Block B is subject to the exercise of an option granted pursuant to an agreement with Elephant Oil Limited, further details of which are set out in paragraph 12.43 of Part VII of this Document.

Current Portfolio Overview:



Further information on UOG's assets is set out in Section D of Part II and the UOG CPRs in Parts IX and X of this Document.

7 Financial Information on the Enlarged Group

7.1 The table below sets out summary historical financial information on Rockhopper Egypt for the three years ended 31 December 2016, 31 December 2017, and 31 December 2018 and for the six month period ended 30 June 2019. The historical financial information was prepared under IFRS. The summary below has been extracted from Section A (ii) and (iii) of Part IV of this Document which contains audited and unaudited historical financial information of Rockhopper Egypt.

	Audited Year ended 31 December 2016 US$	*Audited Year ended 31 December 2017 US$*	*Audited Year ended 31 December 2018 US$*	*Unaudited Six month period ended 30 June 2019 US$*
Revenue	4,292,217	5,003,091	6,123,788	3,184,310
Cost of sales	(4,127,089)	(3,201,333)	(3,730,279)	(1,981,073)
Operating profit/(loss)	(5,819,169)	(1,129,666)	(1,421,141)	815,204
Finance costs	(54,844)	–	–	–
Profit/(Loss) before taxation	(5,874,013)	(1,129,666)	(1,421,141)	815,204
Profit/(Loss) for the period	(5,874,013)	(1,129,666)	(1,421,141)	815,204

7.2 The table below sets out summary historical financial information on the Existing Group for three years ended 31 December 2016, 31 December 2017, and 31 December 2018 restated from Pounds Sterling into US dollars and for the six month period ended 30 June 2019. The historical financial information was prepared under IFRS. The summary below has been extracted from Section B (ii) and (iii) of Part IV of this Document which contains audited and unaudited historical financial information of the Existing Group.

	Audited Year ended 31 December 2016 Restated in US$	Audited Year ended 31 December 2017 Restated in US$	Audited Year ended 31 December 2018 Restated in US$	Unaudited Six month period ended 30 June 2019 US$
Revenue	–	–	–	–
Cost of sales	–	–	–	–
Operating loss	(249,170)	(771,169)	(1,080,272)	(756,408)
Finance costs	–	–	–	–
Loss before taxation	(249,170)	(771,169)	(1,080,272)	(756,408)
Loss for the period	(249,170)	(771,169)	(1,080,272)	(756,408)

7.3 Part V of this Document contains an unaudited pro forma statement of net assets of the Enlarged Group as at 31 December 2018.

8 Current Trading and Prospects

8.1 In the interim results published on 26 September 2019, the Company's CEO, Brian Larkin, reported as follows:

"United has continued to make excellent progress towards our stated goal of building a full cycle oil and gas company. We anticipate that the Rockhopper Egypt acquisition will be concluded in Q4 2019. In advance of this, and post completion of the equity raise, we will recommence trading on the AIM Market of the London Stock Exchange. With this transaction, United will become a producing oil and gas company with significant cash flow. In 2020, we expect to augment that production with the arrival on stream of the Selva Field in Italy. Production from these assets will provide funding to drive future growth in the business."

8.2 Set out in Section A (iii) of Part IV of this Document are the Unaudited Interim Results of Rockhopper Egypt for the six month period ended 30 June 2019. These showed a profit of US$815,204 on revenue of US$3,184,310 and net assets of US$19,396,027.

8.3 Set out in Section B (iii) of Part IV of this Document are the Unaudited Interim Results of the Existing Group for the six month period ended 30 June 2019. These showed a loss before taxation of US$756,408 and net assets of US$9,980,529. The financial information on the Existing Group and Rockhopper Egypt together with an unaudited pro forma of net assets for the Enlarged Group are set out in Parts IV to V of this Document. Following Completion, the Directors believe the Enlarged Group will have a portfolio of assets that will be immediately cash generative. Increased production, improved operational efficiencies and the corresponding earnings enhancing impact on the Enlarged Group, significantly increases the future prospects of the Enlarged Group. The Directors intend to focus the majority of their efforts on integrating the Rockhopper Assets and continuing to identify suitable acquisition targets in line with the Company's growth strategy.

9 Interests in Ordinary Shares and Lock-In Arrangements

9.1 At Admission, the Directors will in aggregate be interested in, directly and indirectly, 18,878,598 Ordinary Shares representing approximately 3.1 per cent. of the Company's Enlarged Ordinary Share Capital. Interests in a further 14,633,500 Ordinary Shares are in the form of Warrants (over unissued Ordinary Shares granted on 25 July 2017, further details of which are set out at paragraph 7 of Part VII of this Document) and 11,117,648 Options (further details of which are set out in paragraph 7.2 of Part VII of this Document). On the assumption that all Warrants and Options are exercised on Admission, the Directors would in aggregate be interested in, directly and indirectly 43,335,628 Ordinary Shares representing approximately 6.0 per cent. of the fully diluted ordinary share capital of the Company.

9.2 Each of the Directors have entered into irrevocable undertakings with the Company, Beaumont Cornish, Cenkos and Optiva, that they, conditionally upon Admission, will not (and will procure, insofar as they are able, that their associates will not) dispose of any interest in Ordinary Shares held by them or their associates for a period of one year from Admission, save in certain circumstances. In addition, they have agreed for a further period of 6 months after expiry of the lock-in period that, subject to certain exceptions, they will only sell interests in Ordinary Shares held by them through the Company's broker from time to time and on an orderly market basis.

9.3 Pursuant to the terms of the Rockhopper Acquisition Agreement and subject to the number of Consideration Shares held by or on behalf of Rockhopper PLC being 3 per cent. or more of the entire issued ordinary share capital of the Company on and following Admission, Rockhopper PLC has agreed with the Company that it will only dispose of any interest in the Consideration Shares for a period of 12 months from Admission in accordance with an orderly market arrangement commencing three months from Admission and through the Company's broker, unless such disposals are with the prior written consent of the Company.

10 Share Options

The Directors believe that the Company's success is highly dependent on the quality and loyalty of the current and future directors and employees to the Group. To assist in the recruitment, retention and motivation of high quality personnel, the Board believes the Company must have an effective remuneration strategy. The Directors consider that an important part of this remuneration strategy is the ability to award equity incentives and, in particular, share options.

The Board has not adopted a formal share option scheme in order to award Options to directors and employees at present. However, it will take into consideration the recommendations of the remuneration committee in determining the appropriate terms in relation to the award of future Options. To date, the Company has only awarded 11,117,648 Options, further details of which are set out in paragraph 4.11 of Part VII of this Document.

11 Risk Factors

The Company's business is dependent on many factors and prospective investors should read the whole of this Document. In particular, your attention is drawn to the Risk Factors set out in Part III of this Document.

12 Taxation

The Company is tax registered in the UK. Information regarding taxation is set out in Part VII of this Document. These details are intended only as a general guide to the current tax position in the UK. If an investor is in any doubt as to his or her tax position or is subject to tax in a jurisdiction other than the UK, he or she should consult his or her own independent financial adviser immediately.

13 General Meeting

A notice convening a General Meeting of the Company to be held at 10.00 a.m. (UK time) on 23 December 2019 at 200 Strand, London WC2R 1DJ is set out at the end of this Document. At that meeting, a resolution will be proposed in order to seek shareholder approval for the Rockhopper Acquisition as required by the AIM Rules. In addition, resolutions will be proposed at the General Meeting to grant powers of allotment and disapplication of statutory pre-emption rights in respect of, *inter alia,* the Placing Shares, Subscription Shares, Consideration Shares, Cenkos December 2019 Warrants and Optiva December 2019 Warrants. Further details of the Resolutions are set out below:

13.1 ***Resolution 1 – Approval of the Rockhopper Acquisition***

Resolution 1 is an ordinary resolution to approve the Rockhopper Acquisition. As the Rockhopper Acquisition constitutes a reverse takeover under the AIM Rules for Companies, Shareholder approval is required under the AIM Rules for Companies.

13.2 ***Resolution 2 – Authority to allot shares***

Resolution 2 is an ordinary resolution to authorise the Directors under section 551 of the Act to issue Ordinary Shares. The Act requires that the authority of the Directors to allot shares and to make offers or agreements to allot shares in the Company or grant rights to subscribe for or convert any security into shares should be subject to the approval of Shareholders in a general meeting or to an authority set out in the Company's Articles. Accordingly, Resolution 2 will be proposed to authorise the directors to allot and issue the (i) Consideration Shares, (ii) Placing Shares, (iii) Subscription Shares, (iv) Cenkos December 2019 Warrants, (v) Optiva December 2019 Warrants, and (vi) otherwise up to a total nominal value of £2,063,847 representing 206,384,656 new Ordinary Shares (being approximately one third of the Enlarged Ordinary Share Capital). The authority will expire on the conclusion of the Company's next annual general meeting.

13.3 ***Resolution 3 – Disapplication of statutory pre-emption rights***

Resolution 3 is a special resolution to disapply statutory pre-emption rights under section 571 of the Act in respect of equity securities (as defined in the Act). The Act requires that any equity securities issued wholly for cash must be offered to existing Shareholders in proportion to their existing shareholders unless otherwise approved by Shareholders in general meeting or excepted under the Company's Articles or law. A special resolution will be proposed at the General Meeting to give the Directors authority to allot the Consideration Shares, Placing Shares, the Subscription Shares, Cenkos December 2019 Warrants, Optiva December 2019 Warrants and otherwise up to a total nominal value of 206,384,656 new Ordinary Shares (being approximately one third of the Enlarged Ordinary Share Capital). This authority will expire on the conclusion of the next annual general meeting.

The issue of the Consideration Shares, Placing Shares and the Subscription Shares is conditional, amongst other matters, on Shareholders passing the Resolutions being proposed at the General Meeting. If Shareholders do not pass the Resolutions, the issue of the Consideration Shares, Placing Shares and the Subscription Shares and the Rockhopper Acquisition will not proceed.

14 Further Information

Your attention is drawn to the remaining parts of this Document which contain further information on the Company, the Assets and the Fundraising. In particular, your attention is drawn to the Risk Factors set out in Part III of this Document.

15 Action to be taken

Shareholders will find enclosed with this Document a Form of Proxy for use at the General Meeting. Whether or not you intend to be present at the General Meeting you are requested to complete, sign and return the Form of Proxy to the Company's registrars, Share Registrars Limited, The Courtyard, 17 West Street, Farnham, Surrey GU9 7DR as soon as possible but, in any event, so as to arrive by no later than 10.00 a.m. on 19 December 2019. The completion and return of a Form of Proxy will not preclude you from attending the meeting and voting in person should you wish to do so.

16 Irrevocable undertakings relating to the Resolutions

It is a condition to completion of the Acquisition, the Placing and the Subscription that all of the Resolutions are approved by Shareholders.

Accordingly, each of the Directors (to the extent that he holds Ordinary Shares) has irrevocably undertaken to vote in favour of the Resolutions in respect of his own shareholdings. In aggregate, the irrevocable undertakings to vote in favour of the Resolutions held by the Company as at the latest practicable date before the publication of this Document amount to 16,045,265 Existing Ordinary Shares.

17 Recommendation

The Directors consider the Fundraising and the Rockhopper Acquisition are in the best interests of the Company and the Shareholders as a whole. Accordingly, the Directors recommend that you vote in favour of the Resolutions at the General Meeting as they have irrevocably undertaken to do so in respect of their own beneficial holdings amounting, in aggregate, to 16,045,265 Existing Ordinary Shares, representing 4.64 per cent. of the Existing Ordinary Shares.

Yours faithfully,

Graham Martin
Non-Executive Chairman

PART II

INFORMATION ON THE ENLARGED GROUP

Section A: Rockhopper Egypt Assets

1 Licence Description

Rockhopper Egypt holds a 22 per cent. working interest in the Abu Sennan Concession. Kuwait Energy, now owned by United Energy Group Ltd, holds 25 per cent. through its subsidiary company Kuwait Energy Egypt, which is the operator. The other partners in the Contractor Group are GlobalConnect, holding a 25 per cent. interest, and Dover, holding a 28 per cent. interest. Kuwait Energy Egypt carries all of Dover's costs related to the concession, and in return is entitled to receive Dover's share of the cost oil plus 7.5 per cent. of Dover's share of the profit oil attributed to the Contractor Group. *(Source: GCA CPR Discussion, 1 Background).*

The Abu Sennan Concession is governed by a production sharing contract ("**PSC**"). Seven development leases have been awarded covering the eight fields that have been discovered and put into production. An exploration licence covers the rest of the concession area. Table 1 lists the licences as at 30th June 2019, in which UOG intends to acquire a 22 per cent. working interest ("**WI**"). *(Source: GCA CPR Executive Summary, License Summary).*

Table 1: Development Lease Summary as at 30th June 2019

Licence	Operator	Interest (%)	Status	Expiry[2]	Area (km^2)	Fields
Al Ahmadi	Kuwait Energy Egypt[1]	22	Development	Mar-32	18	ZZ, Al Ahmadi
Abu Sennan-1			Development	Feb-32	18	Al Jahraa
Abu Sennan-2			Development	Mar-32	15	El Salmiya
Abu Sennan-3			Development	Jul-33	12	ASA
Abu Sennan-4			Development	Apr-35	30	ASH
Abu Sennan-5			Development	Jul-36	30	Al Jahraa SE
Abu Sennan-6			Development	Mar-39	9	ASZ
Exploration			Exploration	Sep-21	644[3]	-

Notes:

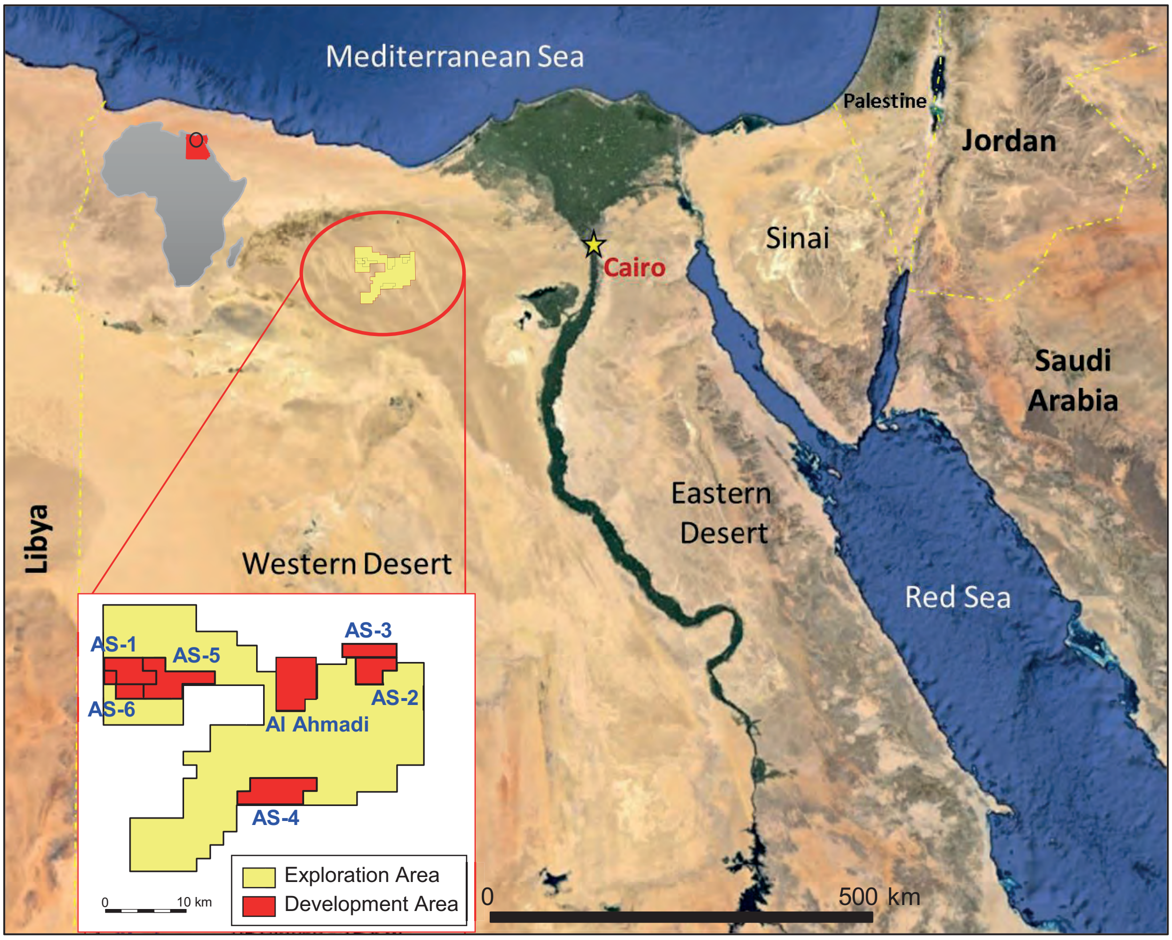
1. Kuwait Energy Egypt (KEE) is a subsidiary of Kuwait Energy, which is now owned by United Energy Group Ltd. KEE operates the development leases through the East Abu Sennan Petroleum Company, which is a joint venture between the Egyptian General Petroleum Company (EGPC, a State-owned company) and the Contractor Group, with the Contractor Group represented by KEE.
2. All the development lease have an optional 5-year extension; the exploration licence has two optional 1-year extensions, each with additional commitments.
3. After excluding the area of the Abu Sennan-6 development lease.
4. All licences are in Egypt.

(Source: GCA CPR Executive Summary, License Summary)

2 Location

The Abu Sennan Concession lies in the Western Desert (Figure 1).

Figure 1: Location of Abu Sennan

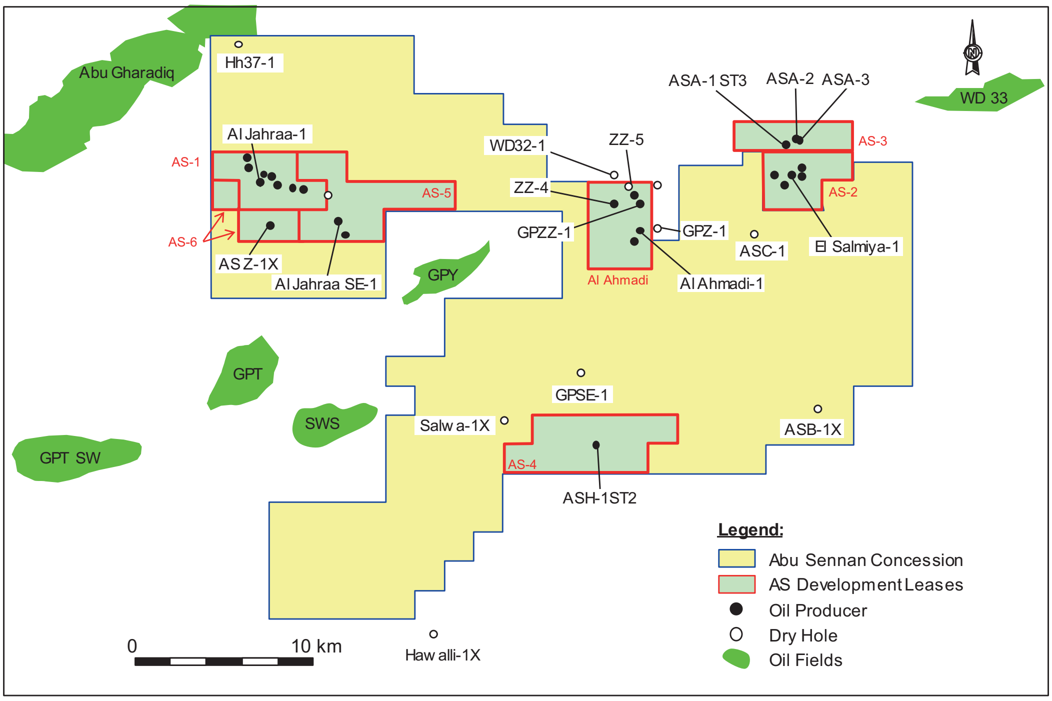


(Source: GCA CPR Introduction)

As at 30th June 2019, seven development leases have been awarded (Figure 2) covering the eight fields that have been discovered and put into production (Table 1). The development leases are operated by the East Abu Sennan Petroleum Company, which is a joint venture between EGPC and the Contractor Group. The Contractor Group is represented by Kuwait Energy Egypt. In practice, Kuwait Energy Egypt is effectively the operator, though all decisions require approval from the joint venture parties.

An exploration licence covers the rest of the concession area. The previous exploration licence expired in May 2016, but a 5-year extension (3 years plus two 1-year extensions at the Contractor Group's option) covering the rest of the concession area (653.4 km^2, after relinquishments) was approved in September 2018. EGPC agreed that the 5-year period should start on 10th September 2018. There is a commitment to spend a minimum of US$6 million in the first 3-year period, to include two exploration wells, and a minimum of US$2 million, to include one exploration well, in each 1-year extension period. The first of these commitment wells, ASZ-1, was drilled in late 2018 and resulted in the most recent discovery in the concession, the ASZ field. *(Source: GCA CPR Discussion, 1 Background).*

Figure 2: Map of Wells and Development Areas



(Source: GCA CPR Discussion, 1 Background)

3 Reserves Summary

The oil and gas reserves attributable to Abu Sennan are shown in Table 2. Reserves are shown both as gross (100 per cent.) field volumes and net to the 22 per cent. interest to be acquired by UOG. Reserves net to that interest represent the net economic entitlement attributable to that interest under the terms of the PSC that governs the asset. *(Source: GCA CPR Executive Summary, Reserves Summary).*

Table 2: Summary of Reserves as at 30th June 2019

(a) Oil

Status	Gross Field (MMBbl)			Net Economic Entitlement (MMBbl)		
	Proved	Proved + Probable	Proved + Probable+ Possible	Proved	Proved + Probable	Proved + Probable+ Possible
Developed	3.09	6.56	8.80	0.30	0.63	0.85
Undeveloped	0.52	3.99	7.13	0.05	0.38	0.62
Total	**3.61**	**10.56**	**15.93**	**0.34**	**1.00**	**1.47**

(b) Gas

Status	Gross Field (Bscf)			Net Economic Entitlement (Bscf)		
	Proved	Proved + Probable	Proved + Probable+ Possible	Proved	Proved + Probable	Proved + Probable+ Possible
Developed	3.6	7.1	12.2	0.3	0.7	1.2
Undeveloped	0.0	0.7	2.3	0.0	0.1	0.2
Total	**3.6**	**7.8**	**14.5**	**0.3**	**0.7**	**1.4**

Notes:

1. Gross Field Reserves are 100 per cent. of the volumes estimated to be commercially recoverable from the asset under the intended development plan.

2. Net Reserves are the net economic entitlement attributable to the interest to be acquired by UOG under the terms of the PSC that governs this asset.

3. For all of the reserves volumes, the Operator is Kuwait Energy Egypt (see note 1 to Table 1).

4. Totals may not exactly equal the sum of the individual entries due to rounding.

(Source: GCA CPR Executive Summary, Reserves Summary)

4 Net Present Value (NPV) Reserves

Reference post-tax NPVs at 10 per cent. discount rate (NPV10) have been attributed to the proved, the proved plus probable, and the proved plus probable plus possible reserves. Discounting has been done on a mid-period basis to 30th June 2019.

The assessment has been based upon GCA's understanding of the fiscal and contractual terms governing the asset, as described therein. All NPVs quoted are those exclusively attributable to the 22 per cent. interest to be acquired by UOG in the asset under review.

GCA's Brent crude oil price scenario for 3Q 2019, shown in Table 3, has been used as the reference oil price. A discount of US$2.00/Bbl for quality and location has been applied for Abu Sennan crude. A gas price of US$2.65/MMBTU has been used. Costs have been escalated at 2.0 per cent. p.a. from 2020. *(Source: GCA CPR Executive Summary, Net Present Value (NPV) Reserves).*

Table 3: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2H 2019	64.70
2020	62.48
2021	66.25
2022	70.00
2023+	+2.0% p.a.

The resulting NPV10s are shown in Table 4. Sensitivity of the NPVs to variations in discount rate, costs and commodity prices are presented in Section 9.5 of the GCA CPR.

Table 4: Post-Tax NPV (US$MM) at 10 per cent. Discount Rate of Future Cash Flow from Reserves, Net to the Interest (to be acquired) as at 30th June 2019

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
10.0	8.7	26.6	42.2

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.

2. All cash flows are discounted on a mid-period basis to 30th June 2019.

3. The reference NPVs reported here do not represent an opinion as to the market value of a property nor any interest therein.

(Source: GCA CPR Executive Summary, Net Present Value (NPV) Reserves)

5 Prospective Resources Summary

The prospective resources attributed to Abu Sennan are shown in Table 5. Prospective resources are shown both as gross (100 per cent.) volumes and net to the interest to be acquired by UOG on a working interest (WI) basis, i.e. the WI fraction of the gross volumes. These do not represent the actual net economic entitlement under the terms of the PSC that governs the asset, which would be lower. Net WI volumes are quoted here since the prospective resources are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the net economic entitlement. *(Source: GCA CPR Executive Summary, Prospective Resources Summary).*

Table 5: Summary of Prospective Resources (Prospects) as at 30th June 2019

Prospect		Gross (MMBbl)			Net (WI Basis) (MMBbl)			P_g (%)
		1U	2U	3U	1U	2U	3U	
ASF-1x	AR-C	0.89	2.18	5.08	0.20	0.48	1.12	14
	AR-E	0.41	0.99	1.93	0.09	0.22	0.43	6
	AR-G	0.61	1.21	2.36	0.13	0.27	0.52	24
	Bahariya	1.31	2.48	4.22	0.29	0.55	0.93	24
ASK-1x	AR-G	0.37	0.73	1.42	0.08	0.16	0.31	17
	Bahariya	0.82	1.56	2.65	0.18	0.34	0.58	17
	AEB	1.94	3.43	5.69	0.43	0.75	1.25	27
	Khatatba	1.89	3.26	5.32	0.42	0.72	1.17	35
Al Ahmadi-3	AR-C	0.11	0.27	0.63	0.02	0.06	0.14	32
	AR-G	0.10	0.19	0.37	0.02	0.04	0.08	32
	Bahariya	0.15	0.29	0.50	0.03	0.06	0.11	22
	Kharita	0.77	1.31	2.09	0.17	0.29	0.46	40
Salmiya West	AR-C	0.16	0.38	0.90	0.03	0.08	0.20	35
	AR-E	0.10	0.25	0.48	0.02	0.05	0.11	35
	Bahariya	0.19	0.36	0.62	0.04	0.08	0.14	42
	Kharita	0.90	1.51	2.37	0.20	0.33	0.52	36
SW Al Ahmadi	AR-C	1.57	5.03	13.53	0.34	1.11	2.98	35
	Bahariya	1.35	3.54	7.19	0.30	0.78	1.58	24
SW-ASH	AEB	0.17	0.39	0.87	0.04	0.09	0.19	48

Notes:

1. Gross prospective resources are 100 per cent. of the volumes estimated to be recoverable from the prospect, in the event that a discovery is made and subsequently developed.
2. Net prospective resources in this table are the working interest fraction of the gross prospective resources; they do not represent the actual net economic entitlement attributable to the interest to be acquired by UOG under the terms of the PSC that governs the asset, which would be lower.
3. The Pg reported here represents an indicative estimate of the probability that drilling this prospect would result in a discovery. This does not include any assessment of the risk that a discovery, if made, may not be developed.
4. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
5. Identification of prospective resources associated with a prospect is not indicative of any certainty that the prospect will be drilled, or will be drilled in a timely manner.
6. Prospective resources should not be aggregated with each other, or with reserves or contingent resources, because of the different levels of risk involved.
7. For the prospective resources, the operator is Kuwait Energy Egypt, which is now owned by United Energy Group Ltd.
8. 1U, 2U and 3U represent low, best and high estimates of prospective resources.

(Source: GCA CPR Executive Summary, Prospective Resources Summary)

6 Work Programme

It is estimated that the development and exploration expenses in respect of the Abu Sennan Concession for the remainder of 2019 and 2020 net to UOG will be US$4.57 million, with US$2.64 million projected for 2021, which includes US$1.1 million of capital expenditure net to UOG relating to the minimum commitment to drill two exploration wells after the first three years of the extension period.

Section B: Overview on The Egyptian Oil and Gas Regulatory Framework

This section is intended as background information in relation to the oil and gas regulatory framework in place in Egypt. Accordingly, it is only an outline of certain pertinent aspects. The Egyptian Ministry of Petroleum is the governmental authority responsible for the regulation and development of the oil and gas industry in Egypt. The Egyptian Ministry of Petroleum acts mainly through two major entities in the oil and gas fields. The first one is the Egyptian General Petroleum Corporation ("**EGPC**") which is a public entity regulating the petroleum industry in Egypt. The second one is the Egyptian Natural Gas Holding Company ("**EGAS**"), which is a private entity owned by the EGPC responsible for regulating the gas industry in Egypt. In some concessions, EGPC is replaced by its subsidiary Ganoub EL Wadi Holding Petroleum Company ("**GANOPE**") who benefits from largely the same rights that are usually granted to EGPC under the standard concession agreements.

Each of EGPC, EGAS and GANOPE is designated to focus on oil and gas activities, adopting an effective action plan to organise and handle the activities of oil and gas resources in Egypt. They are engaged in a wide range of activities, including upstream: exploration and exploitation (drilling and production of oil and gas); and downstream: processing, transmission, distribution of oil and gas in the domestic market and marketing thereof.

Under the Egyptian Constitution issued in 2014, all oil and gas resources are within the control of the state. Accordingly, only the Egyptian Government can grant rights for exploration and exploitation of oil and gas resources for interested investors. Rights of exploration and exploitation of oil and gas resources are granted under the form of a concession agreement.

The concession agreement is issued by virtue of a law. The law issuing the concession agreement authorises the Egyptian Minister of Petroleum to enter into the concession agreement with any of EGPC, EGAS and GANOPE and the contractor company willing to undertake the exploration and the exploitation activities. All concession agreements are published in the Egyptian Official Gazette and generally follow a standard format, with slight deviations in each agreement.

Legal and Regulatory Framework

1 ***Domestic Oil and Gas Legislation***

1.1 *The Egyptian Constitution*

The constitutional framework for the oil and gas sector is organised briefly under the Egyptian Constitution of the year 2014 and the relevant laws to regulate the specificities of the oil and gas legal framework. Only the Egyptian Government can grant rights for exploration and exploitation of oil and gas resources for interested investors by the action of the Egyptian Parliament. In addition, concessions must be granted to the investors by virtue of a law issued by the Egyptian Parliament specifically for the said concession.

1.2 *The Concession Agreement*

Rights of exploration and exploitation to oil and gas resources in Egypt are granted under the form of a concession agreement. The concession agreement is issued from the Egyptian Parliament by virtue of a law which embodies the terms of the agreement and authorises the Egyptian Minister of Petroleum to conclude the agreement with the contractor. The concession agreement overrides any contradictory Egyptian laws but not the Egyptian Constitution. The concession agreement is considered the main licence, which grants subject to particular conditions being met and at particular timelines, exploration and exploitation rights to the contractor. Accordingly, concessions in Egypt are governed by Egyptian law. Amendments to the concession agreement shall be made by virtue of a law amending the previous law that authorised the entry into the concession agreement.

1.3 *The Fuel Materials Law*

In addition to the relevant concession agreement, oil and gas exploitation operations are governed by the fuel material law number 66 of the year 1953 (the "**Fuel Materials Law**"). In the absence of any legal rule under the relevant concession agreement, the exploration/exploitation operations will be subject to the rules of the Fuel Materials Law, its executive regulations and related ministerial decrees (where applicable).

2 ***Title and Term***

2.1 *Law Approving the Concession Agreement*

The right to explore and exploit oil and gas is awarded by the Egyptian Government under the form of a concession agreement entered between the successful bidding contractor company (the "**contractor**"), Egyptian Government represented by the Egyptian Minister of Petroleum, and the relevant Public Party. In this regard, the contractors must fulfil some financial and technical requirements to be granted the concession. The contractor does not need to be an Egyptian entity.

The Public Party leads negotiations on the draft concession agreement. In practice, the Egyptian Government generally adopts a template concession agreement for all concessions in Egypt within the same sector. This leaves the contractor with a limited room for negotiation. Variations across concession agreements may mainly aim at reflecting the underlying commercial arrangements or may be due to changes in the template concession agreements used by the Public Parties over the years.

Once the Public Party reaches mutual consent with the contractor, the draft concession agreement will be submitted to the Egyptian Minister of Petroleum and the Egyptian parliament for approval. A law authorising the Egyptian Minister of Petroleum to execute the precise terms of the concession agreement will then be finally issued by the president of Egypt.

In the absence of the parliament (i.e. if the parliament has not been elected yet) and as per the Egyptian Constitution, the president of Egypt may issue a decree having the force of law to approve the concession agreement. The presidential decree, which issues the concession agreement, must then be presented to, discussed and approved, by the new Parliament within fifteen (15) days from the commencement of its session. In the event the new Parliament does not approve the concession agreement within fifteen (15) days of its first session, it shall retroactively be revoked, unless the Parliament later on decides otherwise.

Amendments to the concession agreement are made by virtue of a new law that authorises the Egyptian Minister of Petroleum to enter into an amendment to the initial concession agreement and determining the terms and conditions of such amendment.

2.2 *Term of Concession*

Any concession passes by two (2) phases. The first one is the exploration phase. The second one is the development and exploitation phase, as explained below.

2.3 *Exploration Phase*

During the exploration phase, the contractor explores the land subject to the concession for oil and/or gas. The contractor does not have the right to extract any material from the ground at this phase. The concession agreement shall be terminated if neither oil nor gas, which is worth to be commercially produced, is discovered by the end of the exploration phase. The duration of the exploration phase is determined under each concession on a case by case basis. The exploration phase period may be extended at the option of the contractor for one or more additional period(s) as agreed under the relevant concession agreement.

2.4 *Development Phase*

(a) Declaration of Commercial Discovery and Execution of Development Lease

Depending on the results of the exploration phase, the contractor may consider that it is economically worthwhile, according to the normal practices of the industry, to develop the explored field or certain parts of it. In such case, the contractor shall notify the relevant Public Party of the existence of a commercial discovery. The contractor and the Public Party shall then agree on the terms of such commercial discovery and determine the date of the commercial discovery in a joint letter that they shall send to the Egyptian Minister of Petroleum for approval (the "**Joint Letter of Commercial Discovery**"). Once the Joint Letter of Commercial Discovery is counter-signed by the Egyptian Minister of Petroleum, such letter is then converted into a development lease without need for any separate agreement. This indicates the end of the exploration phase and the beginning of the development phase.

The duration of the development lease is usually twenty (20) years starting from the date of the relevant commercial discovery. This period may be extended at the option of the contractor and subject to the approval of the relevant Public Party for an additional period in accordance with the relevant concession agreement, and subject to the constitutional limitation.

In case a commercial discovery is confirmed over more than one area in the context of the same concession, the contractor, the Public Party and the Egyptian Government may enter into more than one development lease, each covering a separate area.

Development operations shall be carried out in accordance with good oil field practices and accepted petroleum engineering principles until the field is considered to be fully developed. At the end of the exploration period, any area that did not qualify for a commercial discovery shall be relinquished by the contractor.

(b) Automatic establishment of the operating company

Upon the execution of the development lease, the contractor along with the Public Party incorporate a joint venture company which will undertake the exploitation activities. If no commercial discovery is declared and no development lease is granted, the Public Party has rights to develop the relevant part of the contract area at its sole risk.

2.5 *Constitutional Limitation of the Overall Term of the Concession*

The Egyptian constitution imposes a limitation on the term of concessions in Egypt. Until recent years, the maximum term of Egyptian concessions was thirty-five (35) years. More recently, Article (32) of the new Egyptian Constitution issued in 2014 has reduced the maximum period to thirty (30) years for all concessions (the "**Constitutional Limitation**"). Concessions which term exceeds thirty (30) years are subject to a risk of unconstitutionality, only with respect to the period exceeding such thirty (30) years.

For most concessions, the concession agreement does not impose an overall term for the concession. Instead, it rather stipulates a term for the underlying development leases, typically twenty (20) years from the date of the relevant commercial discovery with possible extensions to thirty (30), or even to thirty-five (35) years in those preceding the Egyptian Constitution of 2014 currently in force, from the date of the underlying commercial discovery.

2.6 *The Public Party's Pre-emption Right*

Any assignment to a third party shall be subject to a pre-emption right given to the Public Party to acquire the interest subject matter of the assignment. In this regard, if the proposed assignee of an interest under the concession is not an affiliated company of the contractor or is not another contractor member under the concession, the Public Party shall enjoy pre-emption rights with respect to the interest under the concession subject matter of the assignment. Accordingly, once the assignor and a proposed third-party assignee have agreed to the final conditions of an assignment, such final conditions must be notified in writing by the assignor to the Public Party. The Public Party shall have the right to exercise its pre-emption by delivering a written notification to the assignor expressing the Public Party's acceptance to acquire the interest intended to be assigned on the same terms agreed with the proposed assignee. If the Public Party does not deliver such notification in the period specified in the concession agreement, the assignor shall have the right to assign to the proposed assignee, subject to the Egyptian Government approval.

3 ***Termination of Concession Agreements***

3.1 *Termination of the Concession Agreement by any of the Parties*

The concession agreement is automatically terminated by the lapse of its term. In addition, the contractor, Public Party and/or the Egyptian Government may terminate the concession agreement in the following cases:

(a) The concession agreement shall be terminated if neither a commercial oil or gas discovery nor, in some concessions, a "**discovery oil well**" was established by the end of the exploration period, as it may be extended;

(b) In case of changes in existing legislation or regulations applicable to the conduct of exploration, development and production of petroleum under the concession agreement, and which significantly affect the economic interest of the concession agreement to the detriment of the contractor, the latter shall notify the Public Party of the subject legislative or regulatory measure. In such case the parties shall use their best effort to re-establish the economic balance under the concession agreement within ninety (90) days from the date of the aforesaid notice. Failure to reach an agreement within such period, a dispute may be submitted to arbitration, and accordingly, this can potentially trigger the termination of the concession agreement.

3.2 *Termination by the Government*

The Egyptian Government typically has the right to terminate the concession agreement in the following instances:

(a) If the contractor has knowingly submitted any false statements to the Egyptian Government which were of a material consideration for the execution and grant of the concession agreement;

(b) If the contractor assigns any interest under the concession agreement without following the standard procedures stipulated upon in the provisions of the concession agreement;

(c) If the contractor is adjudicated bankrupt by a court of competent jurisdiction;

(d) If the contractor does not comply with any final decision reached as the result of court/arbitration proceedings conducted in accordance with the dispute resolution provisions under the concession agreement;

(e) If the contractor intentionally extracts any mineral not authorised by the concession agreement to extract or without the authority of the Egyptian Government; and/or

(f) If the contractor commits any material breach of concession agreement or of the provisions of the Fuel Materials Law.

If the Egyptian Government deems that one of the aforesaid causes (other than a force majeure events) exists, the Egyptian Government shall give the contractor a ninety (90) days' written notice to remedy and remove such cause. If at the end of the said ninety (90) days' notice period such cause has not been remedied and removed, the concession agreement may be terminated by virtue of a presidential decree or, in some concessions, by ministerial order. In relation to breaches other than the above cases, the general principles of administrative law, as determined by the administrative courts of Egypt, shall apply. According to these principles, and depending on the level of the breach, the Egyptian Government may be entitled to compensation representing the losses incurred by the Egyptian Government and its loss of direct foreseeable profits that are caused by the breach.

3.3 *Termination by the Contractor for Force Majeure*

The contractor is entitled to terminate the agreement if a force majeure event occurs during the initial exploration period or any extension thereof and continues in effect for a period of six (6) months. In such case, the contractor shall have the option upon ninety (90) days' prior written notice to the Public Party to terminate its obligations under the concession agreement without further liability of any kind.

Besides the contractor's limited right of termination of the whole concession agreement, the contractor also benefits from certain relinquishment and decommissioning rights and obligations.

Section C: Abu Sennan JOA

The Abu Sennan JOA is largely modelled on the 2012 Model International Joint Operating Agreement produced by the Association of International Petroleum Negotiators, which contains a number of administrative provisions for the handling of operations, including various non-operator specific controls and decision-making functions relating to the joint-operations of the Abu Sennan Concession.

1 Information Supply

Under the Abu Sennan JOA, non-operators have a right to receive most of the information and reports concerning joint operations as they are produced or compiled by Kuwait Energy Egypt, who is effectively operator, including daily drilling reports, quarterly progress reports on development and reports submitted to the Egyptian Government. The non-operators also reserve a right to request additional information from the operator (if so required).

2 Operating Committee & Technical Committee

The overall supervision and direction over joint operations rests with the operating committee, which may also (from time to time) delegate advisory or decision-making functions to various sub-committees, including a technical committee to advise on technical matters. Each party under the Abu Sennan JOA has the right to appoint a representative and an alternative representative to serve on the operating committee. Each party may also appoint a representative to each subcommittee. Non-operators will therefore be entitled to participate in the main decision-making body of the Abu Sennan JOA.

3 Costs and Expenditure

The non-operators are authorised through the operating committee to approve proposed work programmes and budgets prepared by Kuwait Energy Egypt in respect of each calendar year of joint operations under the Abu Sennan JOA. The operating committee is also authorised to revise any approved work programme or budget. The operator is restricted from cumulative total over-expenditures of 5 per cent. of the total annual work programme and budget in question without obtaining operating committee approval. Authorisation for expenditures are required to be submitted by the operator to the parties on the following basis: where exploration or appraisal work programmes or budgets exceed US$200,000; where development work programmes and budgets exceed US$400,000; and where production work programmes and budgets exceed US$400,000.

4 Remedies

The Abu Sennan JOA regulates the circumstances in which non-operators may be removed and a successor elected, including where material breaches have been committed by the operator and have not been remedied within 30 days of written notice from a non-operator; breaches may include cases where the operator has not carried out joint operations diligently and in a safe and efficient manner and in accordance with good and prudent petroleum industry practices and field conservation principles. Any decision to remove an operator by the non-operators will require an affirmative vote of 2 or more of the total of non-operators holding a combined participating interest of at least 51 per cent. (subject to disputes being raised by the operator).

5 Local Management

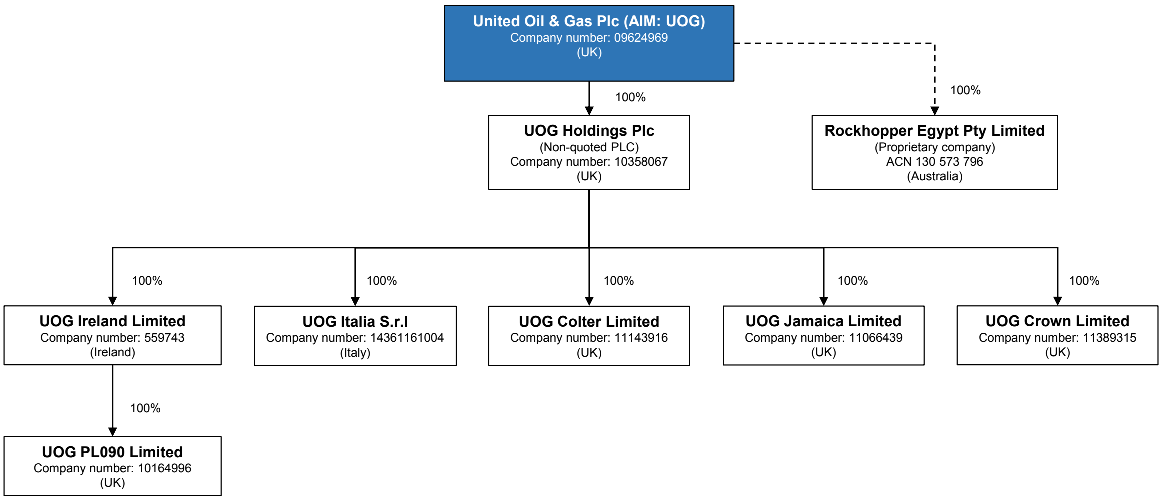
The local management in Egypt representing Rockhopper Egypt's overseas branch comprises an in-country manager and a finance and administration manager, both of whom transferred across to Rockhopper PLC following acquisition of Beach Petroleum (Egypt) Pty Limited from Beach Energy Limited in August 2016. The country manager (69 years old) is responsible for representing the overseas branch's technical position with operators and partners in Cairo, ensuring all technical, legal and financial requirements and obligations are met whilst the finance and administration manager (42 years old) oversees day-to-day administrative and financial management. Both employees liaise closely with Rockhopper PLC's management team in London and following the completion of Acquisition, they will become part of UOG's local management team in Egypt continuing with their duties and preserving the relationships with local operators and partners.

Section D: The Existing Group Structure and Assets

1 Existing Group Structure

The Company acts as the ultimate holding company of the Group and has one wholly-owned subsidiary, UOG Holdings Plc, which in turn has the following five wholly owned subsidiaries; UOG Ireland Limited, UOG Italia S.r.l., UOG Colter Limited, UOG Jamaica Limited and UOG Crown Limited. UOG Ireland has one wholly owned subsidiary, UOG PL090 Limited.

The current ownership structure is illustrated in the diagram below:



* - - - denotes the Enlarged Group structure following Completion of the Rockhopper Acquisition.

2 Existing Assets

As at the date of this Document, the Company has a number of directly held oil and gas assets located in the UK, Italy and Jamaica in development of which it is actively involved and an option to farm in to Block B onshore acreage in Bénin. These are outlined in the UOG Current Assets table with the more detailed description of each asset in this paragraph 2 below.

UOG Current Assets:

Country	*Licence*	*Operator/Administrator*	*UOG's Interest*	*Status*
Italy	Podere Gallina Licence	Po Valley Operations Pty Ltd	20.00%	Production from Podere Maiar well expected in 2020 Evaluation of exploration opportunities continuing
UK	PL090 (Waddock Cross)	Egdon Resources UK Limited	26.25%	Development well drilling targeted in 2020
UK	PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	18.95%	Seismic interpretation continuing
UK	P1918* (Colter)	Corallian Energy Limited	10.00%	Colter well completed Post-well evaluation continuing
UK	PEDL330	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing
UK	PEDL345	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing

Country	*Licence*	*Operator/Administrator*	*UOG's Interest*	*Status*
UK	P2366* (Crown)	United Oil & Gas Plc	95.00%	Divestment process underway – SPA signed with Hibiscus, subject, *inter alia*, to OGA approval
UK	P2480*	United Oil & Gas Plc	100.00%	Seismic data purchase and geological/ geophysical studies to be completed by July 2022
Jamaica	Walton-Morant*	Tullow Jamaica Limited	20%	Farm-down process underway, drill or drop decision Q1 2020
Bénin	Benin Onshore Block B**	Elephant Oil Ltd	20%	Discussions continuing on option execution

* Offshore

** UOG's interest in Bénin Onshore Block B is subject to the exercise of an option granted pursuant to an agreement with Elephant Oil Limited, further details of which are set out in paragraph 12.43 of Part VII of this Document.

2.1 ***Podere Gallina Project (Italy)***

Licence Description

The Podere Gallina Licence is located in the Po Valley plain and covers an area of 506 square kilometres. The currently shut-in Selva gas field lies within this licence area. This field, operated by ENI, the Italian oil and gas multinational, produced 83 Bcf over a 35-year period from 15 wells. Production ceased in 1984.

As a result of a farm-in agreement between Po Valley Operations Pty Ltd (PVO) and UOG UK signed on 4th May 2017, UOG acquired a 20 per cent. working interest in the Podere Gallina Licence on funding 40 per cent. of the cost of the Podere Maiar appraisal well that was drilled in Q4 2017. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63 per cent. working interest in the licence. Prospex Oil and Gas plc hold the remaining 17 per cent. working interest. *(Source: CGG CPR paragraph 1.3).*

Table 6. Podere Gallina Licence Details

Operator	UOG Interest (%)	Status	Licence Expiry Date	Licence Area
PVO	20%	Exploration	3rd February 2018*	506 km^2

* In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorisation time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from 3 February 2018. The application for a production concession to develop the Selva gas field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law. *(Source: CGG CPR paragraph 1.3).*

Further information is set out in the Risk Factors in Part III of this Document.

Location

The Po Basin runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years. The Podere Gallina licence is located approximately 10 km to the east of Bologna, and about 30 km from the coast in the Ferrara and Bologna provinces of the Emilia-Romagna region. *(Source: CGG CPR paragraph 1.1).*

Figure 3. Location Map for Podere Gallina Licence ***(Source: CGG CPR paragraph 1.1)***

Reserves and Resources

A summary of the reserves and resources associated with the Podere Gallina licence, both gross and net, in accordance with the 2007 Petroleum Resource Management System (PRMS) published by the SPE, are shown in the tables below.

The volumes associated with the "Selva Stratigraphic" redevelopment opportunity now incorporate the results of the Podere Maiar-1 well. This well confirmed the presence of undrained gas in the structure and has further de-risked the progression towards a commercial development. A development plan dated May 2018 was submitted to Italian authorities and application was made to convert to a production concession, allowing gas production to commence from the PM-1 well after tie-in to the gas network pipeline nearby. CGG has reviewed the relevant application documents in detail and reports the following reserves and resources for the assets.

In light of the preliminary award of the production concession which was awarded in January 2019 by the Italian authorities, the "Selva Stratigraphic" redevelopment is clarified as reserves.

These volumes have been based on integrating all of the geological and historic production data, including the well test results, to arrive at a range of reserves that reflects the uncertainties that exist in the Selva field.

Once production has started, over time it is expected that this range of reserves will narrow as the production history gives certainty to the recoverable volumes. *(Source: CGG CPR paragraph 1.4).*

Reserves

Standard cubic metre (scm) and standard cubic foot (scf) are the most widely used units used in the natural gas industry to represent an amount of natural gas. Given that in most Continental European countries, including Italy, natural gas is reported in scm, the CGG CPR has been prepared to those standards and figures in "Table 3. *Summary of Reserves for the Selva Redevelopment Project and Net*

Attributable to UOG" (Table 7, below) are presented in MMscm. However, given in the United Kingdom natural gas is reported in scf, figures in Table 7 (Table 3 in the CGG CPR) have been converted from MMscm into bcf (using conversion ratio 1 scm = 35.3147 scf) and these are presented in Table 8, below.

Table 7. Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG in MMscm

	Gross (MMscm)			*20% Net attributable (MMscm)**			
Selva Stratigraphic Trap	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Operator*
C1 Sand	48	129	209	10	26	42	
C2 Sand	69	250	637	14	50	127	PVO
Total	117	379	846	23	76	169	

* The net attributable may not add due to rounding error. *(Source: CGG CPR paragraph 1.4)*

Table 8. Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG in Bcf

	Gross (Bcf)			*20% Net attributable (Bcf)**			
Selva Stratigraphic Trap	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Operator*
C1 Sand	1.70	4.56	7.38	0.35	0.92	1.48	
C2 Sand	2.44	8.83	22.50	0.49	1.77	4.48	PVO
Total	4.13	13.38	29.88	0.81	2.68	5.97	

* The net attributable may not add due to rounding error.

NPVs at base, low and high gas prices are tabulated below for the Selva redevelopment project for a 100 per cent. field interest and respective UOG net interest. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change. *(Source: CGG CPR paragraph 1.4).*

Table 9. Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

	Gross (€ MM)			*Net attributable (€ MM)*			
Gas Price	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Proved*	*Proved & Probable*	*Proved, Probable & Possible*	*Operator*
Base	9.0	26.2	45.0	1.8	5.2	9.0	
Low	6.5	20.1	35.2	1.3	4.0	7.0	PVO
High	11.5	32.2	54.9	2.3	6.4	11.0	

CGG's gas price assumption follows the forward Italian PSV spot gas price curve until 2025, and thereafter escalates at 2 per cent. per year. Low and high price decks have been taken as +/- 15 per cent. for 2019 and 2020, and +/-20 per cent. for 2021 onwards. *(Source: CGG CPR paragraph 1.4).*

Contingent Resources

The following table presents the contingent resources on a gross and a UOG net attributable basis deriving from the licences.

Table 10. Summary of Contingent Resources and Net Attributable to UOG

	Gross			*Net attributable*				
Asset	*1C*	*2C*	*3C*	*1C*	*2C*	*3C*	*Risk factor*	*Operator*
Gas MMscm								
Level B North	99.8	252.3	504.5	20.0	50.5	100.9	70%	PVO
Level B South	27.5	96.6	264.5	5.5	19.3	52.9	60%	PVO
Level A South	29.3	51.2	102.1	5.9	10.2	20.4	60%	PVO
Total	156.6	400.1	871.1	31.3	80.0	174.2	70%	PVO

Notes:

1. Contingent resources are the volumes estimated to be potentially recoverable if the appraisal well is successful and the opportunity is then fully developed
2. Volumes are stated before the application of 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. Full definitions of the contingent resource categories can be found in Appendix A to the CGG CPR
5. The risk factor means the estimated chance that the volumes will be commercially extracted
6. Conversion factor used for cubic metres to cubic feet is 35.31

(Source: CGG CPR paragraph 1.5)

Prospective Resources

With the commerciality of the field demonstrated, an application for an exploitation concession was submitted in May 2018. 3D seismic acquisition over the field is also being planned. Acquisition is expected in 2019, and this will help delineate any further opportunities for undrained gas within the Selva structure.

Table 11. Summary of Gas Prospective Resources by Prospect and Net Attributable to UOG

	Gross (MMscm)			*Net (MMscm)*				
Name	*Low*	*Best*	*High*	*Low*	*Best*	*High*	*Risk factor*	*Operator*
Cembalina	59.5	93.5	133.1	11.9	18.7	26.6	51%	PVO
Fondo Perino	288.9	413.5	580.6	57.8	82.7	116.1	34%	PVO
East Selva	824.1	985.6	1149.8	164.8	197.1	230.0	30%	PVO
Riccardina	367.2	1097.8	3651.5	73.4	219.6	730.3	21%	PVO

Notes:

1. Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects
2. Prospective resources have both an associated chance of discovery and a chance of development
3. Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates
4. Prospective resources are stated before the application of a risk factor and an economic cut-off
5. Full definitions of the prospective resource categories can be found in Appendix A to the CGG CPR
6. The risk factor means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface

(Source: CGG CPR paragraph 1.6)

Work Programme

The Podere Maiar 1 well on the Selva structure was drilled in late December 2017 and tested in early 2018. The well found a significant gas accumulation that flowed strongly on test indicating commercial potential.

Following these results, the operator of the Podere Gallina licence, PVO, is progressing with an application to the Italian Ministry for a Production Concession submitted in May 2018. This mining title will be awarded by the Ministry after i) the competent Ministry's commission positive opinion; ii) the positive environment assessment; and iii) the resolution by the Region Emilia Romagna granting the agreement with the government. As announced in January 2019, the application has been granted preliminary approval as the competent Ministry's commission issued its positive opinion. The award of the production concession will enable the joint venture partners to proceed with the development and establish production. The gross estimated development costs are €2.339 million relating primarily to final surface facilities, compression equipment and pipeline connection to the grid with UOG's total share of the development budget estimated at €570,000 (VAT inclusive). UOG and Po Valley are hoping to take this well into production in late 2020.

The results of the Podere Maiar-1 well also highlighted the significant exploration potential in the Podere Gallina licence, and helped to de-risk the East Selva prospect. To better define this prospectivity, a 3D seismic survey has been proposed. The gross costs associated with this seismic acquisition are currently estimated at €3 million (€0.6 million net to UOG). This is not due to be acquired until after the field is in production.

2.2 *Waddock Cross and Broadmayne Projects (PL090 Licence, UK)*

Waddock Cross Project

Licence Description

UOG acquired its interest in the PL090 Licence through the acquisition of the assets of First Oil's subsidiaries in August 2016. UOG holds a 26.25 per cent. working interest in the Waddock Cross field area (approximately 19 km^2) and a working interest of 18.9541 per cent. in the remainder of the PL090 Licence (approximately 183 km^2). Both areas are operated by Egdon Resources UK Limited ("**Egdon**") and expire on 31 March 2024.There are no outstanding work commitments on the PL090 Licence. *(Source: ERCE CPR 1. Introduction).*

Table 12. Summary of UOG's PL090 Licence Interests

Licence block	*Operator/ Administrator*	*Company*	*Interest (%)*	*Status*	*Licence Expiry Date*	*Licence Area*	*Comments*
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19km^2	
		UOG PL090 Ltd	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	183km^2	
		UOG PL090 Ltd	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				

Location

The Waddock Cross field is located in Licence PL090 and is operated by Egdon Resources UK Limited. The licence is located within the Wessex Basin in the county of Dorset, onshore UK, to the west of the Wytch Farm oil field (Figure 4). *(Source: ERCE CPR para 2.1.1).*

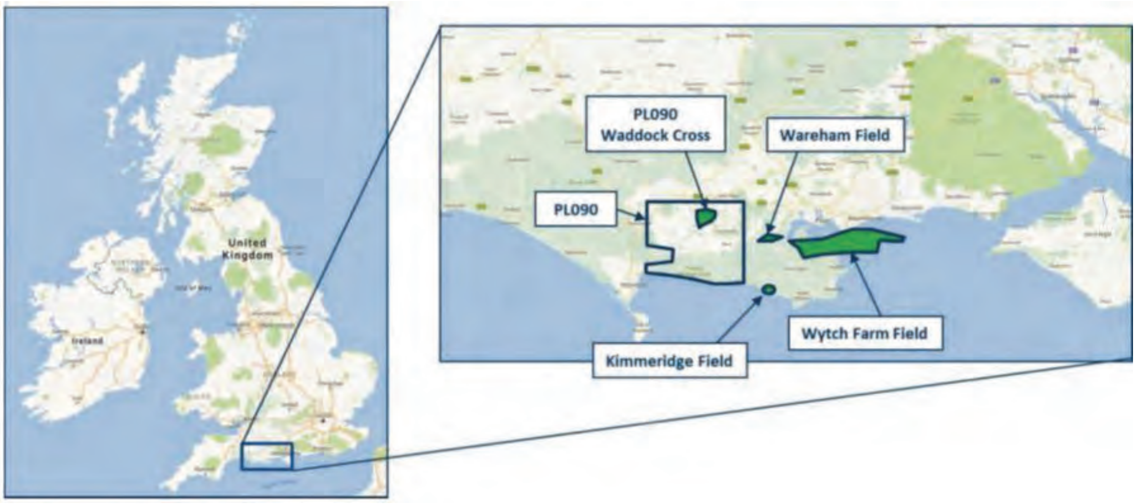


Figure 4. PL090 Licence Location and Neighbouring Oil Fields ***(Source: ERCE CPR para 2.1.1)***

Waddock Cross is located in rural farmland close to woodlands approximately 11.5 km east of Dorchester and 21.6 km west of Poole. The Grid Reference (UK National Grid) for the site is SY805912 and the nearest farm has the post code DT2 8QY. When the field was previously in production in 2013/14, oil was exported via road tanker to Holybourne Oil Terminal in Hampshire, power was supplied via mains electricity, and water was reinjected through the WX-2 well.

Neighbouring oil fields include the Wareham and Wytch Farm oil fields. Wytch Farm field produces oil predominantly from the Triassic Sherwood Sandstone reservoirs, with subordinate production from the younger Jurassic Bridport Sandstone reservoir. The Wareham field also produces oil from the Bridport Sandstone reservoir*. (Source: ERCE CPR para 2.1.1).*

Contingent Resources

According to the Competent Person's report produced by ERC Equipoise Ltd ("ERCE") titled "*Evaluation of certain Contingent and Prospective Resources of United Oil & Gas Plc*", which is included in Part IX of this Document, Waddock Cross field contains oil within the Jurassic Bridport Sandstone reservoir, and has historically undergone production, which ceased due to high water cut. The field is currently shut in. The operator, Egdon Resources UK Limited ("Egdon"), is in the process of investigating the restoration of production, via the drilling of one or more horizontal wells in a structurally higher area of the field. ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. Development is contingent on the preparation and the commitment to a commercial development plan. ERCE agrees with UOG's estimate of the Chance of Development ("Pd") of 75 per cent. (shown in Table 13). Development would likely involve the drilling of two new wells with any water being reinjected. There are no identified Reserves. *(Source: ERCE CPR para 1.2.1.1).*

Table 13: Unrisked Oil Contingent Resources of the Waddock Cross Field, Gross and Net to UOG

			Gross Contingent Resources (MMstb)				*Net Contingent Resources (MMstb)*			
Licence	*Field*	*Operator/Administrator*	*1C*	*2C*	*3C*	*Working Interest*	*1C*	*2C*	*3C*	*Pd*
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%

Notes:

1. "Gross Contingent Resources" are 100 per cent. of the volumes estimated to be recoverable from the field without any economic cut-off being applied.
2. "Net Contingent resources" are UOG's working interest fraction of the gross contingent resources.
3. Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as contingent resources will be recovered.
4. The volumes reported here are unrisked in that they have not been multiplied by the chance of development (Pd).
5. In accordance with SPE PRMS.

(Source: ERCE CPR para 1.2.1.1)

Work Programme

Reprocessing of the Waddock Cross 3D survey was completed in August 2018 indicating that the area has commercial potential. The operator, Egdon, has produced a proposed budget and is awaiting confirmation from all joint venture partners before drilling begins. It is anticipated that the first two wells will be drilled in 2020/2021 but there is no firm commitment or agreement with the operator yet. UOG estimates that the gross cost per well to be in the region of £1 million (£260K net to UOG).

Broadmayne Project

Location

The Broadmayne prospect is situated to the southwest of the Waddock Cross field and is mapped as straddling the PL090 Licence block at Sherwood Sandstone level (Figure 5).

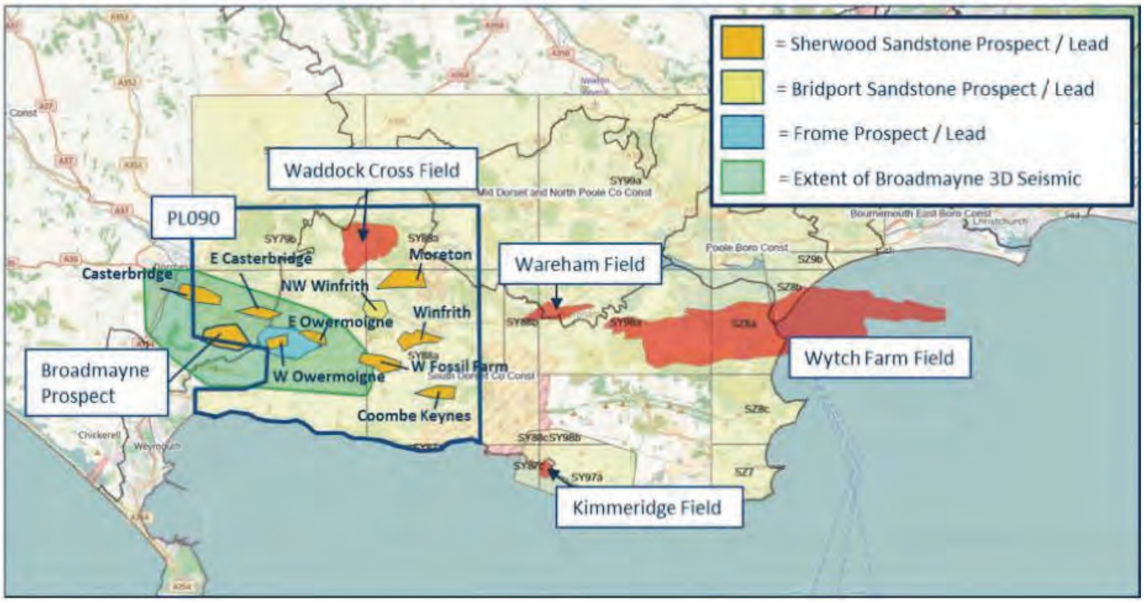


Figure 5. Locations of Wessex Basin Leads **(Source – Oil & Gas Authority)**
(Source: ERCE CPR para 3.1.1)

Prospective Resources

The PL090 partnership is maturing prospectivity within the greater licence area, and identifies a number of undrilled exploration prospects and leads. The licence is located in Wessex Basin onshore UK, to the west of the Wytch Farm oil field. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil prospective resources and geological chance of success for the Broadmayne prospect, which is currently the most mature. *(Source: ERCE CPR Executive Summary).*

The licence contains two 3D surveys; the Waddock Cross 3D seismic survey acquired in 2004 and the larger Broadmayne 3D survey, which was acquired in 2013 and lies to the southwest of Waddock Cross. The data have been reprocessed a number of times and the third vintage of reprocessing has been used by UOG and partners in the mapping and identification of leads and prospects (Figure 5), including the Broadmayne prospect, which is currently the most mature and to which ERCE has restricted its assessment of prospective resources. The data have recently been reprocessed for a fourth time and provisional interpretation performed by UOG over the Broadmayne prospect supports historical mapping and the presence of dip and fault-closure. As such ERCE retains the estimates of unrisked prospective resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report. It is anticipated that mapping and prospect maturation will continue using the results of this recent reprocessing. *(Source: ERCE CPR para 3.1.1).*

ERCE's estimates of the gross unrisked oil prospective resources in Broadmayne and the net unrisked and risked prospective resources attributable to UOG based on the mapped area of the prospect in Licence PL090 are shown in Table 14.

Table 14. STOIIP, Oil Prospective Resources and Geological Chance of Success for the Broadmayne Prospect, Gross and Net UOG

		STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				
Prospect	*Operator/Administrator*	*Low*	*Best*	*High*	*Mean*	*1U*	*2U*	*3U*	*Mean*	**Working Interest*
Broadmayne	Egdon Resources UK Limited	5.0	11.1	24.5	13.4	1.50	3.30	7.40	4.00	18.95%

		Net Unrisked Prospective Resources (MMstb)				Net Risked Prospective Resources (MMstb)				
Prospect	*Operator/Administrator*	*1U*	*2U*	*3U*	*Mean*	*COS*	*1U*	*2U*	*3U*	*Mean*
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

* Net unrisked prospective resources have been calculated by multiplying gross unrisked prospective resources by UOG's working interest in block PL090 (18.95 per cent.) and by the proportion of resources which ERCE estimates to fall within the PL090 block boundary (50 per cent.).

Notes:

1. Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.
2. "Gross Unrisked Prospective Resources" are 100 per cent. of the volumes estimated to be recoverable from an accumulation.
3. "Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources.
4. "Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).
5. The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.
6. Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).

(Source: ERCE CPR para 1.2.2.1)

ERCE has adopted a four component risk matrix in their assessment of geological chance of success (COS) for the Broadmayne prospect, comprising source, reservoir (presence and efficacy), trap and seal.

ERCE sees no material risk associated with reservoir presence, efficacy and top seal, based on the results of the offset wells. The dominant risk factors for the Broadmayne prospect are source/migration and trap integrity.

Source encompasses both the presence of source rock material and migration. The presence of producing oil fields in the area confirms the presence of source rocks. Success for Broadmayne relies upon a migration pathway existing to the west of the main source area of the basin into licence PL090.

Trap embraces all the components that define the competency of the closure. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

ERCE assessment of the COS for the Broadmayne prospect is 30 per cent., as presented in Table 15.

Table 15. Broadmayne Risk Matrix

Prospect	*Source*	*Reservoir*	*Trap*	*Seal*	*COS (frac)*
Broadmayne	0.50	1.00	0.60	1.00	0.30

(Source: ERCE CPR para 3.1.4)

Work Programme

Improved seismic reprocessing was completed by Dayboro Geophysical at the end of 2017. Initial interpretation of this data has been encouraging, but more interpretation work is needed prior to finalising Broadmayne volumes, and a decision being made on the best way forward for the PL090 joint venturers. Although work is continuing, there are currently no plans in place for activity involving capital expenditure on the Broadmayne exploration prospect.

2.3 ***Colter Discovery (formerly Colter East) and Colter South Prospect (P1918 Licence, UK)***

Licence Description

In January 2018, UOG completed a farm-in deal to acquire 10 per cent. of the P1918 Licence (operated by Corallian Energy Limited ("**Corallian**")). The P1918 Licence interests are summarised in Table 16.

Table 16. Summary of UOG's P1918 Licence Interest

Licence Block	*Operator/ Administrator*	*Company*	*Interest (%)*	*Status*	*Licence Expiry Date*	*Licence Area*	*Comments*
P1918	Corallian Energy Limited	Corallian Energy Limited UOG Colter Ltd Baron Oil Resolute Oil & Gas	74.00% 10.00% 8.00% 8.00%	Extant	31/1/2020 (Second Term) 31/1/2038 (Licence End Date)	36.2 km^2	

Location

The Colter discovery is located in licence P1918 and is operated by Corallian. The licence is located offshore southern UK, south of Wytch Farm oil field (Figure 6).

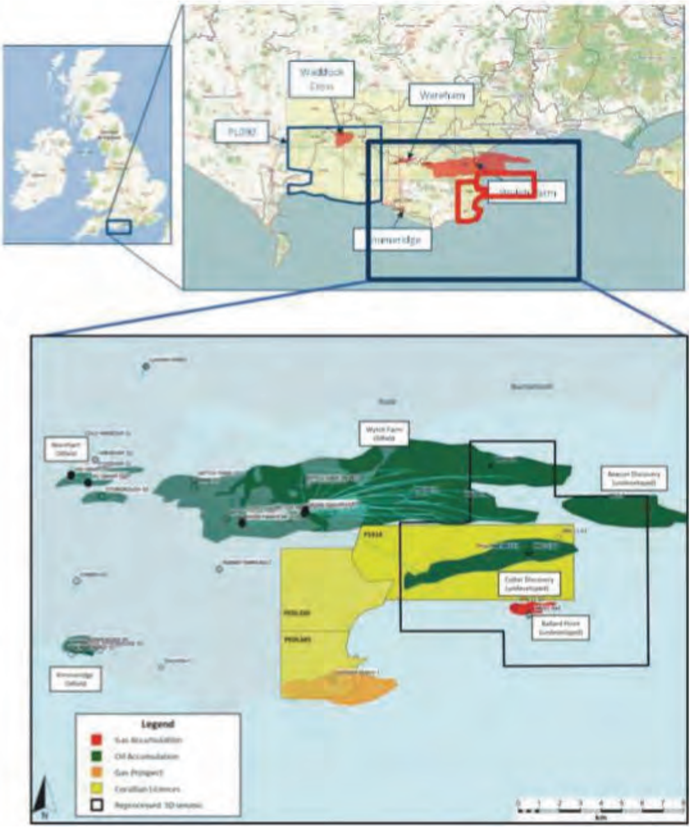


Figure 6. Colter Discovery Location Map ***(Source: ERCE CPR para 2.2.1)***

Colter Discovery (formerly Colter East) Prospect

Contingent Resources

Interpretation of the top reservoir structure is challenging and there is uncertainty associated with the location of the faults that bound the accumulation.

Colter was discovered by Well 98/11-3 in 1986. The well encountered a 10.5 m section of the Sherwood Sandstone reservoir with oil saturations from logs up to 60 per cent., underlain by water-bearing Sherwood Sandstone. A DST was performed on Well 98/11-3, with 8.5 stb of oil produced at surface out of 109 bbl total fluid influx, including water. The well test straddled the oil water contact (OWC) of the discovery.

Well 98/11a-6 was drilled to appraise the Colter discovery in February 2019. The well encountered the Sherwood Sandstone reservoir deeper than prognosed and is interpreted to have penetrated the reservoir on the southern side of the Colter bounding fault. Wireline log interpretation indicates elevated hydrocarbon saturations above a depth of 1780.5 m TVDss. However, the well was not tested and the presence of moveable hydrocarbons has not been demonstrated. ERCE attributes prospective resources to the structures on the southern side of the Colter bounding fault.

Well 98/11a-6z was a side-track to the north from Well 98/11a-6 designed to further appraise the Colter discovery. The well penetrated the northern side of the Colter bounding fault but found the Sherwood Sandstone reservoir below the Colter OWC 1740 m TVDss defined by Well 98/11-3. This results in a reduction in the contingent resources estimates for the Colter discovery.

The results from Well 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area.

ERCE attributes contingent resources (sub-classification development unclarified) to the Colter discovery (Table 17), made by Well 98/11-3. Development of Colter would be contingent on successful exploration drilling of the Colter South prospect. ERCE agrees with UOG's estimate of the chance of development of 30 per cent. *(Source: ERCE CPR para 1.2.1.2).*

Table 17: Unrisked Oil Contingent Resources of Colter Discovery, Gross and Net to UOG

			Gross Contingent Resources (MMstb)				*Net Contingent Resources (MMstb)*			
Licence	*Field*	*Operator/Administrator*	*1C*	*2C*	*3C*	*Working Interest*	*1C*	*2C*	*3C*	*Pd*
PL1918	Colter	Corallian Energy Limited	0.44	0.69	1.06	10.00%	0.04	0.07	0.11	30%

Notes:

1. Refer to notes under Table 14.

(Source: ERCE CPR para 1.2.1.2)

Colter South Prospect (P1918)

Prospective Resources

The results from Wells 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area.

The Colter South prospect is mapped to extend to the southeast up dip from Well 98/11-1. Log interpretation of the Sherwood Sandstone reservoir in Well 98/11-1 indicates elevated hydrocarbon saturations, but well testing flowed water only, defining a water up to for the prospect at 1780 m TVDss. A smaller structure is also mapped around Well 98/11-6 to which prospective resources are also attributed. Petrophysical interpretation of Well 98/11-6 wireline logs indicates elevated hydrocarbon saturations, but movable hydrocarbons have not been sufficiently demonstrated in this well. This prospect has been designated "Colter South (Well#6)".

ERCE's estimates of the gross unrisked oil prospective resources and geological chance of success for Colter South and the net unrisked and risked prospective resources attributable to UOG in the P1918 Licence are shown in Table 18. *(Source: ERCE CPR para 1.2.2.2).*

Table 18: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Colter South Prospect, Gross and Net UOG

		STOIIP (MMstb)				*Gross Unrisked Prospective Resources (MMstb)*				
Prospect	*Operator/Administrator*	*Low*	*Best*	*High*	*Mean*	*1U*	*2U*	*3U*	*Mean*	**Working Interest*
Colter South	Corallian Energy Limited	10	24	52	29	3.9	9.2	21.0	11.3	10%

		Net Unrisked Prospective Resources (MMstb)					*Net Risked Prospective Resources (MMstb)*			
Prospect	*Operator/Administrator*	*1U*	*2U*	*3U*	*Mean*	*COS*	*1U*	*2U*	*3U*	*Mean*
Colter South	Corallian Energy Limited	0.39	0.92	2.10	1.13	65%	0.25	0.59	1.37	0.74

		STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				
Prospect	*Operator/Administrator*	*Low*	*Best*	*High*	*Mean*	*1U*	*2U*	*3U*	*Mean*	**Working Interest*
Colter South *(Well#6)*	Corallian Energy Limited	0.52	1.92	7.00	3.21	0.20	0.75	2.74	1.27	10%

		Net Unrisked Prospective Resources (MMstb)				Net Risked Prospective Resources (MMstb)				
Prospect	*Operator/Administrator*	*1U*	*2U*	*3U*	*Mean*	*COS*	*1U*	*2U*	*3U*	*Mean*
Colter South *(Well#6)*	Corallian Energy Limited	0.02	0.07	0.27	0.13	62%	0.01	0.05	0.18	0.08

* Net unrisked prospective resources have been calculated by multiplying gross unrisked prospective resources by UOG's working interest in the P1918 Licence (10.00 per cent.).

Notes:

1. Refer *to notes under Table 14.*

(Source: ERCE CPR para 1.2.2.2)

Work Programme

Desktop studies investigating drilling and seismic acquisition feasibility to be completed prior to defining next steps towards commercialisation options.

2.4 ***Crown Discovery (P2366 Licence, UK)***

Licence Description

The Crown discovery, in which UOG has a 95 per cent. interest (Table 19) and is the licence administrator, is located in licence P2366 and straddles Blocks 15/18d and 15/19b located at the north west margin of the Witch Ground Graben, offshore the United Kingdom.

UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on 17th July 2019 and the sale and purchase agreement ("SPA") was signed on 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence and regulatory approval and definitive documentation from the OGA. *(Source: ERCE CPR Executive Summary).*

Table 19. Summary of UOG's P2366 Licence Interest

Licence block	*Operator/ Administrator*	*Company*	*Interest (%)*	*Status*	*Licence Expiry Date*	*Licence Area*	*Comments*
P2366 (Crown)	United Oil & Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/09/2021 (Phase A)	13.6 km^2	Phase A work commitment including the reprocessing of 40 km^2 of 3D seismic and an associated Rock Physics study have now been completed. Phase C will start on the condition that there is a firm commitment to drilling a well.
		Swift Exploration Limited	5.00%		30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)		

Location

The Crown discovery is located in Block 15/19 offshore UK. UOG was awarded a 95 per cent. interest in the block in August 2018 as part of the UK offshore 30th Licensing Round. The licence is located offshore UK at the northwest margin of the Witch Ground Graben (Figure 7). *(Source: ERCE CPR para 2.3.1).*

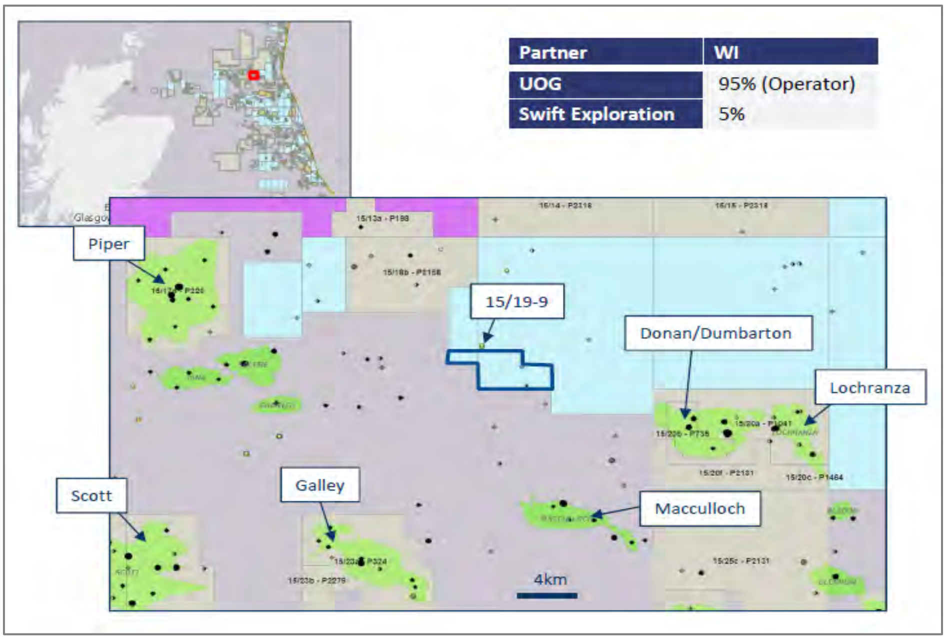


Figure 7: Crown Discovery Location Map ***(Source: ERCE CPR para 2.3.1)***

Contingent Resources

Crown was discovered by Well 15/19-9 in 1998. The well encountered in excess of 200 ft of good quality Balmoral Sandstone reservoir of Palaeocene age. The discovery has an oil rim of thickness between 35 and 55 ft overlain by gas and underlain by water-bearing sandstone. Wireline log oil saturations of up to 80 per cent. are encountered. Reprocessing of the seismic data and an associated rock physics study has recently been completed, satisfying the Phase A work commitments.

ERCE attributes Contingent Resources (sub-classification development unclarified) to Crown discovery. Development is contingent on the preparation and the commitment to a commercial development plan. *(Source: ERCE CPR Executive Summary).*

ERCE's STOIIP and Contingent Resources (sub-classification development unclarified) estimates are presented in Table 20. ERCE has reviewed UOG's assessment of chance of development and feel 60 per cent. is an appropriate estimation. *(Source: ERCE CPR para 2.3.7).*

Table 20: Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

			Gross Contingent Resources (MMstb)				*Net Contingent Resources (MMstb)*			
Licence	*Field*	*Operator/Administrator*	*1C*	*2C*	*3C*	*Working Interest*	*1C*	*2C*	*3C*	*Pd*
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	60%

Notes:

1. Refer to notes under Table 14.
2. Crown carries a 60 per cent. chance of development.
3. UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on 17th July 2019 and the sale and purchase agreement ("SPA") was signed on 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence, regulatory approval and definitive documentation from the OGA.

(Source: ERCE CPR para 2.3.7)

Work Programme

On 7 October 2019 the Company signed a sale and purchase agreement with Anasuria Hibiscus UK Ltd to divest Crown for a total consideration of up to $5 million. This is subject to, *inter alia,* OGA approval.

2.5 ***Colibri Project (Walton-Morant Licence, Jamaica)***

Licence Description

The Walton-Morant licence area is situated offshore Jamaica and covers a large area of 32,065 km^2 (Figure 8). The production sharing agreement (PSA) became effective on 1 November 2014 and Tullow Jamaica is the operator. UOG has signed an agreement with Tullow Jamaica to farm-in to the Walton-Morant Licence at a 20 per cent. equity interest. This will involve paying a 20 per cent. share of costs. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data which was designed to concentrate on the Colibri prospect. Since the acquisition the data have been reprocessed and a number of 3D seismic volumes and derived attributes have been generated. One of the most recent products is an anisotropic PSTM, PSDM and an associated velocity volume. *(Source: ERCE CPR 3.2.1).*

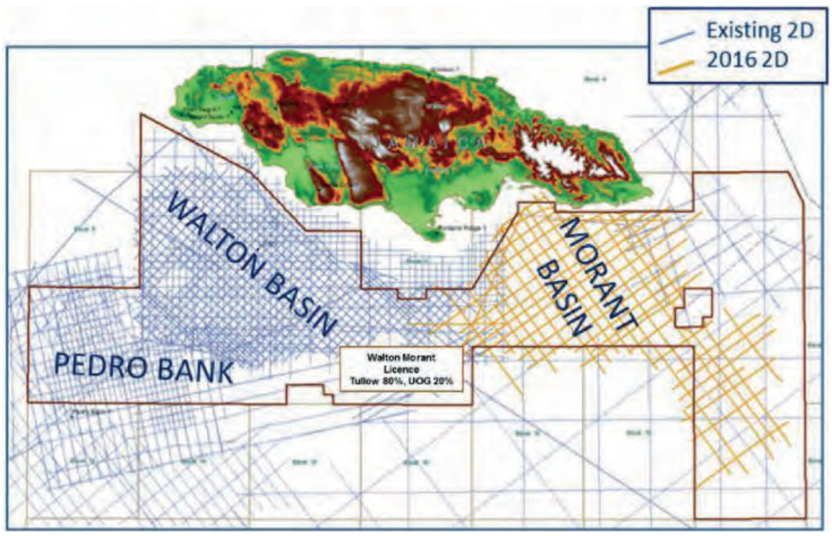


Figure 8. The Walton-Morant Licence, Offshore Jamaica ***(Source: ERCE CPR 3.2.1)***

The Walton-Morant Licence interests are summarised in Table 21.

Table 21. Summary of UOG Licence Interests

Licence block	*Operator/ Administrator*	*Company*	*Interest (%)*	*Status*	*Licence Expiry Date*	*Licence Area*	*Comments*
Walton Morant (Colibri)	Tullow Jamaica Ltd	Tullow Jamaica Ltd UOG Jamaica Ltd	80.00% 20.00%	Extant	2024	32,065 km^2	60% relinquishment, drill or drop Q1 2020

Location

The licence contains the Pedro Bank carbonate platform and the Walton and Morant Basins, of which the Walton Basin is the primary exploration focus as it contains siliciclastic reservoirs located within a thermally mature kitchen area. *(Source: ERCE CPR 3.2.1).*

The Colibri prospect is situated in the Walton Basin in water depths of approximately 750 m (Figure 9). The prospect is a well-defined fault-bounded structure with onlap and drape. The basinal position suggests overlying pelagic shales and marls will likely form a seal. The 3D seismic data demonstrate that some faulting propagates to seabed, implying the possibility of trap breach. The prospect is also well positioned to receive charge from surrounding Eocene and/or Cretaceous kitchens, and is located close to the Blower Rock oil seep. The improved imaging provided by the 3D seismic data provides positive evidence for migration pathways and fluid movement through the Walton Basin. The area has also been interpreted by Tullow Jamaica to sit within the Guy's Hill Formation depositional fairway.

(Source: ERCE CPR 3.2.2).

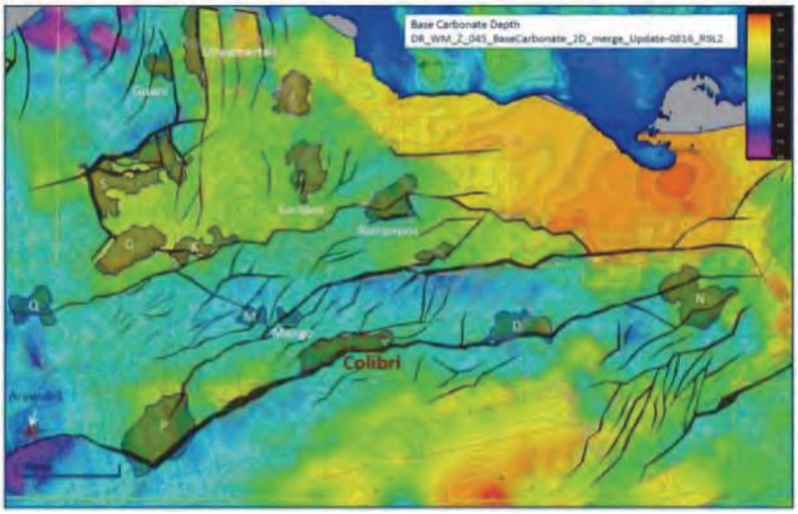


Figure 9. Location of Colibri and Associated Leads in the Walton Basin
(Source: ERCE CPR 3.2.2)

Prospective Resources

The principal offshore exploration target identified by the operator, Tullow Jamaica, is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20 per cent. porosity at outcrop. The Guy's Hill formation is a fluvio-deltaic-shallow marine succession of up to 320 m gross thickness onshore, and is capped by regional shales and marls. Well Arawak-1 is the nearest offshore penetration of the Guy's Hill formation located approximately 70 km to the west of the Calibri prospect. Tullow has identified a number of undrilled prospects and leads, of which the Colibri prospect is currently the most mature. The prospect lies in water depths of approximately 750 m and is a fault-bounded structure prognosed to contain Guy's Hill formation reservoir. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data, including coverage of the Colibri prospect. These data have been reprocessed, and a number of stacked volumes and derived attributes have been generated. These volumes form the basis for the interpretation and ERCE's updated estimation of Prospective Resources. *(Source: ERCE CPR Executive Summary).*

A summary of ERCE's estimates of undiscovered STOIIP and oil Prospective Resources is presented in Table 22.

Table 22: Colibri Prospect – STOIIP and Oil Prospective Resources

		STOIIP (MMstb)				*Gross Unrisked Prospective Resources (MMstb)*				
Prospect	*Operator/Administrator*	*Low*	*Best*	*High*	*Mean*	*1U*	*2U*	*3U*	*Mean*	**Working Interest*
Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%

		Net Unrisked Prospective Resources (MMstb)				*Net Risked Prospective Resources (MMstb)*				
Prospect	*Operator/Administrator*	*1U*	*2U*	*3U*	*Mean*	*COS*	*Low*	*Best*	*High*	*Mean*
Colibri	Tullow Jamaica Ltd	6	26	103	46	20%	1.19	5.00	20.08	8.97

* Net unrisked prospective resources have been calculated by multiplying gross unrisked prospective resources by UOG's working interest in the Walton-Morant Licence (20.00 per cent.).

ERCE assessment of the risk for the Colibri play is 54 per cent., with the prospect risk at 36 per cent., leading to a geological chance of success as 20 per cent. The recently acquired 3D seismic data shows positive evidence of fluid movement and hydrocarbon presence in the basin and ERCE have therefore reduced the risk associated with play source and prospect migration since the last assessment. The dominant prospect risk is reservoir efficacy and presence, given the sparsity of wells and uncertain reservoir distribution in the basin. *(Source: ERCE CPR 3.2.3).*

Work Programme

In November 2017 UOG signed an agreement with Tullow Jamaica to farm-in to the Walton-Morant licence at a 20 per cent. equity interest. In May 2018, the acquisition of 2,250km^2 of 3D seismic data was successfully completed. This was the first ever 3D survey completed in Jamaica, and was focussed on the high-graded Colibri lead. This data has now been processed and interpreted and a joint venture farm-down effort is underway. As well as confirming the presence of a sizeable prospect at Colibri, a number of additional leads and prospects have also been identified on the data. A drill-or-drop decision is required by Q1 2020, and following a successful farm-down, an exploration well could be drilled in 2020/2021. On commencement of work on the well, UOG is committed to pay $350k to the operator but believe this cost will be carried by incoming joint venture farm-in partner(s).

2.6 *North Sea, Greater Crown Area Prospects (Licence P2480)*

Licence P2480 in Central North Sea

Licence Description

As announced on 9 September 2019 the Company has accepted the formal offer from the OGA of a 100 per cent. interest in Blocks 14/15c, 15/11c, 15/12a, and 15/13c (Licence P2480) which have been awarded to the Company in 31st Licensing Round, with the licence term beginning 15 July 2019.

The Blocks have been awarded on the basis of a low-cost work programme involving the purchase of an existing high-quality 3D seismic dataset and detailed geological and geophysical analysis to be completed within 3 years.

Location

The four highly prospective blocks in the Central North Sea cover an area of c. 500 sq km, and include the Zeta prospect. The Blocks, which lie 10km from Crown discovery, are close to the Marigold and Yeoman discoveries and the substantial Piper, MacCulloch and Claymore oil fields.

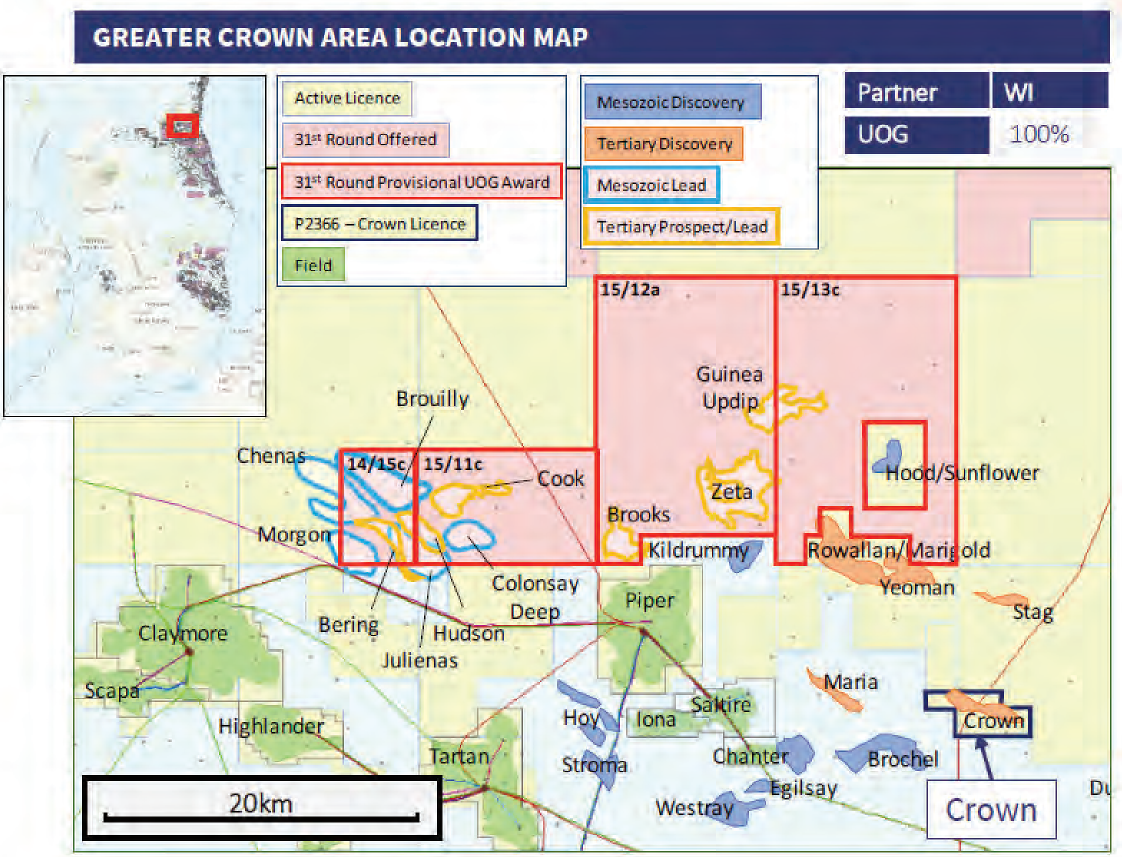


Figure 10. Greater Crown Area Location Map ***(Source: UOG presentation)***

2.7 ***Onshore Block B (Bénin)***

Licence Description

UOG announced the signing of an option agreement on 11th March 2019 with Elephant Oil Ltd ("**Elephant Oil**") to farm in to their Block B onshore acreage in Bénin ("**Bénin Onshore Block B**"), potentially taking a 20 per cent. interest in the onshore Block B production sharing contract which Elephant Oil has entered into with the government of Bénin ("**PSC**").

At this point, the Bénin Onshore Block B licence data is limited to a single seismic line and a CGG-acquired falcon gravity gradiometer survey. This data suggests the presence of numerous large structures in the licence. The Allada structure has already been identified by Elephant Oil as a prospect. However, given the sparsity of the data, no prospective resources have yet been formally assigned.

Passive seismic and field studies have now been completed and provide further evidence to support the presence of all the elements required for a working petroleum system.

If UOG chooses to exercise the option, then the Company will farm into the PSC for a 20 per cent. interest and will be responsible to fund 30 per cent. of the non-drilling and 20 per cent. of the drilling costs in the phase 1 work programme as approved under the PSC. UOG would also pay Elephant Oil the sum of US$260,000, representing one quarter of the *pro rata* (20 per cent.) past costs expended by Elephant Oil on the prospect, with the remaining US$780,000 paid in three equal six monthly instalments.

Location

The Bénin Onshore Block B is located in the Dahomey Embayment (Coastal Basin) and covers an area of 4,590 sq km (approximately 1.1 million acres). The Block is located to the west of Bénin's capital Cotonou continuing to the Togo border.

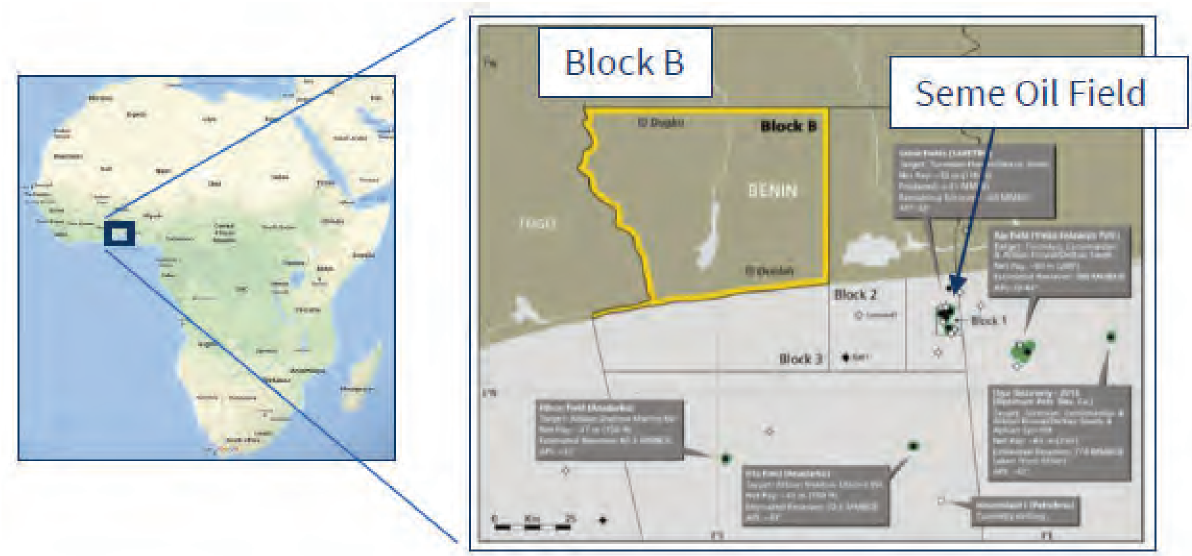


Figure 11. Location of Block B, Bénin ***(Source: UOG presentation)***

Onshore Bénin is a frontier area with only 11 wells drilled to date in the entire Dahomey Embayment; 3 in Ghana and 8 in Nigeria. However, the licence is surrounded by prolific hydrocarbon producing regions, and there are positive indications of a working petroleum system. Not only has a working system been demonstrated in the Shelfal area offshore Bénin but wells drilled along the coast in the same Dahomey Embayment in onshore Ghana and Nigeria have encountered hydrocarbons. Oil and gas seeps have been reported from water wells within Bénin Block B, and an extensive tar belt, potentially indicating the migration of oil through the targeted Cretaceous stratigraphy of Block B, has been reported to the north east of the area.

SECTION E: MARKET OVERVIEW

1 Egypt

During the last decade, the oil and gas industry in Egypt has become increasingly dynamic, with the production of hydrocarbons becoming by far the largest single industrial activity in the country. In terms of hydrocarbon reserves, Egypt has significant energy resource, with proven reserves at 3.3. billion barrels of oil and 62.8 tcf of natural gas at the end of 2017 (or 6.6 billion cubic feet per day in 2018). Egypt is Africa's fifth largest oil and gas producer and currently has over fifty international oil companies ("**IOCs**") operating within its domestic oil and gas sector including majors such as BP PLC, Eni S.p.A., Royal Dutch Shell PLC and large independents such as the Apache Corporation.

In terms of investment potential, Egypt has made commitments to invest around US$38 billion into its petrochemicals sector within the next five years, which represents approximately 12 per cent. of industrial production and which generates revenues totalling approximately US$10 billion by end of 2018. Egypt boasts the largest refinery capacity in Africa, with plans to introduce reforms to update its existing refineries, including introducing privately owned refineries into its domestic market.

Egypt has seen over 80 oil and gas exploration deals with IOCs signed between November 2013 and December 2017, worth cumulatively US$15.5 billion. The Egyptian Government announced a new international bidding round in 2018, including blocks auctioned for the Gulf of Suez and the Western Desert. 12 new exploration and production concessions were entered into in 2019 which received regulatory approval, including with oil majors such as BP, Shell and Exxon Mobil, with estimated investment in the first stage totalling US$800 million. The Egyptian Government recently expanded its range of offerings to include the Red Sea area where several blocks were offered in a bid round by GANOPE that closed on 15 September 2019 and pending announcement of winning bidders (Exxon Mobil, Chevron, Dragon Oil among the announced bidders). First time offerings of The Western Mediterranean waters and new blocks in the Eastern Mediterranean and Delta are expected to be offered in the new bidding rounds. Recent M&A activity in Egypt has included Soco International PLC's acquisition of Merlon Petroleum El Faym Co in September 2018; Dragon Oil PLC's acquisition of BP PLC's concession interests in the Gulf of Suez in June 2019; and Energean Oil & Gas PLC's proposed acquisition of Edison E&P for US$750 million in July 2019.

Egypt has seen greater domestic natural gas investment both in the financial years 2016 and 2017. Although crude oil projects did not see the same levels of domestic investment, several multinational firms have announced commitments in recent years to increase investment to total US$10 billion in the financial years 2018 and 2019. The Zohr field which commenced production in December 2017 is considered to be the largest commercial crude oil discovery in the Mediterranean Sea with production estimates being pegged at around 30 trillion tcf; and the Nooros Gas Field produces 32 million cubic metres per day. Oil and gas has become one of the best prospect industry sectors in Egypt. In addition, and separate to Egypt's prospective production and investment opportunities, the implementation of Egypt's modernisation strategy, spearheaded by the IMF's financial assistance, has assisted Egypt in creating potential opportunities for further international involvement in both its downstream and upstream oil and gas industries. The combination of eliminating fuel subsidies, new bid rounds, and the creation of a new production sharing contract for international oil companies projected to be put in place in 2019, are market trends that show increased signs of buoyancy in Egypt's oil and gas market.

The political and economic climate has been relatively stable in Egypt with President Sisi being reinstated for a second term in March 2018. In November 2016, the IMF approved financial assistance for Egypt for about US$12 billion. The five US$2 billion tranches of the US$12 billion tranche were disbursed in February 2019. Egypt has returned to the international bond markets and is seeking to raise between US$4 to 7 billion in 2019, including the US$4 billion raised in February 2019. The IMF had expressed commitments to eliminate all arrears from EGPC to international oil companies by June 2019.

2 The United Kingdom

The UK is the second largest producer of oil in Europe, after Norway, and the third largest producer of gas, after Norway and the Netherlands.

The UK oil and gas industry in 2017 supported some 300,000 jobs directly and indirectly down from 450,000 at the start of 2014.

The decline in drilling activity over the last decade, particularly exploration and appraisal, has been exacerbated by the downturn. Exploration activity has declined by one third in just three years from 2013 to 2016. In 2016, £8.3 billion of capital expenditure was invested in the UK Continental Shelf, down from £11.7 billion in 2015. Less than £7 billion of capital expenditure was expected in 2017.

The UK Government's Office for Budgetary Responsibility's ("**OBR's**") Fiscal Sustainability Review in June 2015 provided estimates of long term reserves of oil and gas and production. The OBR said: *"Our central long-term assumption is that production falls by 5 per cent. a year from 2020 onwards. For our low production scenario we assume a 7.8 per cent. a year fall. Our high production scenario sees production remaining as we expect in 2019 for a further 5 years, with a fall of 5 per cent. a year thereafter."* For oil and gas reserves, the OBR said: *"Over the long term, recoverable reserves are clearly on a declining path as the basin matures and resources are exhausted or become increasingly difficult or uneconomic to extract."*

Onshore Oil and Gas

The onshore oil and gas industry in the UK has been in existence for over 150 years. Before the First World War, the UK obtained almost all of its oil and gas from outside the country. Oil was discovered in Scotland in 1851 followed by gas in England in 1896.

During both world wars the need for Britain to produce its own oil to help the war effort rather than rely on imports became of real importance to the UK Government and legislation was introduced to enable companies to explore for hydrocarbons more readily.

In 1973, the Wytch Farm oil-field in Eastern Dorset was opened and today it is the largest onshore oil-field discovery in the UK.

Following significant offshore North Sea oil and gas discoveries in the 1960s and the rapid growth in offshore production, onshore oil and gas activity also started to accelerate again after the 1979 oil crisis. As prices rose, domestic production in both the onshore and offshore became increasingly important.

Onshore UK today, there are 120 sites with 250 operating wells producing in total between 20,000 and 25,000 boepd and around 2,000 wells have now been drilled. Approximately 250,000 barrels per day of produced water is disposed of under permits from the relevant authorities.

The onshore oil and gas industry is regulated by a number of statutory bodies including the Environment Agency in England, Scottish Environment Protection Agency in Scotland and Natural Resources Wales in Wales, the Health and Safety Executive, the Department for Business, Energy and Industrial Strategy and the OGA. The OGA operates as a government company whose role is to regulate, influence and promote the UK oil and gas industry in order to maximise the economic recovery of the UK's oil and gas resources. Since its establishment on 1 April 2015, the OGA has been responsible for regulating both onshore and offshore oil and gas operations in the UK. This includes: licensing, exploration and production, the oil and gas fields and wells and the oil and gas infrastructure.

A UK Petroleum Exploration and Development Licence ("**PEDL**") allows a company to pursue a range of oil and gas exploration, development and production activities, subject to conditions placed upon them (if any), necessary drilling/development consents and planning permission. The PEDL is the current form of UK onshore oil and gas licence; older licences have the PL prefix.

The 14th Landward Licensing Round was launched on 28 July 2014 and closed on 28 October 2014. A total of 95 applications were received from 47 companies covering 295 ordnance survey blocks. On 17 December 2015, it was announced that licences for a total of 159 blocks were formally offered to successful applicants.

Similar to the North Sea offshore oil and gas exploration and production sector, there are a number of private and unquoted companies active in the UK onshore sector:

- companies listed on AIM;
- a number of private groups; and
- a number of larger London listed exploration and production companies, international oil companies and UK and international energy utilities.

Offshore Oil and Gas

The offshore oil and gas revolution in the UK began in the late 1960's with the landing of first gas from the West Sole Field in the North Sea.

With the Organisation of the Petroleum Exporting Countries Oil Crisis of the early 1970s, oil prices quadrupled and the search for oil in non-traditional oil producing countries became more attractive. New fields were discovered and the Forties, Brent and Piper, became key suppliers to the UK's energy mix. Oil production would peak in the late 1990s.

Exploration in the North Sea continued and while success was more limited, the discovery of Buzzard in 2001, indicated that there was still considerable opportunity in the North Sea.

The continuing success of operations in UK offshore market, is in part dependent on a favourable taxation regime. The 2011 tax rise by the Government demonstrated that the industry remains sensitive to price shocks. A 12 per cent. levy significantly reduced exploration activity. The tax changes were relatively short lived and the industry rebounded on the back of a more favourable regime that persists to this day.

While the North Sea has declined in terms of importance, it remains a key producer. The profile of owner has changed markedly, with asset sales seeing majors moving on, to be replaced by a new, aggressive, independent sector. This has led to significant investment in the North Sea in recent years, with many new entrants.

The investments being made are a strong vote of confidence of the remaining resource in UK waters. There continues to be a significant resource in place. There is an existing skill set to develop and exploit this resource. There is a favourable regime and broadly stable political and planning framework. There is strong existing demand in the UK for oil and gas – oil and gas provides approximately 70 per cent. of UK primary energy.

3 The Italian Gas Industry

The gas industry in Italy developed after World War Two around the Italian oil and gas multinational, ENI. While searching for oil during World War Two, the state company Agip (Azienda Generale Italiana Petroli) found large quantities of gas in the Po Valley region. A pipeline network was created to reach the large factories in the northern part of the country and this facilitated the expansion of local manufacturing industry in the 1950's and 1960's. The profits from natural gas sales were reinvested into exploration and production activities and in the expansion of the pipeline infrastructure. By 1960, Italy was the largest gas producer and consumer in Europe and the gas network continued to expand to other parts of the country. With a rapid increase in gas consumption in the industrial, residential and commercial sectors, this growing demand began to outstrip domestic supply.

The first imports into Italy started in 1971 when the liquefied natural gas import terminal at Pannigaglia began operations. Since the early 1990's, the length of the Italian pipeline network has tripled.

The liberalisation process started in 1998 with the EU gas directives, designed to create an internal market for gas. Vertically integrated national companies were broken up, allowing competitors to enter on the supply side and customer switching on the demand side.

More than ten years later, the gas industry had been fully liberalised; the Directors believe that competition has yet to reach its full potential with a few players still dominating the upstream and wholesale sectors. Nevertheless, as with the rest of Europe, Italian gas deliveries to power generation are continuing to develop. The Punto di Scambio Virtuale, ("**PSV**"), the virtual hub, was created in 2003 and a gas exchange with spot gas (day ahead, intraday) and balancing gas platforms was launched in 2010 and 2011. Traded volumes are fast increasing, and the PSV day-ahead process has started to track spot prices of North West European hubs since the end of 2012 thanks to governmental measures to improve liquidity and access to the market to new entrants.

According to the Snam Rete Gas ten-year network development plan 2015-2025, Italy consumed 2.38 tcf in gas in 2015, and this expected to grow at 1.9 per cent. per annum to 2025. Of this only 227 bcf (0.23 tcf), or 11 per cent., was produced domestically, with the remaining 2.15 tcf imported from several countries, notably from Russia and from countries in the Mediterranean area.

On 13 February 2019, the law No. 12 of February 11, 2019 on "*Conversion into law, with amendments, of the law decree December 14, 2018, No. 135, containing urgent provisions on matters of support and simplification for enterprises and for the public administration*" ("**Law 12/2019**") came into force in Italy.

Paragraph 4 of Article 11-*ter* on "Sustainable energy transition plan of the appropriate areas" ("**Plan**") of the Law 12/2019 provides for the suspension of all administrative procedures related to the granting of liquid and gaseous hydrocarbons exploration licences. The suspension is provided for a period up to 24 months while the Italian Ministry of Economic Development and the Italian Ministry of Environment and Protection of the Land and Sea approve the adoption of the Plan which will identify the defined framework for the areas where liquid and gaseous hydrocarbons' prospection, exploration and production activities can be performed on the national territory.

Paragraph 5 of Article 11-*ter* of the Law 12/2019 provides that there is no suspension for the award procedures related to the granting of liquid and gaseous hydrocarbons production licences filed prior to the date that Law 12/2019 came into force on 13 February 2019. However, (a) if the Plan is adopted and the area where the application for production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the Italian Ministry of Economic Development will reject the application for the production licence if it has not awarded before the Plan becomes effective; and (b) if the Plan is adopted and the production licence is awarded before the Plan becomes effective but the production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the production licence will be effective until the expiry date but no new applications for the extension will be allowed.

4 Jamaica

Exploration activities in Jamaica have occurred in two phases. The earlier phase spanned 1955 – 1973, done by private companies, and more recently 1978 – 1982 by the PCJ.

Between 1955 and 1973, seven (7) exploratory wells were drilled, one (1) offshore and six (6) onshore. Immediately following on the establishment of the state-owned Petroleum Corporation in 1979, the momentum of activity increased with the drilling of an additional three (3) wells onshore and one (1) offshore during the period 1980-1981.

There have been oil or gas shows in 10 of the 11 onshore and offshore wells drilled in Jamaica to date. The offshore area to the South of the island has been identified as having good frontier exploration potential encompassing three geological provinces, the Pedro Bank carbonate platform and the Walton and "**Southern**" sub basins. Multiple leads have been identified on existing seismic data which lie in 25m to 2,000m water depths.

With advancements in the geological and geophysical sciences over the past two decades, Jamaica is being viewed through "**new**" exploration lenses and is likely to benefit from this reawakening of interest in frontier provinces inside the Caribbean.

PCJ was formed in June 1977, and is empowered by the Petroleum Act of 1979, to pursue the development of Jamaica's energy resources with exclusive rights to explore for oil and develop Jamaica's petroleum resources. The entity initially was mandated to explore for oil and gas along with the procurement of refining, retailing and distribution of petroleum products.

A geological study recently conducted by the PCJ and integrated geoscience company, CGG Robertson (UK) Ltd has revealed further encouraging signs for possible petroleum potential on and off-shore Jamaica.

The investigations, which were carried out over an 18 month period discovered two independent live oil seeps in different sections of Jamaica's oil blocks. Detailed analysis confirmed active working petroleum systems that are generating and expelling liquid hydrocarbons to the surface.

5 Trends

The Directors believe that increasing global industrialisation and urbanisation, particularly in emerging African and Latin American markets, plus increased concern about security of energy supply in some developed economies is likely to lead to increased local demand for energy production in the medium to long term.

Over the same period, the Directors believe that the supply of oil and gas in these markets could face constraints driven by insufficient investment, and this is likely to provide support to future commodity pricing. Indeed, since the start of 2019, oil prices have remained reasonably consistent, with monthly averages ranging between US$59 and US$71.

SECTION F: MANAGEMENT OF THE GROUP AND CORPORATE GOVERNANCE

1 Directors

Details of the Directors and their backgrounds are as follows:

Alan Graham Martin, Non-Executive Chairman (aged 65)

Mr Martin is an experienced senior natural resources executive and brings a wealth of international expertise. He is currently a Non-Executive Director at Kenmare Resources plc, one of the leading global producers of titanium minerals and zircon listed in London and Dublin. He has also previously served as an Executive Director, General Counsel and Company Secretary at Tullow Oil plc.

From 1997 until 2016, Mr Martin was centrally involved in the growth of Tullow Oil plc into a FTSE100 business, and in the company's transformative M&A programme. Prior to Tullow Oil plc, Mr Martin was a partner at the US energy law firm Vinson & Elkins LLP, having started his legal career in Scotland.

Brian Edward Andrew Larkin, Chief Executive Officer (aged 38)

Mr Larkin is a Qualified Accountant and has an MBA from Dublin City University. He has extensive oil and gas industry experience having worked for both Tullow Oil Plc and Providence Resources Plc. At Tullow Oil Plc, Mr Larkin held positions in both finance and commercial, and worked on a variety of production, development and exploration projects in South America and Asia and carried out numerous investment case recommendations.

At Providence Resources Plc, Mr Larkin worked in senior finance and commercial positions. During his time with Providence Resources Plc, Mr Larkin worked on a wide portfolio of assets in regions including the Gulf of Mexico, offshore Ireland, onshore United Kingdom, and offshore Nigeria.

Jonathan James Leather, Chief Operating Officer (aged 43)

Dr Leather has 20 years' experience in the oil industry and holds a Geology degree from Oxford University, a PhD in Sedimentology from Trinity College, Dublin, and an MBA from Warwick University.

He worked for Tullow Oil Plc from 2007 to 2015, where he held a number of senior positions, including membership of the Global Exploration Leadership Team. He also managed Tullow Oil Plc's Subsurface Technology Group – a team he established and built up to provide specialist technical input across the company in both exploration and development. As part of this, Dr Leather worked on global assets and opportunities ranging from onshore producing fields to deepwater frontier exploration.

Prior to Tullow Oil Plc, Dr Leather worked for Shell U.K. Limited. During his time there he was involved in a number of exploration and development projects, and worked on North Sea, European, Middle Eastern and Malaysian assets.

David Thomas Patrick Quirke, Chief Financial Officer (aged 46)

David has 17 years of treasury and corporate finance experience in the upstream oil and gas sector. He established and led the Tullow Oil Group Treasury function for a fifteen-year period from 2003 to 2017, supporting a period of transformational growth. He has extensive experience of the key exploration & production ('E&P') debt and equity instruments such as Reserves Based Lending Facilities, Acquisition Facilities, Corporate Bonds, Trade Finance Facilities and Equity Transactions. More recently, David acted as a Treasury and Financial Consultant advising Assala Energy on their corporate finance and treasury following the acquisition of Shell's onshore assets in Gabon. He has also supported a number of small E&P companies in managing their capital structure and developing financial strategies. David is a qualified chartered management accountant. He holds a BA in Law and Accounting from the University of Limerick.

Alberto Cattaruzza, Non-Executive Director (aged 82)

Mr Cattaruzza graduated as a Chemical Engineer from the University of Padua and, having worked in Germany for LURGI GmbH, he returned to Italy in 1966 and joined Chevron Oil Italiana s.p.a. In 1995, Mr Cattaruzza joined the Oilinvest Group, operating in Europe under the brand name Tamoil, as Managing Director of their German affiliate. He was later appointed Oilinvest Refining & Marketing Officer and a board member of several other group companies. In 2001, Mr Cattaruzza started an independent entity providing technical and business consultancy services in the oil sector and is co-founder of Il Delfino, a non-profit cultural association.

2 Corporate Governance

The Board recognises the importance of sound corporate governance and the Company is guided by the 10 principles set out in the QCA Code.

The Board currently comprises 3 executive directors, Brian Larkin, Jonathan Leather and David Quirke, and 2 non-executive directors, Alberto Cattaruzza and Graham Martin, who are considered by the Board to be independent.

The Board is responsible for formulating, reviewing and approving the Group's strategy, budgets and corporate actions.

The Board has established an audit committee and a remuneration committee with formally delegated duties and responsibilities.

Compliance with the QCA Corporate Governance Code

The Company has published on its website details of how it complies with the QCA Corporate Governance Code and where it diverges from the QCA Corporate Governance Code and explanations of the reasons for doing so. This information is also set out below. The Company will review this information annually in accordance with the requirements of Rule 26 of the AIM Rules for Companies.

The following summary sets out how the Company applies the key governance principles defined in the QCA Corporate Governance Code.

2.1 *Principle One*

Business Model and Strategy

The Board has concluded that the highest medium and long-term value can be delivered to its shareholders by the adoption of a strategy to build a portfolio of production, development and low-risk appraisal and exploration of oil and gas assets in Europe, Greater Mediterranean Area, whilst remaining alert for exceptional growth opportunities on a global basis, primarily in Caribbean, Latin America and Africa.

The Company's interests currently consist of a multi-stage portfolio of low risk European development and appraisal assets and exploration assets in Jamaica.

2.2 *Principle Two and Principle Ten*

Understanding Shareholder Needs and Expectations and Build Trust.

The Board is committed to maintaining good communication and having constructive dialogue with its shareholders. Shareholders and analysts have the opportunity to discuss issues and provide feedback at key industry events and presentations from the Company. In addition, all shareholders are encouraged to attend the Company's Annual General Meeting. Investors also have access to current information on the Company through its website www.uogplc.com.

The Company, through its public relations firms and its info@uogplc.com email address, seek to provide communication lines through which private shareholders can engage with the Company. Through its public announcements, management seeks to engage with shareholders and manage expectations.

The Company shall include, when relevant, in its annual report, any matters of note arising from the audit or remuneration committees.

2.3 *Principle Three*

Considering wider stakeholder and social responsibilities

The Board recognises that the long-term success of the Company is reliant not only upon the efforts of the employees of the Company but also its contractors, suppliers, regulators, local communities and other stakeholders. The Board has sought feedback from stakeholders and has systems in place to ensure that there is oversight, accountability and contact with its key resources and relationships.

2.4 *Principle Four*

Risk Management

In addition to its other roles and responsibilities, the audit and remuneration committees are responsible to the Board for ensuring that procedures are in place and are being implemented effectively to identify, evaluate and manage the significant risks faced by the Company and to ensure that risk management is reflected in board remuneration.

The risk assessment matrix below sets out those risks, and identifies their impact and the controls that are in place. This matrix is updated as changes arise in the nature of risks or the controls that are implemented to mitigate them. The audit committee reviews the risk matrix and the effectiveness of scenario testing on a regular basis. The following principal risks and controls to mitigate them have been identified:

Activity	*Risk*	*Impact*	*Control(s)*
Management	Recruitment and retention of key staff	Reduction in operating capability	Stimulating and safe working environment Balance base salary with longer term incentive plans to align remuneration with shareholders.
Regulatory adherence	Breach of rules	Censure or withdrawal of authorisation	Strong compliance regime instilled at all levels of the Company
Geological	Hydrocarbons are not discovered Recoverable hydrocarbons are not produced in the quantities expected	Reduction in asset value Reduction in asset value	Effective due diligence and technical screening Portfolio strategy mitigates exposure to single asset Reduce exposure by seeking to partner on Company projects
Strategic	Damage to reputation	Inability to secure new capital	Effective and consistent communications with shareholders
Financial	Liquidity, market and credit risk Inappropriate controls and accounting policies	Inability to continue as going concern Reduction in asset values	Capital management policies and procedures Appropriate authority and investment levels.

The Directors have established procedures, as represented by this statement, for the purpose of providing a system of internal control. An internal audit function is not considered necessary or practical due to the size of the Company and the close day-to-day control exercised by the executive directors. However, the Board will continue to monitor the need for an internal audit function.

Maintain A Dynamic Management Framework (Principle Five to Nine)

2.5 *Principle Five*

A Well-Functioning Board of Directors

The Board currently comprises 3 executive directors, Brian Larkin, Jonathan Leather and David Quirke, and 2 non-executive directors, Alberto Cattaruzza and Graham Martin, who are considered by the Board to be independent.

Executive and Non-Executive Directors are subject to re-election at the Company's annual general meeting at intervals of no more than three years. The service agreements and letters of appointment of all Directors are available for inspection at the Company's registered office during normal business hours. The Directors are expected to provide as much time to the Company as is required. The Board elects a Non-Executive Chairman to chair every meeting.

The Board expects to meet at least six times per annum. It has established an audit committee, a remuneration committee and an AIM Rules compliance committee, particulars of which appear hereafter. The Board has agreed that appointments to the Board at this stage would be made by the Board as a whole and so has not created a nominations committee.

Attendance at Board and Committee Meetings

The Company shall report annually on the number of Board and committee meetings held during the year and the attendance record of individual Directors. In order to be efficient, the Directors meet formally and informally both in person and by telephone.

2.6 *Principle Six*

Appropriate Skills and Experience of the Directors

The Board currently consists of five Directors. The Company believes that, at its current stage of development, the balance of skills in the Board as a whole, reflects a sufficiently broad range of commercial and professional skills, together with an in-depth knowledge of the sector and experience of public markets that is necessary to ensure the Company is equipped to deliver its strategy.

2.7 *Principle Seven*

Evaluation of Board Performance

Internal evaluation of the Board, the committees and individual Directors is to be undertaken on an *ad hoc* basis in the form of peer appraisal and discussions to determine the effectiveness and performance in various areas as well as the Directors' continued independence. This process can be regular as part of the board meeting process or *ad hoc* when the Director or Board deem it necessary.

The results and recommendations that come out of the appraisals for the directors shall identify the key corporate and financial targets that are relevant to each Director and their personal targets in terms of career development and training. Progress against previous targets shall also be assessed where relevant.

2.8 *Principle Eight*

Corporate Culture

The Board recognises that their decisions regarding strategy and risk will impact the corporate culture of the Company as a whole and that this will impact the performance of the Company. The Board is very aware that the tone and culture set by the Board will greatly impact all aspects of the Company as a whole and the way that employees behave. The corporate governance arrangements that the Board has adopted are designed to ensure that the Company delivers long term value to its shareholders and that shareholders have the opportunity to express their views and expectations for the Company in a manner that encourages open dialogue with the Board.

The Company maintains an open and respectful dialogue with employees, partners and other stakeholders. Therefore, the importance of sound ethical values and behaviours is crucial to the ability of the Company to successfully achieve its corporate objectives. The Board places great import on this aspect of corporate life and seeks to ensure that this flows through all that the Company does.

The Directors consider that at present the Company has an open culture facilitating comprehensive dialogue and feedback and enabling positive and constructive challenge.

The Company has adopted, with effect from the date on which its shares were admitted to AIM, a code for Directors' and employees' dealings in securities which is appropriate for a company whose securities are traded on AIM and is in accordance with the requirements of the Market Abuse Regulation.

2.9 *Principle Nine*

Maintenance of Governance Structures and Processes

Ultimate authority for all aspects of the Company's activities rests with the Board, the respective responsibilities of the Non-Executive Chairman and Chief Executive Officer arising as a consequence of delegation by the Board. The Board has adopted appropriate delegations of authority which set out matters which are reserved to the Board. The Non-Executive Chairman is responsible for the effectiveness of the Board together with the responsibility to oversee the company's corporate governance practices. The responsibility for the company's day-to-day operations has been delegated by the Board to the chief executive officer. The Board has also established committees to oversee the effectiveness of its operations and to monitor that remuneration is aligned to their effective performance, which are detailed below.

Audit committee

The audit committee which comprises of Alberto Cattaruzza and Graham Martin, has the primary responsibility for monitoring the quality of internal control and ensuring that the financial performance of the Group is properly measured and reported on and for reviewing reports from the Company's auditors relating to the Group's accounting and internal controls. The committee is also responsible for making recommendations to the Board on the appointment of auditors and the audit fee and for ensuring that the financial performance of the Group is properly monitored and reported. The audit committee will meet not less than three times a year.

Remuneration committee

The remuneration committee which comprises Alberto Cattaruzza and Graham Martin, is responsible for the review and recommendation of the scale and structure of remuneration for senior management, including any bonus arrangements or the award of share options with due regard to the interests of the Shareholders and the performance of the Group.

AIM Rules compliance committee

The Company has established an AIM Rules compliance committee which will comprise Graham Martin and Brian Larkin and which prime responsibility will be to ensure the Company has sufficient procedures in place to ensure ongoing compliance with the AIM Rules. The Company has adopted an AIM Rules compliance code to ensure that they have sufficient procedures for ensuring compliance with the AIM Rules.

The Company does not have a nomination committee as the Board does not consider it appropriate to establish such a committee at this stage of the Company's development. Decisions which would usually be taken by the nomination committee will be taken by the Board as a whole.

3 Anti-Bribery, Corruption and Sanctions Policy

The Company has adopted a policy that establishes its procedures in regards to offences under the Bribery Act 2010, corruption and UK and EU financial sanctions imposed on certain designated persons (including individuals and businesses). The Company shall also from time to time adopt certain operational protocols and procedures to ensure that there is adequate compliance with relevant sanctions. This policy has also been designed to assist the Company, its group companies, their management, employees, service providers and investors in whichever country they operate, to ensure strict compliance with UK and EU economic sanctions imposed on Egyptian persons, as a result of its commercial dealings in Egypt. As an undertaking with international operations, the Company is also committed to upholding strict compliance with any other applicable UK and EU sanctions regimes and rules.

4 Social Media Policy

The Company has adopted and implemented a social media policy which details the manner in which all employees, officers, consultants, contractors and other personnel interact with social media in relation to the Company. This policy deals with the use of all forms of social media including Facebook, Linkedin, Twitter, Instagram, ADVFN bulletin board, ii bulletin board and all other social networking sites, internet postings, bulletin boards and blogs. It applies to use of social media for business purposes as well as personal use that may affect the business in any way. It is designed to ensure that there is no unauthorised release of potentially price sensitive information regarding the Company so that all such information is released in the first instance through the correct authorised regulatory news services and that no misleading information is contained in unauthorised media channels. The policy is also designed to mitigate the risk of use of terminology in the media being inconsistent with the Company's authorised regulatory announcements.

PART III

RISK FACTORS

An investment in the Ordinary Shares involves a high degree of risk, including risks in relation to the Enlarged Group's business and strategy, the oil and gas sector, potential conflicts of interest and risks relating to taxation.

Prospective investors should carefully consider all of the information in this Document, including the following risk factors, before investing in the Ordinary Shares. Additional risks and uncertainties not presently known to the Company and the Directors or that the Company and the Directors currently consider to be immaterial may also adversely affect the Enlarged Group's business, operations and financial condition. If any events or circumstances giving rise to any of the following risks, together with possible additional risks and uncertainties which the Company and the Directors consider not to be material in relation to the Enlarged Group's business actually occur, the Enlarged Group's business, financial condition and results of future operations could be materially and adversely affected. In such circumstances, the value of the Ordinary Shares could decline due to any of these risks occurring and investors could lose part or all of their investment.

Prospective investors should pay particular attention to the fact that some of the Enlarged Group's assets are located overseas, in countries which have legal and regulatory regimes that differ materially from the legal and regulatory regimes of the United Kingdom.

There can be no certainty that the Company will be able to successfully implement the strategy as 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 Company will achieve its objectives.

Further, prospective investors are cautioned not to place any undue reliance on any of the forward-looking statements made in this Document. The Company disclaims any obligation to update any such forward-looking statements in the Document to reflect future events or developments. Prior to making an investment decision in respect of the Ordinary Shares, prospective investors should consider carefully all of the information within this Document, including the risk factors set out in this Part. The Board believes these risks to be the most significant for potential investors. However, the risks listed do not necessarily comprise all those associated with an investment in the Company.

If any of the following risks were to materialise, the Enlarged Group's business, financial condition, results or future operations could be materially and adversely affected. In such cases, the market price of the Ordinary Shares could decline and an investor may lose part or all of his investment. The information set out below does not purport to be an exhaustive summary of the risks affecting the Enlarged Group.

RISKS RELATING TO THE ROCKHOPPER ACQUISITION

1 The Rockhopper Acquisition may not complete

Completion of the Rockhopper Acquisition is conditional upon, amongst other things:

- the written waiver, or non-exercise, in accordance with the terms of the Abu Sennan Concession of the pre-emptive rights of EGPC*;
- the written waiver, or non-exercise, in accordance with the terms of the Abu Sennan JOA of the pre-emptive rights by the parties to the Abu Sennan JOA (other than Rockhopper Egypt)*;
- EGPC and the Minister of Petroleum and Mineral Resources of Egypt providing written consent to the Rockhopper Acquisition;
- the release of the security granted in favour of the Falkland Islands Government over the shares in Target and its assets;
- the BTL Facility becoming unconditional in all respects save for any conditions relating to the Rockhopper Acquisition Agreement and Admission;
- the approval of the Resolutions by the Company's Shareholders at the Company's General Meeting.

*satisfied as at the date of this Document

There can be no guarantee that all conditions to the Rockhopper Acquisition (including conditions relating to the drawdown of the BTL Facility and of any necessary regulatory approval) will be satisfied on terms satisfactory to the Group nor at all, or that other completion requirements will be met, and therefore there can be no guarantee that the Rockhopper Acquisition will complete or that Admission will take place.

From a regulatory standpoint, authorities in Egypt may impose additional requirements, limitations or costs outside of those prescribed under the Abu Sennan Concession, which may jeopardise, delay, or sufficiently outweigh the benefits in obtaining final approvals required to complete the Rockhopper Acquisition (if any).

If the Rockhopper Acquisition does not complete, the Company would nonetheless incur significant expenses including in certain circumstances, the forfeit of the Deposit together with the advisory fees incurred in connection with the Rockhopper Acquisition and Admission.

2 Acquisition Financing

The Acquisition is being funded from the Company's existing cash resources, the Subscription, the Placing, the BTL Facility and the Consideration Shares.

Under the Rockhopper Acquisition Agreement, the Company has agreed to pay consideration of US$16 million. Up to 50 per cent. of the consideration is to be funded by the BTL Facility. The BTL Facility itself has certain conditions precedent, including granting first ranking security over the shares in Rockhopper Egypt and over certain bank accounts of the Company and Rockhopper Egypt, which if not satisfied by the agreed date may mean that the Company will not be able to drawdown the BTL Facility and satisfy the payment obligations under the Rockhopper Acquisition Agreement.

The BTL Facility has been structured in the form of a pre-payment financing structure transacted under a 2002 ISDA Master Agreement, which links the cost of the repayments to the commodity price of crude oil throughout the term of the pre-payment. The Company will repay the facility over 30 calendar months based upon dated Brent market prices for an agreed volume, capped at an agreed level. The financing structure generates an upfront payment to the Company that will be used to fund part of the Rockhopper Acquisition and in addition, will hedge a portion of the Company's production during the term of the pre-payment while allowing the Company to benefit from market prices above the capped price for the pre-payment volume. The terms of the BTL Facility seek to limit the downside oil price through associated hedging and therefore sets a ceiling on the repayment amounts owed to BTL throughout the term of the pre-payment. Should the price of Brent fall below the put option strike price the repayment amounts will reduce, whilst the repayment amounts are capped and do not increase when oil prices rise above the agreed level. Therefore, fluctuations in the underlying commodity price of Brent may cause the cost of pre-payments under the BTL facility to fluctuate accordingly throughout the term of the pre-payment.

The Completion of the Rockhopper Acquisition will increase the overall indebtedness and financial leverage of the Enlarged Group.

3 Impact of Leverage

Following Completion of the Rockhopper Acquisition and drawdown of the BTL Facility, the Enlarged Group will have debt service obligations. On Admission, the Enlarged Group's total outstanding indebtedness will be approximately US$8 million. The Directors believe that the level of leverage should reduce over time and the duration of the BTL Facility, however, the degree to which the Enlarged Group will continue to be leveraged could have important consequences for its business, operations and financial performance.

The Enlarged Group will require cash to meet obligations under its indebtedness and sustain the business operations, and the Enlarged Group's ability to do so will depend on many factors beyond its control. The Enlarged Group's ability to meet its obligations under its indebtedness, including making principal, interest and other payments when due, as well as its ability to fund ongoing business operations, will depend upon future operating performance and the Enlarged Group's ability to generate cash, which, in turn, will be affected to some extent by general economic conditions and by financial, competitive, legislative, regulatory and other factors, including those factors discussed in this Part and elsewhere in this Document.

Nothing in this risk factor in any way qualifies the Company's opinion that the working capital of the Enlarged Group taking into account the existing cash balances and the Net Proceeds is sufficient for the present requirements of the Enlarged Group, that is for at least 12 months from the date of this Document.

4 Auction Process

The sale of Rockhopper Egypt by Rockhopper PLC was carried out by means of a competitive auction process involving the Company, and so far as the Company understands, other bidders. Accordingly, the warranties and other buyer protections negotiated with the Seller in the Rockhopper Acquisition Agreement may be limited and may not address all potential liabilities associated with Rockhopper Egypt, whether identified from the Company's due diligence, unidentified or not disclosed. Accordingly, the Company may not have full recourse against, or otherwise may not be able to make a claim in respect of certain losses, or under the existing warranties set out in the Rockhopper Acquisition Agreement, the result of which could adversely affect the Enlarged Group's business, results of operations, financial conditions, and prospects.

The Rockhopper Acquisition Agreement contains financial and time limitations on breaches of warranty claims brought by the Company, which may impede its future recoverability of losses against Rockhopper PLC and could adversely affect the Enlarged Group's business, results of operations, financial conditions and future prospects.

5 Due Diligence on Rockhopper Egypt and the Assets

The Company has carried out certain due diligence on Rockhopper Egypt and the Assets, however, the due diligence carried out may not reveal all defects in the physical condition or ownership of the Assets acquired. Whilst the Rockhopper Acquisition Agreement provides some contractual protection as to the ownership and condition of the Assets, any warranty claims will be subject to customary contractual limitations and common law rules which may restrict the Company's ability to recover all or a substantial proportion of any losses suffered. A material level of defect could have an adverse impact on the Enlarged Group's ability to implement its business plan and could adversely impact the Enlarged Group's ability to realise the benefits of the Rockhopper Acquisition or delay their realisation.

6 The Enlarged Group may not be able fully to realise the benefits of the Rockhopper Acquisition

The Enlarged Group's success will partially depend upon the Company's ability following the Rockhopper Acquisition to integrate the Assets without significant disruption to its business. The Rockhopper Acquisition integration may divert management's attention from the ordinary course operations of the business and raise unexpected issues and may take longer or prove more costly than anticipated. Although the Directors believe that such disruption is unlikely, issues may come to light during the course of integrating the Assets into the Enlarged Group that may have an adverse effect on the financial condition and results of operations of the Enlarged Group. There is no assurance that the Company will realise the potential benefits of the Rockhopper Acquisition including, without limitation, recurring revenue from the Assets to the extent and within the time frame contemplated. If the Company is unable to integrate the Assets successfully into the Enlarged Group then this could have a significantly negative impact on the results of operations and/or financial condition of the Enlarged Group. The Enlarged Group's success will partially depend on there being no adverse change in the Assets between the date of this Document and the date of the completion of the Rockhopper Acquisition.

MATERIAL RISKS RELATING TO EGYPT

7 Political and Economic Risk in Egypt

Since the Arab Spring in 2011, the domestic political environment in Egypt has been the subject of continuous transition, with relative political and economic stability returning only in recent years. On 11 November 2016, the International Monetary Fund approved financial assistance for Egypt, in the form of an extended fund facility arrangement for approximately US$12 billion, to fund the Egyptian Government's proposed plans for economic reform.

Although Egypt's economic situation has significantly improved since 2011, in part due to the financial assistance of the IMF, inflation in Egypt still remains volatile, the result of which could lead to unpredictable economic situations such as the increased cost of operations, transportation or foreign currency risk. The Enlarged Group cannot predict the impact of inflation on oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial conditions, results of operations and cash flows by decreasing its profitability, increasing its costs, limiting its access to capital and decreasing the value of its Assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Egypt may adversely affect Enlarged Group's business and future financial results. Operations may be impacted in various degrees by such factors as government regulations with respect to restrictions on production, price controls, export controls, income taxes, expropriation of property, environmental legislation, land use, water use, land claims of local people and workplace safety.

Further changes in the political, economic and social conditions or other relevant policies of the Egyptian Government, such as changes in laws or regulations, export restrictions, expropriation of its assets or resource nationalization, and/or forced renegotiation or modification of Enlarged Group's existing contracts with EGPC could materially and adversely affect its business, financial conditions and results of operations. The petroleum sector in Egypt is governed by EGPC/GPC, EGAS and GANOPE, which report directly to the Egyptian Ministry of Petroleum. Relatively recent events in Egypt have been unpredictable and further changes may adversely affect the assets and operations of the Company. The Egyptian Ministry of Petroleum and EGPC may also experience personnel changes. Should such changes to the Egyptian Ministry of Petroleum and/or EGPC occur, the consequences and potential disruptions to the operations of the Enlarged Group's cannot be predicted.

In Egypt, licensing is often a matter of administrative discretion, in that laws frequently give wide licensing powers to administrative authorities. These powers are sometimes used inconsistently, are usually subject to unpublished policy considerations, and past practice may at any time be changed without notice. There are no laws that would set an exhaustive list of the licences required for a specific project. Therefore, there can be no guarantee that the licences which have been obtained for the Abu Sennan Concession are necessarily all the licences which may in practice be required. However, the most important licence for each concession is the concession agreements itself. The concession agreements along with the development leases grant the exploration and exploitation licences and, as such, these are the main licences.

Exposure to a range of political developments and consequent changes to the operating and regulatory environment could cause business disruption.

Egypt is a region where political, economic and social transition may take place. Political instability, changes to the regulatory environment or taxation, international sanctions, expropriation or nationalization of property, civil strife, strikes, insurrections, acts of terrorism and acts of war may disrupt or curtail the Enlarged Group's operations or development activities. These may in turn cause production to decline, limit the Enlarged Group's ability to pursue new opportunities, affect the recoverability of its assets or cause it to incur additional costs.

Events in or relating to Egypt, could adversely impact the Enlarged Group's income and investment in or relating to Egypt. The Enlarged Group's ability to pursue business objectives and to recognize production and reserves relating to these investments could also be adversely impacted.

8 Foreign Jurisdiction Risk

The Assets are located in Egypt. As such, following Completion, the Enlarged Group's operations, financial condition and operating results could be significantly affected by risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties, government control over domestic oil and gas pricing, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds; the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where, following Completion, the Enlarged Group will operate; and difficulties in enforcing the Enlarged Group's rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations. Problems may also arise due to the quality or failure of locally obtained equipment or technical support, which could result in failure to achieve expected target dates for exploration operations or result in a requirement for greater expenditure. Company's operations may also be adversely affected by applicable laws and policies of Egypt, the effect of which could have a negative impact on the Enlarged Group's financial and operating results.

9 Counterparty Risk

Following Completion, the Enlarged Group may have increased counterparty risk from its contractual arrangements with EGPC under the Abu Sennan Concession. Significant changes in the crude oil industry, fluctuations in level of commodity prices, prevailing economic political or regulatory conditions and geopolitical risks could adversely impact the Enlarged Group's ability to realise the full balance of its accounts receivable from EGPC in the future. Historically, EGPC has had a significant outstanding receivables balance owed to Rockhopper Egypt. While EGPC, with the commitment of the IMF, have taken significant steps to decrease the balance of receivables owed to all international companies including Rockhopper Egypt, there can be no assurance that future payments will occur on a more timely basis or occur at all. Furthermore, EGPC may fail to meet its on-going payment obligations under the Abu Sennan Concession in the future which could see the balance of receivables due to the Enlarged Group increase over time, which could have a materially adverse effect on the Enlarged Group's financial and operational results.

10 Non-Operator Risk

The Abu Sennan Concession is operated by a third party operator, namely, Kuwait Energy Egypt. Both the Enlarged Group and its partners are obliged to comply with the requirements of the applicable joint operating 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 participant were to fail to cooperate, it may delay or disrupt existing or future projects.

Whilst the Enlarged Group has certain rights under the Abu Sennan JOA which provide it with the ability to influence and/or control management and/or operations, the Enlarged Group relies on Kuwait Energy Egypt to carry out the day-to-day management of operations of the Concession. The Enlarged Group is also dependent on Kuwait Energy Egypt implementing the decisions that have been agreed among the participants of the Abu Sennan Concession and any mismanagement of the asset by Kuwait Energy Egypt may result in delays, disruptions or increased costs with respect to exploration, appraisal, development or production activities. The Enlarged Group also may disagree with actions proposed to be taken by Kuwait Energy Egypt and may be exposed to liability for actions taken by it. Whilst the terms of the Abu Sennan JOA imposes standards and requirements in relation to Kuwait Energy Egypt's activities and recourse for the Enlarged Group for breaches by Kuwait Energy Egypt of those agreements, there can be no assurance that Kuwait Energy Egypt will observe such standards or requirements.

The Enlarged Group may suffer unexpected costs or other losses if Kuwait Energy Egypt or any future partner does not meet its obligations. For example, other participants may experience financial or other difficulties or otherwise default in their obligations to meet capital or other funding obligations in relation to assets in which the Enlarged Group has interests, or the co-investors may experience financial or other difficulties or otherwise default on their obligations to meet capital or other funding obligations. 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 Enlarged Group's partner(s) 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.

11 Currency Risk

The revenues generated by Rockhopper Egypt, and following Completion, the Enlarged Group, may see increased exposure to foreign currency risk if EGPC substantially increases the proportion of payments in Egyptian Pounds beyond the requirements of the Enlarged Group to fund its operating expenses in Egypt, and the value of the Egyptian Pound declines against the US Dollar. Furthermore, increased domestic constraints on Egypt's foreign currency reserves, or potential restrictions on foreign currency remittances or capital controls, could have the potential to impede the Enlarged Group's ability to convert certain quantities of Egyptian Pounds to US dollars going forward, which could also reduce, or delay, its ability to effectively distribute cash to other jurisdictions within the Enlarged Group.

As cash calls under the Abu Sennan JOA can be paid to the operator in Egyptian Pounds, the effect from an increased proportion of EGPC payment being made in Egyptian Pounds, should not materially affect the liquidity of the Enlarged Group.

The devaluation of the Egyptian Pound has contributed to increases in the rate of inflation in Egypt, which has led, and may continue to increase the cost of obtaining domestic goods and services in Egypt.

12 Environmental and Decommissioning Costs

Under the Abu Sennan Concession, the contractor is liable for any damage caused by its exploration operations and is required to indemnify the Egyptian Government or EGPC against all damages resulting from the exploration and/or exploitation of petroleum reserves. Breaches of environmental law in Egypt may result in criminal penalties being levied in respect of damage resulting from oil spills or failures to prevent pollution from oil spills. Although there have been no reported cases of oil spills at Abu Sennan, no assurance can be given of potential environmental breaches in the future despite best efforts of the operator. Furthermore, no assurance can be given that environmental laws in Egypt will not result in the curtailment of production or a material increase in the costs of production, development, or exploration activities under the Abu Sennan Concession.

The Abu Sennan Concession contains a broad decommissioning framework which requires the contractor to undertake and commit to restore the concession area as it was at the time the contractor had received it. Such contractor obligations may extend to, restoring pipelines or petroleum wells, in a such a condition demanded by EGPC upon relinquishment. As EGPC reserves a discretion in relation to decommissioning standards under the Abu Sennan Concession, there is a risk that the Company, or the Enlarged Group could incur increased decommissioning costs, or delays in complying with its relinquishment obligations, where the contractors is required to restore the concession area completely or partially to an acceptable standard set by EGPC.

The licence includes a potential requirement for reinstatement without details as to how this would be implemented. In practice, it is understood that the EGPC tends not to require contractors to carry out decommissioning (i.e. to leave the exploration area as is). If decommissioning is required, UOG would expect EGPC's discretion to fall in line with good and accepted petroleum engineering principles/practices and to work closely with concession parties to agree costs and standards of decommissioning to be imposed (if any). However, should this not be the case, then at present unquantifiable costs could be incurred by the participants in the licence.

RISKS RELATING TO THE ENLARGED GROUP & ITS BUSINESS

13 Prices and Markets

Prices for oil and natural gas are subject to large fluctuations in response to changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Enlarged Group. These factors include economic and political conditions in the United States, Canada, United Kingdom, Europe, China and other emerging markets, the actions of OPEC and other oil and gas exploring nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Enlarged Group's ability to access such markets. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production or oil or natural gas and a reduction in the volumes and the value of the Enlarged Group's reserves. The Company might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Enlarged Group's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Enlarged Group's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Enlarged Group's business, financial condition, results of operations and prospects.

14 Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Enlarged Group depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Enlarged Group may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Enlarged Group's reserves will depend not only on its ability to explore and develop any existing properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Enlarged Group will be able to continue to locate satisfactory properties for acquisition or participation on economically favourable terms or at all. Moreover, if such acquisitions or participations are identified, management of the Enlarged Group may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Enlarged Group.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net reserves to return a profit after drilling, operating and other costs and taxes, royalties or their equivalents. Completion of a well does not assure a profit on investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

While diligent well supervision and effective maintenance operations can contribute to maximising productions rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering sour gas releases and spills, any of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Enlarged Group is not fully insured against all of these risks, nor are all such risks insurable. Although the operators of the Enlarged Group's concessions may be required to maintain liability insurance in an amount that they consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Enlarged Group could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all of the risks typically associated with such operations, including encountering unexpected formalities or pressures, premature decline of reservoirs and the invasion of water into producing formations, with losses resulting from the occurrence of any of these risks.

15 Reliance on Partners

The Company's exploration, development and productions assets currently comprise: (i) a 26.25 per cent. interest in Waddock Cross PL090 Licence; (ii) an 18.85 per cent. interest in the Exploration PL090 Licence; (iii) a 20 per cent. interest in the Podere Gallina Licence; (iv) a 20 per cent. interest in the Walton-Morant Licence; (v) a 10 per cent. interest in the P1918, PEDL 330 and PEDL 345 Licences; (vi) a 95 per cent. interest in the P2366 Licence; (vii) a 100 per cent interest in the P2480 Licence; (viii) potentially a 22 per cent. non-operated W.I. in Abu Sennan; and (ix) potentially a 20 per cent. interest in Block B onshore Bénin.

In November 2017 UOG signed an agreement with Tullow Jamaica to farm-in to the Walton-Morant licence at a 20 per cent. equity interest. A drill-or-drop decision is required by Q1 2020, and the JV partners are actively looking for a farm-down partner(s). Following a successful farm-down, an exploration well could be drilled in 2020/2021. However, should a farm-down partner(s) not be found, the Walton-Morant Licence is likely to be relinquished.

The divestment of the Company's 95 per cent. interest in the P2366 Licence to Hibiscus for US$5 million is conditional on certain milestones being achieved, *inter alia*, obtaining the OGA approval. In the event the agreed milestones are not achieved, and the remainder of the due payment is not made by Hibiscus, the P2366 Licence may be transferred back to the Company for nominal consideration.

In addition, the Company has an option to farm into Block B onshore Bénin for a 20 per cent. interest and will be responsible to fund 30 per cent. of the non-drilling and 20 per cent. of the drilling costs in the Phase 1 work programme as approved under the PSC. There is a possibility that the Company may decide not to exercise its option.

Accordingly, the Company is reliant on its partners, and notwithstanding that the Company performs due diligence on its partners' and potential partners' finances before entering into any such acquisition or farm-in, and fully expects current or future field partners to meet their obligations, any failure or delay in their doing so could have a material effect on the Company's ability to implement its stated strategy and consequently on its financial position and performance.

16 Title Matters

The Company would obtain the right to explore its assets and, to the best of its knowledge, would determine that those rights are in good standing; however, this right would be dependent on both the Company meetings its obligations under its contracts in relation to assets and meeting its obligations under their licences and/or contracts with applicable governments or governmental authorities in relation to the projects. The failure of the Company to perform its obligations could result in the applicable exploration and development licences and/or agreements being revoked or suspended. Furthermore, in any event, no assurance can be given that applicable governments will not revoke or significantly alter the conditions of the applicable exploration and development authorisations, and that such exploration and development authorisations will not be challenged or impugned by third parties. There is no certainty that such rights or additional rights applied or re-applied for will be granted or renewed on terms satisfactory to the Company. There can be no assurances that claims by third parties against the Company's assets or other rights will not be asserted at a future date.

17 Funding Requirements

The Enlarged Group anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. The Enlarged Group's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Enlarged Group may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. The Enlarged Group's ability to externally finance its capital requirements is dependent on, among other factors:

- the overall state of the capital markets;

- commodity prices;
- interest rates;
- the financial performance of the Enlarged Group;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities.

Failure to obtain financing on a timely basis could cause the Enlarged Group to forfeit its interest in certain properties, miss certain acquisition opportunities and/or reduce or terminate its operations. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Enlarged Group's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Enlarged Group's capital expenditure plans may result in a delay in development or production on the Enlarged Group's properties.

18 Reputational Risk

Any environmental damage, loss of life, injury or damage to property caused by the Enlarged Group's operations could damage the Enlarged Group's reputation in the areas in which the Enlarged Group operates. Negative sentiment towards the Enlarged Group could result in a lack of willingness of municipal authorities to grant the necessary licences or permits for the Enlarged Group to operate its business and in residents in areas where the Enlarged Group is doing business opposing further operations in the area by the Enlarged Group. If the Enlarged Group develops a reputation of having an unsafe work site it may impact the ability of the Enlarged Group to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Enlarged Group's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Enlarged Group has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Enlarged Group's operations could result in negative investor sentiment towards the Enlarged Group, which may result in limiting the Enlarged Group's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Ordinary Shares.

19 Foreign Operations: Italy

As at the date of this Document, the term of the exploration licence in Italy conventionally known as the Podere Gallina (the "**Italian Exploration Licence**") in which the Company holds a 20 per cent. interest expired on 3 February 2018. The Italian branch of PVO applied in July 2016 to the Ministry of Economic Development, General Directorate for Energy and Natural Resources – the National Mining Office for Hydrocarbons and Geothermal Energy (the "**Ministry**") for the first 3-year extension of the exploration period. The Company originally expected the licence extension to be awarded in the second quarter of 2018, with such extension having retrospective effect from 3 February 2018. However, as at the date of this Document, the extension has not been granted yet to the titleholder and there can no assurances or guarantees as to when such extension will be granted. Accordingly, the titleholder can finish the works that have been authorised by the Ministry but any further work not approved before 2 February 2018 can only be undertaken after an authorisation by the Ministry and an extension of the Italian Exploration Licence.

On 13 February 2019, the law No. 12 of February 11, 2019 on "Conversion into law, with amendments, of the law decree December 14, 2018, No. 135, containing urgent provisions on matters of support and simplification for enterprises and for the public administration" ("**Law 12/2019**") came into force in Italy.

Paragraph 4 of Article 11-ter on "Sustainable energy transition plan of the appropriate areas" ("**Plan**") of the Law 12/2019 provides for the suspension of all administrative procedures related to the granting of liquid and gaseous hydrocarbons exploration licences. Therefore, the procedure relating to the extension of the Italian Exploration Licence has been suspended. The suspension is provided for a period up to 24 months while the Italian Ministry of Economic Development and the Italian Ministry of Environment and Protection of the Land and Sea approve the adoption of the Plan which will identify the defined framework for the areas where liquid and gaseous hydrocarbons' prospection, exploration and production activities can be performed on the national territory.

If the Plan is not adopted within the period of 24 months of the date that the Law 12/2019 came into force, then the administrative procedure related to the extension of the Italian Exploration Licence can resume. However, if the Plan is adopted and the area where the Italian Exploration Licence is located is defined by the Plan as not compatible for the liquid and gaseous hydrocarbons' prospection, exploration and production activities, the application for extension will be rejected by the Italian Ministry of Economic Development pursuant to the new law.

Even if the administrative procedure related to the extension of the Italian Exploration Licence resumes, there are no guarantees or assurances that the extension will be granted. Furthermore, the Italian Exploration Licence will expire if an extension is not granted. If such expiry did occur, the Enlarged Group would potentially have to expend additional resources, in conjunction with PVO or otherwise, to consider its options as to whether to pursue this interest and/or explore alternative asset opportunities.

Although PVO filed an application in May 2018 for a production licence to develop the Selva Gas Field in Italy and a positive response was issued by the competent ministry in the Italian Government, there are no certainty, assurances or guarantees that PVO will be successful with its application and be awarded the production licence at the end of the award process. The next step of the award process is to carry out an environment assessment and a positive result is required to proceed to the next stage of the award process. If a positive environment assessment is not obtained, the application will not proceed. Even if a positive environment assessment is achieved, a resolution by the local government of the region Emilia Romagna will need to be passed. Furthermore, whilst the application by PVO for the production licence and the related award procedure are not suspended by the Law 12/2019, the application is affected by the Law 12/2019 as follows: (a) if the Plan is adopted and the area where the application for production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the Italian Ministry of Economic Development will reject the application for the production licence if it has not awarded before the Plan becomes effective; and (b) if the Plan is adopted and the production licence is awarded before the Plan becomes effective but the production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the production licence will be effective until the expiry date but no new applications for the extension will be allowed.

The above outline of the effects of the Law 12/2019 is for guidance only as at the date of this Document. There may be further changes and/or interpretation as the full impact is assessed by the Company and interested parties.

20 Foreign Operations: Jamaica

Jamaica is a country with moderate levels of political risk and high levels of economic and financial system risk.

Jamaica faces elevated emigration rates (net migration rate is approximately -0.43 per cent.), especially among college-educated professionals and students, leaving shortages of skilled labour in some sectors.

High debt, equivalent to around 110 per cent. of the country's GDP, combined with the reliance on tourism, increases non-payment risk.

As a small island developing country, Jamaica is particularly vulnerable to the effects of climate change. Hurricanes, droughts, and other extreme weather events have resulted in significant losses and damages. Between 2001 and 2012, Jamaica experienced 11 storm events (including 5 major hurricanes) and several flood and drought events, which resulted in losses and damages of around J$128.5 billion.

The above is not an exhaustive list of risks that might affect the Enlarged Group's operations in Jamaica.

21 Licence Risks

Despite successful acquisitions of interests in new licences, there is no assurance that any subsequent work carried out under any of these licences will be successful or that it will be effective in increasing the value of any of these assets.

No assurance can be given that the Enlarged Group will be able to carry out the work required under each of the licences it has an interest in to effectively realise increased value. In addition, even if the Enlarged Group completes a licence acquisition, general economic and market conditions or other factors outside the Enlarged Group's control could make its strategies difficult or impossible to implement. Any failure to implement its programme on a licence successfully and/or failure of the programme to deliver the anticipated benefits could have a material adverse effect on the Enlarged Groups results of operations and financial condition.

The Enlarged Group's current exploration and development objectives are dependent upon the grant, renewal or continuance in force of appropriate surface and/or sub-surface use contracts, license, permits, regulatory approvals and consents which may be valid only for a defined time period, may be subject to limitations and may provide for withdrawal in certain circumstances. There can be no assurance that such surface and/or sub-surface use contracts, licences, permits, regulatory approvals and consents would be granted, renewed or continue in force or, if so, on what terms.

Withdrawal of licences, termination of surface and/or sub-surface use contracts or failure to secure requisite licences or the cession thereof of surface and/or sub-surface use contracts in respect of any of the Company's operations may have a material adverse impact on the Enlarged Group's business, operating results and financial condition.

The Enlarged Group is not the operator of all the licences to which it is a party and, as a result, is not able to exercise full control over the operations of, and decisions taken by, the operator.

As a non-operator, although the Enlarged Group may have certain rights under an operating agreement, the Enlarged Group will have limited powers to determine the operations and costs relating to a particular asset. In addition, it is possible that the interests of the Enlarged Group, on the one hand, and the operator and/or other commercial partners, on the other will not always be aligned which could result in possible project delays, additional costs or disagreements. Accordingly, the Enlarged Group may be required to undertake (or cease undertaking) certain actions in relation to a particular asset which it does not believe are in the best interests of the Enlarged Group. As a result, the Enlarged Group may suffer unexpected costs and/or be required to contribute to costs which it does not believe are an efficient use of its capital if an operator and/or commercial partners determine that a particular course of action with which the Enlarged Group disagrees should be taken under agreements governing the relationship. For example, the Enlarged Group may be required to fund capital or other obligations in relation to such assets at times specified by an operator that may be less than optimal for the Enlarged Group. In addition, the Enlarged Group's commercial partners may have incentives to delay or attempt to delay certain decisions being taken in relation to investments or expenditure at points in time when the Enlarged Group consider such decisions to be in its interests.

The terms of any relevant operating agreement will generally impose standards and requirements in relation to an operator's activities. While the Enlarged Group has acquired interests in oil and gas assets that are operated by, what the Directors believe to be, reputable operators, there can be no assurance that any such operator will observe such standards or requirements.

Failure by an operator to comply with its obligations under relevant licences including, for example, health and safety and environmental requirements, or the relevant operating agreement may result in delays or increased costs, lead to fines, penalties and restrictions and/or the withdrawal of licences or termination of the agreements under which it operates. The Enlarged Group may also be subject to claims by an operator regarding potential non-compliance with the Enlarged Group's obligations under the relevant licences or operating agreement.

The occurrence of any of the situations described above as a result of the Enlarged Group not being the operator of a particular asset or being able to exercise voting rights in respect of a particular asset to direct or exert influence over decisions relating to such asset could materially and adversely affect the business, financial condition and results of operations of the Enlarged Group.

22 Estimate Risks

The oil and gas contingent and prospective resources data and the production profiles and development plans for the Enlarged Group's assets, detailed in this Document, are only estimates. There are uncertainties inherent in estimating oil and gas resources and reserves for any oil and gas asset. These uncertainties are generally greater for areas where there has been limited historic hydrocarbon exploration. In addition, the contingent and prospective resource estimates contained in this Document are derived from the interpretation of seismic and other geoscientific data and, where appropriate, drilling results. Such interpretation and estimates of the amounts of oil and gas resources are subjective and the results of drilling, testing and production subsequent to the date of any particular estimate may result in substantial revisions to the original interpretation and estimates.

Following Completion, the Enlarged Group will be required to, estimate the quality of oil and gas reserves and resources from underground reservoirs which cannot be precisely measured, and must also estimate the future cash flows likely to be derived from them. Estimates of quantity of commercially recoverable oil and gas reserves, rates of production, net present cash flows and timing of development expenditures depend upon several variables and assumptions such as historical production from the area, interpretation of geological and geophysical data, effects of regulations adopted by governmental agencies, future oil and gas prices, capital expenditure and future operating costs, taxes on the extraction of commercial minerals and workover and remedial costs. This process is complex and subjective and involves numerous uncertainties. In addition, reserves and resources estimates are inherently speculative and may require downward revisions based on the results of subsequent drilling, testing and production, or as a result of changes in oil and gas prices or operating costs or economic factors which are beyond the Enlarged Group's ability to predict or control. Any downward revisions may indicate lower future production, adversely affecting the Enlarged Group's financial condition and prospects.

Fluctuations in the estimates of the Enlarged Group's reserves may also affect its ability to raise capital, where required, for future exploration, appraisal and development.

23 Internal Systems and Controls

The Company faces risks frequently encountered by developing companies such as under-capitalisation, cash shortages and limited resources. In particular, its future growth and prospects will depend on its ability to manage growth and to continue to maintain, expand and improve operational, financial and management information systems on a timely basis, whilst at the same time maintaining effective cost controls. Any damage to, failure of or inability to maintain, expand and upgrade effective operational, financial and management information systems and internal controls in line with the Company's growth could have a material adverse effect on its business, financial condition and results of operations.

24 Retention of Key Business Relationships

The Company relies 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 Company could be adversely affected by the changes to such relationships or difficulties in forming new ones. Any circumstances which causes the early termination or non-reward of one or more of these key business alliances or contracts or the failure to successfully form new ones, could adversely impact the Company, its business, operating results and prospects.

25 Attraction and Retention of Key Employees

The Company's success depends on its current and future executive management team. If any key person was to resign, there would be a risk that no suitable replacement with the requisite skills, contacts and industry experience would be found to replace such person. The senior executive personnel have equity interests in the Company. Notwithstanding this, if key personnel were to leave the Company, it could have a material adverse effect on the Company's business, financial condition and operating results.

26 Political Conditions

Although political conditions in Europe and Jamaica are generally stable, changes may occur in its political, fiscal and legal systems, which might adversely affect the ownership or operation of the Enlarged Group's interests including, *inter alia*, changes in exchange rates, exchange control regulations, expropriation of oil and gas rights, changes in government and in legislative, fiscal and regulatory regimes. The Rockhopper

Acquisition will expose the Enlarged Group to potential risks in Egypt as described in paragraph 7 of this Part III. The Enlarged Group's strategy has been formulated in the light of the current regulatory environment and likely future changes.

Although the Directors believe that the Enlarged Group's activities will be carried out in accordance with all applicable rules and regulations, no assurance can be given that new rules, laws and regulations will not be enacted or that existing or future rules and regulations will not be applied in a manner which could serve to limit or curtail exploration production or development of the Enlarged Group's business or have an otherwise negative impact on its activities. Amendments to existing rules, laws and regulations governing the Enlarged Group's operations and activities or increases in or more stringent enforcement, implementation thereof, could have a material adverse impact on the Enlarged Group's business, results of operations and financial condition and its industry in general in terms of additional compliance costs.

27 "Brexit"

The decision by the United Kingdom to exit from the European Union could have an impact on the Company's business, financial condition and results of operations. There still remain significant uncertainties in relation to the terms and time frame within which such an exit (due by law to take place on 31 October 2019) would be effected, and there are significant uncertainties as to what the impact will be on the fiscal, monetary and regulatory landscape in the UK, including *inter alia*, the UK's tax system, the conduct of cross-border business and export and import tariffs. There is also uncertainty in relation to how, when and to what extent these developments will impact on the economies in the United Kingdom and the EU and the future growth of their various industries, including the oil and gas sector, and on levels of investor activity and confidence, on market performance and on exchange rates. Although it is not possible to predict the effects of possible economic and political uncertainty in either the United Kingdom or the European Union, any of these risks, taken singularly or in the aggregate, could have a material adverse impact on the Company's business, financial condition and results of operations.

28 Insurance Risk

The Company insures its operations in accordance with industry practice and plans to insure the risks it considers appropriate for its needs and circumstances. No assurance can be given that the Enlarged Group will be able to obtain insurance coverage at reasonable rates or at all, or that any coverage it obtains will be adequate and available to cover any claims arising. The Enlarged Group may become subject to liability for pollution or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. 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, the Enlarged Group's business and operations, financial results or financial position may be disrupted and adversely affected.

29 Exchange Rate Risk

The Enlarged Group may make investments in currencies other than Sterling or US dollars. Accordingly, the value of such investments may be adversely affected by changes in currency exchange rates notwithstanding the performance of the investments themselves, which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Enlarged Group.

30 Fluctuations of Revenues and Operating Results

Future revenues, expenses and operating results of the Enlarged Group could vary significantly from period to period as a result of a variety of factors, some of which are outside its control. These factors include general economic conditions, adverse movements in commodity prices, conditions specific to the oil and gas services market, seasonal trends in revenues, capital expenditure and other costs. In response to a changing competitive environment, the Enlarged Group may elect from time to time to make certain pricing, service or marketing decisions or investments that could have a material adverse effect on its revenues, results of operations and financial conditions and prospects.

To the extent that external sources of capital, including the issuance of additional Ordinary Shares, become limited or unavailable, the ability of the Enlarged Group to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired.

31 Legal Systems

The legal systems in jurisdictions in which the Enlarged Group will operate in the future may be different to the legal systems in more established economies, such as the UK, which could result in risks such as (i) effective legal redress in the Courts of such jurisdictions being more difficult to obtain, whether in respect of a breach of law or in an ownership dispute; (ii) a higher degree of discretion on the part of Governmental authorities who may be susceptible to corruption; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, order and resolutions; or (v) relative inexperience of the judiciary and Courts in such matters.

In certain jurisdictions the commitment of local business people, Government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to the Enlarged Group's licences and agreements. There can be no assurance that joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the actions of Government authorities or otherwise and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Given that the Jamaican legal system is based on the English common law system, the Directors are confident that the Enlarged Group, whilst subject to a legal systems different to that in the UK insofar as it relates to the Walton-Morant Licence, is exposed to minimal risks insofar as such risks comprise issues the same or similar to those detailed in (i) through (v) above. Furthermore, the final court of appeal in Jamaica is The Judicial Committee of the Privy Council, which is based in London.

The Company has to date primarily focused on assets based in the UK and Europe. The Rockhopper Acquisition will expose the Enlarged Group to potential foreign jurisdiction risks in Egypt as described in paragraph 8 of this Part III. In addition, the Directors may consider assets in other countries and regions on an opportunistic basis, and therefore may be subject to risks particular to less stable jurisdictions which could negatively impact its operations.

32 Litigation Risks

Whilst the Company currently has no outstanding litigation or disputes, there can be no guarantee that the current or future actions of the Enlarged Group will not result in litigation since there have been a number of cases where the rights and privileges of natural resource companies have been the subject of litigation. The petroleum industry, as with all industries, may be subject to legal claims, both with and without merit, from time to time. The Directors cannot prejudice that such litigation may be brought against the Company, or any other company within the Enlarged Group, in the future. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty of the litigation process, there can be no assurance that the resolution of any particular legal proceedings will not have a material adverse effect on the Enlarged Group's financial position, results or operations. The Enlarged Group's business may be materially adversely affected if it and/or its employees or agents are found not to have met the appropriate standard of care or not exercise their discretion or authority in a prudent or appropriate manner in accordance with accepted standards.

33 Environmental Risks and Hazards

All phases of the Enlarged Group's operations are subject to environmental regulation in the various jurisdictions in which it operates. Environmental legislation is evolving in a manner that will require stricter standards and enforcement, increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their officers, directors and employees. There is no assurance that existing or future responsibility environmental regulation will not materially adversely affect the Enlarged Group's business, financial condition and results of operations. Environmental hazards may exist on the properties on which the Enlarged Group holds interests that are unknown to the Enlarged Group at present and that have been caused by previous or existing owners or operators of the properties.

Governmental approvals and permits are currently, and may in the future be, required in connection with the Enlarged Group's operations. To the extent such approvals are required and not obtained, the Enlarged Group may be curtailed or prohibited from proceeding with planned exploration or development of mineral properties.

Failure to comply with applicable laws, regulations and permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment, or remedial actions. Parties engaged in mining operations, including the Enlarged Group, may be required to compensate those suffering loss or damage by reason of the mining activities and may have civil or criminal fines or penalties imposed for violations of applicable laws or regulations.

Amendments to current laws, regulations and permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions. Parties engaged in oil & gas operations, including the Enlarged Group, may be required to compensate those suffering loss or damage by reason of the exploration, and/or development activities and may have civil or criminal fines or penalties imposed for violations of applicable laws or regulations.

Amendments to current laws, regulations and permits governing operations and activities of oil & gas companies, or more stringent implementations thereof, could have a material adverse impact on the Enlarged Group and cause increase in exploration expenses, capital expenditures or production costs, reduction in levels of production at producing properties, or abandonment or delays in development of new mining properties.

The Enlarged Group's current and future operations that are conducted in Egypt are subject to environmental regulations promulgated by the Egyptian government. Should the Enlarged Group initiate operations in other countries, such operations will be subject to environmental legislation in such jurisdiction. Current environmental legislation in Egypt provides for restrictions and prohibitions on spills, releases or 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 Company's existing operations are subject to such environmental policies and legislation. Environmental legislation and policy are periodically amended. Such amendments may result in stricter standards and enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects 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 expenditures, 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.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Enlarged Group to incur costs to remedy such discharge. No assurance can be given that the application of environmental laws to the business and operations of the Enlarged Group will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Enlarged Group's financial condition, results of operations or prospects.

Environmental legislation in Egypt provides for restrictions and prohibitions on releases or emissions and regulation of the storage and transportation of various substances produced or utilised in association with certain oil industry operations. This legislation and associated regulations can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. Applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licences and authorisations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Environmental legislation and policy are periodically amended. Such amendments may result in stricter standards and enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects 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 expenditures, 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 and associated activities.

34 Competition

The oil and gas industry is very competitive and some of the Enlarged Group's competitors have access to greater financial and technical resources which may give them a competitive advantage. As a result, the Enlarged Group may not be able to compete effectively with competitors or gain access to future growth opportunities.

35 Risks Relating to Taxation

There can be certainty that the current taxation regime in the UK or overseas jurisdictions within which the Enlarged Group currently operates or may operate in the future will remain in force or that the current levels of corporation taxation will remain unchanged. There can be no assurance that there will be no amendment to the existing taxation laws applicable to the Enlarged Group, which may have a material adverse effect on the Enlarged Group's financial position.

Any change in the Company's tax status or in taxation legislation in the UK could affect the Company's ability to provide returns to Shareholders. Statements in this Document concerning the taxation of investors in Shares are based on current law and practice, which is subject to change. The taxation of an investment in the Company depends on the individual circumstances of investors.

The nature and amount of tax which members of the Company expect to pay and the reliefs expected to be available to any member of the Company are each dependent upon several assumptions, any one of which may change and which would, if so changed, affect the nature and amount of tax payable and reliefs available. In particular, the nature and amount of tax payable is dependent on the availability of relief under tax treaties and is subject to changes to the tax laws or practice in any of the jurisdictions affecting the Company. Any limitation in the availability of relief under these treaties, any change in the terms of any such treaty or any changes in tax law, interpretation or practice could increase the amount of tax payable by the Company.

The Company's effective tax rate could be adversely affected by changes in the mix of earnings and losses in countries with differing statutory tax rates, certain non-deductible expenses arising from stock option compensation, the valuation of deferred tax assets and liabilities and changes in international tax laws and accounting principles. Increase in the Company's effective tax rate could materially affect the Company's net financial results.

In addition, the Enlarged Group is subject to income tax audits by many tax jurisdictions. Although the Directors believe that the Company's income tax liabilities are reasonably estimated and accounted for in accordance with applicable laws and principles, an adverse resolution of one or more uncertain tax positions in any period could have a material impact on the results of operations for that period.

Investors who are in any doubt as to their tax position or who are subject to tax in jurisdictions other than the UK are strongly advised to consult their professional adviser.

36 Future Acquisitions

An important part of the Enlarged Group's longer term business strategy involves expansion through acquisition of oil and gas assets which may be at exploration, development or production stages. There is a risk related to the Enlarged Group's ability to accurately identify suitable targets and successfully execute transactions for such a strategy or that any business acquired may not develop or succeed as anticipated or at all. As consideration for such acquisitions, the Company may seek to issue Ordinary Shares. There can be no guarantee that the sellers of target companies, business or assets will be prepared to accept shares traded on AIM as consideration, and this may limit the Enlarged Group's ability to grow its activities and pursue its strategy. The difficulties involved in integrating any companies, businesses or assets acquired by the Enlarged

Group may divert financial and management resources from the Enlarged Group's core business, which could adversely affect the Enlarged Group's business, financial condition, operating results and prospects.

37 Fraud, Bribery and Corruption

Doing business in developing countries brings with it inherent risks associated with the enforcement of the Enlarged Group's legal and contractual rights and third party obligations, fraud, bribery and corruption. Fraud, bribery and corruption are more common in some jurisdictions than in others. Moreover, the oil and gas industries have historically been shown to be vulnerable to corrupt or unethical practices.

Instances of fraud, bribery, corruption, and violations of laws and regulations in the jurisdictions in which the Enlarged Group operate include the UK Bribery Act 2010 could have a material adverse effect on its results of operation and financial conditions. As a result of the Enlarged Group's anti bribery and corruption policy, it could be at a commercial disadvantage and may fail to secure contracts and licences to the advantage other companies who may not have to comply with such anti-corruption safeguards.

RISKS RELATING TO THE ORDINARY SHARES

38 Share Price Volatility and Liquidity

An investment in companies whose shares are traded on AIM is perceived to involve a higher degree of risk and to be less liquid than an investment in companies whose shares are listed on the Official List. There can be no assurance that an active or liquid trading market for the 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 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. Accordingly, 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, 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 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 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 Shares are quoted and the price which investors may realise for their 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 Company and its operations. These factors include, without limitation, (i) the performance of the Company and overall stock market, (ii) large purchases or sales of 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 Company to meet the expectations of the research analysts, (v) changes in legislation or regulations and changes in general economic, political or regulatory conditions, and (vi) other factors which are outside of the control of the Company. Factors unrelated to the Company's performance could include macroeconomic developments nationally or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. Accordingly, the price at which the Shares of the Company will trade cannot be accurately predicted.

Shareholders may sell their Shares in the future to realise their investment. Sales of substantial amounts of Shares following Admission, or the perception that such sales could occur, could materially adversely affect the market price of the Shares available for sale compared to the demand to buy Shares. Such sales may also make it more difficult for the Company to sell equity securities in the future at a time and price that is deemed appropriate. There can be no guarantee that the price of the Shares will reflect their actual or potential market value or the underlying value of the Company's net assets.

39 Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to its contractual commitments under the BTL Facility, as well as the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time could be reduced or suspended entirely.

The market value of the Ordinary Shares may deteriorate if cash dividends are not paid, reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditure or property acquisitions using funds from operations.

40 Dilution and Pre-Emption Rights

Upon issue of the Placing Shares, the Subscription Shares and Consideration Shares as part of the Rockhopper Acquisition, the existing Ordinary Shares in the Company will represent 44.2 per cent. of the total issued shares (excluding treasury shares) immediately following Admission (and assuming no further shares are issued by the Company prior to the Admission of the Enlarged Group to trading on AIM).

The Enlarged Group may make acquisitions in the future, enter into financing arrangements, or other transactions involving further issuances of Ordinary Shares in the Company (debt instruments, or other securities convertible into Ordinary Shares), which may have a potentially dilutive effect on the Company's issued share capital from time to time. The Company cannot predict the size of future issuances of Ordinary Shares (or other securities as described above) or its effect, if any, that further issuances and sales of the Company's securities will have on the market price of the Ordinary Shares.

Each of these events could result in significant dilution of the shareholdings of other Shareholders who do not participate in these issues.

41 Warrants and Options

As described in paragraphs 4.7, 4.11 and 7.2 of Part VII of this Document, the Company has issued Warrants to certain of its existing professional advisers and vendors of UOG UK the as well as Options granted to the Directors and senior management. The Company may, in the future, issue further options and/or warrants to subscribe for new Ordinary Shares to certain advisers, employees, Directors, senior management and/or consultants of the Enlarged Group. The exercise of any such options and warrants would result in a dilution of the shareholdings of other investors.

It should be noted that the 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 crystallise, the Enlarged Group's business, financial condition, results or future operations could be materially adversely affected. In such case, the price of the Ordinary Shares could decline, and investors may lose all or part of their investment.

PART IV

HISTORICAL FINANCIAL INFORMATION OF THE ENLARGED GROUP

SECTION A(i): ACCOUNTANT'S REPORT ON ROCKHOPPER EGYPT HISTORICAL FINANCIAL INFORMATION

Date: 6 December 2019

The Directors
United Oil & Gas Plc
200 Strand
London
WC2R 1DJ

The Directors
Beaumont Cornish Limited
10th Floor 30 Crown Place
London
EC2A 4EB

Dear Sirs,

ROCKHOPPER EGYPT

Introduction

We report on the audited historical financial information on Rockhopper Egypt (the "Company") set out in section A (ii) (the "Company Financial Information"). This Company Financial Information has been prepared for inclusion in the admission document dated 6 December 2019 (the "AIM Admission Document") on the basis of the accounting policies set out in the Notes to the Company Financial Information. This report is required by paragraph (a) of Schedule Two to the AIM Rules for Companies (the "AIM Rules") and is given for the purposes of complying with the AIM Rules and for no other purpose.

Responsibilities

The directors of the Company are responsible for preparing the Company Financial Information in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion on the Company Financial Information as to whether the Company Financial Information gives a true and fair view, for the purposes of the Document and to report our opinion to you.

Save for any responsibility arising under Paragraph (a) of Schedule Two of the AIM Rules for Companies to any person as and to the extent there provided, to the fullest extent permitted by the law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Paragraph (a) of Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the AIM Admission Document.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's 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 financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in the United States of America or other jurisdictions outside the United Kingdom and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion, the Company Financial Information gives, for the purposes of the AIM Admission Document, a true and fair view of the state of affairs of Rockhopper Egypt at 31 December 2016, 31 December 2017 and 31 December 2018, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union and that it has been prepared in a form that is consistent with the accounting policies adopted by Rockhopper Egypt.

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 AIM Admission Document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the AIM Admission Document in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies.

Yours faithfully

UHY Hacker Young LLP
Chartered Accountants

SECTION A(ii): ROCKHOPPER EGYPT HISTORICAL FINANCIAL INFORMATION

Income Statement

	Notes	2016 $	2017 $	2018 $
Revenue		4,292,217	5,003,091	6,123,788
Cost of sales		(4,127,089)	(3,201,333)	(3,730,279)
Gross profit		165,128	1,801,758	2,393,509
Administrative expenses		(386,158)	(507,265)	(406,306)
Admin expenses - foreign exchange loss on related party balance		(5,598,139)	-	-
Admin expenses - impairment of assets		-	(2,424,159)	(3,408,344)
Operating loss	1	(5,819,169)	(1,129,666)	(1,421,141)
Finance costs	3	(54,844)	-	-
Loss before taxation		(5,874,013)	(1,129,666)	(1,421,141)
Taxation	4	-	-	-
Loss for the financial year attributable to the Company's equity shareholders		(5,874,013)	(1,129,666)	(1,421,141)
Loss per share:				
Basic and diluted loss per share (cents)	5	(5.78)	(0.42)	(0.53)

Statement of Comprehensive Income

	2016 $	2017 $	2018 $
Loss for the financial year	(5,874,013)	(1,129,666)	(1,421,141)
Total comprehensive income for the financial year attributable to the Company's equity shareholders	(5,874,013)	(1,129,666)	(1,421,141)

Rockhopper Egypt Pty Limited

Balance Sheet as at 31 December

	Notes	2016	2017	2018
Assets		$	$	$
Non-current assets				
Exploration & evaluation assets	6	6,282,639	5,681,979	5,822,498
Property, plant and equipment	7	6,173,141	5,324,808	5,404,237
		12,455,780	11,006,787	11,226,735
Current assets				
Inventories	8	43,068	32,889	22,823
Trade and other receivables	9	11,936,765	9,838,908	8,749,496
Cash and cash equivalents	10	-	22,251	647,285
		11,979,833	9,894,048	9,419,604
Total assets		24,435,613	20,900,835	20,646,339
Equity and liabilities				
Capital and reserves				
Share capital	11	202,919,136	202,919,136	202,919,136
Retained losses		(181,787,506)	(182,917,172)	(184,338,313)
Shareholders' funds		21,131,630	20,001,964	18,580,823
Current liabilities:				
Trade and other payables	12	3,303,026	898,871	2,065,516
Overdraft		957	-	-
		3,303,983	898,871	2,065,516
Total equity and liabilities		24,435,613	20,900,835	20,646,339

Rockhopper Egypt Pty Limited

Statement of Changes in Equity

	Share capital $	Retained losses $	Total $
For the year ended 31 December 2016			
Balance at 1 January 2016	1	(175,913,493)	(175,913,492)
Loss for the year	-	(5,874,013)	(5,874,013)
Total comprehensive loss for the year	-	(5,874,013)	(5,874,013)
Issue of share capital	202,919,135	-	202,919,135
Balance at 31 December 2016	202,919,136	(181,787,506)	21,131,630
For the year ended 31 December 2017			
Balance at 1 January 2017	202,919,136	(181,787,506)	21,131,630
Loss for the year	-	(1,129,666)	(1,129,666)
Total comprehensive loss for the year	-	(1,129,666)	(1,129,666)
Balance at 31 December 2017	202,919,136	(182,917,172)	20,001,964
For the year ended 31 December 2018			
Balance at 1 January 2018	202,919,136	(182,917,172)	20,001,964
Loss for the year	-	(1,421,141)	(1,421,141)
Total comprehensive loss for the year	-	(1,421,141)	(1,421,141)
Balance at 31 December 2018	202,919,136	(184,338,313)	18,580,823

Rockhopper Egypt Pty Limited

Statement of Cash Flows for the year ended 31 December

	2016	2017	2018
	$	$	$
Cash flow from operating activities			
Loss for the financial year before tax	(5,874,013)	(1,129,666)	(1,421,141)
Depreciation	1,255,920	1,589,310	1,768,910
Impairment of PPE assets	146,248	-	-
Impairment of intangible assets	-	2,424,159	3,408,344
Foreign exchange movements	5,598,139	978	29,874
	1,126,294	2,884,781	3,785,987
Changes in working capital			
(Increase) / decrease in inventories	(43,068)	10,179	10,066
(Increase) / decrease in trade and other receivables	(3,092,071)	2,097,857	1,089,412
Increase / (decrease) in trade and other payables	7,711,999	(2,405,133)	1,136,772
Cash flow from operating activities	5,703,154	2,587,684	6,022,237
Cash outflow from investing activities			
Purchase of property, plant & equipment	(1,962,074)	(740,977)	(1,848,340)
Payments for intangible exploration assets	(3,766,341)	(1,823,499)	(3,548,863)
Net cash used in investing activities	(5,728,415)	(2,564,476)	(5,397,203)
Net (decrease) / increase in cash and cash equivalents	(25,261)	23,208	625,034
Cash and cash equivalents at beginning of financial year	24,304	(957)	22,251
Cash and cash equivalents at end of financial year	(957)	22,251	647,285
Comprising:			
Cash and cash equivalents	-	22,251	647,285
Overdraft	(957)	-	-
	(957)	22,251	647,285

Notes to the historical financial information

Principal Accounting Policies

Basis of preparation
The financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"), as adopted by the European Union and, IFRIC interpretations.

IFRS is subject to amendment and interpretation by the IASB and the IFRS Interpretations Committee, and there is an on-going process of review and endorsement by the European Commission. These accounting policies comply with each IFRS that is mandatory for accounting periods ending on 31 December 2019.

The principal accounting policies set out below have been consistently applied to all periods presented.

Revenue
Revenue arising from the sale of oil and gas is recognised when control over a product or service is transferred to a customer, which is typically at the point that title passes, and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Finance income and costs
Interest is recognised using the effective interest method which calculates the amortised cost of a financial asset or liability and allocates the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments through the expected life of the financial asset or liability to the net carrying amount of the financial asset or liability.

Exploration and evaluation assets
The Company accounts for oil and gas expenditure under the full cost method of accounting.

Costs (other than payments to acquire the legal right to explore) incurred prior to acquiring the rights to explore are charged directly to the income statement. All costs incurred after the rights to explore an area have been obtained, such as geological, geophysical, data costs and other direct costs of exploration and appraisal are accumulated and capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities if technical feasibility is demonstrated and commercial reserves are discovered, then following development sanction, the carrying value of the relevant E&E asset will be reclassified as a development and production asset within tangible fixed assets.

If after completion of appraisal activities in an area, it is not possible to determine technical feasibility or commercial viability, then the costs of such unsuccessful exploration and evaluation are written off to the income statement. The costs associated with any wells which are abandoned are fully amortised when the abandonment decision is taken.

Development and production assets, are accumulated generally on a field by-field basis and represent the costs of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves which have been transferred from intangible E&E assets.

The net book values of development and production assets are depreciated generally on a field-by-field basis using the unit of production method based on the commercial proven and probable reserves. Assets are not depreciated until production commences.

Property, plant and equipment
Property, plant and equipment are stated at cost on acquisition less depreciation. Depreciation is provided on a straight-line basis at rates calculated to write off the cost less the estimated residual value of each asset over its expected useful economic life. The residual value is the estimated amount that would currently be obtained from disposal of the asset if the asset were already of the age and in the condition expected at the end of its useful life.

The annual rate of depreciation for each class of depreciable asset is:
Computer equipment 33%

The carrying value of property, plant and equipment is assessed annually and any impairment is charged to the income statement.

Impairment of non-financial assets
At each balance sheet date, the Directors review the carrying amounts of the Company's tangible and intangible assets, 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. Where the asset does not generate cash flows that are independent from other assets, the Company estimates the recoverable amount of the cash-generating unit to which the asset belongs.

Recoverable amount is the higher of fair value less costs to sell and value in use. 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 its carrying amount, the carrying amount of the asset or cash-generating unit is reduced to its recoverable amount. If the recoverable amount of a cash-generating unit is less than its carrying amount, the impairment loss is allocated to the assets of the unit pro rata based on the carrying amount of each asset in the unit.

An impairment loss is recognised as an expense immediately.

Where an impairment loss subsequently reverses, the carrying amount of the asset or 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 or cash-generating unit in prior periods. A reversal of an impairment loss is recognised in the Income Statement immediately.

Inventories
Inventory comprises oil in tanks and is stated at the lower of cost and net realisable value. Cost is calculated annually based on the ratio of closing inventory to total annual production and the cost of production (including depreciation) for the year.

Cash and cash equivalents
Cash and cash equivalents comprise cash in hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

Financial instruments
Financial assets and financial liabilities are recognised when the Company becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are measured initially at fair value plus transactions costs. Financial assets and financial liabilities are measured subsequently as described below.

Financial assets

The Company classifies its financial assets as 'loans and receivables'. The Company assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are classified as 'trade and other receivables' in the Balance Sheet.

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment.

A provision for impairment of trade receivables is established when there is objective evidence that the Company will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulty, high probability of bankruptcy or a financial reorganisation and default are considered indicators that the trade receivable is impaired. The amount of the provision is the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at original effective interest rate. The loss is recognised in the Income Statement. When a trade receivable is uncollectible, it is written off against the allowance account for trade receivables. Subsequent recoveries of amounts previously written off are credited in the Income Statement.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and all substantial risks and rewards are transferred.

Financial liabilities
The Company’s financial liabilities include trade and other payables.

Trade payables and borrowings are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

A financial liability is derecognised when it is extinguished, discharged, cancelled or expires.

Taxation
Current taxation for the Company is based on the local taxable income at the local statutory tax rate enacted or substantively enacted at the balance sheet date and includes adjustments to tax payable or recoverable in respect of previous periods.

Deferred taxation
Deferred taxation is calculated using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial information. However, if the deferred tax arises from the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss, it is not accounted for. Deferred tax is determined using tax rates and laws that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised, or the deferred tax liability is settled.

Deferred tax liabilities are provided in full.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Changes in deferred tax assets or liabilities are recognised as a component of tax expense in the Income Statement, except where they relate to items that are charged or credited directly to equity in which case the related deferred tax is also charged or credited directly to equity.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

Foreign currency
The functional currency and also the presentational currency of the Company is US dollars.

Transactions in foreign currencies are recorded at the rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the year-end date. All differences are taken to the Income Statement.

Leases
The Company assesses whether a contract is or contains a lease at the inception of the contract. The Company recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets. For these leases, the Company recognises the lease payments as an operating expense on a straight-line basis over the term of the lease.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, the Company uses its incremental borrowing rate.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability, using the effective interest method, and by reducing the carrying amount to reflect the lease payments made.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement date and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Equity
Equity comprises the following:

- “Share capital” represents amounts subscribed for shares at nominal value.
- “Retained earnings” represents the accumulated profits and losses attributable to equity shareholders.

Adoption of New and Revised International Financial Reporting Standards

At the date of authorisation of this financial information, the IASB and IFRS Interpretations Committee have issued standards, interpretations and amendments which are applicable to the Company.

The Company has applied IFRS 16 Leases in preparation of the historical financial information.

IFRS 16 introduces revised requirements with respect to lease accounting. It introduces significant changes to the lessee accounting by removing the distinction between operating and finance lease requirements and requiring the recognition of a right-to-use-asset and a lease liability at commencement for all leases with the exception of short-term leases and leases of low value assets.

IFRS 16 has an immaterial impact on the Company's financial information as the impact is limited to the office lease which is of relatively short duration.

Other than minor changes to standards arising from annual improvements, there have been no other new or revised standards adopted in the preparation of the historical financial information for the current financial year that have had a material impact on the historical financial information of the Company.

There are no standards and interpretations in issue but not yet adopted that the Directors anticipate will have a material effect on the reported income or net assets of the Company.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of financial information in conformity with generally accepted accounting practice requires management to make estimates and judgements that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period.

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The following are the significant judgements used in applying the accounting policies of the Company that have the most significant effect on the financial information:

Impairment of exploration licenses

Management reviews intangible exploration assets for indicators of impairment under IFRS 6 at the end of each reporting period. This review of assets for potential indicators of impairment requires judgement including whether renewal of licences is planned, interpretation of the results of exploration activity and the extent to which the Company plans to continue substantive expenditure on the assets. In determining whether substantive expenditure remains in the Company's plan, management considers factors including future oil prices, plans to develop or renew licences and future exploration plans. If impairment indicators exist the assets are tested for impairment and carried at the lower of the estimated recoverable amount and net book value.

Rockhopper Egypt Pty Limited

Notes to the historical financial information

1. Segmental reporting

Operating segments

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources, assessing the performance of the operating segment and making strategic decision, has been identified as the Board of Directors. The Board of Directors consider that the Company has only one operating segment at corporate level, being the exploration for and production of oil and gas prospects, therefore no additional segmental information is presented.

The Company operates in one geographic area – Egypt.

2. Directors and employees

The aggregate payroll costs of the employees excluding Director remuneration were as follows:

	2016	**2017**	**2018**
	$	**$**	**$**
Staff costs			
Wages and salaries	341,875	328,812	339,135
Social security	232	527	951
	342,107	329,339	340,086

Average monthly number of persons employed by the Company during the year was as follows:

	2016	**2017**	**2018**
	Number	**Number**	**Number**
	2	2	2

	2016	**2017**	**2018**
	$	**$**	**$**
Remuneration of Director			
Emoluments for qualifying services	-	8,780	7,799

No payments of pensions contributions been made on behalf of the Director in any of the periods presented.

3. Finance costs

	2016 $	2017 $	2018 $
Finance facility fee	32,219	-	-
Other interest	22,625	-	-
	54,844	-	-

4. Taxation

	2016 $	2017 $	2018 $
Loss before tax	(5,874,013)	(1,129,666)	(1,421,141)
Loss on ordinary activities multiplied by standard rate of corporation tax in the UK of: 2016: 20%; 2017: 19%, 2018: 19%	(1,174,803)	(214,637)	(270,017)
Tax effects of:			
Unrelieved tax losses carried forward	1,174,803	214,637	270,017
Corporation tax charge	-	-	-

No deferred tax asset was recognised in respect of the accumulated tax losses as there is insufficient evidence that the amount will be recovered in future years.

5. Loss per share

Basic loss per share is calculated by dividing the loss attributable to Ordinary Shareholders by the weighted average number of Ordinary Shares outstanding during the year.

The Company did not have any potentially dilutive shares in any of the periods presented, therefore the basic and diluted loss per share are the same.

Basic and diluted loss per share

	2016 cents	2017 cents	2018 cents
Loss per share from continuing operations (cents)	(5.78)	(0.42)	(0.53)

The loss and weighted average number of ordinary shares used in the calculation of basic loss per share are as follows:

	2016 $	2017 $	2018 $
Loss used in the calculation of total basic and diluted loss per share	(5,874,013)	(1,129,666)	(1,421,141)

Number of shares	**2016 Number**	**2017 Number**	**2018 Number**
Weighted average number of ordinary shares for the purposes of basic and diluted loss per share	101,708,341	269,748,208	269,748,208

6. Intangible assets

	Exploration and Evaluation assets $
Cost	
At 1 January 2016	2,662,546
Additions	3,766,341
At 31 December 2016	6,428,887
Additions	1,823,499
At 31 December 2017	8,252,386
Additions	3,548,863
At 31 December 2018	11,801,249
Impairment	
At 1 January 2016	-
Impairment charge	146,248
At 31 December 2016	146,248
Impairment charge	2,424,159
At 31 December 2017	2,570,407
Impairment charge	3,408,344
At 31 December 2018	5,978,751
Net book value	
At 1 January 2016	2,662,546
At 31 December 2016	6,282,639
At 31 December 2017	5,681,979
At 31 December 2018	5,822,498

Management review the intangible exploration asset for indications of impairment at each balance sheet date based on IFRS 6 criteria.

In 2016 an impairment was determined to have arisen in relation to the North Shadwan assets.

In 2017, management determined that the Al Jahraa SE-2X and Al Jahraa 9 wells were impaired as they did not meet their primary objectives.

In 2018, the assets relating to the El Qa'a concession agreement were impaired due to the concession being relinquished as no hydrocarbons were encountered by the end of the four year term.

The Directors do not consider that any further indication of impairment have arisen and accordingly the remaining exploration and evaluation assets continue to be carried at cost.

7. Property, plant and equipment

	Oil and Gas assets	Other assets	Total
Cost			
At 1 January 2016	17,162,000	70,672	17,232,672
Additions	1,812,178	-	1,812,178
At 31 December 2016	18,974,178	70,672	19,044,850
Additions	740,977	-	740,977
At 31 December 2017	19,715,155	70,672	19,785,827
Additions	1,848,339	-	1,848,339
At 31 December 2018	21,563,494	70,672	21,634,166
Depreciation & impairment			
At 1 January 2016	11,578,128	37,661	11,615,789
Charge for the year	1,255,920	-	1,255,920
At 31 December 2016	12,834,048	37,661	12,871,709
Charge for the year	1,572,422	16,888	1,589,310
At 31 December 2017	14,406,470	54,549	14,461,019
Charge for the year	1,756,464	12,446	1,768,910
At 31 December 2018	16,162,934	66,995	16,229,929
Net book value			
At 1 January 2016	5,583,872	33,011	5,616,883
At 31 December 2016	6,140,130	33,011	6,173,141
At 31 December 2017	5,308,685	16,123	5,324,808
At 31 December 2018	5,400,560	3,677	5,404,237

Depreciation on oil and gas assets is recognised within cost of sales and depreciation on other assets is recognised within administrative expenses.

Depreciation of oil and gas assets is calculated on a units of production basis using the most recently available reserves data established from independent CPR reports.

Management review assets for indications of impairment on an annual basis in accordance with IAS 36. No impairment has been identified in any of the periods presented.

8. Inventories

	2016 $	2017 $	2018 $
Oil inventory	43,068	32,889	22,823

9. Trade and other receivables

	2016 $	2017 $	2018 $
Trade receivables	11,442,823	7,561,389	1,267,238
Other receivables	74,982	-	124,234
Related party receivables	-	1,818,287	6,908,773
Accrued income	418,960	459,232	449,251
	11,936,765	9,838,908	8,749,496

Related party receivables relate to balances receivable from the parent company, Rockhopper Exploration plc (see note 17).

10. Cash and cash equivalents

	2016 $	2017 $	2018 $
Cash at bank (EGP)	-	6,311	646,312
Cash at bank (USD)	-	15,940	973
	-	22,251	647,285

At 31 December 2016, 2017 and 2018 all significant cash and cash equivalents were deposited in Egypt with large international banks in the currencies indicated in the table above.

11. Share capital

Allotted, issued, and fully paid:

Ordinary shares AU$ 1 each:

	2016		**2017**		**2018**	
	Number	**$**	**Number**	**$**	**Number**	**$**
At 1 January	1	1	269,748,208	202,919,136	269,748,208	202,919,136
Issued	269,748,207	202,919,135	-	-	-	-
At 31 December	269,748,208	202,919,136	269,748,208	202,919,136	269,748,208	202,919,136

On 12 August 2016 269,748,207 shares were issued at par of AU$ 1 per share in settlement of an inter-company balance of AU$269,748,207.

As regards income and capital distributions, all categories of shares rank pari passu as if the same constituted one class of share.

12. Trade and other payables

	2016	**2017**	**2018**
	$	**$**	**$**
Trade payables	-	19,218	-
Related party payables	1,310,504	-	-
Other payables	93,970	131,722	461,317
Accruals	1,898,552	747,931	1,604,199
	3,303,026	898,871	2,065,516

Related party payables relate to balances payable to the parent company, Rockhopper Exploration plc (see note 17).

13. Financial instruments

Categories of financial instruments

The tables below set out the Company's accounting classification of each class of its financial assets and liabilities.

Financial assets	Measured at amortised cost 2016 $	2017 $	2018 $
Trade receivables (note 9)	11,442,823	7,561,389	1,267,238
Other receivables (note 9)	74,982	-	124,234
Related party receivables (note 9)	-	1,818,287	6,908,773
Accrued income (note 9)	418,960	459,232	449,251
Cash and cash equivalents (note 10)	-	22,251	647,285
	11,936,765	9,861,159	9,396,781

All of the above financial assets' carrying values are approximate to their fair values, as at 31 December 2016, 2017 and 2018.

Financial liabilities	Measured at amortised cost 2016 $	2017 $	2018 $
Trade payables (note 12)	-	19,218	-
Related party payables (note 12)	1,310,504	-	-
Other payables (note 12)	93,970	131,722	461,317
Accruals (note 12)	1,898,552	747,931	1,604,199
Overdraft	957	-	-
	3,303,983	898,871	2,065,516

In the view of management, all of the above financial liabilities' carrying values approximate to their fair values as at 31 December 2016, 2017 and 2018.

14. Financial instrument risk exposure and management

The Company's operations expose it to degrees of financial risk that include liquidity risk, credit risk, interest rate risk.

This note describes the Company's objectives, policies and process for managing those risks and the methods used to measure them. Further quantitative information in respect of these risks is presented in notes 9, 10, 12, 13, and 15.

Liquidity risk

Liquidity risk is dealt with in note 15 of this historical financial information.

Credit risk

The Company’s credit risk is primarily attributable to its cash balances and trade and other receivables.

Trade and other receivables
The Company’s total credit risk amounts to the total of the sum of the receivables as detailed in note 9.

Cash and cash equivalents
Cash at bank is held with creditworthy financial institutions which are licensed banks in the countries that the Company operates.

Interest rate risk

The Company previously had inter-company borrowings in 2016, however these have been settled during 2017.

The Company’s only exposure to interest rate risk is the interest received on the cash held on deposit, which is immaterial.

Foreign exchange risk

The Company's transactions are carried out in EGP and USD. Operational transactions are carried out predominantly in USD.

Prior to the change in ownership in 2016, the Company held a significant inter-company balance denominated in AUD. A significant foreign exchange loss was recognised on this in 2016. Since August 2016, there have been no inter-company balances held in foreign currencies.

Exposure to foreign currency exchange rates arises from the Company's sales and purchases denominated in EGP. Cash balances are held in EGP (see note 10) and transactional risk is considered manageable.

The Company currently does not consider it necessary to take any action to mitigate foreign exchange risk due to the immateriality of that risk.

15. Liquidity risk

Prudent liquidity risk management includes maintaining sufficient cash balances to ensure the Company can meet liabilities as they fall due.

In managing liquidity risk, the main objective of the Company is therefore to ensure that it has the ability to pay all of its liabilities as they fall due. The Company monitors its levels of working capital to ensure that it can meet its debt repayments as they fall due. The table below shows the undiscounted cash flows on the Company’s financial liabilities as at 31 December 2016, 2017 and 2018, on the basis of their earliest possible contractual maturity.

	Total $	Within 2 months $	Within 2 -6 months $	Within 6 – 12 months $	Within 1-2 years $
At 31 December 2016					
Related party payables	1,310,504	-	-	1,310,504	-
Other payables	93,970	-	-	93,970	-
Accruals	1,898,552	-	1,898,552	-	-
Overdrafts	957	957	-	-	-
	3,303,983	957	1,898,552	1,404,474	-

	Total $	Within 2 months $	Within 2 -6 months $	Within 6 – 12 months $	Within 1-2 years $
At 31 December 2017					
Trade payables	19,218	19,218	-	-	-
Other payables	131,722	-	-	131,722	-
Accruals	747,931	-	747,931	-	-
	898,871	19,218	747,931	131,722	-

	Total $	Within 2 months $	Within 2 -6 months $	Within 6 – 12 months $	Within 1-2 years $
At 31 December 2018					
Other payables	461,317	-	-	461,317	-
Accruals	1,604,199	-	1,604,199	-	-
	2,065,516	-	1,604,199	461,317	-

16. Capital management

The Company's capital management objectives are:

- To ensure the Company's ability to continue as a going concern; and
- To provide long-term returns to shareholders

The Company defines and monitors capital on the basis of the carrying amount of equity less cash and cash equivalents as presented on the face of the balance sheet and as follows:

	2016	2017	2018
	$	$	$
Equity	21,131,630	20,001,964	18,580,823
Less: cash and cash equivalents	957	(22,251)	(647,285)
	21,132,587	19,979,713	17,933,538

The Board of Directors monitors the level of capital as compared to the Company's commitments and adjusts the level of capital as is determined to be necessary by issuing new shares. The Company is not subject to any externally imposed capital requirements.

These policies have not changed in the period. The Directors believe that they have been able to meet their objectives in managing the capital of the Company.

17. Related party transactions

The Director is paid on an invoiced basis and remuneration is disclosed in note 2.

The Company has a related party receivable balance with Rockhopper Exploration plc, as disclosed in note 9 and a related party payable balance with Rockhopper Exploration plc as disclosed in note 12.

Intercompany balances comprise income and expenditure received/paid on behalf of Rockhopper by its parent entity Rockhopper Exploration plc. These arise from certain revenues in USD received directly by the parent company and corresponding costs pertaining to monthly cash calls to the operator paid by the parent entity.

18. Financial commitments

As at 31 December 2018 the Company had a commitment for its 22% share in the 2019 approved budget on the Abu Sennan Concession Agreement, being $7,371,592 net to the Company.

19. Contingent liabilities

As at 31 December 2018, 31 December 2017 and 31 December 2016 the Company had a contingent liability in relation to decommissioning of oil and gas assets. Due to the uncertainty regarding decommissioning requirements in Egypt and the long expected life of the assets such liabilities are considered neither probable nor quantifiable.

20. Events after the balance sheet date

Al Jahraa-11

On 15 April 2019 the Al Jahraa-11 in-fill well reached TD of 4,150m MD in the Kharita formation. Mudlogs and petrophysics indicate the following oil net pay:

- ARC: 7.2m TVD
- ARD: 4.0m TVD
- ARG: 2.5m TVD
- Bahariya: 15m TVD

The well has been successfully tested across the ARC, ARG and Bahariya and has been completed with a dual string to produce from these three reservoirs. The well is currently producing approximately 787 bopd gross. In addition to the oil production from Al Jahraa-11, the operator, Kuwait Energy, is evaluating a gas commercialisation solution through bids for the construction of a sales gas pipeline from Al Jahraa to the gas plant at El Salmiya.

Abu Sennan

A development lease, which contains the ASX-1X discovery in the ARC formation, was awarded on 19 March 2019, and the well brought on stream shortly thereafter. The well is currently producing 150 bopd gross.

As of 2 June 2019, the total gross production from Abu Sennan was 5,135 boepd (1,130 boepd net to RKH).

Al Jahraa-7

The development well, Al Jahraa-7, was spudded on 25 May 2019, and reached total depth of 3,970m MD in the Kharita formation on 23 June 2019. Initial petrophysics indicated pay in the following intervals:

Abu Roash-C	Net Pay: 7m
Abu Roash-E	Net Pay: 4m
Upper Bahariya	Net Pay: 9m
Lower Bahariya_1	Net Pay: 6m
Lower Bahariya_2	Net Pay: 5m

A series of well tests of the Abu Roash-E and Bahariya reservoirs has commenced, initially with the rig on location and subsequently following release of the rig. Al Jahraa-7 was producing at >600bopd in late August 2019.

Al Jahraa-12

The third Al Jahraa field development well (Al Jahraa-12) of this campaign was spudded on 4 August 2019. The well was drilled as a deviated hole to appraise the Abu Roash-C downdip of the Al Jahraa-3 well and in the water leg. In addition, it further explored the potential of the Bahariya reservoirs. The plan is to produce from ARE, then inject into ARC.

Current production from Abu Sennan is approximately 5,000 boepd gross (1,100 boepd net to Rockhopper's 22% working interest).

SECTION A(iii): UNAUDITED INTERIM RESULTS OF ROCKHOPPER EGYPT

Income Statement

	Notes	30 June 2019 Unaudited $	30 June 2018 Unaudited $	31 December 2018 Audited $
Revenue		3,184,310	3,252,281	6,123,788
Cost of sales		(1,981,073)	(1,711,343)	(3,730,279)
Gross profit		1,203,237	1,540,938	2,393,509
Administrative expenses		(388,033)	(146,509)	(406,306)
Admin expenses - impairment of assets		-	(3,390,382)	(3,408,344)
Operating profit / (loss)		815,204	(1,995,953)	(1,421,141)
Finance costs		-	-	-
Profit / (loss) before taxation		815,204	(1,995,953)	(1,421,141)
Taxation		-	-	-
Profit / (loss) for the financial year attributable to the Company's equity shareholders		815,204	(1,995,953)	(1,421,141)
Earnings / (loss) per share:				
Basic and diluted earnings / (loss) per share (cents)	5	0.30	(0.74)	(0.53)

Statement of Comprehensive Income

	30 June 2019 $	30 June 2018 $	31 December 2018 $
Profit / (loss) for the financial year	815,204	(1,995,953)	(1,421,141)
Total comprehensive income for the financial year attributable to the Company's equity shareholders	815,204	(1,995,953)	(1,421,141)

Rockhopper Egypt Pty Limited

Balance Sheet as at 31 December

	Notes	30 June 2019 Unaudited $	30 June 2018 Unaudited $	31 December 2018 Audited $
Assets				
Non-current assets				
Exploration & evaluation assets	4	2,230,804	4,551,464	5,822,498
Property, plant and equipment	5	10,319,924	4,660,391	5,404,237
		12,550,728	9,211,855	11,226,735
Current assets				
Inventories		60,120	32,889	22,823
Trade and other receivables		7,439,756	9,502,265	8,749,496
Cash and cash equivalents		632,713	598,663	647,285
		8,132,589	10,133,816	9,419,604
Total assets		20,683,317	19,345,672	20,646,339
Equity and liabilities				
Capital and reserves				
Share capital		202,919,136	202,919,136	202,919,136
Retained losses		(183,523,109)	(184,913,125)	(184,338,313)
Shareholders' funds		19,396,027	18,006,011	18,580,823
Current liabilities:				
Trade and other payables		1,287,290	1,339,661	2,065,516
		1,287,290	1,339,661	2,065,516
Total equity and liabilities		20,683,317	19,345,672	20,646,339

Statement of Changes in Equity

	Share capital $	Retained losses $	Total $
For the period ended 30 June 2019			
Balance at 1 January 2019	202,919,136	(184,338,313)	18,580,823
Profit for the period	-	815,204	815,204
Total comprehensive income for the period	-	815,204	815,204
Balance at 30 June 2019 (Unaudited)	202,919,136	(183,523,109)	19,396,027
For the period ended 30 June 2018			
Balance at 1 January 2018	202,919,136	(182,917,172)	20,001,964
Loss for the period	-	(1,995,953)	(1,995,953)
Total comprehensive loss for the period	-	(1,995,953)	(1,995,954)
Balance at 30 June 2018 (Unaudited)	202,919,136	(184,913,125)	18,006,011
For the year ended 31 December 2018			
Balance at 1 January 2018	202,919,136	(182,917,172)	20,001,964
Loss for the year	-	(1,421,141)	(1,421,141)
Total comprehensive loss for the year	-	(1,421,141)	(1,421,141)
Balance at 31 December 2018 (Audited)	202,919,136	(184,338,313)	18,580,823

Rockhopper Egypt Pty Limited

Statement of Cash Flows for the year ended 31 December

	30 June 2019 Unaudited $	30 June 2018 Unaudited $	31 December 2018 Audited $
Cash flow from operating activities			
Profit / (loss) for the financial period before tax	815,204	(1,995,953)	(1,421,141)
Depreciation	965,297	815,792	1,768,910
Impairment of intangible assets	-	3,390,382	3,408,344
Foreign exchange movements	(11,668)	24,378	29,874
	1,768,833	2,234,599	3,785,987
Changes in working capital			
(Increase) / decrease in inventories	(37,297)	-	10,066
Decrease in trade and other receivables	1,309,740	336,643	1,089,412
(Decrease) / increase in trade and other payables	(766,558)	416,411	1,136,772
Cash flow from operating activities	2,274,718	2,987,653	6,022,237
Cash outflow from investing activities			
Purchase of property, plant & equipment	(1,979,515)	(151,374)	(1,848,340)
Payments for intangible exploration assets	(309,775)	(2,259,867)	(3,548,863)
Net cash used in investing activities	(2,289,290)	(2,411,241)	(5,397,203)
Net (decrease) / increase in cash and cash equivalents	(14,572)	576,412	625,034
Cash and cash equivalents at beginning of financial period	647,285	22,251	22,251
Cash and cash equivalents at end of financial period	632,713	598,663	647,285

Rockhopper Egypt Pty Limited

Notes to the historical financial information

1. General

The interim financial information for the period to 30 June 2019 and the comparative for the period to 30 June 2018 is unaudited.

2. Accounting policies

The interim financial information in this report has been prepared on the basis of the accounting policies set out in the audited financial statements for the period ended 31 December 2018, which complied with International Financial Reporting Standards as adopted for use in the European Union ("IFRS") and adopting IFRS that the directors expect to be applicable as at 31 December 2019. During the year the company has implemented IFRS 16 which has had an immaterial impact on the financial information due to the company's lease arrangements being limited to a short-term office lease.

IFRS is subject to amendment and interpretation by the International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee and there is an on-going process of review and endorsement by the European Commission.

3. Earnings per share

Basic earnings / (loss) per share is calculated by dividing the profit / (loss) attributable to Ordinary Shareholders by the weighted average number of Ordinary Shares outstanding during the period.

The Company did not have any potentially dilutive shares in any of the periods presented, therefore the basic and diluted earnings / (loss) per share are the same.

Basic and diluted loss per share

	30 June 2019 cents	**30 June 2018 cents**	**31 December 2018 cents**
Earnings / (loss) per share from continuing operations (cents)	0.30	(0.74)	(0.53)

The profit / (loss) and weighted average number of ordinary shares used in the calculation of basic earnings / (loss) per share are as follows:

	30 June 2019 $	**30 June 2018 $**	**31 December 2018 $**
Profit / (loss) used in the calculation of total basic and diluted earnings / (loss) per share	815,204	(1,995,953)	(1,421,141)

Number of shares	30 June 2019 Number	30 June 2018 Number	31 December 2018 Number
Weighted average number of ordinary shares for the purposes of basic and diluted earnings / (loss) per share	269,748,208	269,748,208	269,748,208

4. Intangible assets

	Exploration and Evaluation assets $
Cost	
At 1 January 2018	8,252,386
Additions	3,548,863
At 31 December 2018	11,801,249
Additions	309,775
Transfer to production assets	(3,901,469)
At 30 June 2019	8,209,555
Impairment	
At 1 January 2018	2,570,407
Impairment charge	3,408,344
At 31 December 2018	5,978,751
Impairment charge	-
At 30 June 2019	5,978,751
Net book value	
At 31 December 2017	5,681,979
At 31 December 2018	5,822,498
At 30 June 2019	2,230,804

Management review the intangible exploration asset for indications of impairment at each balance sheet date based on IFRS 6 criteria.

In 2018, the assets relating to the El Qa'a concession agreement were impaired due to the concession being relinquished as no hydrocarbons were encountered by the end of the four year term.

The Directors do not consider that any further indication of impairment have arisen and accordingly the remaining exploration and evaluation assets continue to be carried at cost.

5. Property, plant and equipment

	Oil and Gas assets	Other assets	Total
Cost			
At 1 January 2018	19,715,155	70,672	19,785,827
Additions	1,848,339	-	1,848,339
At 31 December 2018	21,563,494	70,672	21,634,166
Additions	1,979,515	-	1,979,515
Transfer from intangible assets	3,901,469	-	3,901,469
At 30 June 2019	27,444,478	70,672	27,515,150
Depreciation & impairment			
At 1 January 2018	14,406,470	54,549	14,461,019
Charge for the year	1,756,464	12,446	1,768,910
At 31 December 2018	16,162,934	66,995	16,229,929
Charge for the period	961,620	3,677	965,297
At 30 June 2019	17,124,554	70,672	17,195,226
Net book value			
At 1 January 2018	5,308,685	16,123	5,324,808
At 31 December 2018	5,400,560	3,677	5,404,237
At 30 June 2019	10,319,924	-	10,319,924

Depreciation on oil and gas assets is recognised within cost of sales and depreciation on other assets is recognised within administrative expenses.

Depreciation of oil and gas assets is calculated on a units of production basis using the most recently available reserves data established from independent CPR reports.

Management review assets for indications of impairment on an annual basis in accordance with IAS 36. No impairment has been identified in any of the periods presented.

6. Events after the balance sheet date

Al Jahraa-12

The third Al Jahraa field development well (Al Jahraa-12) of this campaign was spudded on 4 August 2019. The well was drilled as a deviated hole to appraise the Abu Roash-C downdip of the Al Jahraa-3 well and in the water leg. In addition, it further explored the potential of the Bahariya reservoirs. The plan is to produce from ARE, then inject into ARC.

Current production from Abu Sennan is approximately 5,000 boepd gross (1,100 boepd net to Rockhopper's 22% working interest).

SECTION B(i): ACCOUNTANT'S REPORT ON THE EXISTING GROUP HISTORICAL FINANCIAL INFORMATION

Date: 6 December 2019

The Directors
United Oil & Gas Plc
200 Strand
London
WC2R 1DJ

The Directors
Beaumont Cornish Limited
10th Floor 30 Crown Place
London
EC2A 4EB

Dear Sirs,

United Oil & Gas plc (the "Company")

Introduction

We report on the audited historical financial information on United Oil & Gas plc (the "Company") set out in section B (ii) (the "Company Financial Information"). This Company Financial Information has been prepared for inclusion in the admission document dated 6 December 2019 (the "AIM Admission Document") on the basis of the accounting policies set out in the Notes to the Company Financial Information. This report is required by paragraph (a) of Schedule Two to the AIM Rules for Companies (the "AIM Rules") and is given for the purposes of complying with the AIM Rules and for no other purpose.

Responsibilities

The directors of the Company are responsible for preparing the Company Financial Information in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion on the Company Financial Information as to whether the Company Financial Information gives a true and fair view, for the purposes of the Document and to report our opinion to you.

Save for any responsibility arising under Paragraph (a) of Schedule Two of the AIM Rules for Companies to any person as and to the extent there provided, to the fullest extent permitted by the law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Paragraph (a) of Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the AIM Admission Document.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's 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 financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in the United States of America or other jurisdictions outside the United Kingdom and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion, the Company Financial Information gives, for the purposes of the AIM Admission Document, a true and fair view of the state of affairs of United Oil & Gas plc at 31 December 2016, 31 December 2017 and 31 December 2018, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union and that it has been prepared in a form that is consistent with the accounting policies adopted by the Company.

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 AIM Admission Document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the AIM Admission Document in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies.

Yours faithfully

UHY Hacker Young LLP
Chartered Accountants

SECTION B(ii): EXISTING GROUP HISTORICAL FINANCIAL INFORMATION

Consolidated Income Statement

	Notes	2016 $	2017 $	2018 $
Revenue		-	-	-
Cost of sales		-	-	-
Gross profit		-	-	-
Administrative expenses		(249,170)	(771,169)	(1,080,272)
Operating loss and loss before taxation		(249,170)	(771,169)	(1,080,272)
Taxation	3	-	-	-
Loss for the financial year attributable to the Company's equity shareholders		(249,170)	(771,169)	(1,080,272)
Earnings per share:				
Basic and diluted loss per share (cents)	4	(4.57)	(0.76)	(0.38)

Consolidated Statement of Comprehensive Income

	2016 $	2017 $	2018 $
Loss for the financial year	(249,170)	(771,169)	(1,080,272)
Foreign exchange (losses) / gains	(6,703)	86,071	(496,793)
Total comprehensive income for the financial year attributable to the Company's equity shareholders	(255,873)	(685,098)	(1,577,065)

United Oil & Gas plc

Consolidated Balance Sheet as at 31 December

	Notes	2016	2017	2018
Assets		$	$	$
Non-current assets				
Intangible assets	6	144,668	1,574,627	5,226,219
Property, plant and equipment	7	-	3,163	4,717
		144,668	1,577,790	5,230,936
Current assets				
Trade and other receivables	8	-	168,607	739,119
Cash and cash equivalents	9	93,482	4,097,985	5,149,907
		93,482	4,266,592	5,889,026
Total assets		238,150	5,844,382	11,119,962
Equity and liabilities				
Capital and reserves				
Share capital	10	334,722	3,054,383	4,564,787
Share premium	10	334,722	5,562,026	9,912,988
Share based payment reserve	11	228,436	600,145	1,465,036
Merger reserve	10	(431,580)	(2,697,357)	(2,697,357)
Translation reserve		(6,459)	79,612	(417,181)
Retained earnings		(264,882)	(1,036,051)	(2,116,323)
Shareholders' funds		194,958	5,562,758	10,711,950
Current liabilities:				
Trade and other payables	12	43,192	281,624	408,012
Total equity and liabilities		238,150	5,844,382	11,119,962

Consolidated Statement of Changes in Equity

	Share capital $	Share premium $	Share based payments reserve $	Retained earnings $	Translation reserve $	Merger reserve $	Total $
For the year ended 31 December 2016							
UOG Holdings plc consolidated							
Balance at 1 January 2016 (United Oil & Gas Ltd)	108	-	-	(15,711)	244	-	(15,359)
Loss for the year	-	-	-	(249,171)	-	-	(249,171)
Foreign exchange difference	-	-	-	-	(6,703)	-	(6,703)
Total comprehensive loss for the year	**-**	**-**	**-**	**(249,171)**	**(6,703)**	**-**	**(255,874)**
Issue of share capital in United Oil & Gas Ltd	16,258	314,632	-	-	-	-	330,890
Redemption of share capital in United Oil & Gas Ltd	(15,263)	-	-	-	-	-	(15,263)
Effect of share for share transaction to incorporate UOG Holdings plc as parent company	258,336	(55,192)	228,436	-	-	(431,580)	-
Issue of share capital in UOG Holdings plc	75,282	75,282	-	-	-	-	150,564
Balance at 31 December 2016	**334,722**	**334,722**	**228,436**	**(264,882)**	**(6,459)**	**(431,580)**	**194,958**

	Share capital $	Share premium $	Share based payments reserve $	Retained earnings $	Translation reserve $	Merger reserve $	Total $
For the period ended 31 December 2017							
United Oil & Gas plc consolidated							
Balance at 1 January 2017 (UOG Holdings plc)	334,722	334,722	228,436	(264,882)	(6,459)	(431,580)	194,958
Loss for the period	-	-	-	(771,169)	-	-	(771,169)
Foreign exchange difference	-	-	-	-	86,071	-	86,071
Total comprehensive loss for the year	-	-	-	(771,169)	86,071	-	(685,098)
Issue of share capital in UOG Holdings plc	158,021	158,021	-	-	-	-	316,043
Share issue expenses	-	(15,976)	-	-	-	-	(15,976)
Effect of combination resulting in United Oil & Gas plc becoming the parent company of the Group	560,552	1,823,560	-	-	-	(2,265,777)	118,335
Share placing	2,001,088	3,629,718	-	-	-	-	5,630,806
Share issue expenses	-	(368,019)	-	-	-	-	(368,019)
Cancellation of share warrants in UOG Holdings plc	-	-	(228,436)	-	-	-	(228,436)
Issue of share warrants in United Oil & Gas plc	-	-	600,145	-	-	-	600,145
Balance at 31 December 2017	3,054,383	5,562,026	600,145	(1,036,051)	79,612	(2,697,357)	5,562,758

	Share capital $	Share premium $	Share-based payments reserve $	Retained earnings $	Translation reserve $	Merger reserve $	Total $
For the year ended 31 December 2018							
Balance at 1 January 2018	3,054,383	5,562,026	600,145	(1,036,051)	79,612	(2,697,357)	5,562,758
Loss for the year	-	-	-	(1,080,272)	-	-	(1,080,272)
Foreign exchange difference	-	-	-	-	(496,793)	-	(496,793)
Total comprehensive income	-	-	-	(1,080,272)	(496,793)	-	(1,577,065)
Exercise of share warrants	827	3,309	-	-	-	-	4,136
Issue of share capital	1,509,577	5,796,341	-	-	-	-	7,305,918
Share issue expenses	-	(1,448,688)	799,829	-	-	-	(648,859)
Issue of share options	-	-	65,062	-	-	-	65,062
Balance at 31 December 2018	4,564,787	9,912,988	1,465,036	(2,116,323)	(417,181)	(2,697,357)	10,711,950

United Oil & Gas plc

Consolidated Statement of Cash Flows for the year ended 31 December

	2016	2017	2018
	$	$	$
Cash flow from operating activities			
Loss for the financial year before tax	(249,170)	(771,169)	(1,080,272)
Share-based payments	-	-	65,062
Shares issued to directors in lieu of fees	147,619	-	-
Share options issued as acquisition expenses	-	32,979	-
Depreciation	-	587	1,732
Foreign exchange movements	17,826	(2,490)	(137,119)
	(83,725)	(740,093)	(1,150,597)
Changes in working capital			
Increase in trade and other receivables	-	(168,607)	(570,512)
Increase in trade and other payables	12,571	194,258	126,387
Cash outflow from operating activities	(71,154)	(714,442)	(1,594,722)
Cash outflow from investing activities			
Cash acquired from United Oil & Gas plc (formerly Senterra Energy plc)	-	438,497	-
Purchase of property, plant & equipment	-	(3,631)	(3,535)
Purchase of intangible exploration assets	(144,668)	(1,429,959)	(3,651,592)
Net cash used in investing activities	(144,668)	(995,094)	(3,655,127)
Cash flow from financing activities			
Issue of ordinary shares (net of expenses)	333,834	5,625,597	6,661,195
Net cash generated from financing activities	333,834	5,625,597	6,661,195
Net increase in cash and cash equivalents	118,012	3,916,061	1,411,346
Cash and cash equivalents at beginning of financial year	-	93,482	4,097,985
Effects of exchange rate changes	(24,530)	88,442	(359,424)
Cash and cash equivalents at end of financial year	93,482	4,097,985	5,149,907

Notes to the consolidated historical financial information

Principal Accounting Policies

Basis of preparation
The financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"), as adopted by the European Union and, IFRIC interpretations.

The information for the years ended 31 December 2018 and 31 December 2017 includes the results of United Oil & Gas plc and its subsidiaries; the information for the year ended 31 December 2016 includes the results of UOG Holdings plc and its subsidiaries.

IFRS is subject to amendment and interpretation by the IASB and the IFRS Interpretations Committee, and there is an on-going process of review and endorsement by the European Commission. These accounting policies comply with each IFRS that is mandatory for accounting periods ending on 31 December 2019.

The principal accounting policies set out below have been consistently applied to all periods presented.

Basis of consolidation
The financial information for 2018 incorporates the results of United Oil & Gas plc ("the Company") and entities controlled by the Company (its subsidiaries). Control is achieved where the Company has the power to govern the financial and operating policies of an investee entity so as to obtain benefits from its activities.

The addition of United Oil & Gas plc (formerly Senterra Energy plc) to the Group in 2017 was not accounted for as a business combination, due to the Company being considered to be a cash shell, but instead the consolidated accounts are presented as a continuation of the financial statements of the UOG Holdings plc Group, adjusted only to reflect the share capital of the new legal parent.

The addition of UOG Holdings plc to the Group in 2016 was not accounted for as a business combination but instead the consolidated accounts are presented as a continuation of the financial statements of United Oil & Gas Ltd, adjusted only to reflect the share capital of the new legal parent.

All intra-Group transactions, balances, income and expenses are eliminated in full on consolidation. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Finance income and costs
Interest is recognised using the effective interest method which calculates the amortised cost of a financial asset or liability and allocates the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments through the expected life of the financial asset or liability to the net carrying amount of the financial asset or liability.

Exploration and evaluation assets
The Group accounts for oil and gas expenditure under the full cost method of accounting.

Costs (other than payments to acquire the legal right to explore) incurred prior to acquiring the rights to explore are charged directly to the profit and loss account. All costs incurred after the rights to explore an area have been obtained, such as geological, geophysical, data costs and other direct costs of exploration and appraisal are accumulated and capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities if technical feasibility is demonstrated and commercial reserves are discovered, then following development sanction, the carrying value of the relevant E&E asset will be reclassified as a development and production asset within tangible fixed assets.

If after completion of appraisal activities in an area, it is not possible to determine technical feasibility or commercial viability, then the costs of such unsuccessful exploration and evaluation are written off to the profit and loss account. The costs associated with any wells which are abandoned are fully amortised when the abandonment decision is taken.

Development and production assets, are accumulated generally on a field by-field basis and represent the costs of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves which have been transferred from intangible E&E assets.

The net book values of development and production assets are depreciated generally on a field-by-field basis using the unit of production method based on the commercial proven and probable reserves. Assets are not depreciated until production commences.

Property, plant and equipment
Property, plant and equipment are stated at cost on acquisition less depreciation. Depreciation is provided on a straight-line basis at rates calculated to write off the cost less the estimated residual value of each asset over its expected useful economic life. The residual value is the estimated amount that would currently be obtained from disposal of the asset if the asset were already of the age and in the condition expected at the end of its useful life.

The annual rate of depreciation for each class of depreciable asset is:
Computer equipment 33%

The carrying value of property plant and equipment is assessed annually and any impairment is charged to the income statement.

Impairment of non-financial assets
At each balance sheet date, the Directors review the carrying amounts of the Group's tangible and intangible assets, other than goodwill, 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. Where the asset does not generate cash flows that are independent from other assets, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs.

Recoverable amount is the higher of fair value less costs to sell and value in use. 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 its carrying amount, the carrying amount of the asset or cash-generating unit is reduced to its recoverable amount. If the recoverable amount of a cash-generating unit is less than its carrying amount, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit pro rata based on the carrying amount of each asset in the unit.

An impairment loss is recognised as an expense immediately.

An impairment loss recognised for goodwill is not reversed in subsequent periods.

Where an impairment loss subsequently reverses, the carrying amount of the asset or 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 or cash-generating unit in prior periods. A reversal of an impairment loss is recognised in the Income Statement immediately.

Cash and cash equivalents
Cash and cash equivalents comprise cash in hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

Financial instruments
Financial assets and financial liabilities are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are measured initially at fair value plus transactions costs. Financial assets and financial liabilities are measured subsequently as described below.

Financial assets
The Group classifies its financial assets as 'loans and receivables'. The Group assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are classified as 'trade and other receivables' in the Balance Sheet.

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment.

A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulty, high probability of bankruptcy or a financial reorganisation and default are considered indicators that the trade receivable is impaired. The amount of the provision is the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at original effective interest rate. The loss is recognised in the Income Statement. When a trade receivable is uncollectible, it is written off against the allowance account for trade receivables. Subsequent recoveries of amounts previously written off are credited in the Income Statement.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and all substantial risks and rewards are transferred.

Financial liabilities
The Group’s financial liabilities include trade and other payables.

Trade payables and borrowings are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

A financial liability is derecognised when it is extinguished, discharged, cancelled or expires.

Taxation
Current taxation for each taxable entity in the Group is based on the local taxable income at the local statutory tax rate enacted or substantively enacted at the balance sheet date and includes adjustments to tax payable or recoverable in respect of previous periods.

Deferred taxation
Deferred taxation is calculated using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial information. However, if the deferred tax arises from the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss, it is not accounted for. Deferred tax is determined using tax rates and laws that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised, or the deferred tax liability is settled.

Deferred tax liabilities are provided in full.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Changes in deferred tax assets or liabilities are recognised as a component of tax expense in the Income Statement, except where they relate to items that are charged or credited directly to equity in which case the related deferred tax is also charged or credited directly to equity.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

Foreign currency
Transactions in foreign currencies are recorded at the rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the year-end date. All differences are taken to the Income Statement.

Assets and liabilities of subsidiaries that have a functional currency different from the presentation currency (US dollar), if any, are translated at the closing rate at the date of each balance sheet presented. Income and expenses are translated at average exchange rates. All resulting exchange differences are recognised in other comprehensive income (loss), if any.

The Group previously adopted a presentation currency of sterling and has made an accounting policy change to adopt a US dollar presentation currency.

Share based payments
Where share warrants have been granted, IFRS 2 has been applied whereby the fair value of the warrants is measured at the grant date and spread over the period during which the warrants vest. A warrants valuation model is used to assess the fair value, taking into account the terms and conditions attached to the warrants. The fair value at grant date is determined including the effect of market-based vesting conditions, to the extent such vesting conditions have a material impact.

The cost of equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled, ending on the date on which the holders become fully entitled to the award (“the vesting date”).

The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group’s best estimate of the number of equity instruments that will ultimately vest.

Equity
Equity comprises the following:
- "Share capital" represents amounts subscribed for shares at nominal value.
- "Share premium" represents amounts subscribed for share capital, net of issue costs, in excess of nominal value.
- "Share based payment reserve" represents the accumulated value of share-based payments.
- "Retained earnings" represents the accumulated profits and losses attributable to equity shareholders.
- "Translation reserve" represents the exchange differences arising from the translation of the historical financial information of subsidiaries into the Group's presentational currency.
- "Merger reserve" represents amounts arising from statutory merger relief arising on business combinations.

New and amended International Financial Reporting Standards adopted by the Group
The Group has adopted the following standards, amendments to standards and interpretations which are effective for the first time. The impact is shown below:

New/Revised International Financial Reporting Standards		**Effective Date: Annual periods beginning on or after:**	**EU adopted**	**Impact on the Group**
IFRS 2	Amendments to IFRS 2 Classification and Measurement of Share-based Payment Transactions	1 January 2018	Yes	None
IFRS 9	Financial Instruments: Classification and Measurement	1 January 2018	Yes	None
IFRS 15	Revenue from Contracts with Customers & Clarifications to IFRS 15 Revenue from Contracts with Customers	1 January 2018	Yes	None
IFRS 16	Leases	1 January 2019	Yes	None
	Annual Improvements to IFRS Standards 2015-2017 Cycle	1 January 2019	Yes	

IFRS 15 'Revenue from Contracts with Customers'

IFRS 15 'Revenue from Contracts with Customers' and the related 'Clarifications to IFRS 15 Revenue from Contracts with Customers' (hereinafter referred to as 'IFRS 15') replace IAS 18 'Revenue', IAS 11 'Construction Contracts', and several revenue-related Interpretations. As the Group is yet to recognise any revenue, there is no impact from the application of this standard.

IFRS 9 'Financial Instruments'

IFRS 9 replaces IAS 39 'Financial Instruments: Recognition and Measurement'. It makes major changes to the previous guidance on the classification and measurement of financial assets and introduces an 'expected credit loss' model for the impairment of financial assets.

The adoption of IFRS 9 has only affected the descriptions of the categories in which financial assets and liabilities are included. All of the Group's financial assets and financial liabilities continue to be held at amortised cost.

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which all leases, other than short-term and small-ticket-item leases, will be accounted for by the recognition on the balance sheet of a right-to-use asset and a lease liability, and the subsequent amortisation of the right-to-use asset over the lease term. IFRS 16 will be effective for annual periods beginning on or after 1 January 2019.

The implementation of IFRS 16 does not have a material effect on the Group's financial statements due to the lack of lease arrangements other than a short-term office lease.

International Financial Reporting Standards in issue but not yet effective

At the date of authorisation of the consolidated financial statements, the IASB and IFRS Interpretations Committee have issued standards, interpretations and amendments which are applicable to the Group.

Whilst these standards and interpretations are not effective for, and have not been applied in the preparation of, these consolidated financial statements, the following could have a material impact on the Group's financial statements going forward:

New/Revised International Financial Reporting Standards		**Effective Date: Annual periods beginning on or after:**	**EU adopted**
IAS 1	Amendments to IAS 1 and IAS 8: Definition of Material	1 January 2020	No
IFRS 3	Amendment to IFRS 3 Business Combinations	1 January 2020	No

New / revised International Financial Reporting Standards which are not considered to potentially have a material impact on the Group's financial statements going forwards have been excluded from the above.

Management anticipates that all relevant pronouncements will be adopted in the Group's accounting policies for the first period beginning after the effective date of the pronouncement. New standards, interpretations and amendments not listed below are not expected to have a material impact on the Group's financial statements.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of financial information in conformity with generally accepted accounting practice requires management to make estimates and judgements that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period.

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The following are the significant judgements used in applying the accounting policies of the Group that have the most significant effect on the financial information:

Impairment of exploration licenses

Management reviews intangible exploration assets for indicators of impairment under IFRS 6 at the end of each reporting period. This review of assets for potential indicators of impairment requires judgement including whether renewal of licences is planned, interpretation of the results of exploration activity and the extent to which the Group plans to continue substantive expenditure on the assets. In determining whether substantive expenditure remains in the Group's plan, management considers factors including future oil prices, plans to develop or renew licences and future exploration plans. If impairment indicators exist the assets are tested for impairment and carried at the lower of the estimated recoverable amount and net book value.

Management did not consider there to be any impairment indicators at any reporting date presented.

Notes to the Consolidated Historical financial information

1. Segmental reporting

Operating segments

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources, assessing the performance of the operating segment and making strategic decision, has been identified as the Board of Directors. The Board of Directors consider that the Group has only one operating segment at corporate level, being the exploration and evaluation of oil and gas prospects, therefore no additional segmental information is presented.

The Group operates in three geographic areas – the UK, other EU and Latin America. The Group's revenue from external customers and information about its non-current assets (other than financial instruments, investments accounted for using the equity method, deferred tax assets and post-employment benefit assets) by geographical location are detailed below.

2016

$	UK	Other EU	Latin America	Total
Revenue	-	-	-	-
Non-current assets	144,668	-	-	144,668

2017

$	UK	Other EU	Latin America	Total
Revenue	-	-	-	-
Non-current assets	275,189	1,164,883	134,556	1,574,627

2018

$	UK	Other EU	Latin America	Total
Revenue	-	-	-	-
Non-current assets	872,229	2,185,608	2,173,099	5,230,936

2. Directors and employees

The aggregate payroll costs of the employees, including both management and Executive Directors, were as follows:

	2016	2017	2018
	$	$	$
Staff costs			
Wages and salaries	21,895	260,765	514,480
Shares issued in lieu of salaries	148,226	-	65,064
Social security	3,289	1,393	19,717
	173,410	262,158	599,261

Average monthly number of persons employed by the Group during the year was as follows:

	2016	2017	2018
	Number	Number	Number
By activity:			
Administrative	-	1	3
Directors	2	3	4
	2	4	7

	2016	2017	2018
	$	$	$
Remuneration of Directors			
Emoluments for qualifying services	21,895	249,243	389,538
Shares issued in lieu of remuneration	148,226	-	57,490
Social security	3,289	-	4,966
	173,410	249,243	451,994

Key management personnel are identified as the Executive Directors.

No share warrants have been exercised by any of the directors, nor have any payments of pensions contributions been made on behalf of directors in any of the periods presented.

3. Taxation

	2016 $	2017 $	2018 $
Loss before tax	(249,170)	(771,169)	(1,080,272)
Loss on ordinary activities multiplied by standard rate of corporation tax in the UK of 20%	(49,834)	(154,234)	(216,054)
Tax effects of:			
Unrelieved tax losses carried forward	49,834	154,234	216,054
Corporation tax charge	-	-	-

The Group has accumulated tax losses of approximately $2,028,900 (2016: $248,900; 2017: $1,053,200). No deferred tax asset was recognised in respect of these accumulated tax losses as there is insufficient evidence that the amount will be recovered in future years.

4. Earnings per share

Basic earnings per share is calculated by dividing the earnings attributable to Ordinary Shareholders by the weighted average number of Ordinary Shares outstanding during the year.

Due to the losses incurred, a diluted loss per share has not been calculated as this would serve to reduce the basic loss per share. There were 93,329,853 (2017: 37,260,000; 2016: 20,000,000) share warrants outstanding at the end of the year that could potentially dilute basic earnings per share in the future.

Basic and diluted loss per share

	2016 $	2017 $	2018 $
Loss per share from continuing operations	(4.57)	(0.76)	(0.38)

The loss and weighted average number of ordinary shares used in the calculation of basic loss per share are as follows:

	2016 $	2017 $	2018 $
Loss used in the calculation of total basic and diluted loss per share	(249,170)	(771,169)	(1,080,272)

Number of shares	2016 Number	2017 Number	2018 Number
Weighted average number of ordinary shares for the purposes of basic and diluted loss per share	5,448,224	100,814,356	282,810,516

5. Subsidiaries

Details of the Group's subsidiaries are as follows:

Name & address of subsidiary	Principal activity	Class of shares	Place of incorporation and operation	% ownership held by the Group		
				2016	2017	2018
UOG Holdings plc 200 Strand, London, WC2R 1DJ	Intermediate holding company	Ordinary	England and Wales	-	100	100
United Oil and Gas Limited* 9 Upper Pembroke Street, Dublin 2, Ireland	Intermediate holding company	Ordinary	Ireland	100	100	100
UOG PL090 Limited*^ 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	100	100	100
UOG Italia Srl* Viale Gioacchino Rossini 9, 00198, Rome,Italy	Oil and gas exploration	Ordinary	Italy	-	100	100
UOG Jamaica Ltd* 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	-	100	100
UOG Crown Ltd* 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	-	-	100
UOG Colter Ltd* 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	-	-	100

*held indirectly by United Oil & Gas plc (2017)
^held indirectly by UOG Holdings plc (2016)

6. Intangible assets

	Exploration and Evaluation assets $
Cost	
At 1 January 2016	-
Additions	157,827
Foreign exchange differences	(13,159)
At 31 December 2016	144,668
Additions	1,363,042
Foreign exchange differences	66,918
At 31 December 2017	1,574,627
Additions	3,902,289
Foreign exchange differences	(250,697)
At 31 December 2018	5,226,219
Net book value	
At 31 December 2016	144,668
At 31 December 2017	1,574,627
At 31 December 2018	5,226,219

United Oil and Gas farmed into a UK licence in the Wessex basin with Corallian Energy Limited in January 2018, in which the Colter well was drilled in Q1 2019. The costs incurred and capitalised to 31 December 2018 are $367,367.

In May 2018 United Oil & Gas plc was awarded two blocks in the UK North Sea's 30th licensing round, which includes the Crown discovery and to 31 December 2018 the company has incurred costs of $123,447. The current work programme consists of Seismic reprocessing and Rock physics, and we continue the farm out process ahead of a well decision later in 2019.

In UOG Italia Srl well drilling and testing was completed at Podere Gallina in the first quarter of 2018. To 31 December 2018 the company has capitalised costs of $2,180,893 and development activities are on track for 2019 after the Italian Ministry granted the Joint Venture an exploitation licence in January 2019.

UOG Jamaica Ltd activity consisted primarily of the 3D Seismic acquisition on the Walton-Morant licence with our partners Tullow Oil, and to 31 December 2018 the company has capitalised costs of $2,173,099. Activities have continued on our UK asset with Egdon Resources on the Waddock Cross licence and to 31 December 2018 the company have capitalised costs of $381,413. The first well to be drilled is targeted for 2H 2019.

Management review the intangible exploration assets for indications of impairment at each balance sheet date based on IFRS 6 criteria. Commercial reserves have not yet been established and the evaluation and exploration work is ongoing. The Directors do not consider that any indication of impairment have arisen and accordingly the assets continue to be carried at cost.

7. Property, plant and equipment

	Computer equipment
Cost	
At 1 January 2016 & 31 December 2016	-
Additions	3,631
Foreign exchange differences	142
At 31 December 2017	3,773
Additions	3,535
Foreign exchange differences	(356)
At 31 December 2018	6,952
Depreciation	
At 1 January 2016 & 31 December 2016	-
Charge for the year	587
Foreign exchange differences	22
At 31 December 2017	609
Charge for the year	1,732
Foreign exchange differences	(106)
At 31 December 2018	2,235
Net book value	
At 31 December 2016	-
At 31 December 2017	3,163
At 31 December 2018	4,717

Depreciation is recognised within administrative expenses.

8. Trade and other receivables

	2016 $	2017 $	2018 $
Unpaid share capital receivable	-	158,655	-
Other receivables	-	-	716,783
Prepayments	-	9,952	22,336
	-	168,607	739,119

No receivables are past due or impaired at any of the reporting dates presented.

9. Cash and cash equivalents

	2016 $	2017 $	2018 $
Cash at bank (GBP)	93,482	3,372,324	4,975,449
Cash at bank (EUR)	-	525,672	74,891
Cash at bank (USD)	-	199,989	99,567
	93,482	4,097,985	5,149,907

At 31 December 2016, 2017 and 2018 all significant cash and cash equivalents were deposited in the UK and Ireland with large international banks.

10. Share capital, share premium and merger reserve

Allotted, issued, and fully paid:

UOG Holdings plc	**No**	**Share capital $**	**2016 Share premium $**
Ordinary shares of $0.01 each			
Opening balance	-	-	-
Allotments:			
1 October 2016	20,000,000	259,440	259,440
6 December 2016	5,925,000	75,282	75,282
At 31 December 2016	25,925,000	334,722	334,722

United Oil & Gas plc	**No**	**Share capital $**	**2017 Share premium $**
Ordinary shares of $0.01 each			
Opening balance	27,000,000	342,089	1,233,517
Allotments:			
31 July 2017	173,935,001	2,293,570	3,440,354
27 December 2017	31,250,000	418,724	1,256,173
Share issue costs	-	-	(368,018)
At 31 December 2017	232,185,001	3,054,383	5,562,026

United Oil & Gas plc	**No**	**Share capital $**	**2018 Share premium $**
Ordinary shares of $0.01 each			
Opening balance	232,185,001	3,054,383	5,562,026
Allotments:			
28 February 2018	60,000	827	3,309
11 May 2018	58,823,530	797,404	2,591,561
08 October 2018	54,545,454	712,173	3,204,780
Share issue costs	-	-	(1,448,688)
At 31 December 2018	345,613,985	4,564,787	9,912,988

As regards income and capital distributions, all categories of shares rank pari passu as if the same constituted one class of share.

Merger reserve

In the year ended 31 December 2015 the only entity that existed was United Oil & Gas Limited, therefore following the formation of UOG Holding plc during 2016, along with UOG PL090 Limited, a share for share exchange was completed whereby UOG Holdings became the parent company of United Oil and Gas Limited.

This has been presented on a merger accounting basis, therefore the results and cash flows of all the combining entities have been brought into the historical financial information of the combined entity from the beginning of the financial year in which the combination occurred with no adjustments to fair value, adjusted so as to achieve uniformity of accounting policies.

The merger reserve arising on consolidation is effectively the difference between the fair value of consideration from the share for share exchange less the net assets at the time and is calculated as follows:

Merger reserve arising in the year ended 31 December 2016:

	$
At 1 January 2016	-
Investment in United Oil and Gas Limited	747,315
United Oil and Gas Limited share capital	(1,104)
United Oil and Gas Limited share premium	(314,631)
At 31 December 2016	431,580

Following the reverse takeover of Senterra Energy Plc (subsequently renamed United Oil & Gas Plc) on 31 July 2017, the results of this entity have been combined with those of the UOG Holdings plc group on a merger accounting basis, however United Oil & Gas plc comparatives have not been included in prior years comparatives.

Merger reserve arising in the year ended 31 December 2017:

	$	$
At 1 January 2017		431,580
Investment in UOG Holdings plc Group	2,054,054	
United Oil & Gas share capital	(506,686)	
United Oil & Gas share premium	(490,071)	
United Oil & Gas (formerly Senterra Energy plc) pre-combination retained deficit	1,208,480	
		2,265,777
At 31 December 2017		2,697,357

11. Share based payments

Options

Details of the number of share options and the weighted average exercise price (WAEP) outstanding during the year are as follows:

2018

	Number of Options	**WAEP £**
Outstanding at the beginning of the year	-	-
Issued	11,117,647	0.05
Outstanding at the year end	11,117,647	0.05
Number vested and exercisable at 31 December 2018	-	-

The fair values of share options issued in the current financial year were calculated using the Black Scholes model as follows:

	Share options
Date of grant	25 June 2018
Number granted	11,117,647
Share price at date of grant	£0.05
Exercise price	0.04
Expected volatility	58%
Expected life from date of grant (years)	6.5
Risk free rate	0.9876%
Expected dividend yield	0%
Fair value at date of grant	£293,069
Earliest vesting date	25 June 2021
Expiry date	25 June 2028

Expected volatility was determined based on the historic volatility of the Company's shares for a period averaging 1 year. The expected life used in the model has been adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The Group recognised total expenses of $65,062 in the income statement in relation to share options accounted for as equity-settled share-based payment transactions during the year in relation (2017: $nil; 2016: $nil).

Warrants

Details of the number of share warrants and the weighted average exercise price (WAEP) outstanding during the year are as follows:

2016

	Number of Warrants	**WAEP £**
Outstanding at the beginning of the year	-	-
Issued	20,000,000	0.02
Outstanding at the year end	20,000,000	0.02
Number vested and exercisable at 31 December 2016	20,000,000	0.02

If the warrants remain unexercised after 31 December 2021, the warrants expire.

2017

	Number of Warrants	**WAEP £**
Outstanding at the beginning of the year	20,000,000	0.02
Cancelled	(20,000,000)	(0.02)
Pre-existing warrants in United Oil & Gas	60,000	0.05
Issued	37,200,000	0.02
Outstanding at the year end	37,260,000	0.07
Number vested and exercisable at 31 December 2017	37,260,000	0.07

2018

	Number of Warrants	WAEP £
Outstanding at the beginning of the year	37,260,000	0.07
Exercised	(60,000)	(0.05)
Issued	45,012,206	0.05
Outstanding at the year end	82,212,206	0.04
Number vested and exercisable at 31 December 2018	41,303,126	0.02

If the warrants remain unexercised after 31 July 2022, the warrants expire.

The fair values of share warrants issued or extended in the current financial year were calculated using the Black Scholes model as follows:

	Share warrants	Share warrants	Share warrants	Share warrants	Share warrants
Date of grant	31 July 2017	31 July 2017	27 December 2017	11 May 2018	18 September 2018
Number granted	28,000,000	9,200,000	1,375,000	2,728,126	40,909,080
Share price at date of grant	£0.03	£0.03	£0.04	£0.04	£0.06
Exercise price	£0.01	£0.03	£0.04	£0.04	£0.08
Expected volatility	59%	59%	55%	56%	58%
Expected life from date of grant (years)	2.5	2.5	2.5	2.5	2.5
Risk free rate	0.5555%	0.5555%	0.7280%	1.0783%	1.1283%
Expected dividend yield	0%	0%	0%	0%	0%
Fair value / incremental fair value at date of grant	£382,533	£72,959	£18,952	£40,957	£550,390
Earliest vesting date	31 July 2017	31 July 2017	27 December 2017	11 May 2018	18 September 2019
Expiry date	31 July 2022	31 July 2022	27 December 2022	11 May 2023	18 September 2022

Expected volatility was determined based on the historic volatility of a comparable company's shares for a period averaging 1 year. The expected life used in the model has been adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The Group recognised total expenses of $799,829 in relation to share warrants accounted for as equity-settled share-based payment transactions during the year (2016: $228,436; 2017: $600,145). These were recognised as follows:

$nil (2016: $228,436; 2017: $504,422) as cost of investment in subsidiary held by United Oil & Gas plc (2016: held by UOG Holdings plc) arising on the formation of the new Group structure, and thus results in an increase in the merger reserve recognised in the Group consolidation (see Statement of Changes in Equity).

$nil (2016: $nil; 2017: $32,979) in relation to the combination of United Oil & Gas plc (formerly Senterra Energy plc) with the UOG Holdings plc group – recognised as expenses in the income statement.

$nil (2016: $nil; 2017: $62,744) as a deduction from share premium related to share warrants accounted for as equity-settled share-based payment transactions during the year.

12. Trade and other payables

	2016 $	2017 $	2018 $
Trade payables	15,035	30,968	10,403
Tax and social security	1,231	14,440	20,571
Other payables	15,923	13,359	1,610
Deferred shares (note 13)	-	40,508	38,281
Accruals	11,003	182,349	337,147
	43,192	281,624	408,012

13. Deferred shares

On 12 October 2015, the Company issued 30,000 Deferred Shares of £1 for £30,000 to the Founder, which have an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent of their nominal value. The Deferred Shares have no voting rights attached to them, and may be redeemed in their entirety by the Company for an aggregate redemption payment of £1.

14. Financial instruments

Categories of financial instruments

The tables below set out the Group's accounting classification of each class of its financial assets and liabilities.

Financial assets	2016 $	2017 $	2018 $
Unpaid share capital receivable (note 8)	-	158,655	-
Cash and cash equivalents (note 9)	93,482	4,097,985	5,149,907
	93,482	4,256,640	5,149,907

All of the above financial assets' carrying values are approximate to their fair values, as at 31 December 2016, 2017 and 2018.

Financial liabilities	**Measured at amortised cost**		
	2016	**2017**	**2018**
	$	**$**	**$**
Trade payables (note 12)	15,035	30,968	10,403
Other payables (note 12)	15,923	13,359	1,610
Accruals (note 12)	11,003	182,349	337,147
	41,961	226,677	349,160

In the view of management, all of the above financial liabilities' carrying values approximate to their fair values as at 31 December 2016, 2017 and 2018.

Fair value measurements

This note provides information about how the Group determines fair values of various financial assets and financial liabilities.

Fair value of financial assets and financial liabilities that are not measured at fair value on a recurring basis

The directors consider that the carrying amounts of financial assets and financial liabilities recognised in the consolidated financial statements approximate their fair values (due to their nature and short times to maturity).

15. Financial instrument risk exposure and management

The Group's operations expose it to degrees of financial risk that include liquidity risk, credit risk, interest rate risk.

This note describes the Group's objectives, policies and process for managing those risks and the methods used to measure them. Further quantitative information in respect of these risks is presented in notes 8, 9, 12, 14, and 16.

Liquidity risk

Liquidity risk is dealt with in note 16 of this historical financial information.

Credit risk

The Group's credit risk is primarily attributable to its cash balances.

The credit risk on liquid funds is limited because the third parties are large international banks.

The Group's total credit risk amounts to the total of cash and cash equivalents.

Interest rate risk

The Group's only exposure to interest rate risk is the interest received on the cash held on deposit, which is immaterial. The Group does not have any borrowings.

Foreign exchange risk

The Group's transactions are carried out in GBP, EUR and USD. Fundraising transactions and parent company operating transactions are carried out in GBP. Operational transactions are carried out predominantly in EUR but also in USD.

Exposures to foreign currency exchange rates arise from the Group's overseas sales and purchases, which are denominated in a number of currencies, primarily EUR and USD. Cash balances held in these currencies are relatively immaterial (see note 9) and transactional risk is considered manageable.

The Group does not hold material non-domestic balances and currently does not consider it necessary to take any action to mitigate foreign exchange risk due to the immateriality of that risk.

16. Liquidity risk

Prudent liquidity risk management includes maintaining sufficient cash balances to ensure the Group can meet liabilities as they fall due.

In managing liquidity risk, the main objective of the Group is therefore to ensure that it has the ability to pay all of its liabilities as they fall due. The Group monitors its levels of working capital to ensure that it can meet its debt repayments as they fall due. The table below shows the undiscounted cash flows on the Group's financial liabilities as at 31 December 2016, 2017 and 2018, on the basis of their earliest possible contractual maturity.

	Total $	**Payable on demand** $	**Within 2 months** $	**Within 2 -6 months** $	**Within 6 – 12 months** $	**Within 1-2 years** $
At 31 December 2016						
Trade payables	15,035	-	15,035	-	-	-
Other payables	15,923	15,923	-	-	-	-
Accruals	11,003	-	-	11,003	-	-
	41,961	15,923	15,035	11,003	-	-

	Total $	**Payable on demand** $	**Within 2 months** $	**Within 2 -6 months** $	**Within 6 – 12 months** $	**Within 1-2 years** $
At 31 December 2017						
Trade payables	30,968	-	30,968	-	-	-
Other payables	13,359	13,359	-	-	-	-
Accruals	182,349	-	-	182,349	-	-
	226,676	13,359	30,968	182,349	-	-

	Total $	Payable on demand $	Within 2 months $	Within 2 -6 months $	Within 6 – 12 months $	Within 1-2 years $
At 31 December 2018						
Trade payables	10,403	-	10,403	-	-	-
Other payables	1,610	1,610	-	-	-	-
Accruals	337,147	-	-	337,147	-	-
	349,160	1,610	10,403	337,147	-	-

Other payables comprise loans from directors which are repayable on demand.

17. Capital management

The Group's capital management objectives are:

- To ensure the Group's ability to continue as a going concern; and
- To provide long-term returns to shareholders

The Group defines and monitors capital on the basis of the carrying amount of equity less cash and cash equivalents as presented on the face of the balance sheet and as follows:

	2016 $	2017 $	2018 $
Equity	194,958	5,562,757	10,711,950
Cash and cash equivalents	(93,482)	(4,097,985)	(5,149,907)
	101,476	1,464,772	5,562,043

The Board of Directors monitors the level of capital as compared to the Group's commitments and adjusts the level of capital as is determined to be necessary by issuing new shares. The Group is not subject to any externally imposed capital requirements.

These policies have not changed in the period. The Directors believe that they have been able to meet their objectives in managing the capital of the Group.

18. Related party transactions

Key management personnel are identified as the Executive Directors, and their remuneration is disclosed in note 2.

Loan from director

	Brian Larkin
	$
Principal	
At 1 January 2016	14,890
Loans issued	3,802
Foreign exchange differences	(2,769)
At 31 December 2016	15,923
Loans repaid	(5,656)
Foreign exchange differences	1,291
At 31 December 2017	11,558
Loans repaid	(11,402)
Foreign exchange differences	(156)
At 31 December 2018	-

The loan balance was repayable on demand with no formal terms.

19. Financial commitments

As at 31 December 2018, the Group's commitments comprise their exploration expenditure interests in Waddock Cross, Crown, Colter, Po Valley and the Walton-Morant licence. These commitments have been summarised below:

Exploration licence	**Year ending 31 December 2019**	**Year ending 31 December 2020**
	$	**$**
Crown	107,045	-
Colter	1,067,590	-
Walton-Morant licence	751,676	-
Po Valley	75,377	-
Waddock Cross	47,039	-
	2,048,727	-

20. Ultimate controlling party

The directors do not consider there to be an ultimate controlling party.

21. Events after the balance sheet date

(i) On 1 March 2019 the Company announced its admission to trading on AIM. No additional capital has been raised upon admission.

(ii) The Colter Well 98/11a-6, situated in the UK Wessex Basin was spudded on 6 February 2019, targeting the fault-block immediately to the south of Wytch Farm. The initial borehole didn't intersect the targeted structure, but made an unexpected new discovery at Colter South. The well was then sidetracked, but the targeted Sherwood Sandstone reservoir section came in below the Oil Water Contact of the 98/11-3 well, suggesting the original Colter structure is smaller than pre-drill estimates. However, the sidetrack found strong shows in the shallower Jurassic section, with encouraging implications for prospectivity along strike. Volumetric evaluation of both the Colter and Colter South structures are underway. The operator, Corallian Energy carried pre-drill recoverable volumes of 15mmbbls for Colter South – likely to be a conservative estimate. The most recent estimated final costs of drilling at Colter to UOG, including the additional sidetrack are circa $1.35m.

(iii) United Oil & Gas Plc has signed an option agreement with Elephant Oil Ltd to farm in to their Block B onshore acreage in Bénin, potentially taking a 20% interest in the production sharing agreement.

Under the farm in option agreement, the Company have agreed to fund passive seismic and field studies up to a value of $175k. The completion of the passive seismic programme is being targeted for April. The goal of the proposed work programme will be to calibrate the depth to basement and obtain further information on the oil and gas seeps. This will further de-risk maturity and migration in the area ahead of the completion of a final decision to exercise the farm in option.

If United chooses to exercise the option, then the Company will farm into the PSC for a 20% interest and will be responsible to fund 30% of the non-drilling and 20% of the drilling costs in the Phase 1 work programme as approved under the PSC. United would also pay Elephant the sum of US$260,000, representing one quarter of the pro rata (20%) past costs expended by Elephant on the prospect, with the remaining US$780,000 paid in three equal six monthly instalments.

(iv) On 17 July 2019, the company announced the proposed sale of North Sea Blocks 15/18d, and 15/19b to Anasuria Hibiscus UK Limited for a consideration of up to US $5 million. The SPA was signed on the 7th October 2019.

(v) On 23 July 2019, the Company announced the conditional acquisition of Rockhopper Egypt for US $16 million with an effective date of 1 January 2019. Rockhopper Egypt has a 22% interest in the Abu Sennan concession. As the acquisition constitutes a Reverse Takeover under AIM rules, trading in the shares of the Company were suspended on 23 July 2019 and remain suspended pending the publication of the AIM readmission document. On the same date the Company signed up to a prepayment financing structure of up to US $8m with BP which will part fund the acquisition.

(vi) On 9 September 2019, the Company announced the confirmation of the formal award of four Blocks in the UK North Sea. Blocks 14/15c, 15/11c, 15/12a and 15/13c (Licence P2480) were provisionally awarded on 5th June 2019 and the Company has now accepted the formal offer from the Oil and Gas Authority, the UK oil and gas regulator.

SECTION B(iii): UNAUDITED INTERIM RESULTS OF THE EXISTING GROUP

Consolidated Income Statement

	Note	Period ended 30 June 2019 Unaudited $	Period ended 30 June 2018 Unaudited $	Year ended 31 December 2018 Audited $
Administrative expenses		(756,408)	(603,764)	(1,080,272)
Operating loss and loss before taxation		(756,408)	(603,764)	(1,080,272)
Taxation		-	-	-
Loss for the financial period attributable to the Company's equity shareholders		(756,408)	(603,764)	(1,080,272)
Loss per share from continuing operations expressed in cents per share:				
Basic and diluted	4	(0.22)	(0.24)	(0.38)

Consolidated Statement of Comprehensive Loss

	Period ended 30 June 2019 Unaudited $	Period ended 30 June 2018 Unaudited $	Year ended 31 December 2018 Audited $
Loss for the financial period	(756,408)	(603,764)	(1,080,272)
Foreign exchange difference	24,987	(99,701)	(496,793)
Loss for the financial period attributable to the Company's equity shareholders	(731,421)	(703,465)	(1,577,065)

Consolidated Balance Sheet

	Note	30 June 2019 Unaudited $	30 June 2018 Unaudited $	31 December 2018 Audited $
Non-Current Assets				
Intangible Assets	5	7,986,167	4,853,373	5,226,219
Property, Plant and Equipment		3,525	3,612	4,717
		7,989,692	4,856,985	5,230,936
Current Assets				
Trade and other receivables		579,547	9,943	739,119
Cash and cash equivalents		1,787,179	3,176,404	5,149,907
		2,366,726	3,186,347	5,889,026
Total Assets		10,356,418	8,043,332	11,119,962
Capital and Reserves Attributable to Equity Holders of the Company				
Share capital	6	4,564,787	3,852,614	4,564,787
Share premium	6	9,912,988	7,666,197	9,912,988
Share-based payment reserve		1,465,036	600,145	1,465,036
Merger reserve		(2,697,357)	(2,697,357)	(2,697,357)
Translation reserve		(392,194)	(20,089)	(417,181)
Retained earnings		(2,872,731)	(1,639,815)	(2,116,323)
Total Equity		9,980,529	7,761,695	10,711,950
Current Liabilities				
Trade and other payables		375,890	281,637	408,012
Total Liabilities		375,890	281,637	408,012
Total Equity and Liabilities		10,356,418	8,043,332	11,119,962

Consolidated Statement of Changes in Equity

	Share capital $	Share premium $	Share-based payment reserve $	Retained earnings $	Translation reserve $	Merger reserve $	Total equity $
For the period ended 30 June 2019							
Balance at 1 January 2019	4,564,787	9,912,988	1,465,036	(2,116,323)	(417,181)	(2,697,357)	10,711,950
Loss for the period	-	-	-	(756,408)	-	-	(756,408)
Foreign exchange difference	-	-	-	-	24,987	-	24,987
Total comprehensive loss for the period	-	-	-	(756,408)	24,987	-	(731,421)
Contributions by and distributions to owners:							
Total contributions by and distributions to owners	-	-	-	-	-	-	-
Balance at 30 June 2019 (Unaudited)	4,564,787	9,912,988	1,465,036	(2,872,731)	(392,194)	(2,697,357)	9,980,529
For the period ended 30 June 2018							
Balance at 1 January 2018	3,054,383	5,562,026	600,145	(1,036,051)	79,612	(2,697,357)	5,562,758
Loss for the period	-	-	-	(603,764)	-	-	(603,764)
Foreign exchange difference	-	-	-	-	(99,701)	-	(99,701)
Total comprehensive loss for the period	-	-	-	(603,764)	(99,701)	-	(703,465)
Contributions by and distributions to owners:							
Issue of shares on exercise of warrants	827	3,309	-	-	-	-	4,136
Issue of shares	797,404	2,591,562	-	-	-	-	3,388,966
Expenses of issue	-	(490,700)	-	-	-	-	(490,700)
Total contributions by and distributions to owners	798,231	2,104,171	-	-	-	-	2,902,402
Balance at 30 June 2018 (Unaudited)	3,852,614	7,666,197	600,145	(1,639,815)	(20,089)	(2,697,357)	7,761,695
For the period ended 31 December 2018							
Balance at 1 January 2018	3,054,383	5,562,026	600,145	(1,036,051)	79,612	(2,697,357)	5,562,758
Loss for the period	-	-	-	(1,080,272)	-	-	(1,080,272)
Foreign exchange difference	-	-	-	-	(496,793)	-	(496,793)
Total comprehensive loss for the year	-	-	-	(1,080,272)	(496,793)	-	(1,577,065)
Contributions by and distributions to owners:							
Exercise of share warrants	827	3,309	-	-	-	-	4,136
Issue of share capital	1,509,577	5,796,341	-	-	-	-	7,305,918
Share issue expenses	-	(1,448,688)	799,829	-	-	-	(648,859)
Issue of share options	-	-	65,062	-	-	-	65,062
Balance at 31 December 2018 (Audited)	4,564,787	9,912,988	1,465,036	(2,116,323)	(417,181)	(2,697,357)	10,711,950

Consolidated Statement of Cashflows

	Period ended 30 June 2019 Unaudited $	Period ended 30 June 2018 Unaudited $	Year ended 31 December 2018 Audited $
Cash flows from operating activities			
Loss before taxation	(756,408)	(603,764)	(1,080,272)
Adjustments for:			
Share-based payments	-	-	65,062
Depreciation	1,149	676	1,732
Foreign exchange movements	(21,718)	-	(137,119)
	(776,977)	(603,088)	(1,150,597)
Decrease / (increase) in trade and other receivables	159,572	158,663	(570,512)
(Decrease) / increase in trade and other payables	(32,122)	13	126,387
Net cash used in operating activities	(649,527)	(444,412)	(1,594,722)
Cash flows from investing activities			
Purchase of property, plant & equipment	-	(1,218)	(3,535)
Payments for intangible exploration assets	(2,830,448)	(3,278,745)	(3,651,592)
Net cash used in investing activities	(2,830,448)	(3,279,963)	(3,655,127)
Cash flows from financing activities			
Issue of ordinary shares (net of expenses)	-	2,902,402	6,661,195
Net cash from financing activities	-	2,902,402	6,661,195
(Decrease) / increase in cash and cash equivalents	(3,479,975)	(821,973)	1,411,346
Cash and cash equivalents at beginning of period / year	5,149,906	4,097,985	4,097,985
Effects of exchange rate changes	117,246	(99,609)	(359,424)
Cash and cash equivalents at end of period / year	1,787,178	3,176,403	5,149,907

Notes to the financial information

1. General

The interim financial information for the period to 30 June 2019 is unaudited.

2. Accounting Policies

The interim financial information in this report has been prepared on the basis of the accounting policies set out in the audited financial statements for the period ended 31 December 2018, which complied with International Financial Reporting Standards as adopted for use in the European Union ("IFRS").

IFRS is subject to amendment and interpretation by the International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee and there is an on-going process of review and endorsement by the European Commission.

The financial information has been prepared on the basis of IFRS that the Directors expect to be applicable as at 31 December 2019. During the year the Group has implemented IFRS 16 which has had an immaterial impact on the financial statements due to the Group's lease arrangements being limited to a short-term office lease.

The Directors have adopted the going concern basis in preparing the financial information. In assessing whether the going concern assumption is appropriate, the Directors have taken into account all relevant available information about the foreseeable future.

Presentation currency

The Group has taken the decision to change its presentation currency to USD. This has been accounted for retrospectively as a change in accounting policy. In making this change in presentation currency, the Company followed the requirements set out in IAS 21, The Effects of Change in Foreign Exchange Rates. In accordance with IAS 21, the change in presentational currency is applied retrospectively and financial statements for the previous financial periods have therefore been translated into the new presentation currency.

Foreign currency

The Group has taken the decision to change its presentation currency to USD. This has been accounted for retrospectively as a change in accounting policy.

Going Concern

The Group's business activities, together with the factors likely to affect its future development, performance and position are set out in the CEO's Statement and Directors' Report.

In the financial statements for the year to 31 December 2018, the Group stated that based on the cash balance at year end and the Group's commitments, the Group had sufficient funding to meet planned financial commitments in relation to operational activities and a level of contingency. Based on current cash balances and the Group's commitments, the funding position remains unchanged.

The directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future, therefore they continue to adopt the going concern basis of accounting in preparing the financial statements.

Exploration and evaluation assets
The group accounts for oil and gas expenditure under the full cost method of accounting.

Costs (other than payments to acquire the legal right to explore) incurred prior to acquiring the rights to explore are charged directly to the profit and loss account. All costs incurred after the rights to explore an area have been obtained, such as geological, geophysical, data costs and other direct costs of exploration and appraisal are accumulated and capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities if technical feasibility is demonstrated and commercial reserves are discovered, then following development sanction, the carrying value of the relevant E&E asset will be reclassified as a development and production asset within tangible fixed assets.

If after completion of appraisal activities in an area, it is not possible to determine technical feasibility or commercial viability, then the costs of such unsuccessful exploration and evaluation are written off to the profit and loss account. The costs associated with any wells which are abandoned are fully amortised when the abandonment decision is taken.

Development and production assets, are accumulated generally on a field by-field basis and represent the costs of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves which have been transferred from intangible E&E assets.

The net book values of development and production assets are depreciated generally on a field-by field basis using the unit of production method based on the commercial proven and probable reserves. Assets are not depreciated until production commences.

3. Related Party Transactions

The directors are considered to be the key management personnel of the company. During the interim period, the company paid fees to executive and non-executive directors amounting to $188,500 (Period ended 30 June 2018 - $148,708).

4. Loss per Share

Basic loss per share is calculated by dividing the loss attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the period.

Given the Group’s reported loss for the period, share options and warrants are not taken into account when determining the weighted average number of ordinary shares in issue during the year as they would be anti-dilutive, and therefore the basic and diluted loss per share are the same.

Basic and diluted loss per share

	Period ended 30 June 2019	Period ended 30 June 2018	Year ended 31 December 2018
Loss for the period ($)	(756,408)	(603,764)	(1,080,272)
Weighted average number of ordinary shares (number)	345,613,985	248,798,040	282,810,516
Loss per share from continuing operations (cents per share)	(0.22)	(0.24)	(0.38)

5. Intangible Assets

	Exploration and Evaluation assets $
Cost	
At 31 December 2017	1,574,627
Additions	3,902,289
Exchange differences	(250,697)
At 31 December 2018	5,226,219
Additions	2,830,448
Exchange differences	(70,500)
At 30 June 2019	7,986,167
Net book value	
At 31 December 2018	5,226,219
At 30 June 2019	7,986,167

Drilling commenced on the Colter Appraisal Well in early February 2019. The well delivered a new discovery, Colter South, which opens up new opportunity within the licence. A sidetrack to Colter North was also drilled and encountered a reservoir, it did so deeper than expected. Work continues on evaluating the well results. The costs incurred and capitalised to 30 June 2019 are $1,964,336.

In the UK North Sea, the work programme involving seismic reprocessing and rock physics commenced on the P2366 Crown asset that was awarded to the company in 2018. At the balance sheet date, a total of $368,318 had been capitalised to Intangible assets.

In Italy well drilling and testing was completed at Podere Gallina in the first quarter of 2018, and development planning is well advanced ahead of first production in late 2020. $2,246,744 has been spent and capitalised by the Company at 30 June 2019.

In Jamaica work continues on the new 3D data acquired offshore in 2018 which has identified further prospectivity, whilst a joint venture farm-down process is currently underway with the operating partners, Tullow Oil. As at the balance sheet date $2,547,603 has been capitalised by the Company.

Well planning has continued on our Waddock Cross licence and to 30 June 2019 the company have capitalised costs of $432,419.

The Company continue to pursue new opportunities and $426,747 has been capitalised in the year to date on two particular opportunities. A farm-in option on Benin has been agreed with Elephant Oil Limited on their Block B licence. The company has also recently announced a deal to acquire Rockhopper Egypt, which is expected to complete in Q4 2019. New Venture pre-licence type activity amounting to $260,097 was expensed in the 6 months to 30 June 2019 and is included within administrative expense in the consolidated income statement.

Management review the intangible exploration assets for indications of impairment at each balance sheet date based on IFRS 6 criteria. Commercial reserves have not yet been established and the evaluation and exploration work is ongoing. The Directors do not consider that any indications of impairment have arisen and accordingly the assets continue to be carried at cost.

6. Share Capital & Share Premium

Allotted, issued, and fully paid:

			30 June 2019
	No	Share capital $	Share premium $
Ordinary shares of £0.01 each			
Opening balance	345,613,985	4,564,787	9,912,988
At 30 June	345,613,985	4,564,787	9,912,988

			30 June 2018
	No	Share capital $	Share premium $
Ordinary shares of £0.01 each			
Opening balance	232,185,001	3,054,383	5,562,026
Allotments:			
7 March 2018	60,000	827	3,309
11 May 2018	58,823,530	797,404	2,591,562
Share issue costs	-	-	(490,700)
At 30 June	291,068,531	3,852,614	7,666,197

		31 December 2018	
		Share	**Share**
		capital	**premium**
	No	**$**	**$**
Ordinary shares of £0.01 each			
Opening balance	232,185,001	3,054,383	5,562,026
Allotments:			
28 February 2018	60,000	827	3,309
11 May 2018	58,823,530	797,404	2,591,561
08 October 2018	54,545,454	712,173	3,204,780
Share issue costs	-	-	(1,448,688)
At 31 December	345,613,985	4,564,787	9,912,988

7. Events after the balance sheet date

On 17th July 2019, the company announced the proposed sale of North Sea Blocks 15/18d, and 15/19b (Crown Discovery) to Anasuria Hibiscus UK Limited for a consideration of up to US $5 million. The SPA was signed on the 7th October 2019.

On 23rd July 2019, the Company announced the conditional acquisition of Rockhopper Egypt for US $16 million with an effective date of 1 January 2019. Rockhopper Egypt has a 22% interest in the Abu Sennan concession. As the acquisition constitutes a Reverse Takeover under AIM Rules, trading in the shares of the Company were suspended on 23rd July 2019 and remain suspended pending the publication of the AIM readmission document. On the same date the Company signed a prepayment financing structure of up to US $8m with BP, which will part fund the acquisition.

On 9th September 2019, the Company announced the confirmation of the formal award of four Blocks in the UK North Sea. Blocks 14/15c, 15/11c, 15/12a and 15/13c (Licence P2480) were provisionally awarded on 5 June 2019 and the Company has now accepted the formal offer from the Oil and Gas Authority, the UK oil and gas regulator.

PART V

UNAUDITED PRO FORMA FINANCIAL INFORMATION FOR THE ENLARGED GROUP

SECTION A: ACCOUNTANT'S REPORT ON THE PRO FORMA NET ASSETS

Date: 6 December 2019

PRIVATE & CONFIDENTIAL
The Directors
United Oil & Gas plc
200 Strand
London WC2R 1DJ

The Directors
Beaumont Cornish Limited
10th Floor
30 Crown Place
London EC2A 4EB

Dear Sirs

United Oil & Gas plc (the "Company")

Pro forma financial information

We report on the unaudited pro forma statements of net assets as at 31 December 2018 of United Oil & Gas plc ("the Company") (the "Unaudited Pro Forma Financial Information") set out in section Part V Section B of the admission document dated 6 December 2019 of the company (the "AIM Admission Document") which has been prepared on the basis described, for illustrative purposes only, to provide information about how the acquisition and certain other subsequent events might have affected the financial information presented on the basis of accounting policies adopted by the Company in preparing the historical financial information for the year ended 31 December 2018.

Responsibilities

This report is as agreed between us in writing and is given for the purpose of complying with that requirement and for no other purpose.

Save for any responsibility that we have expressly agreed to in writing to assume, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report.

It is the responsibility of the Directors of the Company to prepare the pro forma financial information, which has been prepared in accordance with Schedule Two of the AIM Rules for Companies with reference to 18.4.1 of Annex 1 to the Commission Delegated Regulation (EU) No. 2019/980 attached to the AIM Rules for Companies as if it had been applicable.

It is our responsibility to form an opinion, which would have been required by paragraph 7 of Annex II of the Prospectus Rules attached to the AIM Rules for Companies 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 opinion

We conducted our work in accordance with the Standards for Investment Reporting by the Auditing Practices Board in the United Kingdom. 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 discussion the Pro Forma Financial Information with the Directors.

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 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.

Our work has not been carried out in accordance with auditing standards generally accepted in the United Kingdom and accordingly should not be relied upon as if it had been carried out in accordance with those standards.

Opinion

In our opinion:

(a) The Pro Forma Financial Information has been properly compiled on the basis stated; and

(b) Such basis is consistent with the accounting policies of the Company.

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 AIM Document and declare that we have taken all reason able care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely affect its import. This declaration is included in the AIM Document in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies.

Yours faithfully

UHY Hacker Young LLP

Chartered Accountants

UNAUDITED PROFORMA FINANCIAL INFORMATION FOR THE ENLARGED GROUP

SECTION B: PRO FORMA NET ASSETS

Set out below is an unaudited pro forma statement of net assets of United Oil & Gas plc as at 31 December 2018. The unaudited pro forma statement of net assets have been prepared for illustrative purposes only to illustrate the effect on the net assets of United Oil & Gas plc of the proposed acquisition, and certain other subsequent events as described in the notes below, as if they had taken place as at 31 December 2018. Because of the nature of pro forma financial information, this unaudited pro forma statement of net assets address a hypothetical situation and does not therefore represent the actual financial position of United Oil & Gas plc as at 31 December 2018. The unaudited pro forma statement of net assets has been prepared on the basis described in the notes set out below and after making the adjustments described in those notes.

Unaudited Pro Forma Statement of Net Assets of United Oil & Gas plc

	The Company at 31 December 2018	*Rockhopper Egypt at 31 December 2018*	*Admission to trading on the AIM market*	*Acquisition adjustments*	*Pro forma net assets (unaudited)*
	Note 1	*Note 2*	*Note 3*	*Note 4*	
	$	*$*	*$*	*$*	*$*
ASSETS					
Non-current assets					
Intangible assets	5,226,219	5,822,498	–	–	11,048,717
Property, plant and equipment	4,716	5,404,237	–	4,327,950	9,736,903
Total non-current assets	5,230,935	11,226,735	–	4,327,950	20,785,620
Current assets					
Inventories	–	22,823	–	–	22,823
Trade and other receivables	739,119	8,749,496	–	(6,908,773)	2,579,842
Cash and cash equivalents	5,149,907	647,285	(252,500)	2,083,316	7,628,008
Total current assets	5,889,026	9,419,604	(252,500)	(4,825,457)	10,230,673
TOTAL ASSETS	11,119,961	20,646,339	(252,500)	(497,507)	31,016,293
LIABILITIES					
Current liabilities					
Trade and other payables	408,012	–	2,065,516	–	–
Loans	–	–	4,722,032	2,473,528	4,722,032
Total current liabilities	408,012	2,065,516	–	4,722,032	7,195,560
Non-current liabilities					
Loans	–	–	–	3,037,968	3,037,968
Total non-current liabilities	–	–	–	3,037,968	3,037,968
NET ASSETS	10,711,949	18,580,823	(252,500)	(8,257,507)	20,782,765

Notes

1. The financial information for United Oil & Gas plc has been extracted without adjustment from the historical financial information as at 31 December 2018.
2. The financial information for Rockhopper Egypt has been extracted without adjustment from the historical financial information as at 31 December 2018.
3. On 1 March 2019 the ordinary shares of the company of 1 pence each were admitted to trading on the AIM market of the London Stock Exchange following the cancellation of trading of the Ordinary Shares on the standard listing segment of the Official List and to trading on the Main Market. The adjustments reflect the expenses associated with the admission to the AIM market.
4. The above adjustments reflect the acquisition of Rockhopper Egypt by United Oil & Gas plc. As part of this transaction a placing and subscription of 159,036,167 new ordinary shares of 1p each in the capital of the Company at a price of 3.0 pence per Placing Share raised $5.96 million net of placing expenses. The above reflects the net cash proceeds following completion of the acquisition, placing, transaction fees and funds of $8 million drawn down through the BTL Facility. The intercompany debtor balance between Rockhopper Egypt and Rockhopper Exploration Plc will be extinguished on completion therefore the above proforma balance sheet reflects the Rockhopper Egypt financials excluding this debtor balance.

PART VI

TAXATION IN THE UK

The following section is a summary guide only to certain aspects of tax in the UK. This is not a complete analysis of all the potential tax effects of acquiring, holding and disposing of Ordinary Shares, nor will it relate to the specific tax position of all Shareholders in all jurisdictions. This summary is not a legal opinion. Shareholders are advised to consult their own tax advisers.

1 Taxation in the United Kingdom

The following information is based on UK tax law and HM Revenue and Customs 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 adviser immediately.

2 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:

2.1 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

2.2 Who intend to acquire Ordinary Shares as part of tax avoidance arrangements; or

2.3 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.

3 Dividends

Where the Company pays dividends, 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 dividend tax allowance. Dividend receipts in excess of £2,000 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 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 or withholding tax imposed.

4 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 the rate is 20 per cent.

For Shareholders within the charge to UK corporation tax, the corporation tax rate applicable to its taxable profits is 19 per cent. It was proposed in 16 March 2016 budget that the rate of corporation tax after 1 April 2020 will fall to 17 per cent.

4.1 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 HM Revenue and Customs to raise tax assessments so as to cancel "tax advantages" derived from certain prescribed "**transactions in securities**".

5 Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

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 SDRT or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

5.1 *Ordinary Shares held in certificated form*

No UK stamp duty or SDRT will be payable on the issue of the Ordinary Shares. Most investors will purchase existing Ordinary Shares using the CREST paperless clearance system and these acquisitions will be subject to SDRT at 0.5 per cent. Where Ordinary Shares are acquired using paper (i.e. non-electronic settlement) stamp duty will become payable if the purchase consideration exceeds £1,000.

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 law 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 or she is resident, or otherwise subject to taxation, in a jurisdiction other than the UK, should consult his or her professional adviser.

PART VII

ADDITIONAL INFORMATION

1 Responsibility Statement

1.1 The Company and the Directors accept responsibility for the information contained in this Document, including individual and collective responsibility, and for the Company's compliance with the AIM Rules for Companies. 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 makes no omission likely to affect the import of such information.

1.2 UHY Hacker Young LLP, whose address appears on pages 9 and 211 of this Document, accepts responsibility for the information contained in Parts IV Section A (i), IV Section B (i) and V Section A of this Document. To the best of the knowledge and belief of UHY Hacker Young LLP (who have taken all reasonable care to ensure that such is the case) the information contained in Parts IV through V of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.3 Gaffney, Cline & Associates, whose address appears on page 9 of this Document, accepts responsibility for the information contained in Part VIII of this Document. To the best of the knowledge and belief of Gaffney, Cline & Associates (who have taken all reasonable care to ensure that such is the case) the information contained in Part VIII of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.4 ERC Equipoise Ltd, whose address appears on page 9 of this Document, accepts responsibility for the information contained in Part IX of this Document. To the best of the knowledge and belief of ERC Equipoise Ltd (who has taken all reasonable care to ensure that such is the case) the information contained in Part IX of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.5 CGG Service (UK) Limited, whose address appears on page 9 of this Document, accepts responsibility for the information contained in Part X of this Document. To the best of the knowledge and belief of CGG Service (UK) Limited (who have taken all reasonable care to ensure that such is the case) the information contained in Part X of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

2 Incorporation and Status of the Company

2.1 The Company was incorporated and registered in England and Wales as a company limited by shares on 5 June 2015 under the Act, with the name Senterra Energy Limited and with registered number 09624969. On 15 October 2015, the Company was re-registered as a public limited company under the legal and commercial name Senterra Energy plc. On 28 July 2017 the Company changed its legal and commercial name to United Oil & Gas Plc. The Company is domiciled in England.

2.2 The liability of the members of the Company is limited.

2.3 The principal legislation under which the Company operates is the Act and the regulations made thereunder.

2.4 The registered office of the Company is at 200 Strand, London WC2R 1DJ.

2.5 The telephone number of Company is +353 1 9053557.

3 The Subsidiaries

3.1 The Company acts as the ultimate holding company of the Group.

3.2 The Company has the following direct subsidiary which is a public limited company:

Name	*Country of incorporation*	*Registered office*	*Proportion of ownership*	*Principal interest activity*
UOG Holdings PLC	England and Wales	200 Strand London WC2R 1DJ	100%	Holding Company

Following completion of the Rockhopper Acquisition, the Company will own 100 per cent. of the shares in Rockhopper Egypt, to be renamed UOG Egypt Pty Limited following Completion.

3.3 The Company has the following indirect subsidiaries which are private limited companies:

Name	*Country of incorporation*	*Registered office*	*Proportion of ownership*	*Principal interest activity*
UOG Ireland Limited	Ireland	6 Upper Pembroke Street Dublin 2, Ireland	100%	Holding Company
UOG PL090 Limited	England and Wales	200 Strand London WC2R 1DJ, UK	100%	Oil & Gas Exploration and Production
UOG Italia S.r.l	Italy	Viale Gioacchnio, Rossini 9, Cap 00198, Rome, Italy	100%	Oil & Gas Exploration and Production
UOG Jamaica Limited	England and Wales	200 Strand London WC2R 1DJ, UK	100%	Oil & Gas Exploration and Production
UOG Colter Limited	England and Wales	200 Strand London WC2R 1DJ, UK	100%	Oil & Gas Exploration and Production
UOG Crown Limited	England and Wales	200 Strand London WC2R 1DJ, UK	100%	Oil & Gas Exploration and Production

4 Share Capital of the Company

4.1 The issued share capital of the Company, as at the date of this Document and immediately following Admission, is and will be as follows:

	Nominal value (£) of Ordinary Shares issued and credited (in aggregate)	*Number of Ordinary Shares*
At the date of this Document	3,456,139.85	345,613,985
On Admission	6,191,539.69	619,153,969

4.2 The Company was incorporated on 5 June 2015 with an issued share capital of £1 consisting of one ordinary share of £1. On 12 October 2015, the Company issued and allotted 19,999 additional ordinary shares of £1 each for a total subscription price of £19,999, together with 30,000 Deferred Shares for a total subscription price of £30,000. The Deferred Shares, whose rights are described in paragraph 4.3 below, have negligible value.

4.3 The Deferred Shares, each confer an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent. of their nominal value (equivalent to an aggregate dividend payment of £30 on all the Deferred Shares which is first payable on the first anniversary of their issue (being 5 June 2016) and annually thereafter). The Deferred Shares carry no further right to participate in the profits or assets of the Company and carry no Voting Rights. They may all be redeemed by the Company for an aggregate redemption payment of £1.

4.4 On 12 October 2015, the Company subdivided each ordinary share of £1 into 100 ordinary shares of £0.01 each.

4.5 On 6 November 2015, a further 25,000,000 Ordinary Shares were conditionally allotted and issued pursuant to a placing at a price of 5 pence per Ordinary Share.

4.6 On 24 July 2017, the Company conditionally allotted and issued 120,000,000 Ordinary Shares to placees at 2.5p per share.

4.7 On 31 July 2017, the Company issued 53,935,001 Ordinary Shares and 28,000,000 Warrants under the UOG Warrant Instrument to certain persons pursuant to the acquisition of UOG UK.

4.8 On 27 December 2017, a further 31,250,000 Ordinary Shares were allotted at a price of 4 pence per Ordinary Share.

4.9 On 2 March 2018, 60,000 Ordinary Shares were issued as a result of the exercise in full of Warrants granted to it by the Company.

4.10 On 11 May 2018, 58,823,530 Ordinary Shares were issued at a placing price of 4.25 pence per Ordinary Share pursuant to a placing.

4.11 On or about 2 August 2018, the Company granted Options over an aggregate number of 11,117,648 Ordinary Shares to certain Directors as set out in the table below.

Name	*No of Options*
Brian Larkin	4,235,294
Jonathan Leather	4,058,824
Graham Martin	1,176,471
Alberto Cattaruzza	352,941

The Options vest three years from the date of grant, have an expiry date of ten years from the date of vesting and are exercisable at a price of 4.25 pence per Ordinary Share. The Options are only exercisable if the option holder is employed by the Company and he has not served, or has had served upon him by the Company, notice to terminate his employment or appointment at the time of exercise.

4.12 On 10 October 2018, a further 54,545,454 Ordinary Shares were allotted and issued at a price of 5.5 pence per Ordinary Share and 40,909,080 Warrants were granted with an exercise price of 8p per Ordinary Share pursuant to a placing.

4.13 On 6 December 2019, the Company conditionally granted 6,389,167 Warrants pursuant to the Optiva December 2019 Warrant Agreement and 1,141,667 Warrants pursuant to the Cenkos December 2019 Warrant Agreement.

5 Warrants

The table below sets out the outstanding existing Warrants at the date of the Document:

Instrument	*Latest Exercise Date*	*Number*	*Exercise*	*Exercise Period*
UOG Warrant Instrument	31 July 2022	28,000,000*****	1.42857p	31 July 2017 to 31 July 2022
Beaumont Cornish Warrant Instrument	31 July 2022	3,200,000	2.5p	31 July 2017 to 31 July 2022
Optiva Warrant Instrument	31 July 2020	6,000,000	2.5p	31 July 2017 to 31 July 2020
Optiva December 2017 Warrant Instrument	27 December 2022	1,375,000	4p	27 December 2017 to 27 December 2022
Optiva April 2018 Warrant Instrument	27 December 2022	2,728,126	4.25p	27 December 2017 to 27 December 2022
September 2018 Warrant Instrument	10 October 2023	40,909,080	8p	10 October 2019 to 8 October 2022

***these warrants have been issued to certain persons (further details of which are set out in paragraph 12.13)**

5.1 The Articles were adopted by the Company pursuant to a special resolution passed on 12 October 2015, the principal terms of which are summarised in paragraph 6 of this Part VII.

5.2 No Ordinary Shares are currently in issue with a fixed date on which entitlement to a dividend arises and there are no arrangements in force whereby future dividends are waived or agreed to be waived.

5.3 Save as disclosed in this Part VII:

(a) no share or loan capital of the Company has been issued or is proposed to be issued, fully or partly paid, either for cash or for a consideration other than cash;

(b) no share or loan capital of the Company is under option or is the subject of an agreement, conditional or unconditional, to be put under option; and

(c) no commission, discounts, brokerage or other special term has been granted by the Company or is now proposed in connection with the issue or sale of any part of the share or loan capital of the Company.

6 Articles of Association

The following is a description of the rights attaching to the Ordinary Shares based on the Articles and English law. This description does not purport to be complete and is qualified in its entirety by the full terms of the Articles.

6.1 *Voting*

Subject to any rights or restrictions attaching to any class of shares, every member present in person at a general meeting or class meeting has, upon a show of hands, one vote, and every member (excluding any member holding shares as treasury shares) present in person or by proxy has, upon a poll, one vote for every share held by him. The Deferred Shares carry no voting rights.

In the case of joint holders of a share 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 and, for this purpose, seniority shall be determined by the order in which the names stand in the register in respect of the joint holding.

6.2 *Dividends and other Distributions*

The profits of the Company available for dividend in accordance with the Act and determined to be distributed shall be applied in the payment of dividends to the members in accordance with their respective rights and priorities. The Company may by ordinary resolution declare dividends accordingly. Subject to the rights of persons (if any) entitled to ordinary shares with special rights as to dividend, all dividends shall be declared and paid according to the amounts paid up on the Ordinary Shares in respect whereof the dividends are paid, but no amount paid up on a share in advance of calls shall be treated as paid up on the Ordinary Shares; all dividends shall be apportioned and paid *pro rata* according to the amounts paid up on the Ordinary Shares during any portion or portions of the period in respect of which the dividend is paid, except that if any share is issued on terms providing that it shall rank for dividend as if paid up (in whole or in part) as from a particular date such share shall rank for dividend accordingly. The Deferred Shares carry a dividend entitlement as described below in this paragraph.

The Company may by ordinary resolution from time to time declare dividends not exceeding the amount recommended by the Board. Subject to the Act, the Board may pay interim dividends, and also any fixed rate dividend, whenever the financial position of the Company, in the opinion of the Board, justifies its payment. If the Board acts in good faith, it is not liable to holders of shares with preferred or *pari passu* rights for losses arising from the payment of interim or fixed dividends on other shares. There are no fixed dates for the payment of dividends, except as described below.

The Board may withhold payment of all or any part of any dividends or other moneys payable in respect of the Company's shares from a person with at least a 0.25 per cent. interest if such a person has been served with a direction notice (as defined in the Articles) after failure to provide the Company with information concerning interests in those shares required to be provided under the Act.

Except insofar as the rights attaching to, or the terms of issue of, any share otherwise provide, all dividends shall be apportioned and paid *pro rata* according to the amounts paid up on the share during any portion of the period in respect of which the dividend is paid. Except as set out above, dividends may be declared or paid in any currency.

The Board may, if authorised by an ordinary resolution of the Company, offer ordinary Shareholders (excluding any member holding shares as treasury shares) in respect of any dividend the right to elect to receive Ordinary Shares by way of scrip dividend instead of cash. Any dividend unclaimed after a period of 12 years from the date when it was declared or became due for payment shall be forfeited and revert to the Company.

The Company may stop sending cheques, or similar financial instruments, in payment of dividends by post in respect of any shares or may cease to employ any other means of payment, including payment by means of a relevant system, for dividends if either (i) at least two consecutive payments have remained uncashed or are returned undelivered or that means of payment has failed or (ii) one payment remains uncashed or is returned undelivered or that means of payment has failed, and reasonable inquiries have failed to establish any new address or account of the holder. The Company may resume sending dividend cheques if the holder requests such resumption in writing.

Each Deferred Share confers an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent. of its nominal value, payable on the first anniversary of their date of issue and on each such anniversary thereafter. The Deferred Shares carry no other right to participate in the profits or assets of the Company and carry no voting rights. The Deferred Shares may be redeemed in their entirety for an aggregate redemption payment of £1.

6.3 ***Transferability of Shares***

The shares are in registered form. Any shares in the Company may be held in uncertificated form and, subject to the Articles, title to uncertificated shares may be transferred by means of a relevant system. Provisions of the Articles do not apply to any uncertificated shares to the extent that such provisions are inconsistent with the holding of shares in uncertificated form or with the transfer of shares by means of a relevant system.

Subject to the Articles, any member may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any other form which the Board may approve. The instrument of transfer must be executed by or on behalf of the transferor and (in the case of a partly-paid share) the transferee.

The transferor of a share is deemed to remain the holder until the transferee's name is entered in the register.

The Board may, in its absolute discretion (but subject to any rules or regulations of the London Stock Exchange or any rules published by AIM applicable to the Company from time to time), decline to register any transfer of any share which is not a fully paid share. The Board may also decline to register a transfer of a certificated share unless the instrument of transfer:

is duly stamped or certified or otherwise shown to the satisfaction of the Board to be exempt from stamp duty and is accompanied by the relevant share certificate and such other evidence of the right to transfer as the Board may reasonably require;

is in respect of only one class of share; and

if to joint transferees, is in favour of not more than four such transferees.

Registration of a transfer of an uncertificated share may be refused in the circumstances set out in the Regulations and where, in the case of a transfer to joint holders, the number of joint holders to whom the uncertificated share is to be transferred exceeds four.

The Board may decline to register a transfer (not an approved transfer) of any of the Company's certificated shares by a person with at least a 0.25 per cent. interest, if such a person has been served with a direction notice as defined in the Articles, after failure to provide the Company with information concerning interests in those shares required to be provided under the Act, unless (i) the person is not himself in default as regards supplying the information requested, and (ii) the transfer is of part only of the member's holding and when presented for registration is accompanied by a certificate by the member in a form satisfactory to the Board to the effect that after due and careful enquiry the member is satisfied that no person in default as regards supplying such information is interested in any of the shares which are the subject of the transfer.

6.4 *Variation of Rights*

Subject to the Act, rights attached to any class of shares may be varied with the written consent of the holders of not less than three-fourths in nominal value of the issued shares of that class (calculated by excluding any shares held as treasury shares), or with the sanction of a special resolution passed at a separate general meeting of the holders of those shares. At every such separate general meeting (except an adjourned meeting) the quorum shall be two persons holding or representing by proxy not less than one-third in nominal value of the issued shares of the class (calculated by excluding any shares held as treasury shares).

The rights conferred upon the holders of any shares shall not, unless otherwise expressly provided in the rights attaching to those shares, be deemed to be varied by the creation or issue of further shares ranking *pari passu* with them.

6.5 *Changes in Capital*

The Company may by ordinary resolution increase, consolidate, consolidate and then divide, or (subject to the Act) sub-divide its shares or any of them. The Company may, subject to the Act, by special resolution reduce its share capital, share premium account, capital redemption reserve or any other undistributable reserve.

6.6 *Untraced Shareholders*

The Company may sell any certificated shares in the Company on behalf of the holder of, or person entitled by transmission to, the shares at the best price reasonably obtainable at the time of sale if:

the shares have been in issue throughout the period of twelve years immediately preceding the date of publication of the advertisements (as referred to in the Articles) or the first of the two advertisements to be published if they are published on different dates (the "**Qualifying Period**") and at least three cash dividends have become payable on the shares during that period and no cash dividend payable on the shares has either been claimed or satisfied in the manner specified in the Articles at any time during the period beginning on the commencement of the Qualifying Period and ending three months following the date of publication of the advertisements (or of the last of the two advertisements to be published if they are published on different dates) (the "**Relevant Period**");

the Company has not at any time during the Relevant Period received any communication from the holder of, or person entitled by transmission to, the shares; and

the Company has on or after the expiry of twelve years published two advertisements, one in a newspaper with a national circulation and the other in a newspaper circulating in the area in which the last known postal address of the holder of, or person entitled by transmission to, the shares (or the postal address at which service of notices may be effected under the Articles) is located, giving notice of its intention to sell the shares and a period of three months has elapsed from the date of publication of the advertisements or of the last of the two advertisements to be published if they are published on different dates.

The net proceeds of sale shall belong to the Company and, upon their receipt, the Company shall become indebted to the former holder of, or person entitled by transmission to, the shares for an amount equal to the net proceeds.

6.7 *Non-UK Shareholders*

There are no limitations in the Articles on the rights of non-UK shareholders to hold, or exercise voting rights attaching to, Ordinary Shares. A shareholder whose registered address is not within the UK will not be entitled to receive notices (including notices of general meetings), documents or information from the Company unless it provides a registered UK address to the Company (not being an electronic address).

6.8 ***General Meetings***

Subject to the provisions of the Act, an annual general meeting and a general meeting convened for the passing of a special resolution or a resolution of which special notice has been given to the Company shall be called by not less than twenty one clear days' notice in writing. All other meetings shall be called by not less than fourteen clear days' notice in writing.

The notice must specify the place, day and time of the meeting and in the case of special business, the general nature of the business to be transacted.

Notices shall be given to the auditors of the Company and to all members other than any who, under the provisions of the Articles or the terms of issue of the shares they hold, are not entitled to receive such notice. Notice may be via electronic communication and publication on a website in accordance with the Act.

Each director shall be entitled to attend and speak at any general meeting. The chairman of the meeting may invite any person to attend and speak at any general meeting where he considers that this will assist in the deliberations of the meeting.

The Board may direct that persons wishing to attend any general meeting should submit to such searches or other security arrangements or restrictions as the Board shall consider appropriate in the circumstances and shall be entitled in its absolute discretion to, or to authorise one or more persons who shall include a director or the secretary or the chairman of the meeting to refuse entry to, or to eject from, such general meeting any person who fails to submit to such searches or otherwise to comply with such security arrangements or restrictions.

6.9 ***Return of Capital***

On a liquidation, the liquidator may, with the sanction of a special resolution of the Company and any other sanction required by the Act, divide among the members (excluding any member holding shares as treasury shares) in kind all or part of the assets of the Company (whether they shall consist of property of the same kind or not) and, for that purpose, set such values as the liquidator deems fair upon any property to be divided and determine how the division shall be carried out as between the members or different classes of members, or vest the whole or any part of the assets in trustees upon such trusts for the benefit of the members as the liquidator, with the like sanction, shall think fit, but no member shall be compelled to accept any shares or other assets upon which there is any liability.

6.10 ***Pre-Emption Rights***

There are no rights of pre-emption under the Articles in respect of transfers of issued Ordinary Shares.

In certain circumstances, the Company's shareholders may have statutory pre-emption rights under the Act in respect of the allotment of new shares in the Company. These statutory pre-emption rights would require the Company to offer new shares for allotment to existing shareholders on a *pro rata* basis before allotting them to other persons. In such circumstances, the procedure for the exercise of such statutory pre-emption rights would be set out in the documentation by which such shares would be offered to the Company's shareholders.

6.11 ***Sanctions on Shareholders***

Unless the Board otherwise determines, no Shareholder shall be entitled in respect of shares held by him to vote at a general meeting or meeting of the holders of any class of shares of the Company either personally or by proxy or to exercise any other right conferred by membership in relation to meetings of the Company or of the holders of any class of shares of the Company if any call or other sum presently payable by him to the Company in respect of such shares remains unpaid.

6.12 ***Directors' Fees***

Each of the Directors shall be paid a fee at such rate as may from time to time be determined by the Board for their services in the office of director, but the aggregate of all such fees so paid to the Directors shall not exceed the amount per annum set out in the Articles or such higher amount as may from time to time be decided by ordinary resolution of the Company. Any Director who is appointed to any executive office shall be entitled to receive such remuneration (whether by way of salary, commission, participation in profits or otherwise) as the Board or any committee authorised by the Board may decide, either in addition to or in lieu of his remuneration as a Director. In addition, any Director who performs services which in the opinion of the Board or any committee authorised by the Board go beyond the ordinary duties of a Director, may be paid such extra remuneration as the Board or any committee authorised by the Board may determine. Each Director may be paid his reasonable travelling, hotel and incidental expenses of attending and returning from meetings of the Board, or committees of the Board or of the Company or any other meeting which as a Director he is entitled to attend, and shall be paid all expenses properly and reasonably incurred by him in the conduct of the Company's business or in the discharge of his duties as a Director. The Company may also fund a Director's expenditure on defending proceedings (whether civil or criminal) as provided in the Act, or in connection with any application for relief from liability made by a Director under the Act.

6.13 ***Directors' Conflicts of Interest***

Subject to the provisions of the Act, and provided he has declared the nature of his interest to the Board as required by the Act, a Director is not disqualified by his office from contracting with the Company in any manner, nor is any contract in which he is interested liable to be avoided, and any Director who is so interested is not liable to account to the Company or the members for any benefit realised by the contract by reason of the director holding that office or of the fiduciary relationship thereby established.

A Director may hold any other office or place of profit with the Company in conjunction with his office of Director and may be paid such extra remuneration for so doing as the Board may decide, either in addition to or in lieu of any remuneration provided for by other Articles. A Director may also be or become a director or other officer of, or otherwise interested in, or contract with any company promoted by the Company or in which the Company may be interested and shall not be liable to account to the Company or the members for any benefit received by him, nor shall any such contract be liable to be avoided.

A Director may act by himself or 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.

6.14 ***Votes and Directors' Interests***

No Director may vote on or be counted in the quorum in relation to any resolution of the Board concerning his own appointment, or the settlement or variation of the terms or the termination of his own appointment, as the holder of any office or place of profit with the Company or any other company in which the Company is interested save to the extent permitted specifically in the Articles. Except as mentioned below, no Director may vote on, or be counted in a quorum in relation to any resolution of the Board in respect of any contract in which he is to his knowledge materially interested and, if he does so, his vote shall not be counted. These prohibitions do not apply where that material interest arises only from one or more of the following matters:

the resolution relates to the giving to him of a guarantee, security, or indemnity in respect of money lent to, or an obligation incurred by him for the benefit of the Company or any of its subsidiary undertakings;

the resolution relates to the giving to a third party of a guarantee, security, or indemnity in respect of an obligation of the Company or any of its subsidiary undertakings for which the Director has assumed responsibility in whole or part and whether alone or jointly with others under a guarantee or indemnity or by the giving of security;

the resolution relates to the giving to him of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other Directors and/or to the funding by the Company of his expenditure on defending proceedings or the doing by the Company of anything to enable him to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements;

the resolution relates to the purchase or maintenance for any Director or Directors of insurance against any liability;

his interest arises by virtue of his being, or intending to become, a participant in the underwriting or sub-underwriting of an offer of any shares in or debentures or other securities of the Company for subscription, purchase or exchange;

the resolution relates to an arrangement for the benefit of the employees and Directors and/or former employees and former Directors of the Company or any of its subsidiary undertakings, and/or the members of their families (including a spouse or civil partner or a former spouse or former civil partner) or any person who is or was dependent on such persons, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any Director any privilege or advantage not generally accorded to the employees and/or former employees to whom the arrangement relates; or

the resolution relates to a transaction or arrangement with any other company in which he is interested, directly or indirectly (whether as director or shareholder or otherwise) provided that he is not the holder of or beneficially interested in 1 per cent. or more of any class of the equity share capital of that company and not entitled to exercise 1 per cent. or more of the voting rights available to members of the relevant company (and for the purpose of calculating the said percentage there shall be disregarded (i) any shares held by the Director as a bare or custodian trustee and in which he has no beneficial interest, (ii) any shares comprised in any authorised unit trust scheme in which the Director is interested only as a unit holder, and (iii) any shares of that class held as treasury shares).

Subject to the Act, the Company may by ordinary resolution suspend or relax the above provisions to any extent or ratify any transaction not duly authorised by reason of a contravention of such provisions.

6.15 ***Retirement***

At every annual general meeting, there shall retire from office any Director who shall have been a Director at each of the two preceding annual general meetings and who was not appointed or re-elected by the Company in a general meeting at, or since, either such annual general meeting. A retiring Director shall be eligible for re-election. A Director retiring at a meeting shall, if he is not re-elected at such meeting, retain office until the conclusion of the meeting or adjourned meeting at which he is due to retire. Where a Director is a non-executive director and has been in office for nine years or more he shall retire from office at every annual general meeting.

Subject to the provisions of the Articles, at the meeting at which a Director retires the Company can pass an ordinary resolution to re-elect the Director or to elect some other eligible person in his place.

6.16 ***Borrowing Powers***

Subject to the Articles and the Act, the business of the Company will be managed by the Board who may exercise all the powers of the Company, whether relating to the management of the business of the Company or not. In particular, the Board may exercise all the powers of the Company to borrow money and to mortgage or charge any of its undertaking, property, assets (present and future) and uncalled capital and to issue debentures and other securities and to give security for any debt, liability or obligation of the Company or of any third party. The Board must restrict the borrowings of the Company and exercise all voting and other rights or powers of control exercisable by the Company in relation to its subsidiary undertakings so as to secure that the aggregate principal amount from time to time outstanding of all borrowings by the group (exclusive of borrowings within the group) shall not, without the previous sanction of an ordinary resolution of the Company, exceed £10 million.

6.17 ***Objects***

The Articles do not provide for any objects of the Company and accordingly, the Company's objects are unrestricted.

7 Interests of the Management

7.1 The interests (all of which are beneficial unless otherwise stated) of the Directors and their immediate families and the persons connected with them (within the meaning of section 252 of the Act) in the Existing Share Capital or the existence of which could, with reasonable diligence, be ascertained by any Director as at the date of this Document and as expected to be immediately following Admission are as follows:

Name	*No. of Ordinary Shares*	*% of Existing Share Capital*	*No. of Ordinary Shares over which Warrants are granted*	*No. of Ordinary Shares over which Options are granted*	*No. of Subscription Shares*	*% of Enlarged Ordinary Share Capital*	*% of fully diluted Enlarged Ordinary Share Capital*
Brian Larkin	9,755,691	2.8%	9,755,690	4,235,294	0	1.6%	3.3%
Jonathan Leather	4,877,810	1.4%	4,877,810	4,058,824	0	0.8%	1.9%
Graham Martin	1,411,764	0.4%	0	1,176,471	2,000,000	0.6%	0.6%
David Quirke	0	0.0%	0	0	833,333	0.1%	0.1%
Alberto Cattaruzza	0	0.0%	0	352,941	0	0.0%	0.0%
Total	16,045,265	4.6%	14,633,500	9,823,530	2,833,333	3.0%	6.0%

7.2 Other than the abovementioned Ordinary Shares, Warrants and Options, no Director or any person connected with any said Director holds any interest in Ordinary Shares or any related financial product related to Ordinary Shares.

7.3 Save as disclosed above, none of the Directors (or persons connected with the Directors within the meaning of section 252 of the Act) has any interest, whether beneficial or non-beneficial, in any share or loan capital of the Company.

7.4 There are no outstanding loans granted or guarantees provided by the Company to or for the benefit of any of the Directors.

7.5 Save as disclosed above, and save as otherwise disclosed in this Document, no Director has any interest, whether direct or indirect, in any transaction which is or was unusual in its nature or conditions or significant to the business of the Company taken as a whole and which was effected by the Company since its incorporation and which remains in any respect outstanding or under-performed.

7.6 None of the Directors or any person connected with them (within the meaning of section 252 of the Act) is interested in any related financial product referenced to the Ordinary Shares (being a financial product whose value is, in whole or in part, determined directly or indirectly by reference to the price of the Ordinary Shares including a contract for difference or a fixed odds bet).

8 Directors' Terms of Engagement

8.1 ***Executive Directors***

(a) Brian Larkin was appointed by the Company to act as Chief Executive Officer pursuant to a service agreement dated 25 July 2017. His appointment commenced on 31 July 2017 and continues unless terminated on not less than six months' prior written notice by either party with such notice not to be given prior to the first anniversary. He is entitled to a salary of £120,000 per annum.

(b) Jonathan Leather was appointed by the Company to act as Technical Director pursuant to a service agreement dated 25 July 2017. His appointment commenced on 31 July 2017 and continues unless terminated on not less than six months' prior written notice by either party with such notice not to be given prior to the first anniversary. He is entitled to a salary of £115,000 per annum. Mr Leather's current role is Chief Operating Officer. A new service agreement has not been entered into as a result of this change of role.

(c) David Quirke was appointed by the Company to act as Chief Financial Officer pursuant to the terms of a service agreement dated 24 June 2019. His appointment commenced on 24 June 2019 and continues unless terminated on not less than six months' prior written notice by either party. He is entitled to a salary of £110,000 per annum to be paid in Euros.

8.2 ***Non-Executive Directors***

(a) Graham Martin was appointed by the Company to act as Non-Executive Chairman under a letter of appointment dated 15 February 2018. His appointment commenced on 19 February 2018, is for an initial term of three years and is terminable on one month's prior written notice by either party. He is entitled to a fee of £40,000 per annum.

(b) Alberto Cattaruzza was appointed as a director of the Company on 4 November 2015 and his appointment as a Non-Executive Director is regulated by a letter of appointment dated 25 July 2017. His appointment is terminable on three months' prior written notice by either party. He is entitled to a fee of £15,000 per annum.

8.3 The aggregate remuneration and benefits in kind, paid by the Company to the Directors by any member of the Group in respect of the financial years ending 31 December 2016, 31 December 2017, 31 December 2018 (being the last completed financial year of the Group) was US$173,410, US$249,243 and US$451,994 respectively.

9 Additional information on the Directors

9.1 Other than the directorship of the Company, the names of all companies and partnerships of which the Directors have been a director or partner at any time in the five years preceding the date of this Document and indicating whether they are current or past are set out below:

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
Graham Martin	Kenmare Resources plc	Energy Africa UK Limited
	Sabelgrade Limited	Planet Oil International Limited
	Meadowside Twickenham Limited	Planet Oil Limited
		Tullow CMS (North Sea) Limited
		Tullow Energy Limited
		Tullow Exploration and Production UK Limited
		Tullow Greenland Exploration Limited
		Tullow Group Services Limited
		Tullow Guinea Limited
		Tullow Jamaica Limited
		Tullow Oil (International) Norge Limited
		Tullow Oil Finance Limited
		Tullow Oil plc
		Tullow Oil SK Limited
		Tullow Oil SNS Limited
		Tullow Oil SPE Limited
		Tullow Oil 100 Limited
		Tullow Oil 101 Limited
		Tullow Oil TS Limited
		Tullow Mozambique Limited
		Tullow Uruguay Limited
		Tullow Gambia Limited

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
		Tullow Côte D'Ivoire Onshore Limited
		Tullow Africa New Ventures Limited
		Tullow Chinguetti Production Pty Ltd
		Hardman Mauritania Finance Pty Ltd
		Hardman Oil and Gas Pty Ltd
		Tullow Petroleum (Mauritania) Pty Ltd
		Hardman Petroleum (Uganda) Pty Ltd
		Hardman Petroleum (West Africa) Pty Ltd
		Hardman Petroleum Tanzania Pty Ltd
		Hardman Resources Pty Ltd
		Tullow Uganda Operations Pty Ltd
		Tullow Cote D'Ivoire Exploration Limited
		Tullow Cote D'Ivoire Limited
		Tullow Madagascar Limited
		Tullow Ghana Limited
		Tullow India Operations Limited
		Tullow Oil International Limited
		Tullow Pakistan (Developments) Limited
		Tullow Oil Limited
		Tullow Oil Overseas Finance Limited
		Tullow South Africa (Pty) Limited
		EA Bredasdorp Pty Ltd
		Tullow Oil Gabon SA
		Tulipe Oil SA
		Invest in Africa
		Tullow Oil Holdings (Guernsey) Ltd
		Tullow Oil (Mauritania) Ltd
		Eagle Drill Limited
		Tullow (EA) Holdings Limited
		Tullow Oil Norge AS
		Tullow Oil (Bream) Norge AS
		Hardman Petroleum France SAS
		T.U. S.A.
		Tullow Do Brasil Petroleo E Gas Ltd
		Tullow Oil Canada Ltd
		Tullow Uganda Limited
		Tullow Congo Limited
		Tullow Senegal Limited
		Tullow Mauritania Limited
		Tullow Kudu Limited
		Tullow Gabon Limited
		Tullow Gabon Holdings Limited
		Tullow Equatorial Guinea Limited
		Tullow Mexico BV
		Tullow Angola BV
		Tullow DRC BV

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
		Tullow Ethiopia BV Tullow Sierra Leone BV Tullow Guyana BV Tullow Tanzania BV Tullow Kenya BV Tullow Liberia BV Tullow Zambia BV Tullow 101 Netherlands BV Tullow 6 BV Tullow Exploration & Production BV Tullow Exploration & Production Netherlands BV Tullow Global Compliance BV Tullow Hardman Holdings BV Tullow Netherlands Holding Cooperatief BA Tullow Overseas Holdings BV Tullow Suriname BV Tullow Uganda Holdings BV Zetah Kouilou Limited Tullow Bangladesh Limited Energy Africa Namibia Limited Tullow Romania Limited Tullow Senegal Operations Limited Tullow Filala Romania S R L Tullow Trinidad Limited General Mining Union Corp (UK) Ltd Unitrust Holdings Limited Jubilee Support Services INC Tullow Netherlands BV
Brian Larkin	UOG Holdings Plc UOG Ireland Limited UOG PL090 Limited UOG Italia S.R.L UOG Jamaica Limited UOG Colter Limited UOG Crown Limited	BLUOG Limited
Jonathan Leather	UOG Holdings Plc UOG Ireland Limited UOG PL090 Limited UOG Italia S.R.L UOG Jamaica Limited UOG Colter Limited UOG Crown Limited	None

Director	Current directorships/partnerships	Past directorships/partnerships
David Quirke	UOG Holdings Plc	Tullow Oil Limited
	UOG Ireland Limited	Tullow Oil Overseas Finance Limited
	UOG PL090 Limited	
	UOG Jamaica Limited	
	UOG Colter Limited	
	UOG Crown Limited	
	Inspired Marketing Services Limited	
Alberto Cattaruzza	None	None

9.2 ***None of the Directors has:***

(a) any unspent convictions in relation to indictable offences;

(b) had any bankruptcy order made against him or entered into any voluntary arrangements;

(c) been a director of a company which has been placed in receivership, compulsory liquidation, administration, been subject to a voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors whilst he was a director of that company or within the 12 months after he ceased to be a director;

(d) been a partner in any partnership which has been placed in compulsory liquidation, administration or been the subject of a partnership voluntary arrangement whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

(e) been the owner of any asset or been a partner in any partnership which owned any asset which while he owned that asset, or while he was a partner or within the 12 months after he ceased to be a partner in the partnership which owned the asset, entered into receivership;

(f) been the subject of any public criticism by any statutory or regulatory authority (including recognised professional bodies); or

(g) been disqualified by a court from acting as a director of any company or from acting in the management or conduct of the affairs of any company.

9.3 Save as disclosed in this Document, none of the Directors has or has had any interest in transactions effected by the Company since its incorporation which are or were unusual in their nature or conditions or which are or were significant to the business of the Company.

9.4 Each of the Directors has given an undertaking not to dispose of any of their Ordinary Shares (if any), save in certain specified circumstances, for the period of 12 months from the date of Admission and for six months following such period, they will only dispose of their Ordinary Shares through the Company's broker in order to create an orderly market.

9.5 No loans made or guarantees granted or provided by the Company or any Group company to or for the benefit of any Director are outstanding.

10 Significant Shareholders

10.1 The Company is only aware of the following person who, at the date of this Document and immediately following Admission, represents an interest (within the meaning of Disclosure and Transparency Rules, Chapter 5) directly or indirectly, jointly or severally, in three per cent. or more of the Existing Share Capital, or the Enlarged Ordinary Share Capital or could exercise control over the Company:

	At the date of this Document		*on Admission*	
Name	*No. of Ordinary Shares*	*% of Existing Share Capital*	*No. of Ordinary Shares*	*% of Enlarged Ordinary Share Capital*
Rockhopper Exploration PLC	0	0%	114,503,817	18.5%
Douglas John Wright	11,067,500	3.2%	11,067,500	1.7%

10.2 None of the Directors nor any persons named in paragraph 10.1 has voting rights which are different to any other holder of Ordinary Shares.

10.3 Save as disclosed in paragraph 10.1 above, the Company and the Directors are not aware of (i) any person or entity who directly or indirectly, jointly or severally, exercises or could exercise control over the Company at Admission, nor (ii) any arrangements the operation of which may at a subsequent date result in a Change of Control of the Company at Admission.

11 Employees

11.1 ***The Group***

(a) As at the date of this Document, the Group has three full-time employees in addition to the three executive Directors. The number of employees employed in the Group (by reference to the year-end of 31 December) for each of the last three financial years was as follows: nil (2016), one (2017) and three (2018).

(b) The current breakdown of persons employed, excluding the executive Directors, by main category of activity was as follows: 1 Finance, 1 Technical Services and 1 Administrative Support.

11.2 ***Rockhopper Egypt***

As at the end of financial periods ended 31 December 2016, 31 December 2017 and 31 December 2018, Rockhopper Egypt had 2 employees.

11.3 ***Enlarged Group***

Following completion of the Rockhopper Acquisition, it is expected that the Enlarged Group will have 5 full time employees in addition to the three executive Directors.

12 Material Contracts

The following contracts: (i) (not being contracts entered into in the ordinary course of business) have been entered into in the two years preceding the date of this Document by any member of the Group or Rockhopper Egypt and are, or may be, material to the Group or Rockhopper Egypt or have been entered into by any member of the Group and contain any provision under which any member of the Group or Rockhopper Egypt has any obligation or entitlement which is material to the Group or Rockhopper Egypt at the date of this Document; or (ii) are subsisting agreements which are included within or which relate to the oil assets and liabilities of the Group (notwithstanding whether such agreements are within the ordinary course or were entered into outside of the 2 years immediately preceding the publication of this Document) and are, or may be material to the Group or Rockhopper Egypt.

The Existing Group

12.1 ***Waddock Cross Field Sale and Purchase Agreement***

On 14 June 2016, First Oil Expro Limited (In Administration) acting by its agents, Richard James Beard, James Robert Tucker and Blair Carnegie Nimmo of KPMG LLP (together the "**Administrators**") and UOG PL090, entered into an agreement for the sale by FOEL and purchase by UOG PL090 of such rights, title and interest (if any) FOEL had in certain petroleum production licences, including data and field facilities (the "**Purchase**").

The Purchase comprised of an initial deposit of US$10,000 payable to FOEL on execution of the sale and purchase agreement held in an escrow account, and the remaining consideration of US$ 115,000 payable by UOG PL090 to FOEL, as adjusted pursuant to clause 3.8 of the sale and purchase agreement (the "**Final Consideration**"), for FOEL's:

(a) undivided legal and beneficial interest in United Kingdom Petroleum Production Licence No. PL090 dated 30 May 1968 and United Kingdom Licence No. PEDL237 dated 30 October 2008 (together, the "**Licences**");

(b) entire interest in and under the joint operating agreements in respect of the Licences (the "**JOAs**");

(c) entire interest in the petroleum production, wellhead, platform, processing and transportation facilities, equipment or other materials and the interconnecting pipelines used in relation to the hydrocarbon accumulation known as Waddock Cross field; and

(d) the entire legal and beneficial, right, title and interest in all data in the possession of FOEL relating to the above-mentioned interests and forming part of the property jointly owned by FOEL and other parties to the JOAs.

The Final Consideration payable on completion of the sale and purchase agreement resulted in the total consideration being paid by UOG PL090 to FOEL of the sum of US$126,913.

12.2 ***Waddock Cross Field Sale and Purchase Agreement Side Letter***

On 14 June 2016, FOEL, the Administrators and UOG PL090 entered into a side letter to the Waddock Cross Field Sale and Purchase Agreement (the "**Side Letter**"). In connection with a joint venture waiver letter dated 2 June 2016 from Aurora Production (UK) Limited, Dorset Exploration Limited, Egdon Resources U.K. Limited and Egdon Resources plc addressed to FOEL, in relation to an understanding between the parties under the JOAs (the "**JV Waiver Letter**"), it was agreed that at completion, that in relation to the aggregate amounts outstanding under the terms of the JOAs (being approximately £68,408.50 as at the date of the JV Waiver Letter) as owing from FOEL:

(a) FOEL pays £55,085.95 to Egdon (as operator pursuant to the JOAs), being an amount equal to the outstanding sums due by FOEL under the JOAs in respect of the periods prior to 00:01 hours (London time) on 1 January 2016 (the "**Economic Date**");

(b) FOEL pays £6,301.28 to Egdon (as operator pursuant to the JOAs), being an amount equal to half of the outstanding sums due by FOEL under the JOAs in respect of the period from the Economic Date to the date of the JV Waiver Letter;

(c) UOG PL090 pays £6,301.28 to Egdon (as operator pursuant to the JOAs), being an amount equal to half of the outstanding sums due by FOEL under the JOAs in respect of the period from the Economic Date to the date of the JV Waiver Letter; and

(d) UOG PL090 pays to Egdon (as operator pursuant to the JOAs), an amount equal to the outstanding sums due by FOEL under the JOAs in respect of the period from the date of the JV Waiver Letter to completion.

On completion, UOG PL090 paid a total of £13,035.79 to Egdon.

12.3 ***Deed of Assignment of PL090***

On 11 August 2016, FOEL, the Administrators, Aurora, Corfe Energy Limited, Dorset and Egdon assigned to Aurora, Corfe, Dorset, Egdon, and UOG PL090, all rights, interest, obligations and liabilities of PL090, with the consent of The Secretary of State for Energy and Climate Change.

12.4 ***Deed of Novation of Agency Agreement relating to PL090***

On 11 August 2016, FOEL, the Administrators, UOG PL090, and Aurora, Corfe, Dorset, Egdon and Star Energy Weald Basin Limited, executed a deed of novation, whereby FOEL ceased to be a party to an Oil Handling Promotion and Sales Agency Agreement relating to Crude Oil produced from the Oil Field at Licence Area PL090 dated 11 October 2013 (the "**Affected Agreement**"), and FOEL transferred its entire undivided legal and beneficial interest in and under the Affected Agreement, together with all rights, title, obligations, liabilities and interests attaching thereto, to UOG PL090, in relation to a 26.25 per cent. interest in PL090.

12.5 ***Deed of Novation of Affected Petroleum Agreements***

On 11 August 2016, FOEL, the Administrators, UOG PL090, and Aurora, Corfe, Dorset and Egdon executed a deed of novation whereby FOEL ceased to be a party to certain affected petroleum agreements (the "**Affected Petroleum Agreements**") in respect of FOEL's:

(a) 26.25 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PL090 dated 3 February 1997 as applied to a separate contract to Area A (Waddock Cross) (the "**Area A JOA**");

(b) 22.6042 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PL090 dated 3 February 1997 as applied as a separate contract to Area B (the "**Area B JOA**"); and

(c) 22.6042 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PEDL237 dated 26 March 2013 (the "**PEDL 237 JOA**")

(together, the "**Operating Agreements**") together with all corresponding legal and beneficial rights, title, interest and obligations under the Affected Petroleum Agreements.

The recital to this deed records that PEDL237 expired as of 30 June 2016, however as the PEDL237 JOA had not been terminated, it was being novated pursuant to this deed.

This deed records that the pre-transfer, and following execution of this deed, the post-transfer per cent. interests of the participants held under the Operating Agreements are as follows:

(a) The Area A JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	18.750%	18.750%
Dorset	10.000%	10.000%
Egdon	45.000%	45.000%
FOEL	26.250%	0.000%
UOG PL090	0.000%	26.250%
Total	100%	100%

(b) The Area B JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	16.1458%	16.1458%
Corfe	12.500%	12.500%
Dorset	10.000%	10.000%
Egdon	38.750%	38.750%
FOEL	22.6042%	0.000%
UOG PL090	0.000%	22.6042%
Total	100%	100%

(c) The PEDL 237 JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	16.1458%	16.1458%
Corfe	12.500%	12.500%
Dorset	10.000%	10.000%
Egdon	38.750%	38.750%
FOEL	22.6042%	0.000%
UOG PL090	0.000%	22.6042%
Total	100%	100%

12.6 ***Podere Gallina Farm-in Agreement***

On 4 May 2017, UOG UK and Po Valley Operations Pty Ltd, a company incorporated and registered in Australia, a wholly owned subsidiary of Po Valley Energy Ltd, entered into the Podere Gallina Farm-in Agreement, pursuant to which PVO conditionally agreed to sell to UOG UK, and UOG UK conditionally agreed to acquire from PVO, a 20 per cent. interest in the Podere Gallina Exploration Licence ("**Participating Interest**") held by PVO and awarded by the Ministry of Economic Development (the "**Ministry**") on 2 December 2008 (the "**Exploration Licence**"), and which includes the Podere Maiar-1 exploration well (the "**Exploration Well**").

On execution of this agreement, UOG UK paid to PVO an exclusivity fee of €50,000 (the "**Exclusivity Fee**") for the period commencing 19 April 2017 and ending at 12 p.m. on 31 July 2017 (or such other later time and date as may otherwise be agreed by the parties in writing) (the "**Exclusivity Period**"). The Exclusivity Fee would only be refunded to UOG UK in the event that PVO withdraws from negotiations.

Additionally, on execution of this agreement, UOG UK agreed to file an application with the Ministry to qualify as a non-operating entity. Immediately after UOG UK has received confirmation from the Ministry that its application has been approved, PVO agreed to file with the Ministry an application to obtain preliminary authorisation to assign to UOG UK the Participating Interest ("**Preliminary Approval**").

Subject to certain conditions, PVO agreed to sell and UOG UK agreed to purchase the Participating Interest for €1,280,000. It was agreed that the consideration be applied towards costs associated with the Exploration Well, as set out in a budget attached to the agreement ("**Well Costs**"). The promote element, that is incremental 20 per cent. of the Well Costs paid by UOG UK in addition to their *pro rata* share of the Participating Interest, is capped at €640,000.

Any additional costs incurred on the Exploration Licence above the Well Costs would be allocated proportionately between UOG UK and PVO on a 20/80 split, in accordance with their respective participating interests.

12.7 ***Deed of Collective Novation***

On 14 June 2017, Egdon, Aurora, UOG PL090, Corfe and Dorset executed a deed of collective novation in respect of a joint operating agreement and a trust deed relating to PL090 Area A (Waddock Cross) and Area B (Other) and other agreements. The recital to the deed records that Egdon, Aurora and UOG PL090 wished to be released and discharged from their liabilities in respect of the Area B JOA and provided opt-out notices to Corfe (the "**Opt-Out Notices**"). Egdon assigned to Corfe 6.2500 per cent., Aurora assigned to Corfe 2.6041 per cent., and UOG PL090 assigned to Corfe 3.6459 per cent. (the "**Opt-Out Interests**"). The effect of the Opt-Out Notices on the Area B JOA was that the percentage interests of the parties were varied as set out below. These variations also applied to the other related agreements where the table appears:

Participant	*Pre-Opt-Out Notice (%)*	*Post-Opt-Out Notice (%)*
Aurora	16.1458%	13.5417%
Corfe	12.5000%	25.0000%
Dorset	10.0000%	10.0000%
Egdon	38.7500%	32.5000%
UOG PL090	22.6042%	18.9583%
Total	100%	100%

12.8 ***Supplement to Earn-in Agreement***

On 14 June 2017, Egdon, Aurora, UOG PL090 and Corfe executed a supplement to an earn-in agreement dated 23 March 2013 (the "**Earn-in Agreement**") in relation to United Kingdom onshore licences PL090 and PEDL237. The Earn-in Agreement was novated under the Deed of Novation of Affected Petroleum Agreements set out at paragraph 12.5 The parties entered into the agreement to clarify or modify the application of certain provisions in the Earn-in Agreement relating to the exercise of the Opt-Out Notices.

The agreement provides that subject to the Earn-in Agreement, Egdon, Aurora and UOG PL090 shall cease to be required to pay earn-in costs under the Area B JOA after the accounting date. The agreement notes that Egdon, as operator under the Area B JOA, had agreed with the EPI Group a contract for certain seismic processing services. The contract included the below schedule of services and prices:

Item		*Unit*	*Rate*
1	Seismic Processing – test sequence as defined in EPI's "**Proposal for Seismic Processing Services**" to CLIENT dated 13 December 2016	Lump Sum	£10,800
2	Full delivery of pre & post stack data	Lump Sum	£32,400
3	Full depth imaging sequence	Lump Sum	£39,350
4	PSDM 'lite' depth imaging	Lump Sum	£9,800

Under the agreement, the cost of Item 1 is an item for which Egdon, Aurora and UOG PL090 are bound to pay for the shares attributable to their respective Opt-Out Interests as it was contracted before the accounting date. Provided that the decision to proceed with the contract with the EPI Group in respect of items 2, 3 and 4 is taken after the accounting date, then the costs associated with items 2, 3 and 4 will only accrue on or after the date the decision is taken, and accordingly the share of the costs attributable to the Opt-Out Interests will be payable by Corfe.

12.9 ***Acquisition Agreement***

The Company agreed on 25 July 2017 to purchase the entire issued share capital of UOG UK from the vendors subject to certain conditions. The consideration for the Acquisition comprised of new Ordinary Shares (representing 26.84 per cent. of the share capital of the Group as at 31 July 2017).

The vendors provided certain warranties in respect of their ownership of the shares of UOG UK in the sale and purchase agreement. Brian Larkin as warrantor provided certain warranties in the sale and purchase agreement. The warranties relate, *inter alia*, to accounting and financial matters, regulatory and legal matters, intellectual property matters, taxation, litigation, assets and employees. Mr Larkin's liability under the agreement was limited to the purchase price.

12.10 ***2017 Placing Agreement***

On 25 July 2017, (1) Beaumont Cornish; (2) Optiva; (3) the Company; (4) the former directors of the Company; and (5) the Directors entered into a placing agreement.

Under this agreement, Beaumont Cornish agreed to act as financial adviser to the Company and Optiva agreed to use its reasonable endeavours (as agents of the Company) to procure subscribers for Ordinary Shares at a placing price of 2.5 pence per Ordinary Share.

In consideration for the services provided by Beaumont Cornish and Optiva, the Company agreed (a) to pay Beaumont Cornish, a corporate finance fee of £50,000; and to issue the Beaumont Cornish Warrants to Beaumont Cornish pursuant to the Beaumont Cornish Warrant Instrument; and (b) to pay Optiva: (i) a corporate finance fee of £15,000; (ii) a commission of 5 per cent. of the aggregate value of the Ordinary Shares at a placing price of 2.5 pence per Ordinary Share where such placees had been introduced by Optiva; and (iii) to issue the Optiva Warrants to Optiva pursuant to the Optiva Warrant Instrument.

The Company, the former directors and the Directors gave certain customary warranties and indemnities to Beaumont Cornish and Optiva.

12.11 ***Beaumont Cornish Warrant Instrument***

Pursuant to the Beaumont Cornish Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 3,200,000 Beaumont Cornish Warrants which each entitle Beaumont Cornish to subscribe for 1 new Ordinary Share at 2.5 pence per Ordinary Share for a period of five years from 31 July 2017. The Beaumont Cornish Warrants are unlisted, fully transferable and are exercisable in whole or in part.

12.12 ***Optiva July 2017 Warrant Instrument***

Pursuant to the Optiva Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 6,000,000 Optiva Warrants which each entitle Optiva to subscribe for 1 new Ordinary Share at 2.5 pence per share for a period of three years from 31 July 2017. The Optiva Warrants are unlisted, fully transferable and are exercisable in whole or in part.

12.13 ***UOG Warrant Instrument***

Pursuant to the UOG Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 28,000,000 UOG Warrants which each entitle the holder of such warrants to subscribe for 1 new Ordinary Share at the exercise price of 1.42857 pence for a period of five years from 31 July 2017. The UOG Warrants are unlisted, freely transferable after on 31 July 2018, and are exercisable in whole or in part. The exercise price of 1.42857 pence was calculated based on the agreed acquisition ratio for the shares of UOG UK.

12.14 ***Italian JOA***

On 18 October 2017 and further to the Podere Gallina Farm-in Agreement detailed at paragraph 12.6 above, PVO and UOG Italy entered into a joint operating agreement in respect of the Podere Gallina exploration licence. PVO is the operator of the petroleum activity operations and activities forming the subject of this agreement.

The agreement is based on the Model JOA for joint ventures in Italy and contains the normal clauses and financial and operations procedures common to Italian agreements of this type.

The agreement became effective on 31 July 2017 and recorded the participating interests of the parties as PVO holding 80 per cent. and UOG Italy holding 20 per cent. Within 90 days of the signature of this agreement, the parties were to set up an operating committee comprised of the parties' representatives, the chairman of which is the representative of PVO. The operating committee is qualified to decide upon work programmes and budgets, as well as upon any matters regarding the orderly supervision and direction of the petroleum activity and is convened at least once a year by PVO to approve the work programmes and relevant budget.

Decisions of the operating committee are passed by at least two parties not being affiliates, representing at least 50 per cent. of the aggregate participating interests. Certain decisions require the unanimous vote of the representatives, such as: (a) the voluntary relinquishment or expiry without request of a mining licence or a portion of the area of a mining licence; (b) the enlargement of the area of a mining licence; (c) the decision to authorise PVO in respect of an approved annual work programme to make budget item expenditures in excess of the relevant budget exceeding 10 per cent. of each item of such budget (which will not be unreasonably withheld); and (d) the decision to authorise PVO in respect of the aggregate of the excess budget expenditures to exceed 5 per cent. of the total approved budget (also not to be unreasonably withheld). Also within 90 days of the signature of this agreement, the parties were to set up a technical committee to assist and advise the operating committee, which is comprised of representatives of each party. The chairman on this committee is the representative of PVO. The functions of the technical committee include: (a) to keep the parties regularly informed of the execution of operations in the contract area; (b) to cooperate in the preparation of work programmes; and (c) to prepare appropriate recommendations for the operating committee.

The functions of the operator are in accordance with and subject to the work programmes and relevant budgets approved by the operating committee. In carrying out its duties, the operator has various duties such as: (a) using its best efforts to ensure that all operations are conducted as diligently, economically, safely, efficaciously and efficiently as possible in accordance with good international petroleum industry practices and engineering techniques, and in compliance with applicable laws and regulations; (b) to supply the parties promptly with various documentation (such as surveys and statistics); (c) prepare and supply various reports and data; and (d) pay on behalf of the parties the indirect taxes and any other amounts due under the mining licences.

The operator undertook to carry out the work programmes approved by the operating committee and agreed not to undertake any operations not included in said approved programmes. The operator is authorised to make expenditures with regard to each annual work programme and relevant approved budget, to make expenditures for operations in the contract area not contemplated in the work programme and budget for a total amount not exceeding €51,645.69.

The agreement sets out the procedures for awarding contracts that either exceed, or do not exceed, €250,000.

The operator has the right to resign from its duties at any time by giving the non-operators no less than three months' prior written notification. In the event the operator holds a participating interest of less than 50 per cent. by way of assignment, the operator is to notify the non-operators of its willingness to resign provided that one of the parties is prepared to take over the duties as operator and that party's participating interest is at least twice as much as the participating interest the operator would be left with after the assignment.

The agreement contains a procedure to remove the operator if the non-operators deem the operator responsible for gross negligence, wilful misconduct or fraud during the performance of its duties.

Within 120 days of notification of resignation of the operator, the parties will appoint one of them as the new operator, subject to the relevant provisions concerning that party's participating interest.

All costs and expenses relating to the petroleum activity are borne by the parties in proportion to their respective participating interests and determined and settled in accordance with the accounting procedure. Any costs or expenses relating to the petroleum activity and resulting from actions or omissions committed by the operator with gross negligence, wilful misconduct or fraud are borne entirely by the operator. In the event a party fails to pay its proportion, interest is payable and the non-defaulting parties will be invited to pay the additional shares of the funds required, in proportion to the ratio of their participating interest to the aggregate of the non-defaulting parties. Each party will also pay its share of the succeeding calls for funds, in the proportions detailed above. These payments will continue until the defaulting party has remedied its default, or the defaulting party's participating interest has been taken over or the agreement has been terminated as the non-defaulting parties decide not to take over the defaulting party's participating interest. In the event of default, the defaulting party loses various entitlements under the agreement, including voting and participating rights at meetings.

Each party owns, in proportion to its respective participating interest, all petroleum discovered and produced in the contract area, subject to the relevant articles of the agreement and unless otherwise agreed by the parties in writing.

The agreement is governed by Italian law.

12.15 ***Tullow Jamaica Farm-out Agreement***

On 24 November 2017, Tullow Jamaica and UOG Jamaica entered into a farmout agreement pursuant to which Tullow Jamaica agreed to transfer an undivided legal and beneficial twenty per cent. interest in the production sharing agreement between Tullow Jamaica and the PCJ dated 16 October 2014 , relating to the Walton Basin and Morant Basin consisting of blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a portion of block 1, offshore Jamaica, from 1 November 2017 (the "**Effective Date**") but subject to fulfilment by Tullow Jamaica and UOG Jamaica of their respective obligations under the agreement ("**Closing**").

From the Effective Date, but subject to Closing, the interests of the parties in the rights and obligations of the Contractor (as defined in the Contract), and the respective participating interests of the parties in the joint operating agreement to be entered into by the parties on the Closing Date, were to be:

Tullow Jamaica	80 per cent. and operator
UOG Jamaica	20 per cent.

The conditions precedent to transferring the Assigned Interest were:

(a) signature of a deed of assignment by the parties;

(b) the written approval of the government of Jamaica and the relevant consents being obtained;

(c) UOG Jamaica providing Tullow Jamaica with a parent company guarantee; and

(d) UOG Jamaica providing a parent company guarantee to the government of Jamaica, issued by UOG Jamaica's guarantor (being the Company).

The agreement recorded that if each of the above conditions precedent had not been satisfied on or before the date which is twelve months following the date of signature of this agreement (or such later date as the parties may agree in writing), then the agreement may be terminated by either party giving written notice to the other.

In consideration for the transfer of the Assigned Interest by Tullow Jamaica to UOG Jamaica, UOG Jamaica agreed to:

(a) pay to Tullow Jamaica at Closing an amount equal to the Assigned Interest share of the joint account expenses incurred between the Effective Date and the date of completion;

(b) pay to Tullow Jamaica an amount equal to the Assigned Interest share of the joint account expenses (including UOG Jamaica's share of the 3D seismic cost) from the date of completion (ground floor costs) under the Jamaica JOA; and

(c) provided Tullow Jamaica gives notification to the PCJ pursuant to the Contract and elects to proceed into the second exploration period of the Contract (as defined in the Contract), UOG Jamaica is to reimburse Tullow Jamaica for the equivalent of US$ 350,000 of the documented past costs incurred by Tullow Jamaica in respect of the second sub-period of the initial exploration period (as defined in the Contract), within 30 days of such election notice.

The consideration referred to above is payable by UOG Jamaica at Closing. During the period commencing on the Effective Date and up to and including the date of completion, Tullow Jamaica agreed to continue to, amongst other conditions:

(a) continue to hold the Assigned Interest in the ordinary and usual course of business and in accordance with the terms of the contract documents and good industry practice;

(b) keep UOG Jamaica informed of any material developments relating to the petroleum operations; and

(c) not, without UOG Jamaica's prior written consent, enter into any new material agreements in connection with the petroleum operations other than in the ordinary and usual course of business, and amend, agree to amend, supplement, terminate, replace, withdraw from, voluntarily surrender or relinquish any rights under the contract documents.

Customary warranties, undertakings and indemnities for an agreement of this type were provided by the parties.

12.16 ***Optiva December 2017 Warrant Instrument***

Pursuant to the Optiva December 2017 Warrant Instrument constituted on 27 December 2017 and executed by the Company, the Company issued 1,375,000 Optiva December 2017 Warrants which each entitle Optiva to subscribe for 1 new Ordinary Share at 4 pence per Ordinary Share for a period of five years from 20 December 2017. The Optiva December 2017 Warrants are unlisted, fully transferable and exercisable in whole or in part.

12.17 ***Deed of Assignment of Licence PL090***

On 8 January 2018, Egdon, Aurora, UOG PL090, Corfe and Dorset assigned to Egdon, Aurora, UOG PL090 and Corfe all rights, interest, obligations and liabilities of PL090, with the consent of the OGA.

12.18 ***Deed of Collective Novation in respect of a joint operating agreement and a trust deed relating to the PL090 Licence***

On 14 June 2017, Egdon, Aurora, UOG PL090, Corfe and Dorset executed a deed of novation whereby Dorset ceased to be a party to (a) a trust agreement dated 26 March 2013 relating to the PL090 licence; and (b) the Area A JOA and Area B JOA. The 10 per cent. interest in the PL090 licence previously held by Dorset, was assigned to Egdon upon completion.

This deed records the post-transfer per cent. interests of the participants held under the Area A JOA and Area B JOA following execution of the deed as follows:

(a)	Area A JOA	
	Egdon	55.00%
	Aurora	18.75%
	UOG PL090	26.25%
	Total	100.00%
(b)	Area B JOA	
	Egdon	42.5000%
	Aurora	13.5417%
	UOG PL090	18.9853%
	Corfe	25.0000%
	Total	100.0000%

12.19 ***Corallian Farmout Agreement***

On 15 January 2018, Corallian and UOG Colter entered into a farmout agreement, pursuant to which Corallian agreed to farm out to UOG Colter:

(a) a 10 per cent. legal and beneficial interest (the "**Initial Farmed Interest**") in each of the Corallian Licences; and

(b) an additional 10 per cent. legal and beneficial interest in each of the Corallian Licences (the "**Additional Farmed Interest**").

"**Farmed Interest**", as defined in the Corallian Farmout Agreement means the Initial Farmed Interest or the Additional Farmed Interest (as the context requires), and "**Farmed Interests**" means both of them.

As consideration for the Farmed Interest, UOG Colter agreed to:

(a) Subject to (f) below, pay its percentage interest in the Corallian Licences ("**Percentage Interest**") share of all costs pursuant to the joint operating agreement between the holders of the Corallian Licences attributable to the Farmed Interest with effect from 1 February 2012 (the "Corallian Economic Date") and of all insurance costs; and

(b) Subject to the (c) below, with effect from 15 January 2018 (the "**Farmout Date**"), pay an additional amount equivalent to 13.33 per cent. of the Farmed Interest's share of the costs charged to the joint account under the joint operating agreement in respect of the Colter Well, up to and including the point when the Colter Well has been permanently plugged and abandoned.

(c) In calculating the amount payable under (b) above, the applicable cost charged to the joint account under the joint operating agreement shall:

  (i) exclude the uplift charged pursuant to paragraph 3.2.12 of the accounting procedure to the joint operating agreement; and

  (ii) be limited to the total applicable share of total costs of the Colter Well of up to eight million pounds (£8,000,000) (excluding the uplift referred to above) and any costs above that shall be borne in proportion to the Percentage Interest shares under the joint operating agreement.

(d) For the avoidance of doubt, where the Colter Well preparations commenced before the Farmout Date then the costs of such work are included in the sums to which (b) and (c) above apply.

(e) Any other costs attributable to the Corallian Licences since 1 February 2017, such as licence fees and levies and reprocessing of seismic data, are borne in proportion to the Percentage Interest shares under the JOA. These costs will exclude those which relate to PEDL 330 and PEDL 345 Licences.

(f) The costs associated with PEDL 330 and PEDL 345 Licences incurred since 1 February 2017, and all other costs attributable to the Licences between the Corallian Economic Date and 1 February 2017 shall become payable 12 months after the Colter Well has been permanently plugged and abandoned but limited to a maximum of £56,250 net to UOG Colter if only the Initial Farmed Interest has been assigned to UOG Colter or £112,500 net to UOG Colter if both the Farmed Interests have been assigned to UOG Colter.

The agreement records that the Farmed Interests are subject to an agreement dated 23 February 2017 between Corallian and Infrastrata pursuant to which Corallian undertook to pay to Infrastrata sums in respect of profits made as a result of the production of petroleum from the P1918 Licence (the "**NPI Agreement**"). The agreement states that on completion of the assignments of the Farmed Interests, the NPI Agreement will be novated to provide that UOG Colter bears the applicable Farmed Interest's share of the obligations under the NPI Agreement.

Customary representations, warranties and indemnities for an agreement of this type were given by UOG Colter and Corallian.

In the event that before the work detailed at (b) above in this paragraph has been completed, UOG Colter fails without proper reason to make any payment due under clause 3.1 of this agreement, then Corallian may give UOG Colter notice of default and of its intention to terminate the agreement in accordance with the agreement. If the default is not remedied, Corallian can terminate the agreement and require UOG Colter to retransfer the Farmed Interests to it, without any consideration. Such transfer will not relieve UOG Colter of liability to make payments under the agreement (pursuant to clause 3 of the agreement).

The agreement records that in the event a licensee of the Corallian Licences submits an application for the award of a petroleum licence over blocks defined within the area defined in Appendix A of this agreement ("**AMI**"), or acquires an interest in a licence within the AMI, then such licensee shall invite the other licensees to join in such application or acquisition on a ground-floor basis for a participating interest in the same ratio as the licensees have participating interests in the Corallian Licences. The AMI will apply for a period expiring 30 January 2022 or on the expiry of the Corallian Licences, whichever is the later.

12.20 ***Swift Option Agreement***

On 23 January 2018, the Company, Swift and Stelinmatvic (together, Swift and Stelinmatvic are the "**Licence Holders**") entered into an option agreement pursuant to which the Company was granted the opportunity to acquire from the Licence Holders a 24 per cent. interest in the P2264 Licence (the "**P2264 Participating Interest**") as it relates to the area of block 49/29c which forms part of the licensed area of the P2264 Licence (the "**P2264 Farm-in Area**").

With effect from the date of this agreement and in consideration of the Company agreeing to pay £40,000 on such date as the farm-in agreement whereby the Company acquires the P2264 Participating Interest setting out the respective responsibilities and obligations of the parties in respect of exploration of the P2264 Farm-in Area (the "**P2264 Farm-in Agreement**"), being a payment of £20,000 to each of the Licence Holders, each Licence Holder undertook that it would not at any time before 30 June 2018 or such other date as the OGA may specify as being an amendment to the 30 June 2018 date by which Swift will have negotiated a sale and purchase agreement, as specified in a letter dated 27 November 2017 from the OGA to Swift ("**Expiry Date**"), enter into any agreements with a third party/ies which would result in such Licence Holder retaining less than a 12 per cent. participating interest in the P2264 Farm-in Area.

The agreement records that subject to:

(a) a firm well commitment becoming applicable to the P2264 Licence by no later than 31 August 2018 (or such later date as the OGA may permit);

(b) the parties agreeing all the terms of a farm-in agreement by no later than the Expiry Date; and

(c) obtaining all necessary consents and approvals under the P2264 Licence,

the Company will be entitled to receive a transfer of the P2264 Participating Interest upon execution of the farm-in agreement. Each of the Licence Holders will contribute a 12 per cent. participating interest to such transfer of the P2264 Participating Interest, or such other percentage as the parties agree. Following completion of the transfer to the Company, the Company will contribute 30 per cent. towards the well costs. In the event that before the Expiry Date, no third party farmee or alternative means of funding 70 per cent. of the well costs is forthcoming, the Licence Holders have agreed to discuss with the Company whether it will wish to increase its 30 per cent. contribution.

12.21 ***Deed of Assignment and Assumption and Amendment Agreement No.5***

On 1 March 2018, Tullow Jamaica assigned to UOG Jamaica the Assigned Interest in the Contract. As a result of the assignment, UOG Jamaica agreed to accept the Assigned Interest and assume the obligations attendant with the Assigned Interest under the Contract.

12.22 ***Jamaica JOA***

On 1 March 2018, Tullow Jamaica and UOG Jamaica entered into the Jamaica JOA. The Jamaica JOA recorded that Tullow Jamaica had transferred the Assigned Interest to UOG Jamaica, and that the Jamaica JOA defined the respective rights and obligations concerning operations and activities under the Contract.

The Jamaica JOA continues in effect until:

(a) the Contract terminates;

(b) all materials, equipment and personal property acquired for or used in connection with joint operations or exclusive operations (as defined in the Jamaica JOA) have been disposed of or removed; and

(c) final settlement (including settlement of any financial audit carried out under the accounting procedure) has been made.

The parties can terminate the Jamaica JOA in certain situations, such as if they unanimously agree or they surrender the contract area.

The purpose of the Jamaica JOA was to establish the respective rights and obligations of the parties concerning the operations and activities under the Contract, including the joint exploration, appraisal, development and production of hydrocarbons (including treatment, storage and handling of produced hydrocarbons upstream of the delivery point), the determination of entitlements at the delivery point and decommissioning.

Tullow Jamaica was designated the operator under the Jamaica JOA, and agreed to have exclusive charge of the joint operations and conduct all joint operations, in the manner associated with an agreement of this type. Tullow Jamaica can resign as operator by notifying UOG Jamaica at least 120 days before the effective date of such resignation. Tullow Jamaica, as operator, shall be removed upon receipt of notice from any non-operator (i.e. UOG Jamaica) in certain situations, including if it has committed a material breach of the Jamaica JOA, such as if Tullow Jamaica becomes insolvent or bankrupt or makes an assignment for the benefit of its creditors, if a receiver is appointed for a substantial part of Tullow Jamaica's assets or Tullow Jamaica dissolves, liquidates, winds up or otherwise terminates its existence.

In the event there is a change of operator, the joint operating committee will meet as soon as possible to appoint a successor operator pursuant to the voting procedure under the Jamaica JOA. If Tullow Jamaica is removed as operator, neither it or any affiliate of it shall have the right to be considered as a candidate for the successor operator.

Under the Jamaica JOA, a joint operating committee was to be established to provide for the overall supervision and direction of joint operations, consisting of a representative from each party holding a participating interest. Each party shall appoint one representative and one alternative representative. The joint operating committee has the power and duty to authorise and supervise the joint operations that are necessary or desirable to fulfil the Contract and properly explore the contract area under the Jamaica JOA, the Contract, and applicable laws. Voting on all proposals is decided by the affirmative vote of two or more of the parties that are not affiliates having collectively at least 65 per cent. of the participating interests.

The operator is to deliver to the parties on or before 1 October each year, a proposed annual work programme and budget, along with the estimated costs forecasts for the remainder of the calendar year. The Jamaica JOA also sets out the procedures to be followed by the operator and the parties if a commercial discovery is made that may lead to commercial production, and the procedures for the operator awarding contracts for joint operations during the various phases (including the obligations on the operator to provide certain information to the non-operators before any commitment or expenditure is made for a joint operation).

In the event a party fails to pay its share of joint account charges (including cash calls and interest), the Jamaica JOA sets out the rights that are lost by the defaulting party (for example, voting rights), and the allocations of the non-defaulting parties to pay their respective portions of the amount in default.

The Jamaica JOA sets out the rights of the parties in respect of their entitlement to own, take in kind or separately dispose of its quantity of hydrocarbons. If crude oil is to be produced from the development and production area, the parties will in good faith and not less than 90 days prior to the anticipated first delivery of crude oil, negotiate and conclude the terms of an offtake agreement.

12.23 ***Deed of Guarantee***

On or around 1 March 2018, the Company agreed to execute and deliver to the PCJ a deed of guarantee in favour of the PCJ, to unconditionally and irrevocably guarantee the due and timely performance of UOG Jamaica's obligations under the Contract. Such obligations include UOG Jamaica's minimum expenditure obligation for the third sub-period of the initial exploration period. The maximum aggregate liability of the Company is an amount equal to the sum of the minimum exploration expenditure for the third sub-period, plus 25 per cent. of the minimum exploration expenditure for the third sub-period. The guarantee remains in force until all obligations of UOG Jamaica for the third sub-period of the initial exploration period have been discharged in full, or the obligations of UOG Jamaica have been terminated.

12.24 ***Parent Company Guarantee***

On 1 March 2018, the Company entered into a parent company guarantee in favour of Tullow Jamaica, to irrevocably and unconditionally guarantee to Tullow Jamaica the punctual observance and performance by UOG Jamaica of its obligations due and owing from, or otherwise incurred by, UOG Jamaica to Tullow Jamaica under the farmout agreement with Tullow Jamaica. Under this guarantee, the Company undertook that if UOG Jamaica did not pay any amount comprised in the guaranteed obligations when due to Tullow Jamaica, the Company would promptly pay on demand, but no later than ten business days from such demand, the amount to Tullow Jamaica.

12.25 ***2018 Placing Agreement***

On 26 April 2018, (1) the Company; (2) Beaumont Cornish; (3) Optiva; and (4) SP Angel Corporate Finance LLP ("**SP Angel**") entered into a placing agreement. Under the placing agreement, Beaumont, Optiva and SP Angel agreed to act as agents to the Company for the placing, and Optiva and SP Angel agreed to use their reasonable endeavours (as agents of the Company) to procure subscribers for the Ordinary Shares at the placing price of 4.25 pence per Ordinary Share. In consideration for the services provided by Beaumont, Optiva and SP Angel, the Company agreed upon admission to:

(a) Pay Beaumont:

 (i) a fee of £60,000, less any sums already paid to Beaumont in respect of this transaction;

(b) Pay Optiva:

 (i) a commission of 5 per cent. of the aggregate value of the Ordinary Shares at 4.25 pence per Ordinary Share where placed by Optiva; and

 (ii) to issue warrants to Optiva pursuant to the Optiva April 2018 Warrant Instrument; and

(c) Pay SP Angel:

 (i) a commission of 5 per cent. of the aggregate value of the Ordinary Shares at 4.25 pence per Ordinary Share where placed by SP Angel.

The Company gave certain customary warranties and indemnities to Beaumont, Optiva and SP Angel.

12.26 ***Optiva April 2018 Warrant Instrument***

Pursuant to a warrant instrument dated 30 April 2018 and executed by the Company, the Company issued 2,728,126 Optiva April 2018 Warrants which each entitles Optiva to subscribe for 1 new Ordinary Share at the exercise price of 4.25 pence per share for a period of five years from admission. The Optiva April 2018 Warrants are unlisted, fully transferable and exercisable in whole or in part.

12.27 ***September 2018 Warrant Instrument***

Pursuant to a warrant instrument dated 18 September 2018 and executed by the Company, the Company created and granted 40,909,018 warrants to subscribe for Ordinary Shares. Each warrant entitled the holder to subscribe for 1 new Ordinary Share at the exercise price of 8 pence for a period commencing on 10 October 2019 and expiring on 8 October 2022.

12.28 ***September 2018 Placing Agreement***

On 18 September 2018, Stockdale Securities Limited ("**Stockdale**") and the Company entered into a placing agreement.

The placing agreement was conditional upon, amongst others, (i) the Company passing board resolutions by 7.00 a.m. on the date of the placing agreement to approve entry into the placing documents and conditional issuance and allotment of the placing shares, subscription shares and the September Placing 2018 Warrants, (ii) the resolutions set out in the circular of the company seeking approval of the resolutions relating to the placing, subscription and warrants and containing details of the placing and the notice of general meeting, being passed at the general meeting of the Company held on 8 October 2018, and (iii) admission taking place by not later than 8.00 a.m. on 10 October 2018 (or such later date as the Company and Stockdale may agree), but in any event not later than 31 October 2018.

Under the placing agreement, Stockdale agreed to act as agent to the Company for the placing and to use its reasonable endeavours (as agent of the Company) to procure placees for the new ordinary shares at the placing price. In consideration for the services provided by Stockdale, the Company agreed upon admission to pay Stockdale a fee of £20,000 as a placing agent fee.

The Company gave certain warranties as to the accuracy of the information contained in the presentation, placing letters, application, circular and announcement and other matters in relation to the Company and the business of the Group. The Company gave certain customary indemnities to Stockdale. Stockdale could terminate the placing agreement in certain specified circumstances prior to admission, principally in the event of a material breach of the placing agreement or any of the warranties contained in it, or any failure by the Company to comply with their obligations which was or would be in the opinion of Stockdale, materially prejudicial in the context of the placing.

12.29 ***Deed of Novation and Amendment of the NPI Agreement***

On 1 October 2018, Corallian, UOG Colter and Infrastrata entered into a deed of novation and amendment relating to the NPI Agreement pursuant to which with effect from 27 April 2018, Corallian is released and discharged from and UOG Colter agrees to assume the liabilities and performs the obligations of Corallian under or in respect of the NPI Agreement in respect of an 8 per cent. participating interest in the P1918 Licence. Accordingly, UOG Colter's participating interest in P1918 Licence consists of an 8 per cent. participating interest that is subject to the NPI Agreement and a 2 per cent. participating interest that is not so burdened.

12.30 ***Deed of Novation and Amendment of the NPI Agreement***

On 1 October 2018, Infrastrata, Westmount Energy Limited ("**Westmount**"), Corallian and UOG Colter entered into a deed of novation and amendment relating to the NPI Agreement pursuant to which with effect from 1 October 2018, Infrastrata will be released and discharged from and Westmount will assume the liabilities and perform the obligations of Infrastrata under or in respect of the NPI Agreement.

12.31 ***Deed of Variation of the P1918 Licence***

On 27 November 2018, Corallian, Corfe, UOG Colter and the OGA entered into a deed of variation which varies the P1918 Licence as follows:

(a) any reference to the "Initial Term" was a reference to the period of eight years beginning with 1 February 2012;

(b) any reference to the "Second Term" was a reference to the period of one year beginning immediately after the expiry of the period mentioned in paragraph (a) above;

(c) any reference to the "Third Term" was a reference to the period of 17 years beginning immediately after the expiry of the period mentioned in paragraph (b) above.

12.32 ***Deed of Novation and Amendment of the NPI Agreement***

On 12 December 2018, Corallian, UOG Colter, Baron and Westmount entered into a deed of novation and amendment relating to the NPI Agreement, pursuant to which Corallian agreed to assign Baron a Participating Interest (as defined in the NPI Agreement) of 6.4 per cent. (which was subject to the NPI Agreement), which prior to the assignment represented 16 per cent. of Corallian's obligations under the NPI Agreement (being in respect of a Relevant Percentage (as defined in the NPI Agreement) of 13.333 per cent. (the "**Transferred Interest**")). The parties agreed that Corallian was to be released and discharged from, and Baron was to assume the liabilities and perform the obligations of Corallian under or in respect of the NPI Agreement in respect of the Transferred Interest from the date of the deed.

12.33 ***Deed of Licence Assignment of the P1918 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3), ((1) through (3) are together the ("**P1918 Assignors**")), Baron (4) ((the Assignors and Baron are together the ("**P1918 Assignees**")) and the OGA (5) entered into a deed of licence assignment, pursuant to which the P1918 Assignors assigned to the P1918 Assignees all rights, interest, obligations and liabilities of the P1918 Assignors in, under, pursuant to and in respect of the P1918 Licence.

12.34 ***Restated and Amended Joint Operating Agreement in respect of the P1918 Licence***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a restated and amended joint operating agreement in respect of the P1918 Licence (the "**P1918 JOA**"), pursuant to which it was stated that the P1918 JOA was entered into by the parties for the purpose of regulating operations under the P1918 Licence and to define their respective rights, interests, duties and obligations in connection with the P1918 Licence and in connection with petroleum produced under the P1918 Licence. Furthermore, it was stated that the P1918 JOA corrected and replaced a similar agreement dated 5 February 2013 (as novated to Corallian, Corfe and UOG Colter).

12.35 ***Deed of Licence Assignment of the PEDL330 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3) ((1) through (3) are together the ("**PEDL330 Assignors**"), Baron (4) ((the PEDL330 Assignors and Baron are together the ("**PEDL330 Assignees**")) and the OGA (5) entered into a deed of licence assignment of the PEDL330 Licence, pursuant to which the PEDL330 Assignors assigned to the PEDL330 Assignees all rights, interest, obligations and liabilities of the PEDL330 Assignors in, under, pursuant to and in respect of the PEDL330 Licence.

12.36 ***Deed of Novation of the PEDL330 Joint Operating Agreement***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a deed of novation of the PEDL330 joint operating agreement ("**PEDL330 JOA**"), pursuant to which:

(a) Corallian wished to be released and discharged from, and Baron wished to assume the liabilities and obligations under or in respect of the PEDL330 JOA in respect of the Baron Transferred Interest (as defined therein) and Corfe and United agreed to release and discharge Corallian upon and subject to the terms therein contained; and

(b) Corfe wished to be released and discharged from, and Corallian wished to assume the liabilities and obligations under or in respect of the PEDL330 JOA in respect of the Corfe Transferred Interest (as defined therein), and UOG Colter agreed to release and discharge Corfe upon and subject to the terms therein contained.

12.37 ***Deed of Licence Assignment of the PEDL345 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3) ((1) through (3) are together the ("**PEDL345 Assignors**"), Baron (4) ((the PEDL345 Assignors and Baron are together the ("**PEDL345 Assignees**")) and the OGA (5) entered into a deed of licence assignment of the PEDL345 Licence, pursuant to which the PEDL345 Assignors assigned to the PEDL345 Assignees all rights, interest, obligations and liabilities of the PEDL345 Assignors in, under, pursuant to and in respect of the PEDL345 Licence.

12.38 ***Deed of Novation of the PEDL345 Joint Operating Agreement***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a deed of novation of the PEDL345 joint operating agreement ("**PEDL345 JOA**"), pursuant to which:

(a) Corallian wished to be released and discharged from, and Baron wished to assume the liabilities and obligations under or in respect of the PEDL345 JOA in respect of the Baron Transferred Interest (as defined therein) and Corfe and United agreed to release and discharge Corallian upon and subject to the terms therein contained; and

(b) Corfe wished to be released and discharged from, and Corallian wished to assume the liabilities and obligations under or in respect of the PEDL345 JOA in respect of the Corfe Transferred Interest (as defined therein), and UOG Colter agreed to release and discharge Corfe upon and subject to the terms therein contained.

12.39 ***Engagement Letter between Beaumont Cornish and the Company***

An engagement letter dated 16 October 2018 was signed by the Company under which Beaumont Cornish agreed to act as the Company's financial adviser in connection with the Admission and the Company's nominated adviser for purposes of the AIM Rules. In consideration of the services set out in the engagement letter, the Company agreed to pay Beaumont Cornish a fee of £65,000 plus applicable VAT and disbursements.

12.40 ***Nominated Adviser Agreement between Beaumont Cornish and the Company***

The Company and Beaumont Cornish entered into a nominated adviser agreement dated 22 February 2019 pursuant to which Beaumont Cornish agreed to act as the nominated adviser to the Company for the purposes of the AIM Rules. The agreement is for an initial term of 12 months conditional on Admission and may be terminated by either party by giving the other party 3 months' written notice provided if such notice is given by the Company, it does not expire earlier than the first 12 months. The Company has agreed to pay Beaumont Cornish an annual fee of £50,000 plus VAT in accordance with terms of the agreement.

12.41 ***Introduction Agreement between Beaumont Cornish and the Company***

An introduction agreement dated 22 February 2019 was entered into by the Company, the Directors and Beaumont Cornish in respect of the Admission and the obligations and responsibilities of the parties. The Company has agreed to pay Beaumont Cornish a fee of £65,000.

The Introduction Agreement contains warranties and indemnities from the Company in favour of Beaumont Cornish. In addition, it has been agreed to appoint another independent non-executive director with appropriate financial expertise within 6 months of the date of the Admission and to appoint a finance director at the appropriate juncture.

12.42 ***Broker Engagement Letter***

The Company and Optiva entered into an engagement letter dated 11 January 2019 with respect to the appointment by the Company of Optiva as broker for the purposes of the AIM Rules. In consideration of the services to be provided by Optiva, the Company has agreed to pay an annual retainer of £25,000 conditional on Admission. In addition, Optiva will be entitled to the following:

(a) 5 per cent. placing commission fee of the funds raised and/or introduced by Optiva in any fundraising by the Company;

(b) 5 per cent. broker warrants in the Company exercisable at the placing price of each placing and exercisable for a period of 3 years from the date of completion of such placings equal in value to the placing commission fee above; and

(c) 1 per cent. handling fee in respect of funds not raised by Optiva where they send out placing letters and/or subscription agreements on behalf of the Company.

The appointment may be terminated by either party on giving not less than 3 months' prior written notice.

12.43 ***Data Acquisition, Sharing and Option Agreement***

On 6 March 2019, the Company, Elephant Oil Bénin SA and Elephant Oil Limited (together, EOB and EOL, the "**Licence Holders**") entered into an option agreement pursuant to which the Company was granted the opportunity by the Licence Holders to acquire a 20 per cent. participating interest in the Production Sharing Contract ("**Bénin PSC**") over the onshore Block B in Bénin. In order to obtain the right to exercise the option, the Company will fund its proposed acquisition, processing, analysis and interpretation of passive seismic data from the Block up to an aggregate amount of US$175,000. The Company will make a payment to EOB to assist with its geological and geophysical costs during the 2019 period. The option is required to be exercised within 60 days of receipt of the data and report of the result of the processing of the data. Then the parties have 30 days to conclude the farm in agreement. The Parties have agreed the following indicative terms of the farm in agreement:

(a) the Company will fund 30 per cent. of the non-drilling costs during Phase 1 of the proposed work programme; and

(b) the Company will fund 20 per cent. of any costs associated with drilling during Phase 1 of the work programme or subsequent phases under the Bénin PSC.

The Company will pay EOB the sum of US$260,000 in cash 14 days after the farm in agreement is executed ("**Effective Date**"), and US$780,000 in three equal instalments of US$260,000 with the first instalment paid at the end of the six-month period after the Effective Date, the second instalment at the end of the twelve-month period after the Effective Date, and the final instalment paid at the end of the eighteen-month period after the Effective Date.

12.44 ***Rockhopper Acquisition Agreement***

The Company entered into the Rockhopper Acquisition Agreement pursuant to which it conditionally agreed to acquire the entire issued share capital of Rockhopper Egypt which owns the Assets with an effective date of 1 January 2019. The consideration payable by the Company for the Rockhopper Acquisition is US$16 million (approximately £12.2 million) in accordance with terms of the Rockhopper Acquisition Agreement. A deposit of US$0.3 million has been paid on signing the Rockhopper Acquisition Agreement and the balance of US$15.7 million is to be satisfied in cash and Consideration Shares at Completion.

The deemed value of the Consideration Shares to be issued to Rockhopper PLC is equal to the amount of US$4.5 million.

Pursuant to the terms of the Rockhopper Acquisition Agreement and subject to the number of Consideration Shares held by or on behalf of Rockhopper PLC being 3 per cent. or more of the entire issued ordinary share capital of the Company on and following Admission, Rockhopper PLC has agreed with the Company that it will only dispose of any interest in the Consideration Shares for a period of 12 months from Admission in accordance with an orderly market arrangement commencing three months from Admission and through the Company's broker, unless such disposals are with the prior written consent of the Company.

For so long as Rockhopper PLC (or any member of its group or nominee) holds 10% or more of the entire issued ordinary share capital of the Company, it will have the right to appoint or re-appoint one person to be a director of the Company subject to consultation with the Company and regulatory approval by the Company's nominated adviser.

Completion of the Rockhopper Acquisition Agreement is conditional, amongst other matters:

(a) the written waiver, or non-exercise of EGPC's pre-emptive rights under the Abu Sennan Concession*;

(b) EGPC and the Minister of Petroleum and Mineral Resources of Egypt providing written consent to the Rockhopper Acquisition;

(c) the written waiver, or non-exercise, in accordance with the terms of the Abu Sennan JOA of the pre-emptive rights by each party to the Abu Sennan JOA (other than Rockhopper Egypt)*;

(d) the release of the security granted in favour of the Falkland Islands Government over the shares in Rockhopper Egypt and its assets;

(e) the BTL Facility becoming unconditional in all respects save for any conditions relating to the Rockhopper Acquisition Agreement and Admission;

(f) passing of the Resolutions by Shareholders at the General Meeting; and

(g) Admission occurring.

*satisfied as at the date of this Document.

Rockhopper PLC gives certain warranties (including tax warranties) in favour of the Company in relation to, amongst other things, the business of Rockhopper Egypt together with fundamental warranties in respect to the Abu Sennan Concession, status, capacity and title to the shares it holds in Rockhopper Egypt and the Assets. The maximum aggregate liability of Rockhopper PLC in respect of all substantiated relevant claims and for all tax claims shall not exceed 100 per cent. of the cash consideration received pursuant to the terms of the agreement.

The Company has also given certain warranties in favour of Rockhopper PLC in relation to, amongst other things, its status and capacity to enter into the agreement.

Subject to Completion taking place, the Company and Rockhopper PLC will each be liable in the following proportions: (i) 75 per cent. by the Company; and (ii) 25 per cent. by Rockhopper PLC for the assignment fee due to EGPC on the date of Egyptian Government approval of the Rockhopper Acquisition, but subject to certain adjustments in accordance with the terms of the Rockhopper Acquisition Agreement whereby each party may be liable to a higher or lesser proportion of such assignment fee.

The Rockhopper Acquisition Agreement is subject to reciprocal termination rights and permits each party to terminate if a breach of a fundamental warranty occurs prior to the date of submission of a deed of assignment to EGPC and the Minister of Petroleum & Mining Resources. The Rockhopper Acquisition Agreement contains an automatic termination provision if any of the Conditions have not been fulfilled on or before the date falling six months after the date of the Rockhopper Acquisition Agreement (or such other date as the parties may agree in writing) (the "**Backstop Date**").

If Completion does not occur by the Backstop Date, due to (i) Rockhopper PLC's breach of a fundamental warranty at Completion; (ii) the exercise of pre-emption rights of a joint-venture party under the Abu Sennan JOA; or (iii) Rockhopper PLC's failure to obtain the release and discharge of an encumbrance over the assets of Rockhopper Egypt by the Backstop Date; the Deposit will be returned to the Company in full. Rockhopper PLC has a right to retain the Deposit in all other circumstances.

If the conditions to Completion other than the Admission condition or the assignment condition are not satisfied on, or before the Backstop Date, (or by such other date agreed to between the parties); the Rockhopper Acquisition Agreement will terminate with the exception of certain terms that will remain in force following its termination.

The Rockhopper Acquisition Agreement is capable of termination by the Company where (i) Rockhopper PLC commits a breach of its fundamental warranties at Completion; (ii) the BTL Facility is terminated by BTL; or (iii) the Company receives notice that BTL will exercise its right not to make payment, or requests the repayment of drawn down funds under the BTL Facility. The Company's right of termination can only be exercised prior to the date Rockhopper PLC submits the deed of assignment to EGPC and the Minister of Petroleum and Mineral Resources of Egypt.

12.45 ***BTL Facility***

On 22 July 2019, BTL agreed to provide the Company with a pre-payment financing structure of up to US$8 million, transacted under a 2002 ISDA Master Agreement. Pursuant to the terms of the BTL Facility, the Company will make repayments over 30 calendar months based upon dated Brent market prices for an agreed volume, capped at an agreed level. The financing structure will generate an upfront payment to the Company that will be used to fund part of the Rockhopper Acquisition and in addition, will hedge a portion of the Company's production during the term of the pre-payment while allowing the Company to benefit from market prices above the capped price for the pre-payment volume.

The execution of the Side Letter Agreement was a condition precedent to the execution of the BTL Facility. The Side Letter Agreement contains certain acknowledgments and agreements amongst the parties in relation to crude oil and natural gas entitlements.

The 2002 ISDA Master Agreement contains standard representations and warranties, events of default (including payment default) and undertakings as to the performance of the obligations of the Company in relation to the pre-paid swap arrangement.

The duration of the BTL Facility will be 30 calendar months from the first settlement date in accordance with the pre-payment confirmation and is subject to the payment to BTL of a non-refundable execution fee of 3 per cent. of the pre-payment amount. BTL will take security over certain assets of the Company and Rockhopper Egypt.

Early termination events apply to the pre-payment agreement, including (but not limited to) events of default by the Company, any event that would be reasonably likely to have a material adverse effect on the Company's ability to perform its payment obligations under the agreement, or if a change of control occurs following drawdown where the Company would cease to have direct control of, or beneficially hold more than 100 per cent. of the issued share capital in Rockhopper Egypt. All rights and obligations under the pre-payment agreement will cease on the date which BTL notifies the Company that no early termination date has occurred and no obligations in respect of any transaction remain outstanding; or if the conditions precedent have not been satisfied prior to draw down of the pre-payment facility.

12.46 ***Engagement Letter between Beaumont Cornish and the Company***

An engagement letter dated 5 July 2019 was signed by the Company under which Beaumont Cornish agreed to act as the Company's Nominated Adviser for the purposes of the AIM Rules and as financial adviser in relation to the Rockhopper Acquisition and Admission. In consideration of the services set out in the engagement letter, the Company agreed to pay Beaumont Cornish a fee of £70,000 plus applicable VAT and disbursements.

12.47 ***Broker Engagement Letters***

Cenkos Engagement Letter

The Company appointed Cenkos as its joint broker pursuant to an engagement letter dated 22 July 2019. In consideration of the services to be provided by Cenkos, the Company has agreed to pay a fixed corporate finance fee of £50,000 plus applicable VAT and disbursements. In addition, Cenkos will be entitled to the following:

(a) a success fee of 4 per cent. of the gross total monies raised in connection with the placing of shares for the Rockhopper Acquisition;

(b) a discretionary fee of 1 per cent. of gross monies raised from investors other than monies raised as part of the debt financing or subscription; and

(c) 5 per cent. warrants of the total gross proceeds raised from Cenkos investors.

Optiva Engagement Letter

The Company appointed Optiva as its joint broker for the purposes of the Placing and Admission pursuant to an engagement letter dated 22 July 2019. In consideration of the services to be provided by Optiva, the Company has agreed to pay:

(a) a 4 per cent. commission fee of the funds raised and or introduced by Optiva in connection with the Placing;

(b) an additional 1 per cent. placing commission fee of funds raised pursuant to the Placing and/or introduced by Optiva subject to a Placing Price of 4 pence or more;

(c) 5 per cent. warrants of the total gross proceeds raised from Optiva investors.

The Optiva engagement letter was concluded on, and is subject to, Optiva's standard terms and conditions.

12.48 ***Subscription Agreement(s)***

(a) Certain investors entered into subscription agreements with the Company during December 2019 to conditionally subscribe for new Ordinary Shares in the Company at a subscription price of 3 pence per Ordinary Share. The subscription is conditional on Admission occurring by no later than 22 January 2020 and the Rockhopper Acquisition Agreement turning unconditional.

(b) Alan Graham Martin and David Thomas Patrick Quirke as directors of the Company have entered into subscription agreements with the Company on 6 December 2019 to conditionally subscribe for new Ordinary Shares in the Company at a subscription price of 3 pence per Ordinary Share. Similar to 12.48 (a) above, the subscription is conditional on Admission occurring by no later than 22 January 2020 and the Rockhopper Acquisition Agreement turning unconditional.

12.49 ***2019 Placing Agreement***

On 6 December 2019, Beaumont Cornish, Optiva, Cenkos, the Company and the Directors entered into a placing agreement pursuant to which Beaumont Cornish agreed to act as the Company's nominated adviser for the purposes of Admission and the Placing. Cenkos and Optiva agreed to act as jointly appointed brokers to the Company and to both use reasonable endeavours to procure subscribers for the Placing Shares at a Placing Price of 3 pence per Ordinary Share conditional upon certain conditions that are typical for an agreement of this nature. These conditions include, among others: (i) the Rockhopper Acquisition Agreement having become unconditional (i) Admission occurring and becoming effective by 8.00 a.m. on or prior to 6 January 2020 (ii) (or such later time and/or date, not being later than 4.00pm by 31 January 2020 as the parties may agree); and (iii) the Placing Agreement not having been terminated in accordance with its terms.

The placing agreement may be terminated by Beaumont Cornish, Optiva and Cenkos in certain customary circumstances prior to Admission.

In consideration for its services in relation to the Placing and conditional upon Admission, Cenkos will be paid:

(a) a fixed corporate finance fee of £50,000 plus applicable VAT and disbursements;

(b) a commission of 4 per cent. of the gross monies raised from Cenkos investors in the Placing;

(c) a discretionary fee of 1 per cent. of the aggregate value of the Placing; and

(d) warrants in the Company to the value of 5 per cent. of the total gross proceeds raised from Cenkos investors.

Optiva will be entitled to receive the following payments conditional upon Admission occurring:

(a) a 4 per cent. commission fee of the funds raised and or introduced by Optiva in connection with the Placing;

(b) an additional 1 per cent. placing commission fee of funds raised pursuant to the Placing and/or introduced by Optiva subject to a Placing Price of 4 pence or more;

(c) warrants in the Company to the value of 5 per cent. of the total gross proceeds raised from Optiva investors.

Beaumont Cornish will be paid a sum of £70,000 plus VAT and disbursements for nominated adviser services provided pursuant to the placing agreement and its engagement letter, details of which are set out in paragraph 12.46 of this Part VII.

The Company and the Directors have given warranties and indemnities to Cenkos, Optiva and Beaumont Cornish concerning, *inter alia*, the accuracy of the information contained in this document. The warranties and indemnities given by the Company and the Directors are standard for an agreement of this nature.

The Placing Agreement is governed by the laws of England and Wales.

12.50 ***Optiva December 2019 Warrant Agreement***

Pursuant to the Optiva December 2019 Warrant Agreement executed by the Company, the Company granted 6,389,167 Warrants to Optiva. Each Warrant entitles Optiva to subscribe for 1 new Ordinary Share at 3 pence per share for a period of five years from Admission. The Optiva Warrants are unlisted, fully transferable and are exercisable in whole or in part.

12.51 ***Cenkos December 2019 Warrant Agreement***

Pursuant to the Cenkos December 2019 Warrant Agreement executed by the Company, the Company granted 1,141,667 Warrants to Cenkos. Each Warrant entitles Cenkos to subscribe for 1 new Ordinary Share at 3 pence per share for a period of five years from Admission. The Cenkos Warrants are unlisted, fully transferable and are exercisable in whole or in part.

12.51A ***Shard Introducer Agreement***

On or around 19 November 2019, the Company and Shard entered into an introducer agreement pursuant to which the Company appointed Shard on a non-exclusive basis to introduce the Company to prospective investors in connection with the provision of funding to the Company. The Company has agreed to pay Shard a success fee equal to 4 per cent. of the gross funding for every completed transaction with a prospective investor introduced by Shard and an additional payment of 1 per cent. payable at the discretion of the Company.

The Company or Shard has a right to terminate the agreement for any reason on giving not less than one month's written notice to the other.

12.52 ***Crown SPA***

On 17 July 2019, the Company announced that it had entered into non-binding heads of terms to sell its interest in North Sea blocks 15/18d and 15/19b (containing the Crown discovery) held under the P2366 licence to Hibiscus. Following the announcement, the Company and its minority partner, Swift, entered into a sale and purchase agreement dated 7 October 2019 to sell the entire legal and beneficial interest in the P2366 licence to Hibiscus, of which 95 per cent. of the licence is held by the Company; and 5 per cent. held by Swift. The consideration payable by Hibiscus is the sum of up to US$5 million, which is allocated between the Company and Swift on a 95 per cent. to 5 per cent. basis, of which:

(a) a payment of US$100,000 is payable on signing. This payment will be returned to Hibiscus in limited circumstances (except where a default under the agreement is caused by Hibiscus);

(b) a US$900,000 will be payable on completion of the agreement;

(c) an additional sum of US$3 million will be payable within 7 business days upon an agreed milestone being achieved, which is expected to be by 31 December 2020 or such later date agreed to by the parties. In the event that the agreed milestone is not achieved, Hibiscus will either make a further payment of US$3 million within 7 business days following such non-achievement, or transfer the P2366 licence back to the Company and Swift for nominal consideration within 20 business days following such non-achievement); and

(d) a further US$1 million will become payable once the Crown discovery is on production.

The transaction is conditional on the OGA providing its written consent to (a) the assignment of the P2366 licence and (b) Hibiscus being appointed as the operator, but either the Company or Hibiscus may decide to waive these conditions by mutual agreement. Failure to waive, or satisfy the conditions on or before 31 December 2019, or such later date mutually agreed to between the parties (but by no later than 31 March 2020), will result in termination of the agreement (subject to certain specified terms).

The parties agree to appoint a joint-expert to produce a competent person's report following receipt of the OGA's written consent.

Hibiscus will indemnify UOG, Swift and their respective affiliates in respect of any pre and post completion environmental and decommissioning liabilities and any liabilities related to the decommissioning or abandonment of any wells, to the extent that such liabilities are attributable to the P2366 licence.

Rockhopper Egypt

12.53 ***Abu Sennan Concession***

Parties and Interest Percentages

The Abu Sennan Concession provides for the exploration and exploitation of petroleum in the Abu Sennan Area, Western Desert, Egypt. As at the date of the Rockhopper Acquisition Agreement, the contractual parties to the Abu Sennan Concession are the Egyptian Government, EGPC, Kuwait Energy Egypt, GlobalConnect, Dover and Rockhopper Egypt. The respective interest percentages of the Contractors under the Abu Sennan Concession are as follows:

Name of Contractor	*Interest (%)*
Kuwait Energy Egypt	25%
GlobalConnect	25%
Dover	28%
Rockhopper Egypt	22%
Total:	100%

EGPC has assigned its rights and obligations under certain provisions of the Abu Sennan Concession to the General Petroleum Company in Egypt including provisions on cost recovery and production sharing, and title to assets. Notwithstanding such assignment, EGPC and the General Petroleum Company will be jointly and severally liable in respect of those assigned provisions.

The Contractors are jointly and severally liable for the performance of the obligations of the Contractors under the Abu Sennan Concession.

Extension of Term

The Abu Sennan Concession has an initial exploration period of three years which has been extended pursuant to its terms. In October 2018, EGPC confirmed in writing its agreement to extend the exploration period under the Abu Sennan Concession, with the first exploration period expiring on 9 September 2021, the second exploration period expiring on 9 September 2022, and the third exploration period expiring on 9 September 2023.

Minimum Work

The Contractors are required to:

- spend a minimum of US$6,000,000 on exploration operations with the obligation of drilling two additional wells during the initial three-year period ending on 9 September 2021 ("**Initial Exploration Period**");
- spend no less than US$2,000,000 during the first 1-year extension period on 9 September 2022 and drill one well; and
- spend no less than US$2,000,000 during the second 1-year extension period on 9 September 2023 and drill one well.

Amounts spent and wells drilled by the Contractor Group in excess of the requirements for the Initial Exploration Period can be carried over to the subsequent extension period. If the Contractor Group surrenders its exploration rights before or at the end of the Initial Exploration Period or the subsequent extension period without having spent the required amount, it shall be obligated to pay to EGPC the unspent balance of its commitments. If a commercial discovery of petroleum is not made by the end of the exploration phase, the Abu Sennan Concession will terminate.

After the Initial Exploration Period, the Contractor Group is required to relinquish 25 per cent. of the original concession area that has not been converted into a development lease, with the remaining area that has not been converted into a development lease to be relinquished at the end of the third extension period. The Contractor Group shall not be required to relinquish any area where a commercial oil or gas well is discovered. If the Contractor Group is in the process of drilling or testing a well, it will be granted up to 6 months to enable it to discover a commercial oil or gas well.

Cost Recovery and Production Sharing

The Contractors will recover quarterly all costs in respect of exploration, development and operation out of 30 per cent. of all petroleum produced within the concession area. To the extent that the value of such cost recovery petroleum exceeds the actual recoverable costs, the value of the excess cost recovery petroleum will be divided between EGPC and the Contractors in accordance with the percentages of production sharing as set out below.

The remaining 70 per cent. of the petroleum will be divided between EGPC and the Contractors as follows:

	EGPC's share	*Contractors' share*
Crude Oil	82.1%	17.9%
Gas and LPG	82.1%	17.9%

With respect to the Contractors' share of the crude oil produced, priority will be given to meet the requirement of the Egyptian market for which EGPC has a preferential right to purchase. With respect to the gas and liquefied petroleum gas produced, priority will be given to meet the requirement of the local market as determined by EGPC. Where EGPC or EGAS is the buyer of the gas sold to the local markets, the sale will be by virtue of a long term gas sales agreement to be entered into between EGPC and the Contractors (as sellers) and EGPC or EGAS (as buyer).

Bonus Payment

The Abu Sennan Concession provides for certain bonus payments payable to EGPC by the Contractors such as upon approval of each Development Lease and by the relevant Contractor in the event of assignment of its rights and obligations under the Abu Sennan Concession (see below). In addition, the Contractors are obliged to make certain production bonus payments to EGPC upon production reaching certain agreed thresholds.

Cancellation

The Egyptian Government is entitled to cancel the Abu Sennan Concession by order or presidential decree with respect to any Contractor under certain circumstances such as a material breach of the Abu Sennan Concession provided that the relevant Contractor is given 90 days to remedy such breach.

Assignment and Change of Control

The Contractors cannot assign directly or indirectly any of their rights or obligations under the Abu Sennan Concession to any person either directly or indirectly (including a change of control of the relevant Contractor) without a prior written consent of the Egyptian Government. As the Rockhopper Acquisition constitutes a change of control (i.e. an indirect assignment) for the purposes of the Abu Sennan Concession, a bonus assignment fee will be payable to EGPC will be the aggregate of (i) 10 per cent. of the total financial commitment of the current exploration period (in accordance with the assigned percentage) and (ii) 10 per cent. of the value of the assignment deal.

The summary of the Rockhopper Acquisition Agreement (at paragraph 12.44) details the apportionment of the above assignment fee between the Company and Rockhopper PLC payable to EGPC upon approval by the Egyptian Government to the assignment.

Except for assignment to an affiliate, EGPC will also have a pre-emptive right to purchase the assigned interest in any direct or indirect assignment (including change of control) by a Contractor.

Governing Law

The Abu Sennan Concession is governed by Egyptian law and any dispute or claim arising from the agreement, insofar as it relates to the Egyptian Government, will be subject to the jurisdiction of the courts of Egypt and, insofar as it relates to EGPC, will be subject to the arbitration with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

12.54 ***Abu Sennan JOA***

The joint operating agreement is dated 14 January 2008 and subsequently amended on 24 October 2010 when Rockhopper Egypt became a party to it.

Parties and Interest Percentages

The Abu Sennan JOA provides that subject to the terms of the Abu Sennan Concession, all rights and interests in and under the Concession Agreement, all joint property and any hydrocarbons produced from the contract area are owned by the Contractors in accordance with their respective participating interest percentages in the Abu Sennan Concession. At the date of the Rockhopper Acquisition Agreement, the Contractors are Kuwait Energy Egypt, GlobalConnect, Dover and Rockhopper Egypt and their respective participating interest percentages are set out in paragraph 12.53 above. The rights and obligations of the parties under the Abu Sennan JOA are several.

Term

The Abu Sennan JOA continues in effect until:

(a) the Abu Sennan Concession terminates;

(b) all materials, equipment, and personal property used in connection with joint operations or exclusive operations have been disposed of or removed; and

(c) final settlement (including settlement of any financial audit carried out under the accounting procedure) has been made.

Operating Committee

Under the Abu Sennan JOA, a joint operating committee is established to provide for the overall supervision and direction of joint operations, consisting of a representative from each party holding a participating interest. Each party is entitled to appoint one representative and one alternative representative. The joint operating committee has the power and duty to authorise and supervise joint operations that are necessary or desirable to fulfil the Abu Sennan Concession and properly explore the contract area in accordance with the Abu Sennan JOA. Voting on any minimum work programme or budget or part thereof is decided by the affirmative vote of two or more of the Contractors that are not affiliates having collectively at least 60 per cent. of the participating interests save that if the representatives of the Contractors acting reasonably fail to agree on such matters which are necessary to maintain the Abu Sennan Concession in force and effect, then the proposed work programme or budget (to the extent necessary to maintain the Abu Sennan Concession in force and effect) will be deemed approved by the operating committee, and the operator will be deemed authorised to incur such expenditure for the joint account. Certain decisions such as development plans, annual gross budget in excess of agreed thresholds and obligatory relinquishments require unanimity among the Contractors.

In the event a Contractor fails to pay its share of joint account expenses (including cash calls and interest) or fails to obtain and maintain any security required of such party under the Abu Sennan Concession or the Abu Sennan JOA; the Abu Sennan JOA sets out the rights that are lost by the defaulting party, including rights to attend or vote at operating committee meetings, to access any data or information relating to joint operations, or which may result in all or part of a defaulting party's participating interest under the Abu Sennan JOA transferred to the non-defaulting parties.

Operator

Kuwait Energy Egypt is currently designated as the operator under the Abu Sennan JOA, and agreed to have exclusive charge of the joint operations and conduct all joint operations in the manner associated with an agreement of this type. Kuwait Energy Egypt can resign as operator by notifying the other parties at least 120 days before the effective date of such resignation. Kuwait Energy Egypt, as operator, can be removed upon receipt of notice from any non-operator (i.e. Dover, Rockhopper Egypt or GlobalConnect) in certain situations, including if it has committed a material breach of the Abu Sennan JOA, where the operator becomes insolvent, bankrupt or makes an assignment for the benefit of its creditors, if a receiver is appointed for a substantial part of Kuwait Energy Egypt's assets or Kuwait Energy Egypt dissolves, liquidates, winds up or otherwise terminates its existence.

In the event of a change in the operator, the joint operating committee will meet as soon as possible to appoint a successor operator pursuant to the voting procedure under the Abu Sennan JOA. If Kuwait Energy Egypt is removed as operator, neither it or any affiliate of it shall have the right to be considered as a candidate for the successor operator.

The operator is required to deliver to the other parties, on or before 1 October each year, a proposed production work programme and budget detailing the joint operations to be performed in the exploitation area and the projected schedule for the following calendar year. The operating committee is required to agree the proposed production work programme and budget within forty-five days of delivery. The Abu Sennan JOA also sets out the procedures to be followed by the operator and the parties if a commercial discovery is made that may lead to commercial production, including, the delivery of a development plan, together with the work programme and budget, and the procedures for the operator awarding contracts for joint operations during the various phases (including the obligations on the operator to provide certain information to the non-operators before any commitment or expenditure is made for a joint operation).

Change of Control

A change of control insofar as a Contractor is concerned under the Abu Sennan JOA is defined as a change of the ownership directly or indirectly of more than 50 per cent. of the voting rights in such legal entity.

In the event of a change of control of a Contractor, the Abu Sennan JOA provides that the other Contractors will have the right to acquire the participating interest of such Contractor on the same terms and conditions as it is being acquired within 30 days of receipt of the acquired party's notice contained in the prescribed information.

Crude Oil

The Abu Sennan JOA sets out the rights of the parties in respect of their entitlement to own, take in kind or separately dispose of its quantity of hydrocarbons. If crude oil is to be produced from an exploitation area, the parties shall in good faith, and not less than 3 months prior to the anticipated first delivery of crude oil, negotiate and conclude the terms of an offtake agreement.

12.55 ***Development Leases***

Seven development leases have been granted under the Abu Sennan Concession following commercial oil and gas discoveries across the concession area. The Abu Sennan development leases are valid for a period of twenty years extendable for an additional period of five years, as summarised below.

On 2 July 2012, the following three development leases were agreed between the Contractors and approved by the Minister of Petroleum & Mining Resources:

- Abu Sennan-1 Development Lease, in respect of the discovery well Jahraa-1X which is valid until 21 February 2032 (with an option to extend by a further 5 years);
- Abu Sennan-2 Development Lease, in respect of the discovery well El Salmiya-1X which is valid until 05 March 2032 (with an option to extend by a further 5 years);
- Al Ahmadi Development Lease, in respect of the discovery well Al Ahmadi-1X which is valid until 05 March 2032 (with an option to extend by a further 5 years);

On 21 July 2013, Abu Sennan-3 Development Lease were agreed between the Contractors and approved by the Minister for well ASA1X ST2, which is valid until 06 March 2033 (with an option to extend by a further 5 years);

On 22 April 2015, Abu Sennan-4 Development Lease were agreed between the Contractors and approved by the Minister for well ASH1X ST1 and is valid until 06 April 2035 (with an option to extend by a further 5 years);

On 24 August 2016, Abu Sennan-5 Development Lease were agreed between the Contractors and approved by the Minister for well AL Jahraa SE-1X, which is valid until 26 July 2036 (with an option to extend by a further 5 years); and

On 19 March 2019, Abu Sennan-6 Development Lease were agreed between the Contractors and approved by the Minister, which is valid until 18 March 2039 (with an option to extend by a further 5 years).

13 Share Dealing Code

The Board has adopted a share dealing code for PDMRs and their Closely Associated Persons, which complies with Rule 21 of the AIM Rules and also with the requirements of MAR. The share dealing code provides that there are certain periods during which dealings in the Company's Ordinary Shares cannot be made. Such periods include the periods leading up to the publication of the Company's financial results, including interim results, and any periods in which the Directors and other relevant employees and key personnel may be in possession of unpublished price sensitive information.

The Company will take all reasonable steps to ensure compliance by PDMRs and their Closely Associated Persons with the share dealing code.

14 Dividend Policy

The Directors do not intend to declare a dividend at the current time and it intends to retain all of its future earnings, if any, to finance the growth and development of the Company's and the Group's business. Under English law, a company can only pay cash dividends to the extent that it has distributable reserves and cash available for this purpose. The Company may not pay dividends if the Directors believe this would cause the Company to be inadequately capitalised or if, for any other reason, the Directors conclude it would not be in the best interests of the Company and the Group. Any of the foregoing could limit the payment of dividends to Shareholders or, if the Company does pay dividends, the amount of such dividends. Any return to Shareholders will, for the foreseeable future, therefore be limited to appreciation of their investment.

15 Litigation

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened) of which the Company is aware, which may have or have had during the 12 months immediately preceding the date of this Document a significant effect on the financial position or profitability of the Company or the Group.

16 Working Capital

In the opinion of the Directors, having made due and careful enquiry, the working capital available to the Enlarged Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of Admission.

17 Takeover Code

17.1 *Mandatory Takeover Bids*

The Company is subject to the Takeover Code. Brief details of the Panel, the Takeover Code and the protections they afford are described below. The Takeover Code is issued and administered by the Panel. The Takeover Code applies to all takeover and merger transactions, however effected, where the offeree company is, *inter alia*, a listed public company resident in the United Kingdom. The Company is a public company resident in the United Kingdom and its shareholders are therefore entitled to the protections afforded by the Takeover Code. 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 (as defined in the Takeover Code) which (taken together with shares already held by him and any interest in shares held or acquired by persons acting in concert with him) carry 30 per cent. or more of the voting rights of a company, that person is normally required to make a general offer to all the holders of any class of equity share capital or other class of transferable securities carrying voting rights in that company to acquire the balance of their interests in the company. Rule 9 of the Takeover Code also provides that, among other things, where any person who, 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 but does not hold shares carrying more than 50 per cent. of the voting rights of such a company, and such person, or any person acting in concert with him, acquires an additional interest in shares which increases the percentage of shares carrying voting rights in which he is interested, then such person is normally required to make a general offer to all the holders of any class of equity share capital or other class of transferable securities carrying voting rights of that company to acquire the balance of their interests in the company.

An offer under Rule 9 of the Takeover Code must be in cash (or with a cash alternative) and at not less than the highest price paid within the preceding twelve months for any shares in the company by the person required to make the offer or any person acting in concert with him. Rule 9 of the Takeover Code further provides, among other things, that where any person who, together with persons acting in concert with him holds over 50 per cent. of the voting rights of a company, acquires an interest in shares which carry additional voting rights, then they will not generally be required to make a general offer to the other shareholders to acquire the balance of their shares. However, individual members of a concert party will not be able to increase their percentage interest in shares through or between a Rule 9 threshold without Panel consent. For the purposes of the Takeover Code, persons acting in concert comprise persons who, pursuant to an agreement or understanding (whether formal or informal), co-operate to obtain or consolidate control of a company. Paragraph (9) of the definition of 'acting in concert' also deems any shareholders in a private company who sell their shares in that company in consideration for the issue of new shares in a company to which the Takeover Code applies to be acting in concert for the purposes of the Takeover Code unless the contrary is established.

17.2 ***Squeeze Out***

Under the Act, if a "**takeover offer**" (as defined in section 974 of the Act) is made for the Ordinary Shares and the offeror were to acquire, or unconditionally contract to acquire, not less than 90 per cent. in value of the Ordinary Shares to which the takeover offer relates (the "**Takeover Offer Shares**") and not less than 90 per cent. of the voting rights attached to the Takeover Offer Shares within three months of the last day on which its offer can be accepted, it could acquire compulsorily the remaining 10 per cent. It would do so by sending a notice to outstanding Shareholders telling them that it will acquire compulsorily their Takeover Offer Shares and then, six weeks later, it would execute a transfer of the outstanding Takeover Offer Shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for the outstanding Shareholders. The consideration offered to the Shareholders whose Takeover Offer Shares are acquired compulsorily 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 a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer relates to all the Ordinary Shares and at any time before the end of the period within which the offer could be accepted the offeror holds or has agreed to acquire not less than 90 per cent. of the Ordinary Shares (being voting shares that carry voting rights in the Company), any holder of Ordinary Shares to which the offer relates who has not accepted the offer is entitled by a written communication to the offeror to require it to acquire its Ordinary Shares. The offeror is 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 the minority Shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or, if later, the giving notice. If a Shareholder exercises his other rights, the offeror is bound to acquire those Ordinary Shares on the terms of the offer or on such other terms as may be agreed.

18 Competent Persons

18.1 The Competent Persons have confirmed to the Company, Beaumont Cornish, Optiva and Cenkos that: (i) they have reviewed the information that relates to the information contained in the Competent Persons' Reports in this Document, set out in Parts VIII, IX and X, which is contained in a portion of this Document other than in such report; and (ii) such information contained in a portion of this Document other than such report is, to the best of the Competent Persons' knowledge, correct on its facts, accurate, balanced, complete, not inconsistent with such report and contains no material omissions likely to affect its import.

18.2 The Competent Persons have no material interests in the Company.

19 General

19.1 The total costs and expenses relating to the Admission payable by the Company are estimated to be approximately £839,422 (excluding VAT).

19.2 UHY Hacker Young LLP of Quadrant House, 4 Thomas More Square, London E1W 1YW has given and not withdrawn its written consent to the issue of this Document with inclusion in it of their reports as set out in Part IV Section A (i), Part IV Section B (i) and Part V Section A of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports.

19.3 Beaumont Cornish 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.

19.4 Optiva Securities 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.

19.5 Cenkos 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.

19.6 Gaffney, Cline & Associates has given and not withdrawn its consent to the issue of this Document with inclusion in it of their reports as set out in Part VIII of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports. Gaffney, Cline & Associates has also confirmed to the Company and Beaumont Cornish that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in the Competent Person's Report since the effective date of such report.

19.7 ERC Equipoise Ltd has given and not withdrawn its consent to the issue of this Document with inclusion in it of their reports as set out in Part IX of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports. ERC Equipoise Ltd has also confirmed to the Company and Beaumont Cornish that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in the Competent Person's Report since the effective date of such report.

19.8 CGG Service (UK) Limited has given and not withdrawn its consent to the issue of this Document with inclusion in it of their reports as set out in Part X of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports. CGG Service (UK) Limited has also confirmed to the Company and Beaumont Cornish that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in the Competent Person's Report since the effective date of such report.

19.9 The accounting reference date of the Company is 31 December.

19.10 The Directors are unaware of any exceptional factors which have influenced the Company's activities.

19.11 There are no patents or other intellectual property rights, licences or particular contracts which are or may be of fundamental importance to the Company's business.

19.12 Save as disclosed in this Document, the Company has no principal investments in progress and there are no principal investments on which the Company has made a firm commitment.

19.13 Other than as disclosed in this Document, there have been no significant changes in the trading or financial position of the Company since 31 December 2018, being the date to which the last audited accounts were made up.

19.14 CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by written instrument. The Articles permit the holding and transfer of shares under CREST. The Company has applied for the issued Ordinary Shares to be admitted to CREST and it is expected that the issued Ordinary Shares will be so admitted, and accordingly enabled for settlement in CREST.

19.15 Save as disclosed in paragraph 12.51A of Part VII of this Document, no person directly or indirectly (other than the Company's professional advisers and trade suppliers or as disclosed in this Document) in the last 12 months received or is contractually entitled to receive, directly or indirectly, from the Company on or after Admission any payment or benefit from the Company to the value of £10,000 or more or securities in the Company to such value or entered into any contractual arrangements to receive the same from the Company at the date of Admission.

19.16 Where information which appears in this Document has been sourced from a third party, the information has been accurately reproduced. As far as the Directors and the Company are aware and able to ascertain from such information supplied or published by a third party, no facts have been omitted which would render any reproduced information false, inaccurate or misleading.

19.17 Save as disclosed in this Document, there are no known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Enlarged Group's prospects for at least the current financial year.

20 Documents Available for Inspection

20.1 Copies of the following documents may be inspected at the registered office of the Company during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of this document until one month following Admission:

(a) the memorandum and articles of association of the Company; and

(b) this Document.

21 Availability of this Document

Copies of this Document are available free of charge from the Company's registered office during normal business hours on any weekday (Saturdays and public holidays excepted) and shall remain available for at least one month after Admission. An electronic version of this Document can be downloaded from the Company's website: www.uogplc.com.

PART VIII

COMPETENT PERSON'S REPORT – Gaffney, Cline & Associates (Egypt)

Gaffney,
Cline &
Associates

Competent Person's Report on the Abu Sennan Concession in Egypt

Prepared for

United Oil & Gas plc

29th October 2019

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29th October 2019

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The Directors
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Dear Directors,

Introduction

At the request of United Oil & Gas plc (UOG), Gaffney, Cline & Associates (GCA) has prepared a Competent Person's Report (CPR) on the Abu Sennan concession (Abu Sennan) in Egypt (Figure 1) as at an Effective Date of 30th June 2019.

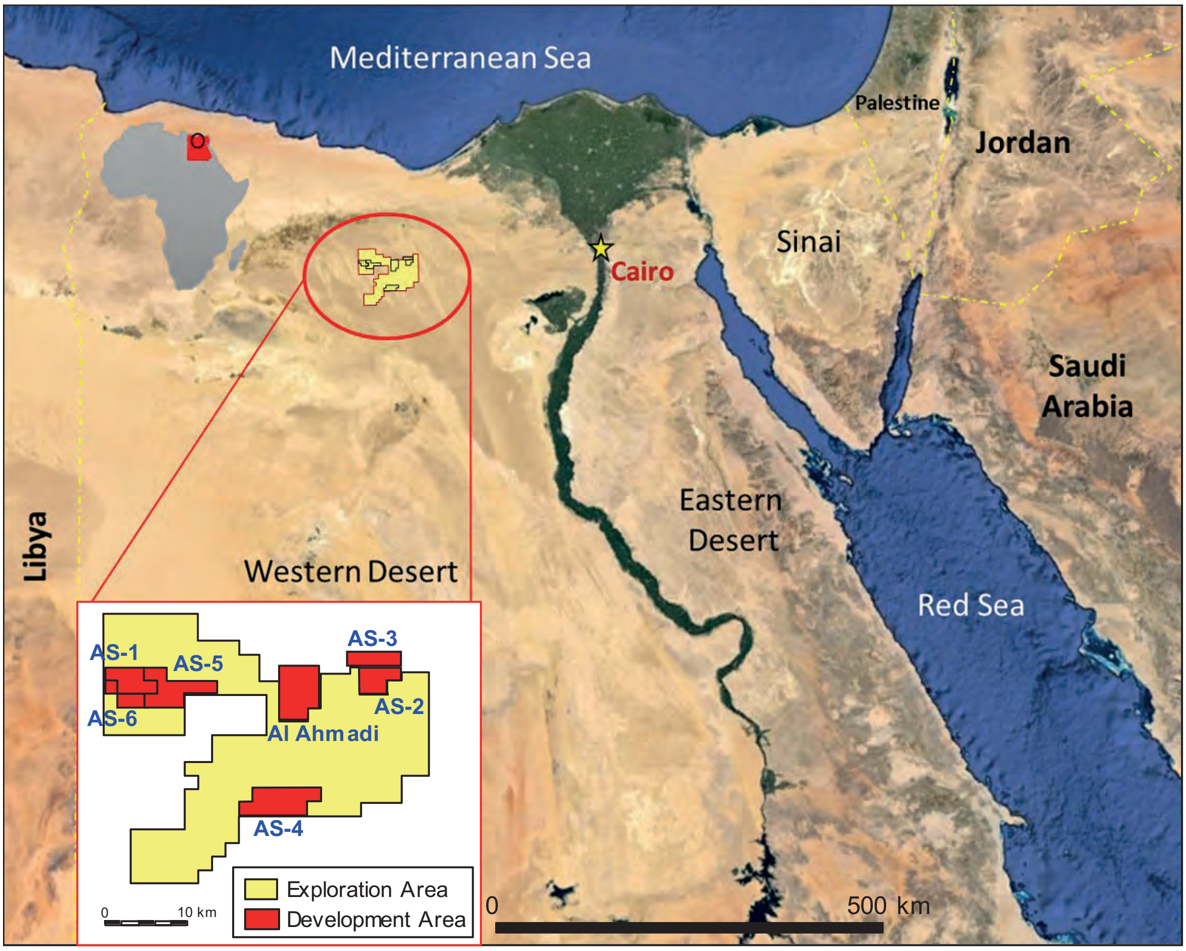
GCA understands that UOG intends to acquire the entire issued share capital of Rockhopper Egypt Pty Limited (Rockhopper Egypt), which holds a 22% working interest (WI) in Abu Sennan, from Rockhoppper Exploration plc (Rockhopper), and that this transaction constitutes a reverse takeover under the rules of AIM, the London Stock Exchange market on which UOG is listed. This CPR has been prepared for inclusion in an AIM re-admission document to be published in connection with the reverse takeover, and must only be used for that purpose.

The report has been prepared and is presented in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM Guidance Note"). This report also conforms with the guidelines and definitions of Reserves and Resources of the Petroleum Resources Management System (PRMS), an updated version of which was published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers in June, 2018 (an abbreviated form of the PRMS is included as Appendix I).

The Al Jahraa-7 well was drilled in June 2019, but had not been tested by the end of the month. It has subsequently tested at 160 bopd from the Lower Bahariya Formation, 500 bopd from the Upper Bahariya, and more than 700 bopd from the AR-E reservoir. The combined rate from the Upper and Lower Bahariya is slightly above expectation, while that for the AR-E is well above expectation and represents an upside not captured in this report.

Other than the above, GCA confirms it is not aware of any material change in the status of the Abu Sennan licence in the period between the Effective Date and the date of issue of this report that would require modifications to this report.

Figure 1: Location of Abu Sennan



Source: UOG (adapted)

GCA has not undertaken any site visit as part of the present work, but previously undertook a site visit to Abu Sennan, through its sub-contractor, on 23rd January 2017. The site visit report is included as Appendix II to this report. GCA's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. GCA does not warrant they are, or were at the time of the visit, in compliance with any applicable regulations in terms of standards, rating, health, safety, and environment. GCA is not aware of any major additions to the facilities since the date of its visit, but is not in a position to comment on any changes in their condition.

This report relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. It must be considered in its entirety.

A glossary of abbreviations used in this report is contained in Appendix III.

Executive Summary

License Summary

The Abu Sennan concession is governed by a Production Sharing Contract (PSC). Seven development licences have been awarded covering the eight fields that have been discovered and put into production. An exploration licence covers the rest of the concession area. Table 1 lists the licences as at 30th June 2019, in which UOG intends to acquire a 22% WI.

Table 1: Licence Summary as at 30th June 2019

Licence	Operator	Interest (%)	Status	Expiry[2]	Area (km^2)	Fields
Al Ahmadi	Kuwait Energy Egypt[1]	22	Development	Mar-32	18	ZZ, Al Ahmadi
Abu Sennan-1			Development	Feb-32	18	Al Jahraa
Abu Sennan-2			Development	Mar-32	15	El Salmiya
Abu Sennan-3			Development	Jul-33	12	ASA
Abu Sennan-4			Development	Apr-35	30	ASH
Abu Sennan-5			Development	Jul-36	30	Al Jahraa SE
Abu Sennan-6			Development	Mar-39	9	ASZ
Exploration			Exploration	Sep-21	644[3]	-

Notes:

1. Kuwait Energy Egypt (KEE) is a subsidiary of Kuwait Energy, which is now owned by United Energy Group Ltd. KEE operates the development licences through the East Abu Sennan Petroleum Company), which is a Joint Venture between the Egyptian General Petroleum Company (EGPC, a State-owned company) and the Contractor Group, with the Contractor Group represented by KEE.
2. All the development licences have an optional 5-year extension; the exploration licence has two optional 1-year extensions, each with additional commitments.
3. After excluding of the area of the Abu Sennan-6 development licence.
4. All licences are in Egypt.

Overview

GCA has performed an independent assessment of the Reserves, Contingent Resources and Prospective Resources in Abu Sennan. GCA's assessment has been conducted on the basis of a data set of technical information made available to GCA by UOG (and, at UOG's instruction, by Rockhopper) through July 2019, including details of concession interests and agreements, geological and geophysical data, interpretations and technical reports, historical production and engineering data, cost and commercial data, and approved development plans as at the Effective Date. GCA's work included such checks and calculations as were considered necessary.

Oil and gas Reserves are attributed to the eight fields, based on the Operator's development plans. Prospective Resources are attributed to a number of exploration Prospects that have been identified by the Operator within the concession area. No Contingent Resources have been quantified as part of this assessment.

Reserves Summary

The oil and gas Reserves attributable to Abu Sennan are shown in Table 1. Reserves are shown both as gross (100%) field volumes and net to the 22% interest to be acquired by UOG.

Reserves net to that interest represent the net economic entitlement attributable to that interest under the terms of the PSC that governs the asset.

Table 2: Summary of Reserves
as at 30th June 2019

(a) Oil

Status	Gross Field (MMBbl)			Net Economic Entitlement (MMBbl)		
	Proved	Proved + Probable	Proved + Probable+ Possible	Proved	Proved + Probable	Proved + Probable+ Possible
Developed	3.09	6.56	8.80	0.30	0.63	0.85
Undeveloped	0.52	3.99	7.13	0.05	0.38	0.62
Total	**3.61**	**10.56**	**15.93**	**0.34**	**1.00**	**1.47**

(b) Gas

Status	Gross Field (Bscf)			Net Economic Entitlement (Bscf)		
	Proved	Proved + Probable	Proved + Probable+ Possible	Proved	Proved + Probable	Proved + Probable+ Possible
Developed	3.6	7.1	12.2	0.3	0.7	1.2
Undeveloped	0.0	0.7	2.3	0.0	0.1	0.2
Total	**3.6**	**7.8**	**14.5**	**0.3**	**0.7**	**1.4**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Net Reserves are the net economic entitlement attributable to the interest to be acquired by UOG under the terms of the PSC that governs this asset.
3. For all of the Reserves volumes, the Operator is Kuwait Energy Egypt (see note 1 to Table 1).
4. Totals may not exactly equal the sum of the individual entries due to rounding.

Net Present Value (NPV) of Reserves

Reference Post-Tax NPVs at 10% discount rate (NPV10) have been attributed to the Proved, the Proved plus Probable, and the Proved plus Probable plus Possible Reserves. Discounting has been done on a mid-period basis to 30th June 2019.

The assessment has been based upon GCA's understanding of the fiscal and contractual terms governing the asset, as described herein. All NPVs quoted are those exclusively attributable to the 22% interest to be acquired by UOG in the asset under review.

GCA's Brent crude oil price scenario for 3Q 2019, shown in Table 3, has been used as the reference oil price. A discount of US$2.00/Bbl for quality and location has been applied for Abu Sennan crude. A gas price of US$2.65/MMBTU has been used. Costs have been escalated at 2.0% p.a. from 2020.

Table 3: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2H 2019	64.70
2020	62.48
2021	66.25
2022	70.00
2023+	+2.0% p.a.

The resulting NPV10s are shown in Table 4. Sensitivity of the NPVs to variations in discount rate, costs and commodity prices are presented in Section 9.4.

Table 4: Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flow from Reserves, Net to the Interest to be Acquired, as at 30th June 2019

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
10.0	8.7	26.6	42.2

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. All cash flows are discounted on a mid-period basis to 30th June 2019.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property nor any interest therein.

Prospective Resources Summary

The Prospective Resources attributed to Abu Sennan are shown in Table 5. Prospective Resources are shown both as gross (100%) volumes and net to the interest to be acquired by UOG on a working interest (WI) basis, i.e. the WI fraction of the gross volumes. These do not represent the actual net economic entitlement under the terms of the PSC that governs the asset, which would be lower. Net WI volumes are quoted here since the Prospective Resources are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the net economic entitlement.

Table 5: Summary of Prospective Resources (Prospects)
as at 30th June 2019

Prospect		Gross (MMBbl)			Net (WI Basis) (MMBbl)			P_g (%)
		1U	2U	3U	1U	2U	3U	
ASF-1x	AR-C	0.89	2.18	5.08	0.20	0.48	1.12	14
	AR-E	0.41	0.99	1.93	0.09	0.22	0.43	6
	AR-G	0.61	1.21	2.36	0.13	0.27	0.52	24
	Bahariya	1.31	2.48	4.22	0.29	0.55	0.93	24
ASK-1x	AR-G	0.37	0.73	1.42	0.08	0.16	0.31	17
	Bahariya	0.82	1.56	2.65	0.18	0.34	0.58	17
	AEB	1.94	3.43	5.69	0.43	0.75	1.25	27
	Khatatba	1.89	3.26	5.32	0.42	0.72	1.17	35
Al Ahmadi-3	AR-C	0.11	0.27	0.63	0.02	0.06	0.14	32
	AR-G	0.10	0.19	0.37	0.02	0.04	0.08	32
	Bahariya	0.15	0.29	0.50	0.03	0.06	0.11	22
	Kharita	0.77	1.31	2.09	0.17	0.29	0.46	40
Salmiya West	AR-C	0.16	0.38	0.90	0.03	0.08	0.20	35
	AR-E	0.10	0.25	0.48	0.02	0.05	0.11	35
	Bahariya	0.19	0.36	0.62	0.04	0.08	0.14	42
	Kharita	0.90	1.51	2.37	0.20	0.33	0.52	36
SW Al Ahmadi	AR-C	1.57	5.03	13.53	0.34	1.11	2.98	35
	Bahariya	1.35	3.54	7.19	0.30	0.78	1.58	24
SW-ASH	AEB	0.17	0.39	0.87	0.04	0.09	0.19	48

Notes:

1. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect, in the event that a discovery is made and subsequently developed.
2. Net Prospective Resources in this table are the Working Interest fraction of the Gross Prospective Resources; they do not represent the actual net economic entitlement attributable to the interest to be acquired by UOG under the terms of the PSC that governs the asset, which would be lower.
3. The P_g reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery. This does not include any assessment of the risk that a discovery, if made, may not be developed.
4. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
5. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
6. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.
7. For the Prospective Resources, the Operator is Kuwait Energy Egypt, which is now owned by United Energy Group Ltd.
8. 1U, 2U and 3U represent Low, Best and High estimates of Prospective Resources.

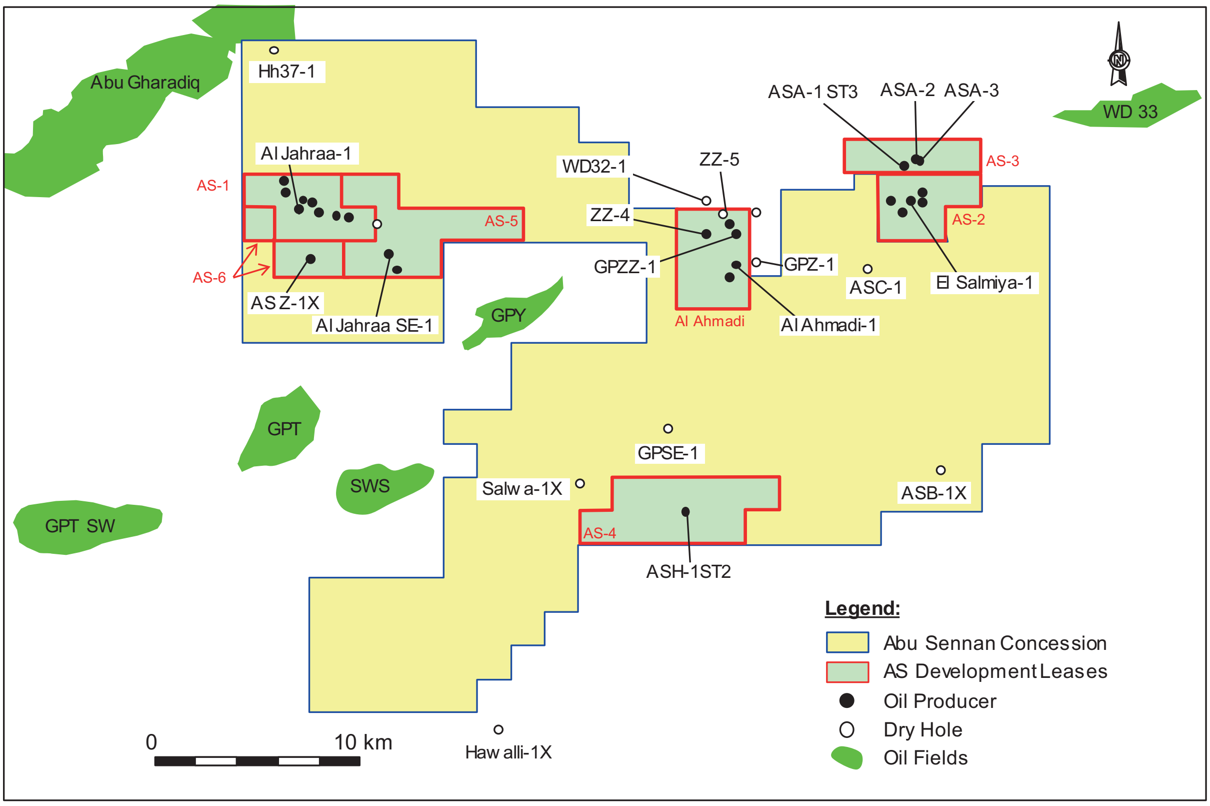
Discussion

1 Background

Rockhopper Egypt holds a 22% WI in the Abu Sennan concession. Kuwait Energy (KE), now owned by United Energy Group Ltd, holds 25% through its subsidiary company Kuwait Energy Egypt (KEE), which is the Operator. The other partners in the Contractor Group are Global Connect Ltd, holding a 25% interest, and Dover Investments Ltd (Dover), holding a 28% interest. KEE carries all of Dover's costs related to the concession, and in return is entitled to receive Dover's share of the cost oil plus 7.5% of Dover's share of the profit oil attributed to the Contractor Group.

The concession lies in the Western Desert (Figure 1). As at 30th June 2019, seven development licences have been awarded (Figure 2) covering the eight fields that have been discovered and put into production (Table 1). The development licences are operated by KEE through the East Abu Sennan Petroleum Company, which is a joint venture (JV) between EGPC and the Contractor Group, with the Contractor Group represented by KEE. KEE is the Operator, though all decisions require approval from the JV parties. Any references to the Operator in this report refer to KEE.

Figure 2: Map of Wells and Development Areas



An exploration licence covers the rest of the concession area. The previous exploration license expired in May 2016, but a 5-year extension (3 years plus two 1-year extensions at the Contractor's option) covering the rest of the concession area (653.4 km^2, after relinquishments) was approved in September 2018. Because of the delay in granting approval, EGPC agreed that the 5-year period should start on 10th September 2018. There is a commitment to spend a minimum of US$6 MM in the first 3-year period, to include two exploration wells, and a minimum of US$2 MM, to include one exploration well, in each 1-year extension period. The first of these commitment wells, ASZ-1, was drilled in late 2018 and resulted in the most recent discovery in the concession, the ASZ field.

1.1 Exploration and Production History

Five wells were drilled on the concession prior to 1985, resulting in the discovery of oil in the ZZ field (formerly known as GP ZZ), but this was not developed at the time.

In 2007-8, 3D seismic data covering most of the concession area were acquired, processed and interpreted. Activity was suspended in 2009 and 2010 awaiting military approvals, but four wells were drilled in 2011, discovering the Al Ahmadi, Al Jahraa and El Salmiya fields. Development licences covering these and the ZZ field were awarded in 2012.

In July 2012, an extended period of trial production began following installation of rented processing facilities, with produced oil being exported by truck and produced gas being flared. Results were mixed, however, with some wells declining rapidly and others being limited by restrictions on the amount of gas that could be flared. Two additional wells were drilled in 2013 and seven more in 2014, adding to production and discovering the ASA field as well as additional reservoirs in El Salmiya and Al Jahraa.

Three permanent production and processing stations were constructed in 2014, serving El Salmiya and ASA (the main station), Al Ahmadi and Al Jahraa respectively; these replaced the rented production facilities. A gas pipeline to a GPC gas facility located approximately 12 km from Al Ahmadi and 23 km from El Salmiya was constructed in 2014. Rented gas handling facilities were also installed, and gas export began in April 2015. Produced oil continues to be transported by truck.

A sixth discovery was made at ASH in 2015, a seventh at Al Jahraa SE in 2016 and an eighth at ASZ at the end of 2018. Additional reservoirs were discovered at Al Jahraa in 2018 and 2019. In total, at least 22 separate accumulations have been discovered in the eight fields. The most significant is the AR-C reservoir at Al Jahraa/Al Jahraa SE, with a STOIIP estimated at between 16 and 34 MMBbl.

The 3D seismic data were reprocessed in 2015-16 and interpretation has been ongoing since then, focusing initially on the main reservoirs and more recently on exploration targets.

The oil production history is shown in Figure 3. The oil production rate peaked at 6,000 bopd in June 2015 before declining to approximately 2,500 bopd by June 2016. It subsequently remained fairly stable, apart from a dip in mid-2018, but has risen significantly in 2019 as new wells have been brought on stream in Al Jahraa, reaching 4,000 bopd by the end of June, with Al Jahraa-7 still to be put into production. Average rates in June 2019 and cumulative production to 30th June 2019 are shown in Table 6.

Figure 3: Oil Production History to June 2019

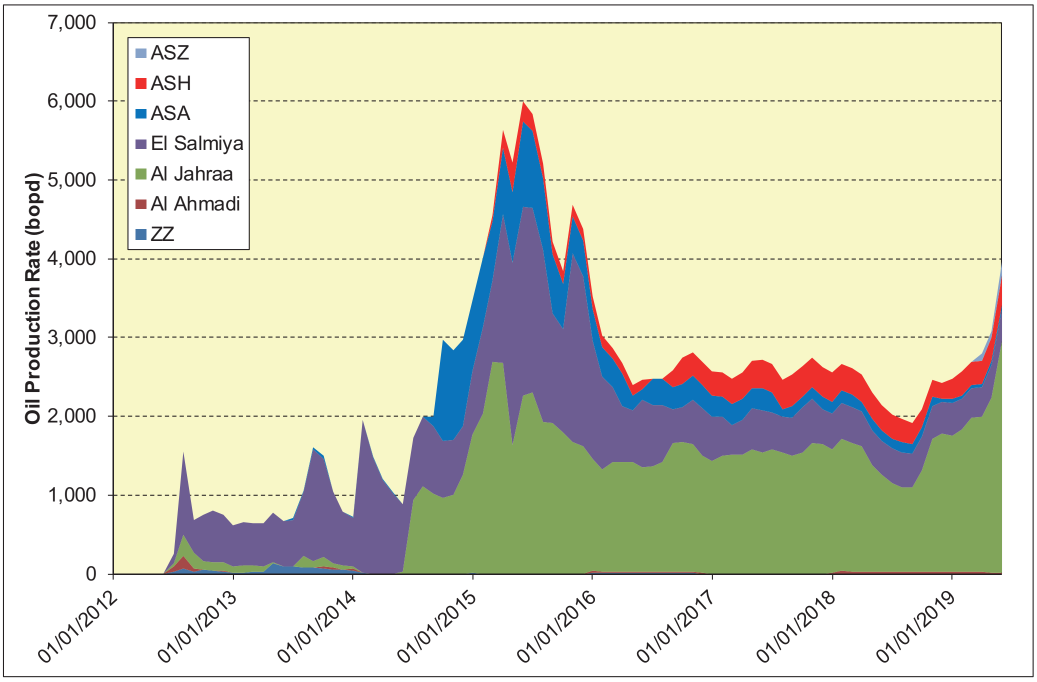


Table 6: Production Rates and Cumulative Production, June 2019

Field	Production Rate		Cumulative Production	
	Oil (bopd)	Gas (MMscfd)	Oil (MMBbl)	Gas (Bscf)
ZZ	0	0.00	0.04	1.86
Al Ahmadi	20	1.86	0.03	0.87
Al Jahraa	2,935	0.00	2.97	0.00
El Salmiya	399	4.43	2.08	8.70
ASA	60	0.00	0.65	0.00
ASH	371	0.00	0.41	0.00
ASZ	177	0.00	0.01	0.00
Total	**3,962**	**6.29**	**6.20**	**11.43**

Notes:

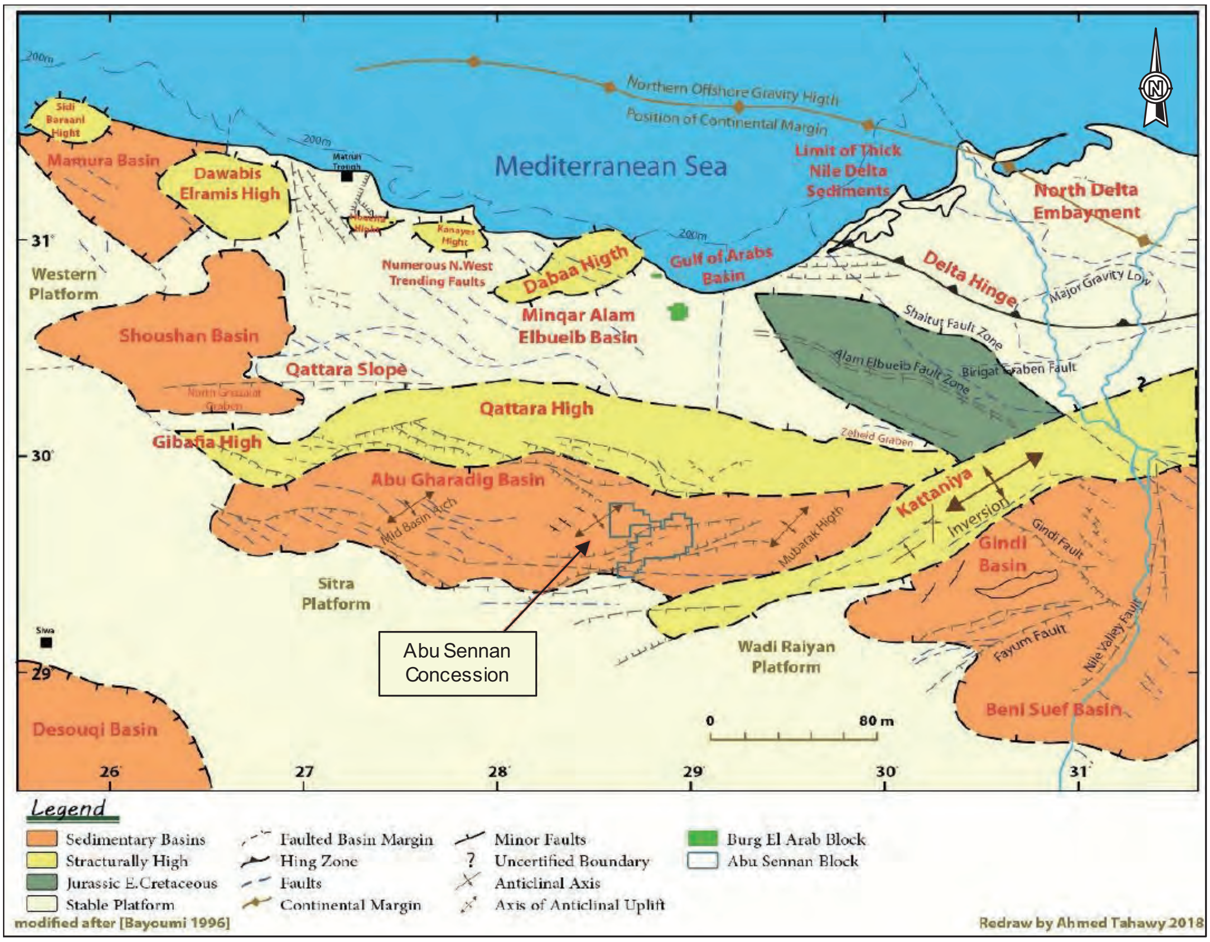
1. Al Jahraa SE production is included with Al Jahraa.
2. Gas volumes shown are exported volumes, and do not include gas used for fuel or flared.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

2 Geology

2.1 Regional Tectonic Framework

Geologically, Abu Sennan lies in the Abu Gharadig Basin in the northern part of the Western Desert (Figure 4), and incorporates the Abu Sennan sub-basin to the north and the Mubarak High to the south. The northwest corner of the concession is bounded by the Abu Gharadig anticline. The Abu Gharadig Basin has been interpreted as an intra-cratonic, asymmetric graben of middle Jurassic to late Cretaceous age.

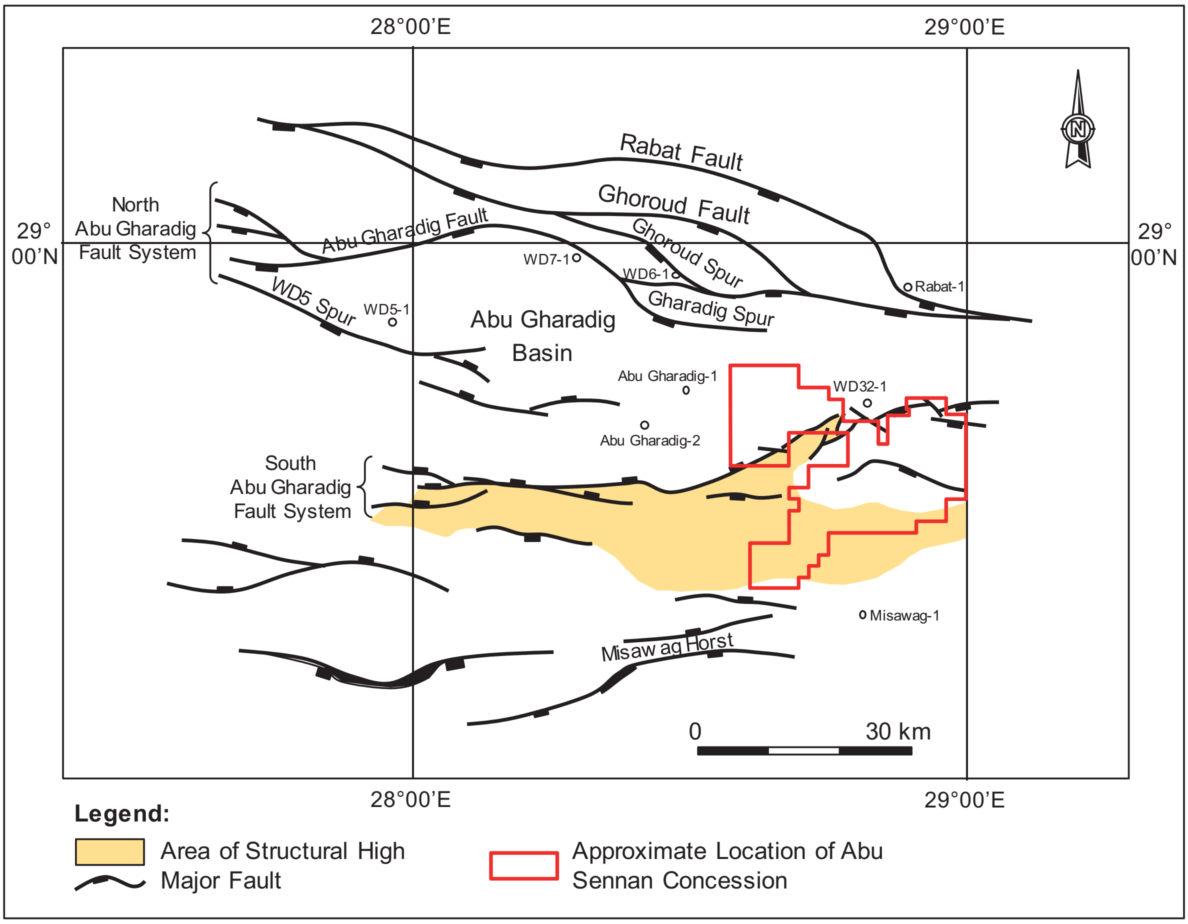
Figure 4: Regional Structural Framework – Northern Western Desert



Source: UOG

The Abu Sennan sub-basin is a typical half graben and is configured by a series of E-W and NW-SE interconnecting faults, accommodating a complex history of vertical and lateral displacement. The major bounding faults occur to the north, outside of the concession, and are known as the Rabat, Ghoroud and Abu Gharadig. The major tectonic framework of the Abu Gharadig Basin is shown in Figure 5.

Figure 5: Tectonic Framework of the Abu Gharadig Basin



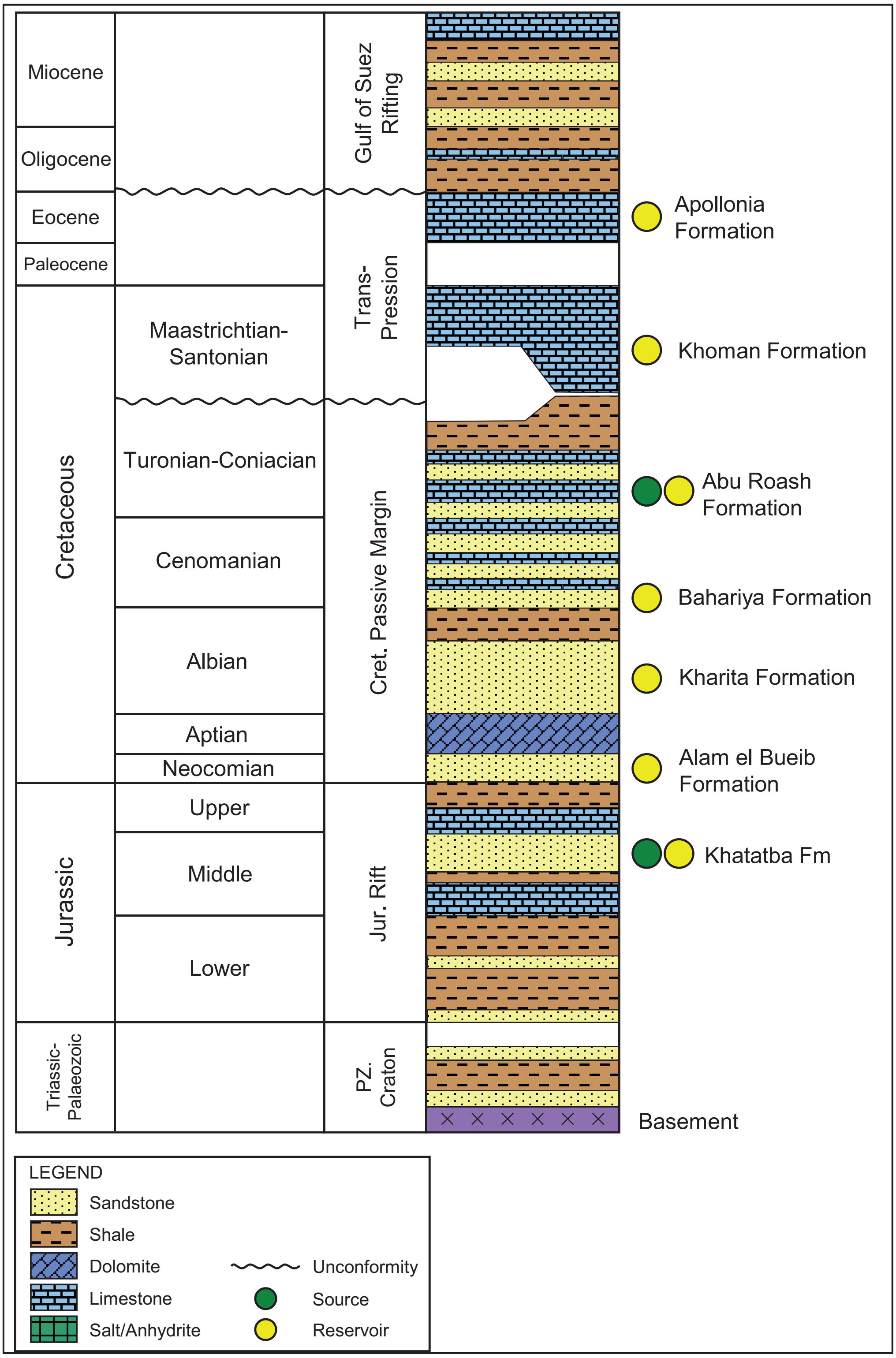
Source: UOG

2.2 Regional Stratigraphy and Petroleum System

The overall stratigraphy of the Western Desert is summarised in Figure 6. The proven reservoirs within the Abu Sennan concession are Cretaceous in age and comprise a series of interbedded marine sandstones and carbonates. The Lower Bahariya Formation and Abu Roash Members C, D, E, and G (AR-C, AR-D, AR-E and AR-G) are of Cenomanian to Turonian age, the Kharita Formation is of Albian age and the Alam El Bueib (AEB) Formation is of Neocomian age. Seals are provided mainly by interbedded marine mudstone units.

Additional prospective reservoirs are identified locally in sandstones of the deeper, Middle Jurassic Khatatba Formation. This formation also provides the principal hydrocarbon source rock, although distribution and level of maturity varies between fault blocks. Traps are predominantly structural, occasionally with four-way dip closure but more commonly reliant on fault seal on one or more sides.

Figure 6: Composite Stratigraphy, Western Desert

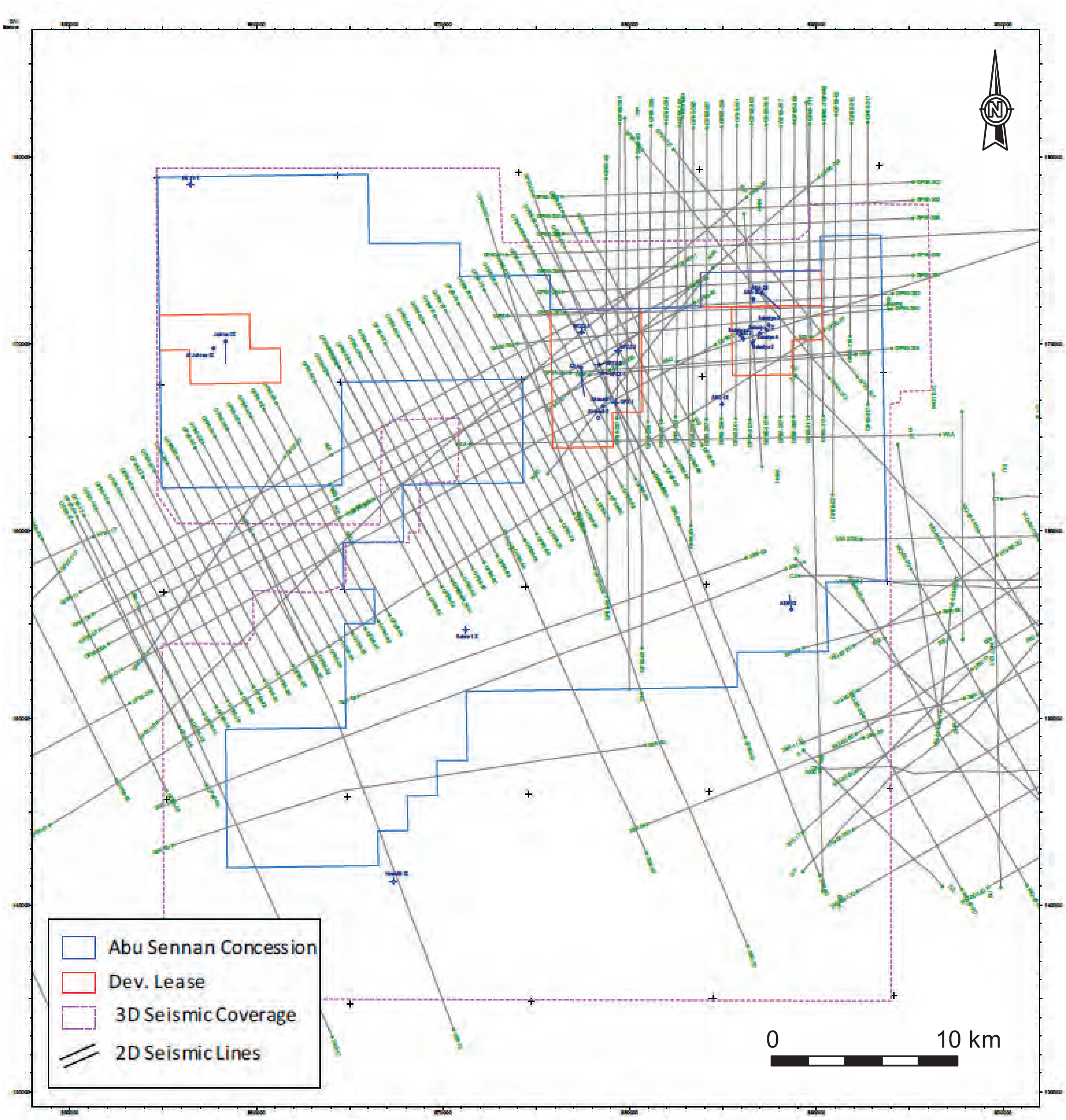


2.3 Seismic Data

The Abu Sennan concession is covered by 2D seismic data of various vintages, including a 2D survey acquired in 1996. A 3D seismic survey of approximately 1,620 km^2 was acquired in 2007 and processed in 2008.

The 2D and 3D seismic coverage across the concession is shown in Figure 7. The 3D seismic data were reprocessed in 2015 with the final reprocessed Post-Stack Time Migrated (PSTM) and Post-Stack Depth Migrated (PSDM) cubes completed in 2016. The seismic data are generally of good quality allowing confident fault and horizon interpretation across the concession.

Figure 7: Seismic Data Coverage, Abu Sennan Concession



Source: UOG

3 Hydrocarbon Initially In Place

Hydrocarbon initially in place (HCIIP) estimates made by the Operator for each of the fields discovered to date were previously audited by GCA and are presented in Table 7. These estimates pre-date the most recent wells in Al Jahraa and the reinterpretation of the ASH structure, while the estimates for ASZ are GCA's own, based on maps generated by the Operator. GOR was very high in some of the initial production tests and there was debate as to whether the hydrocarbons exist in some of the reservoirs as volatile oil or gas condensate. Table 7 reflects the latest view, based on PVT reports and the production data.

Table 7: HCIIP Estimates

Field	Reservoir	Fluid	STOIIP/CIIP (MMBbl)			GIIP (Bscf)		
			Low	Best	High	Low	Best	High
ZZ	AR-G	Gas Condensate	0.2	0.2	0.2	2.1	2.7	3.2
	L Bahariya	Volatile Oil	0.1	0.2	0.2	0.2	0.3	0.4
Al Ahmadi	AR-G	Volatile Oil	0.1	0.1	0.1	0.2	0.3	0.4
	L Bahariya	Gas Condensate	0.3	0.4	0.4	4.0	5.0	6.0
Al Jahraa + Al Jahraa SE	AR-C	Oil	15.7	24.2	33.9	5.7	8.9	12.4
	AR-D	Oil	3.0	3.0	3.0	1.4	1.4	1.4
	AR-E	Oil	2.2	3.4	4.7	0.9	1.4	1.9
	L Bahariya	Oil	1.5	2.8	4.0	-	-	-
El Salmiya	AR-C	Volatile Oil	3.7	4.7	6.2	7.3	9.3	12.5
	AR-E	Oil	0.6	1.1	1.7	0.2	0.4	0.6
	L Bahariya	Volatile Oil	0.5	1.4	5.7	1.1	3.5	19.8
	Kharita	Volatile Oil	4.3	5.8	7.7	9.5	12.9	17.0
ASA	AR-C	Oil	0.9	1.5	2.3	0.4	0.7	1.1
	AR-E	Oil	5.6	6.1	6.7	2.7	2.9	3.2
ASH	AEB	Oil	2.9	5.7	11.4	4.1	8.0	16.0
ASZ	AR-C	Oil	0.4	0.8	1.2	-	-	-
Total			**42.0**	**61.2**	**89.4**	**40.0**	**57.7**	**95.8**

Notes:

1. Estimates pre-date the most recent wells on Al Jahraa and the reinterpretation of the ASH structure.
2. GIIP for Al Jahraa L Bahariya and ASZ have not yet been evaluated.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

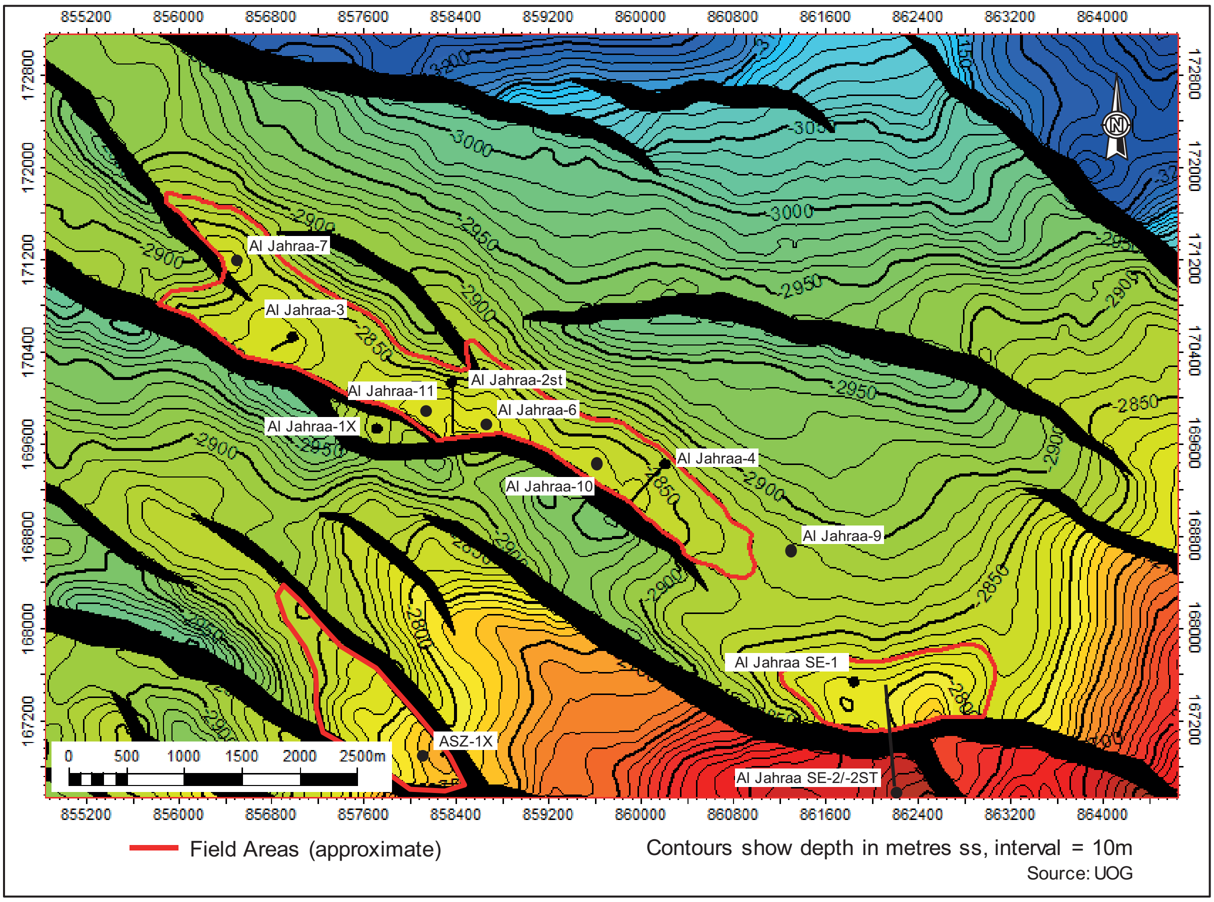
The Al Jahraa-7 well, drilled in June 2019, found oil in the Upper and Lower Bahariya reservoirs in the Al Jahraa field. The former is a new discovery, and the well also proved up a larger area in the Lower Bahariya. Interpretation of the data gathered in the well is still in progress, and Table 7 does not yet reflect these positive results.

As described further in Section 5.3, the structure of the ASH field has recently been reinterpreted by the Operator, resulting in the south-western part of the structure being reclassified as an exploration Prospect. This may lead to a downward revision of STOIIP in the main part of the ASH field, which is not yet reflected in Table 7.

4 Al Jahraa and Al Jahraa SE Fields

Al Jahraa is located in the AS-1 development area on the western side of the concession (Figure 2). Eleven wells have been drilled to date (including Al Jahraa SE-1 and SE-2). Oil is found in the AR-C, AR-D, AR-E, Upper and Lower Bahariya reservoirs, of which the most significant is the AR-C (Figure 8), at depths of 2,750-3,050 m ss. The reservoirs contain light oil with a GOR of approximately 400 scf/stb in the AR-C, AR-D and AR-E, higher in the Upper and Lower Bahariya. The field is an elongated anticline, partly controlled by a fault to the south. The Al Jahraa SE-1 well was drilled in 2016. It found oil in the AR-C at lower than the expected initial pressure, suggesting communication with the existing Al Jahraa wells that were already in production. However, the two oil pools in the AR-C (Al Jahraa and Al Jahraa SE) are separate and correspond to the two mapped structural closures, as indicated in Figure 8, with pressure communication taking place via an aquifer. This was confirmed by the Al Jahraa-9 well, drilled in 2017, which produced water from the AR-C when tested.

Figure 8: Top AR-C Reservoir, Al Jahraa, Al Jahraa SE and ASZ Fields



Al Jahraa-SE-2 was also drilled in 2017, initially as an exploration well on the southern side of the main bounding fault (Figure 8). It was drilled to a total depth of 3,460 m, in the Kharita Formation, but found no hydrocarbon so was side-tracked to the north of the fault where it encountered oil in the AR-C and AR-E, testing at 275 bopd in the latter. After producing for 18 months from the AR-E, its rate had declined to less than 40 bopd; it was then also perforated in the AR-C, which added 250 bopd.

Two wells were drilled in 2018. Al Jahraa-6 found oil in the Lower Bahariya reservoir, a new discovery, as well as in the AR-C and AR-D. It came on production from the Lower Bahariya in late September and after cleaning up reached 500 bopd by early November, declining to 400 bopd by end June 2019. Al Jahraa-10 was drilled as an AR-C producer and came on production in December at approximately 130 bopd.

Two further wells were drilled in 2019. Al Jahraa-11 found oil in the Lower Bahariya and AR-C reservoirs and has been fitted with a dual completion. It started producing in May at 420 bopd from the Lower Bahariya (long string) and 480 bopd from the AR-C (short string). Drilling of Al Jahraa-7 was completed in June; it found oil in the AR-C, AR-E, Upper Bahariya (a new discovery) and two intervals in the Lower Bahariya. Subsequent to the Effective Date of this report, it has tested at 160 bopd from the Lower Bahariya, 500 bopd from the Upper Bahariya, and more than 700 bopd from the AR-E.

Initial production rates of up to 1,200 bopd were achieved in the early wells. Overall production from the AR-C reservoir to end June 2019 was 2.2 MMBbl, from seven wells (including Al Jahraa SE-1 and SE-2). Reservoir pressure has fallen, indicating that the aquifer is of limited size, and the Operator is now implementing a water injection project in this reservoir, with water being injected in Al Jahraa-9 since July 2018 at a rate of 2,000 bpd.

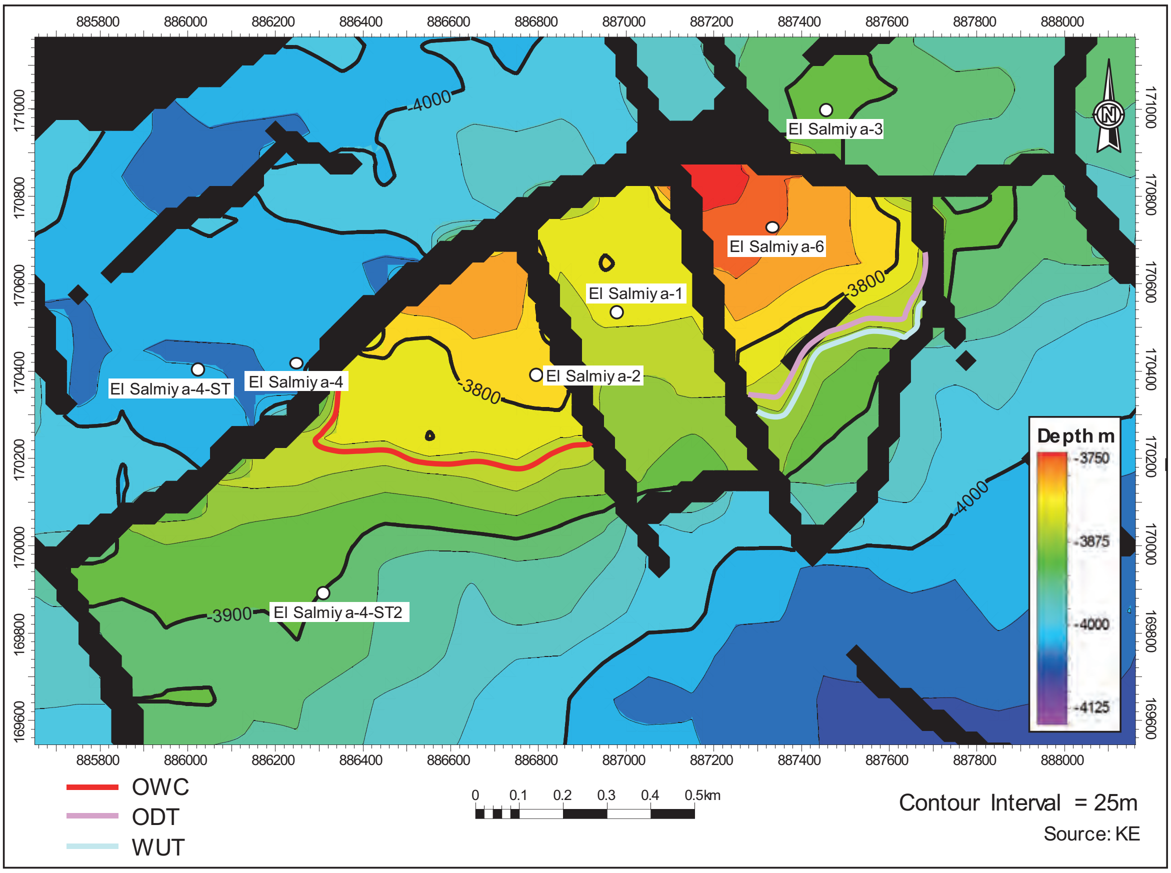
5 Other Fields

5.1 El Salmiya Field

El Salmiya is located in the AS-2 development area on the eastern side of the concession (Figure 2). Five wells have been drilled in the field to date. Oil has been found in the AR-C, AR-E, Lower Bahariya and Kharita reservoirs at depths of 3,200 to 3,800 m ss. Apart from the AR-E, where 33°API oil with a GOR of 200-300 scf/stb was found, all the reservoirs contain volatile oil with high GOR in the order of 1,900-2,500 scf/stb.

The field is a complex, heavily faulted, anticlinal structure, and there are at least two separate pools in each of the AR-C and Kharita reservoirs. Figure 9 shows the depth structure map for the Kharita reservoir, which is estimated to contain approximately 40% of the STOIIP in the field; only El Salmiya-2 and El Salmiya-6 have penetrated this reservoir, which is the deepest so far encountered.

Figure 9: Top Kharita Reservoir, El Salmiya Field

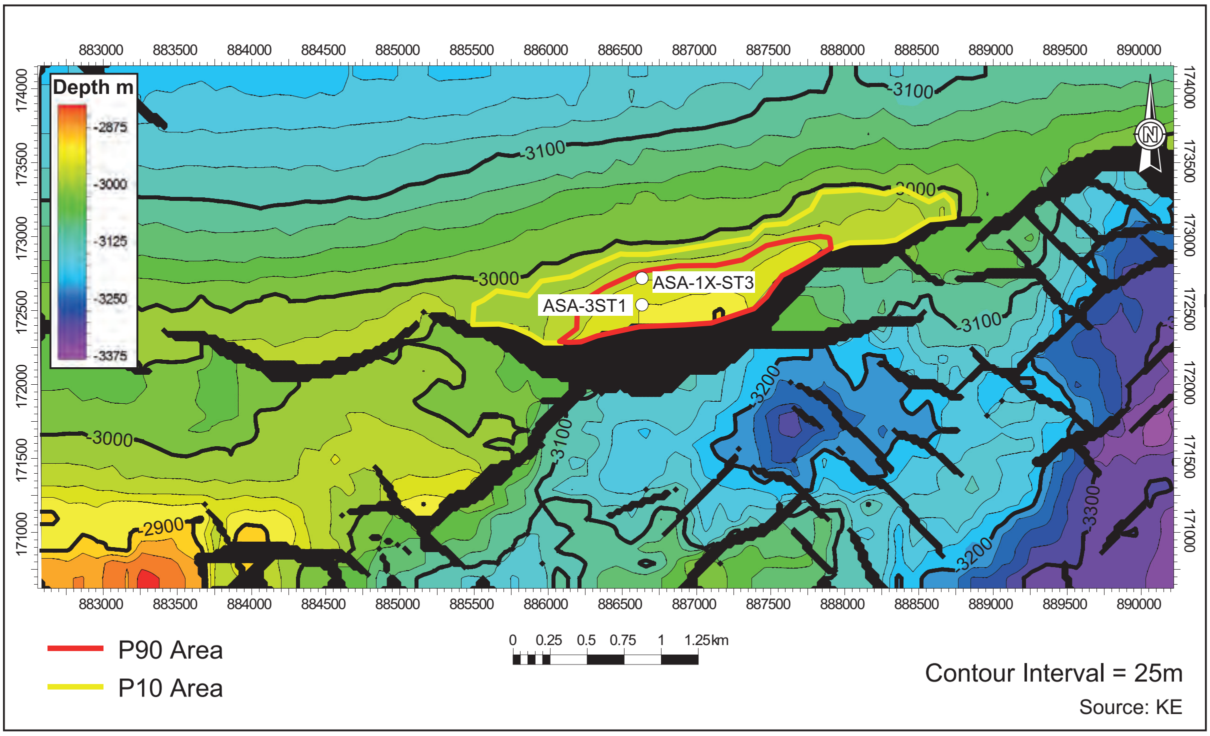


Although initial production rates of up to 3,500 bopd were achieved in several of the wells, production was initially constrained due to the high GOR. After gas export was put in place, rates increased but then declined quite steeply, confirming the compartmentalised nature of the reservoirs. In April 2019, El Salmiya-1 was producing 50 bopd and 1.7 MMscfd from the AR-C, El Salmiya-2 110 bopd from the AR-E and El Salmiya-6 220 bopd and 2.8 MMscfd from the Kharita. Sucker-rod pumps were installed in El Salmiya-1, El Salmiya-2 and El Salmiya-3 (AR-C) in 2017, but the latter produced for less than a month. El Salmiya-4 was recompleted in the AR-E in 2018 but there was no flow.

5.2 ASA

ASA, located in the AS-3 development area (Figure 2), is a tilted fault structure to the north of El Salmiya (Figure 10). Two wells and two side-tracks have been drilled in the field to date. Light oil with a GOR of approximately 400 scf/stb has been found in the AR-C and AR-E reservoirs at a depth of approximately 3,000 m ss. Production in April 2019 was from ASA-3 only (AR-E reservoir) as ASA-1ST3, which is completed in the AR-C and AR-E reservoirs, stopped producing in late 2018 and is awaiting a work-over.

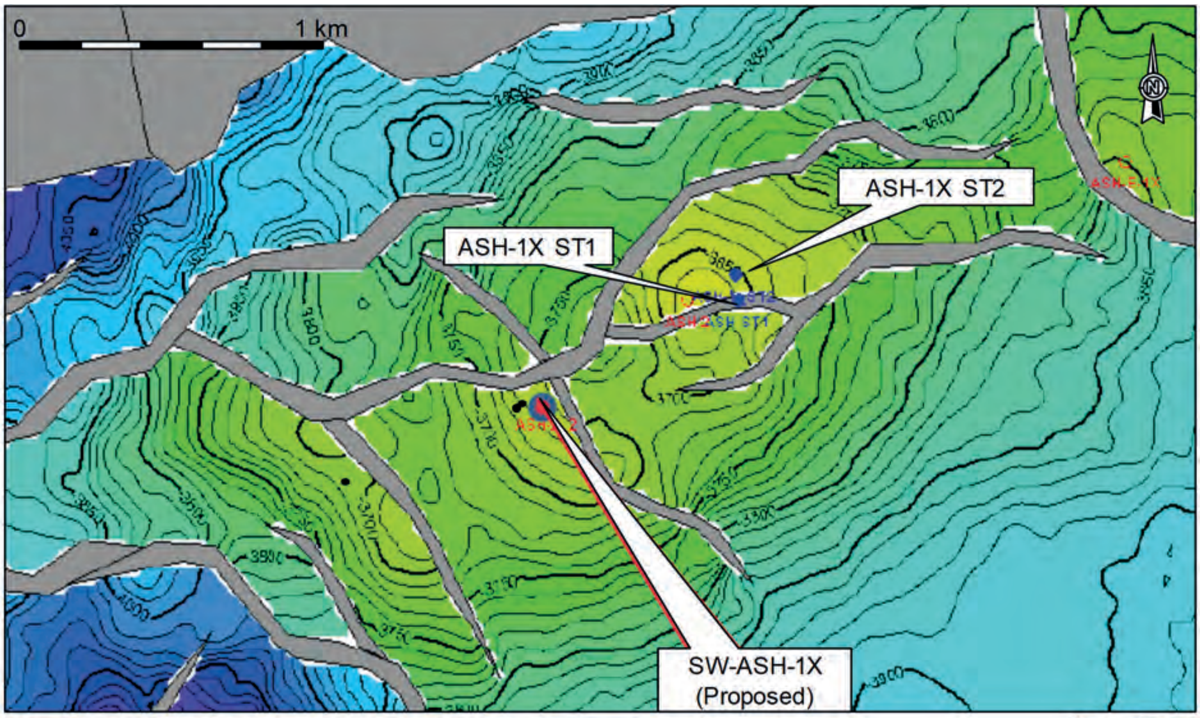
Figure 10: Top AR-E Reservoir, ASA Field



5.3 ASH

The ASH-1X exploration well was drilled in 2015 in the southern part of the concession area (Figure 2). Previous wells in this area had been dry and there were doubts about the presence of source rock. However, the well discovered light oil with a GOR of approximately 1,400 scf/stb in the AEB Formation at a depth of 3,700 m TVDss. The structure is difficult to resolve on seismic, being fairly small and faulted. A second well was planned on an interpreted second culmination to the southwest of the existing well. However, the structure has recently been reinterpreted by the Operator and the south-western area is now seen as a separate compartment (Figure 11), which will be the target for the SW-ASH-1X exploration well (see Section 8). The existing well penetrated the OWC, and although an initial rate of more than 1,000 bopd was achieved, it declined rapidly as the water cut rose and it was side-tracked to a more up-dip location in 2016.

Figure 11: Top Upper Sand, AEB Reservoir, ASH Field



Note: Contour interval 10 m

Source: UOG

5.4 ASZ

In late 2018, the ASZ-1X exploration well was drilled in a fault block just to the south of the Al Jahraa field (Figure 2 and Figure 8). It encountered 6 m of net oil pay in the AR-C reservoir. It came on production in April 2019 and after cleaning up had reached a rate of 200 bopd by June.

5.5 ZZ and Al Ahmadi

The ZZ (formerly GP ZZ) and Al Ahmadi fields have proven to be smaller than originally envisaged and to contain either gas condensate or very volatile oil with high GOR. Small volumes of oil and gas have been produced from one well in each field, and there are no plans for further development. Currently, there is no production from ZZ, but the Al Ahmadi-1 well continues to produce gas at a rate of approximately 1.8 MMscfd with some 20 bopd of condensate.

6 Development Plans

The Operator is planning up to three new production wells in Abu Sennan in 2020, one in each of ASA, El Salmiya, and Al Jahraa, with a further two new production wells in Al Jahraa in 2021. The first Al Jahraa well will target the AR-D and AR-C, while the others will be AR-C producers. The Operator also plans up to four more water injection wells in the AR-C in Al Jahraa, with the first of these in the second half of 2019. Table 8 shows the drilling schedule by year and by Reserves category.

Table 8: Planned Drilling Schedule

Year	Production Wells			Water Injection Wells		
	1P	2P	3P	1P	2P	3P
2H 2019	0	0	0	1	1	1
2020	1	3	3	0	1	1
2021	2	2	2	0	0	1
2022	0	0	0	0	0	1
Total	**3**	**5**	**5**	**1**	**2**	**4**

Note:

1. The above table shows development wells only, not exploration wells or water source wells.

7 Reserves

7.1 Production Profiles

GCA has prepared Low, Best and High production profiles for all the fields. Future production from currently producing wells has been estimated mainly by decline curve analysis, adjusted where necessary to be consistent with volumetric estimates of STOIIP and ultimate recovery. An exception is for the AR-C reservoir in Al Jahraa, where the production profiles for existing and future planned wells are taken from material balance reservoir models constructed by the Operator, with certain adjustments made to reflect the results of the latest wells. For the other planned new wells, initial oil production rates and decline rates have been estimated using regional analogues and recoverable volume estimates.

7.2 Costs

Future CAPEX and OPEX estimates associated with the development plans have been made by the Operator. GCA has reviewed these and considers them to be reasonable. Key elements include:

- US$3.5 MM per well, including flowline, for each new well in Al Jahraa or ASA;
- US$3.1 MM per well for an injection well;
- US$4.3 MM per well in ASH;
- US$4.5 MM per well in El Salmiya;
- US$0.3 MM for a major work-over and recompletion;
- US$2.9 MM facilities CAPEX over the period 2019-2020 (none in the Developed case), including additional capacity for the Al Jahraa water injection project;
- Fixed OPEX of US$5.0 MM p.a.; and
- Variable OPEX of US$3.2/Bbl for transportation (trucking), processing and handling.

GCA understands that the Contractor has no liability for abandonment costs.

7.3 Reserves

The Low, Best and High production profiles and associated costs have been subject to economic limit tests (Section 9), which determine the Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves respectively.

Table 9 shows the gross field production and cost profiles corresponding to the Proved Reserves. Table 10 shows the corresponding values for the Proved plus Probable Reserves and Table 11 those for the Proved plus Probable plus Possible Reserves.

Table 12 shows the breakdown by field of the gross Reserves summarized in Table 2 in the Executive Summary.

Table 9: Production and Cost Profiles, Proved Reserves, as at 30th June 2019

Year	Gross Field Production		CAPEX (US$ MM)	OPEX (US$ MM)
	Oil (MMBbl)	Gas (Bscf)		
2H 2019	0.64	0.96	0.95	4.51
2020	0.91	1.27	5.40	7.87
2021	0.64	0.74	7.00	7.03
2022	0.52	0.44	-	6.64
2023	0.39	0.14	0.30	6.24
2024	0.29	0.05	-	5.91
2025	0.23	0.02	-	5.72
Total	**3.61**	**3.62**	**13.65**	**43.91**

Table 10: Production and Cost Profiles, Proved plus Probable Reserves, as at 30th June 2019

Year	Gross Field Production		CAPEX (US$ MM)	OPEX (US$ MM)
	Oil (MMBbl)	Gas (Bscf)		
2H 2019	0.70	1.05	4.05	4.71
2020	1.39	1.90	16.50	9.40
2021	1.42	1.48	7.00	9.50
2022	1.26	1.07	-	9.00
2023	1.07	0.78	-	8.37
2024	0.96	0.55	-	8.03
2025	0.76	0.33	0.60	7.39
2026	0.59	0.17	-	6.87
2027	0.49	0.13	-	6.55
2028	0.43	0.11	-	6.35
2029	0.38	0.09	-	6.19
2030	0.33	0.07	-	6.05
2031	0.29	0.02	-	5.92
2032	0.26	0.00	-	5.81
2033	0.23	0.00	-	5.71
Total	**10.56**	**7.76**	**28.15**	**105.85**

Table 11: Production and Cost Profiles, Proved plus Probable plus Possible Reserves as at 30th June 2019

Year	Gross Field Production		CAPEX (US$ MM)	OPEX (US$ MM)
	Oil (MMBbl)	Gas (Bscf)		
2H 2019	0.72	1.10	4.05	4.78
2020	1.61	2.45	16.50	10.09
2021	1.80	2.25	10.10	10.70
2022	1.77	1.77	3.10	10.58
2023	1.62	1.42	-	10.11
2024	1.41	1.16	-	9.44
2025	1.20	0.96	-	8.79
2026	1.05	0.78	-	8.31
2027	0.95	0.64	0.30	7.99
2028	0.83	0.55	-	7.63
2029	0.69	0.35	0.30	7.20
2030	0.57	0.23	-	6.80
2031	0.47	0.20	-	6.49
2032	0.40	0.18	-	6.25
2033	0.34	0.16	-	6.06
2034	0.28	0.15	-	5.90
2035	0.23	0.13	-	5.74
Total	**15.93**	**14.49**	**34.35**	**132.85**

Table 12: Field Level Breakdown of Gross Reserves as at 30th June 2019

Field	Gross Field Oil Reserves (MMBbl)			Gross Field Gas Reserves (Bscf)		
	Proved	Proved + Probable	Proved + Probable + Possible	Proved	Proved + Probable	Proved + Probable + Possible
Al Jahraa	2.91	8.80	12.99	0.00	0.00	0.00
El Salmiya	0.24	0.62	1.29	2.45	4.80	9.11
ASA	0.07	0.41	0.71	0.00	0.00	0.00
ASH	0.31	0.54	0.65	0.00	0.00	0.00
ASZ	0.07	0.14	0.24	0.00	0.00	0.00
Al Ahmadi	0.01	0.03	0.06	1.17	2.95	5.38
Total	**3.61**	**10.56**	**15.93**	**3.62**	**7.76**	**14.49**

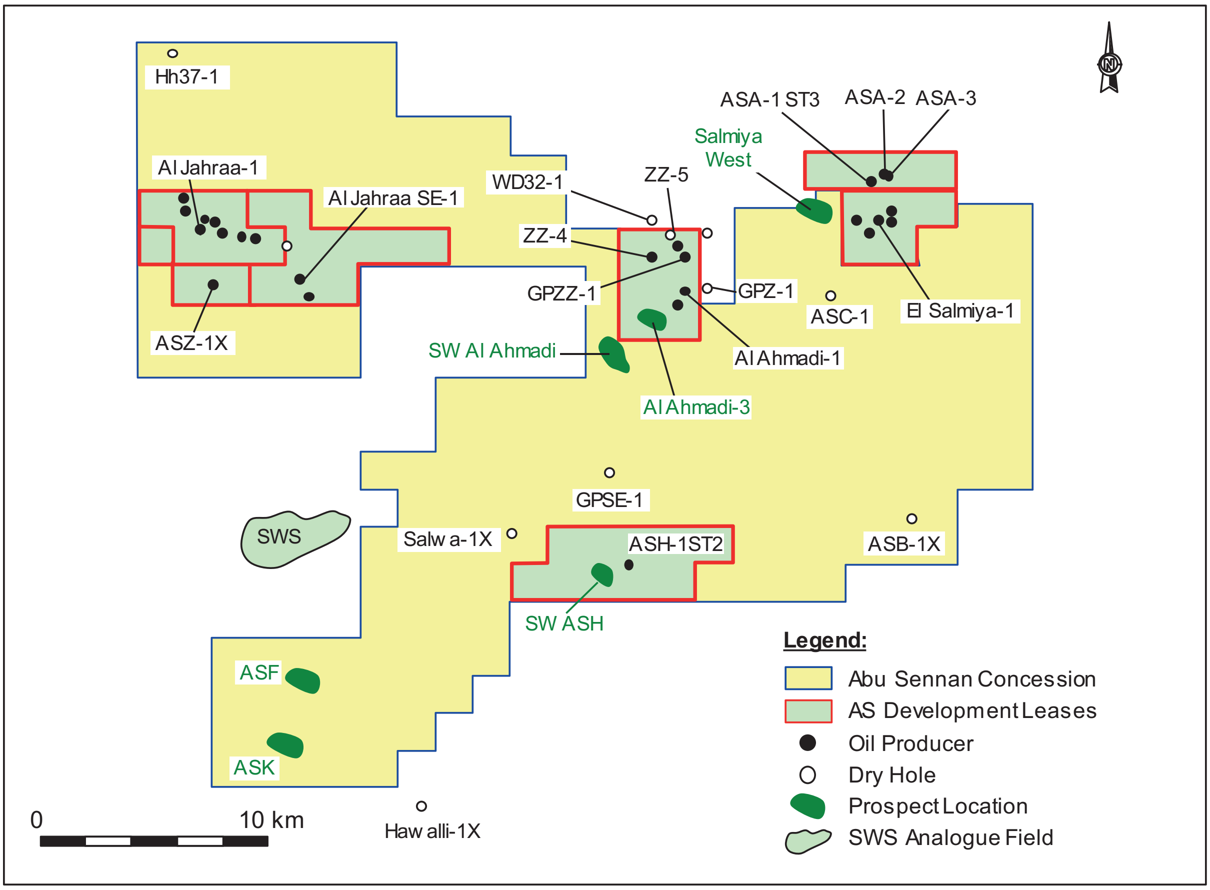
Notes:

1. The Reserves shown here equate to the Reserves shown in Table 2.
2. Reserves in Al Jahraa SE are included in Al Jahraa, and those in ZZ are included in Al Ahmadi.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

8 Prospective Resources

A significant amount of exploration potential remains in the Abu Sennan Concession and the Operator previously presented five Prospects (Figure 12) to GCA for audit, matured from a larger portfolio of Leads. SW-ASH has subsequently been added as a Prospect, though no volumes have been presented to GCA for audit. Each of the five Prospects has 2-4 reservoir targets that could be tested with a single exploration well. The targets are in the established Upper Cretaceous plays (Abu Roash, Bahariya and Kharita Formations) and in some cases in deeper, higher risk Lower Cretaceous and Jurassic plays (AEB and Kharita Formations). The targets lie at depths between 2,000 m and 4,000 m, being shallower in the ASF and ASK Prospects in the southwest part of the concession.

Figure 12: Location of Prospects



The Prospective Resources associated with these five Prospects and SW-ASH are shown in Table 5 in the Executive Summary. The estimates shown for SW-ASH are GCA's own, made on the basis of a map showing the Operator's latest interpretation of the ASH structure. Table 5 reflects GCA's view on the volumetric uncertainty of each prospective target and the associated Chance of Geologic Discovery (P_g). While individual target volumes are mostly fairly modest, and there is some uncertainty on the nature of any fluids (oil or gas-condensate) that may be present in some of the targets, the chance of success in some of the Prospects close to the existing fields is relatively high.

Almost the entire licence area is covered by 3D seismic data. The seismic dataset and its interpretation are sufficiently robust to define the Prospects presented, with some uncertainty surrounding the definition of small structural closures and the linkage between shallow and deep faults.

Volumes have been estimated from the results of the mapping and estimates of rock and fluid parameters from wells within Abu Sennan or in nearby analogues (e.g. SWS – see Figure 12). The discovery of the ASH oil field (AEB reservoir) lowered the migration risk in the southern part of the concession, which was previously thought to have been in a migration shadow (preventing hydrocarbon charge). Uncertainty remains within the individual Prospects, with the key geological risks being associated with trap integrity (fault seal) and reservoir presence/quality, plus hydrocarbon migration in the southwest extremes of the concession. There is a risk that hydrocarbon present in the Al Ahmadi-3 Prospect, if any, may be gas.

GCA is aware that Rockhopper has a different view of the Prospective Resources than does the Operator, and has identified a significantly larger number of Prospects and Leads. However, GCA has not attempted to audit Rockhopper's view, or to conduct its own original analysis.

The first 3-year phase of the current exploration licence carries a commitment to drill two exploration wells, one of which has already been drilled (ASZ-1X).

9 Economic Assessment

GCA has conducted an economic limit test for the Low, Best and High production and cost profiles to assess Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves. The economic limit (or economic cut-off) is defined as the time when the maximum cumulative net cash flow occurs for a project. Additionally, GCA has conducted an economic entitlement calculation based on the PSC terms in order to derive Net Entitlement Reserves attributable to the interest to be acquired in the asset by UOG, which derive from the cost recovery and profit share.

Finally, GCA has calculated the NPV of the cash flow, net to the interest to be acquired, for each Reserves case, discounted on a mid-year basis to 30th June 2019.

These assessments have been based upon GCA's understanding of the fiscal and contractual terms governing these assets, and the various economic and commercial assumptions described herein.

9.1 Contract and Fiscal Terms

The relevant elements of the Egyptian fiscal regime for petroleum operations as they currently stand, together with the terms of the PSC that governs the asset, are summarised below and are assumed to remain constant going forward:

- Royalty: 10% of Gross Production. It is borne and paid by EGPC on behalf of the Contractor Group.
- Cost Recovery Limit: 30% of Gross Production with any unused cost recovery going fully to EGPC.
- Cost Recovery Depreciation: exploration and development costs to be recovered at a rate of 20% p.a. Operating cost to be recovered in the year incurred. Unrecovered costs can be carried forward until fully recovered.
- Production Sharing: 82.1% of all hydrocarbon (after cost recovery) to EGPC and 17.9% to the Contractor Group.
- Production Bonuses: when reaching certain rates of oil production, the following amounts (which are not cost recoverable) must be paid:

Production Rate (bopd)	Bonus (US$ MM)
3,000	0.5
5,000	1.0
10,000	1.5
25,000	2.0

- Training Fee: US$50,000 p.a. for the duration of the exploration phase.
- Corporate tax: borne and paid by EGPC on behalf of the Contractor Group.

For the purpose of these assessments, the following forward schedule of gross unrecovered historical costs has been used. These are estimates based on information from Rockhopper provided to GCA by UOG as at 31st March 2019. The cost recovery pool is not expected to be fully recovered, so its exact value does not impact the results of this assessment.

Year	Unrecovered Costs (US$ MM)
Balance at 30th June 2019	115.7
2019 Addition	8.7
2020 Addition	9.6
2021 Addition	6.1
2022 Addition	3.5
2023 Addition	1.8

9.2 Costs

Estimates of CAPEX and OPEX are discussed in Section 7.2. For the cash flow calculations, CAPEX and OPEX have been escalated at 2.0% p.a. from 2020 onwards.

9.3 Oil and Gas Prices

GCA's Brent crude oil price scenario for 3Q 2019, shown in Table 13, has been used as the reference oil price.

Table 13: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2H 2019	64.70
2020	62.48
2021	66.25
2022	70.00
2023+	+2.0% p.a.

The above price scenario has been adjusted by a discount of US$2.00/Bbl for quality and location for Abu Sennan crude.

For gas, as advised by UOG, a price of US$2.65/MMBTU will apply if the Brent price is US$22/Bbl or more. A calorific value of 1.240 MMBTU/Mscf has been used to arrive at a gas price of US$3.29/Mscf.

9.4 Results

The economic limit for production was found to occur at end 2025, 2033 and 2035 in the Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves cases respectively. Corresponding limits for the Developed Reserves cases were end 2024, 2030 and 2034 respectively.

The resulting Reserves, both gross (100%) and net to the interest to be acquired by UOG, are shown in Table 2 in the Executive Summary. The corresponding NPVs at a discount rate of 10% (NPV10), net to the interest to be acquired, are shown in Table 4.

9.5 Economic Sensitivity

The sensitivity of the NPVs to different discount rates (7.5% and 12.5%) is shown in Table 14.

Table 14: Sensitivity to Discount Rate of Post-Tax NPV (US$ MM) of Future Cash Flow from Reserves, Net to the Interest to be Acquired as at 30th June 2019

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
7.5	9.0	29.1	46.8
10.0	8.7	26.6	42.2
12.5	8.4	24.5	38.3

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs shown here are for the Developed plus Undeveloped Reserves.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest in it.

The sensitivity of the NPV10 to variation in the reference oil prices (±US$10/Bbl) and variation in CAPEX and OPEX (±20%) is presented in Table 15 for the Proved plus Probable Reserves case. The greatest sensitivity is to oil price, where a ±25% variation is observed, then to OPEX (±11%) and CAPEX (±4%). Gas price was also varied by ±20% but there was no significant impact (±2%) on NPV10 due to the relatively small revenues from gas compared to those from oil.

Table 15: Sensitivity to Oil Price and Costs of Post-Tax NPV10 (US$ MM) of Future Cash Flow from Proved plus Probable Reserves, Net to the Interest to be Acquired as at 30th June 2019

Base	Oil Price		CAPEX		OPEX	
	-US$10/Bbl	+US$10/Bbl	-20%	+20%	-20%	+20%
26.6	19.9	33.4	27.7	25.5	29.7	23.7

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs shown here are for the Developed plus Undeveloped Reserves.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest in it.

Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by, or at the direction of, UOG and/or obtained from other sources (e.g., public domain), the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcomes will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, UOG and/or obtained from other sources, and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

This report has been prepared based on GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

GCA has not undertaken any site visit and inspection as part of this work, although GCA previously undertook a site visit to Abu Sennan in January 2017. GCA's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. GCA does not warrant they are in compliance with any applicable regulations in terms of standards, rating, health, safety, and environment.

Reserves and Resources

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. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test (pre-tax and exclusive of accumulated depreciation amounts) prior to any NPV analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social issues may exist. Contingent Resource volumes reported herein are un-risked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated “Chance of Geologic Discovery” (P_g) and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Prospective Resources include Prospects and Leads. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered drillable. Leads, on the other hand, are not sufficiently well defined to be drillable, and need further work and/or data. In general, Leads are significantly more risky than Prospects and may not be suitable for explicit quantification.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any reserve estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes appearing in this report have been quoted at stock tank conditions. Natural gas volumes have been quoted in standard cubic feet and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60°F.

For the avoidance of doubt, Contingent Resources and Prospective Resources do not include Reserves.

Use of Net Present Values

It should be clearly understood that the NPVs of future revenue potential of a petroleum property, such as those discussed in this report, do not represent GCA’s opinion as to the market value of that property, nor any interest therein.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e. that Reserves may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the reference NPVs presented herein.

Qualifications

GCA is an independent international energy advisory group of more than 55 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with UOG. GCA is independent of UOG, its directors, senior management and advisers. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed as part of this report. GCA is remunerated by way of a fee that is not linked to the value of UOG. GCA is not a sole practitioner.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work. They have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being the interest in the licences proposed to be acquired by UOG.

The team was led by Dr John Barker, who has 34 years of industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

The CPR has been reviewed by Dr Shane Hattingh, who has 32 years of industry experience. He holds a Ph.D. in Applied Mathematics from the University of Cape Town. He is a Fellow of the Energy Institute, a Member of the Society of Petroleum Engineers, a founder member of the Europe Chapter of the Society of Petroleum Evaluation Engineers and a UK Chartered Scientist.

Both the Energy Institute and the Society of Petroleum Evaluation Engineers are self-regulatory organisation of engineers and geoscientists, and Dr Barker's and Dr Hattingh's memberships are in good standing.

GCA accepts responsibility for the information contained in this report. We declare that to the best of our knowledge and belief, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information. To the extent that GCA has relied on information provided by UOG in compiling the report, GCA has assumed that such information is accurate and complete.

Yours sincerely,

Gaffney, Cline & Associates

John Barker

John Barker, Technical Director

Shane Hattingh, Technical Director

Appendix I
Abbreviated Form of PRMS

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

1 These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guideline s
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	**Guidelines**
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	**Guidelines**
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	**Guidelines**
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

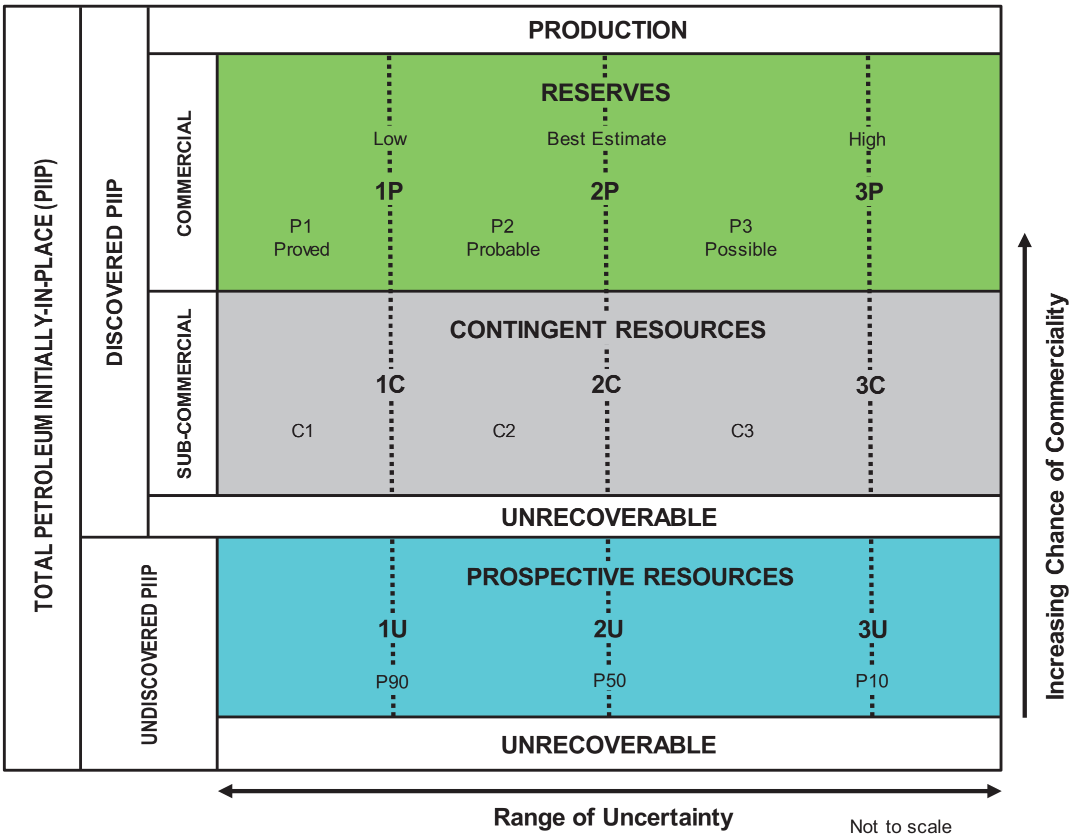
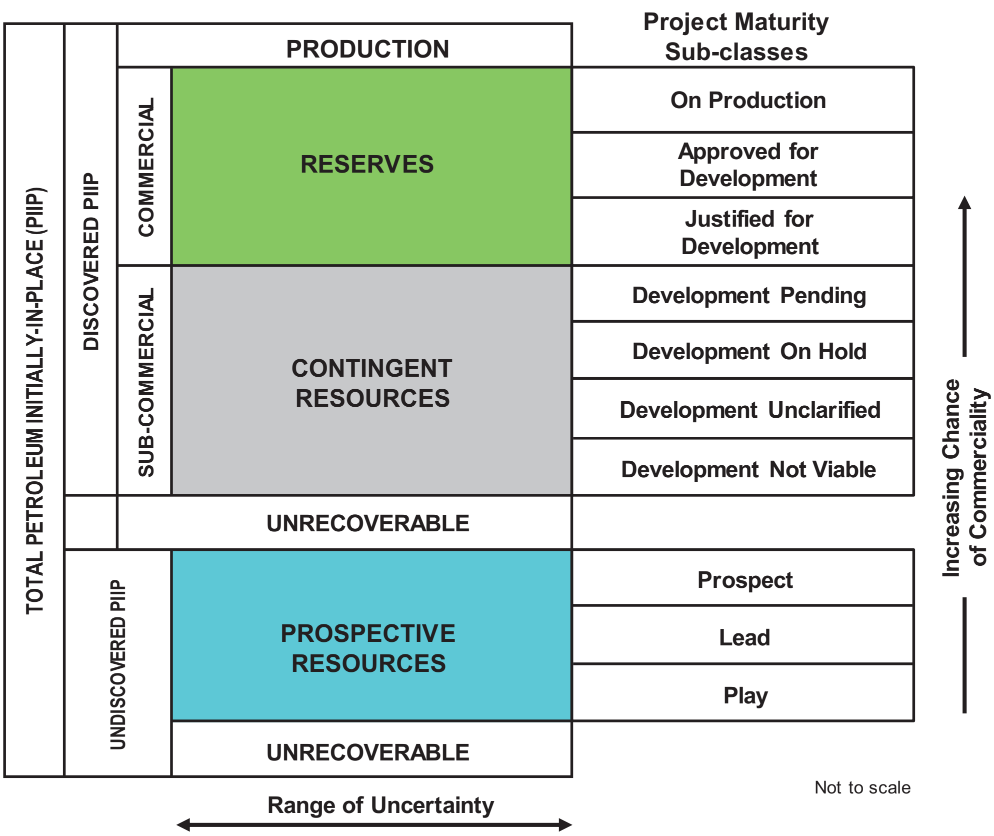


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix II
Site Visit Report

Summary

GCA, through its sub-contractor, undertook a site visit to Abu Sennan on 23rd January 2017.

GCA's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. The site visit was limited in duration and no testing of any kind was carried out. The visit provided a snapshot of the overall facilities, pipelines and well sites, but it should be recognized that such a short visit can only provide an overview of the condition of the facilities and the state of operations. GCA does not warrant that they are in compliance with any applicable regulations in terms of standards, rating, health, safety and environment.

GCA's overall impression was that the facilities appeared generally to be in good condition and fit for purpose relating to the current operations. No risk to continued operation due to mechanical conditions was obviously apparent. Some minor external corrosion was noted in places. No obvious safety hazards were noted and there were no complaints from the staff about lack of safety measures.

Site Visit

Abu Sennan is located in the Western Desert. It is operated by KEE through a JV company owned equally by the Contractor Group and EGPC. There are several processing facility centres within the licence area, at Al Ahmadi, Al Jahraa, ASH and El Salmiya. There are production wells and flowlines that consolidate at each facility, with produced gas being exported via a gas facility and pipeline to a nearby General Petroleum Company (GPC) gas plant. The facilities are relatively new, having been constructed in 2013-14.

The one-day site visit commenced at about 12:30 pm with a 45-minute HSE and operational discussion, followed by a two-hour site inspection. Due to the limited time available, only the El Salmiya site was visited. This is where the main East Abu Sennan base is located; the base is reached via an approximately 60 km long unpaved road from the Qarun main road.

During the site visit, the gas facility and oil station at El Salmiya were observed, as well as one oil production well (El Salmiya-6).

The gas facility has dehydration and compression equipment along with metering and ancillary services. Gas is exported from the gas facility via an 8" underground pipeline, 25 km long, to the GPC facility and then to the national gas grid. Oil is exported from the site via truck to a number of destinations. Produced water is transported by truck to a safe disposal plant.

AII.1 Tanks

In El Salmiya oil station there are 5 oil storage tanks each of 2,400 Bbl capacity. All appeared to be in good condition (Figure AII.1). The tanks are also serviced by the firefighting system. The oil is trucked from the tanks to either the BADR location or the GPC facility. The tanks were surrounded by a 2 m concrete bund wall. There was no fencing around the facility, but according to operations personnel a security fence is planned.

During the visit, the loading of one truck was observed. The Operations Manager mentioned that they transport about 2,680 bopd via trucks.

Figure AII.1: Production Tanks at El Salmiya Oil Station

AII.2 Manifolds

Two manifolds gather production through the flowlines from the El Salmiya Area (Figure AII.2). The manifolds themselves looked in very good condition but some of the pipelines seemed to be old with minor external surface corrosion. The pipelines entering the manifold were laid directly on the sand with no other support, as is common practice in the Western Desert.

Figure AII.2: Production Manifold at El Salmiya Oil Station

AII.3 El Salmiya Oil Station

Equipment at the El Salmiya oil station includes a rented, indirect heater that is used during the winter season to heat the oil to improve the water separation when required. The indirect heater looked in a good condition but it was not operating at the time of the visit.

A 3-phase separator separates gas, oil and water. The separator is reportedly capable of handling 30 MMscfd and 5,000 bopd. It has pneumatic control valves to control the fluid level inside the separator. The separator looked new and in an excellent condition (Figure AII.3).

Figure AII.3: 3-Phase Separator

Two air compressors support the separator, manufactured by Stanley; these also looked new and in an excellent condition.

There are two gas boots inside the oil station, which separate the remaining associated gas from the production after the separator and send it to the gas facility. The gas boots have a capacity of 1 MMscfd and can work in parallel or in independent service. The gas boots appeared in good condition.

There are two electrically-operated shipping pumps (Figure AII.4), both manufactured by Goulds. Each pump has a capacity of 15,000 bpd and both appeared to be in excellent condition. Although fully connected to the tanks, the pumps were not operating during the field visit.

Finally, a firefighting system is located between the oil station and the gas facility. It seemed to be in excellent condition.

Figure AII.4: Shipping Pumps at El Salmiya Oil Station

AII.4 El Salmiya Gas Facility

The gas facility (Figure AII.5) purifies the gas coming from the oil station prior to shipping it through the 8-inch gas export pipeline. A small part of this produced gas is used to feed the gas generators inside the gas facility. The gas facility was originally used by Qarun Petroleum Company before being transferred to El Salmiya.

Figure AII.5: General View of Gas Facility

The gas facility control room is equipped with the following:

- SCADA Compressors Control Panel - used to automatically control the compressors and the Molecular Sieve units;

- Rectifier Control Panel;
- Fire and Gas Detectors Unit;
- Switch Gear Unit; and
- UPS System – its main purpose is to provide the gas facility control units with back-up power in case the generators inside the facility go down.

A Free Water Knock Out (FWKO) drum is used to separate the free water associated with the gas before being processed. The FWKO drum is equipped with level control valves working automatically by SCADA and can handle 3,000 bwpd and 30 MMscfd. The FWKO drum looked in a good condition but its valves looked old with some external corrosion evident (Figure AII.6); the Operator has informed GCA that the valves were inspected, repaired and tested before installation and are under a new maintenance contract.

A closed drain vessel is used to collect the knocked out water and this looked in good condition with some minor external corrosion.

Figure AII.6: FWKO Vessel and its Valves

A dehydration package is present and is used to remove the water associated with the gas. The dehydration unit has two molecular sieve towers, with a capacity of 28 MMscfd. At the time of the visit, one tower was operating and the other was under regeneration. Some valves of the molecular sieve unit and associated pipelines looked old and corroded, though the Operator has informed GCA that all welds have been inspected and the pipe network was hydro-tested to the maximum rated pressure with water and nitrogen. There is also an indirect gas heater used for the molecular sieve regeneration purpose, which looked in good condition.

A number of other equipment items were observed and appeared in good or reasonable condition including:

- Gas engines for the low and high pressure compressors;
- Rectifying tower after the dehydration unit for gas processing;

- Overhead drum; and
- Heat exchangers.

In addition, there were two generators at the gas facility (Figure AII.7). One generator uses produced gas and is manufactured by Waukesha. It is used to supply the power demands of the gas facility, the oil station and the camp. Another rented standby generator is also available, this being a diesel generator manufactured by CAT.

Figure AII.7: Power Generators

There are also two air compressors to support the units, manufactured by ATLAS COPCO. One is in operation and the other one on standby.

Finally, there is a metering unit to meter the transported gas. This is a dual flow meter unit with a capacity of 16 MMscfd per meter, linked to the Control Unit. During the visit, only one meter was operating.

The produced sales gas is transported some 25 km to the GPC plant via an 8-inch shipping line. The first section of the line is on supports (Figure AII.8) and the remaining section is buried. The unburied part and the valves looked to be in very good condition.

AII.6 Water Treatment

The produced water goes to a safe disposal plant. Production is about 600 bwpd and is sent to an open pond, from where the water is trucked (through a contract with UNICO) to UNICO`s facilities for treatment.

Figure AII.8: Gas Shipping Line

AII.7 Wells and Drilling

No rigs were observed during the visit but some time was made available to view the El Salmiya-6 well. It is a naturally flowing well producing about 200 bopd and about 1.6 MMscfd. The X-mas tree and valves looked in an excellent condition (Figure AII.9).

Figure AII.9: El Salmiya – 6 Well

AII.8 Other Observations

- No leaks or signs of oil spills were seen during the visit.
- The operations personnel confirmed that there is no H_2S present in the production.
- Some maintenance records were present, specifically the hours of maintenance for the gas compressors, low pressure compressors and the air compressors.
- There was a reporting sheet for the routine activities on each compressor such as change-overs or greasing. The running hours of equipment are recorded manually in a sheet and on SCADA.

AII.9 HSE

- A copy of the HSE policy was available on site as well as an Emergency Response Plan.
- Safety shoes, safety glasses, helmets and coveralls were provided to all personnel.
- The incident log was not inspected, but the HSE Manager mentioned that the last LTI was on 7th December 2015 (a vehicle accident) and there had been 408 perfect HSE days without any incident.
- The facilities are all secured by fencing except for the El Salmiya oil station; GCA understands that fencing for the oil station is planned.
- The HSE Manager mentioned that a fire detection and alarm system is being commissioned for the camp, a tender for sewage water treatment has been launched, and there are plans for a water disposal well, which is waiting for environmental approvals.
- The condition of the road to the El Salmiya area is poor with sand dunes and potholes; GCA understands that it is intended to reconstruct this road.

Appendix III
Glossary of Abbreviations

Glossary

API	American Petroleum Institute
^{o}API	Degrees API (a measure of oil gravity)
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
bopd	Barrels of oil per day
bpd	Barrels per day
bwpd	Barrels of water per day
Bscf	Billion standard cubic feet
BTU	British thermal unit
CAPEX	Capital expenditure
CGR	Condensate gas ratio
CIIP	Condensate initially in place
DST	Drill Stem Test
EGPC	Egyptian General Petroleum Corporation
ELT	Economic Limit Test
ESP	Electrical submersible pump
°F	Degrees Fahrenheit
GIIP	Gas initially in place
GOR	Gas oil ratio
ft	Foot or feet
HCIIP	Hydrocarbon initially in place
HSE	Health, safety and environment
H_2S	Hydrogen sulphide
km	Kilometres
km^2	Square kilometres
m	Metres
M	Thousand
MBbl	Thousand barrels
Mbopd	Thousands of barrels of oil per day
MM	Million
MMBbl	Million barrels
MMBTU	Million British thermal units
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
Mscf	Thousand standard cubic feet
NPV	Net Present Value
OPEX	Operating expenditure
OWC	Oil-water contact
p.a.	Per annum
P_g	Chance of Geologic Success
PSC	Production Sharing Contract
psia	Pounds per square inch absolute

PVT	Pressure, volume, temperature
RF	Recovery factor
scf	Standard cubic feet
SRP	Sucker-rod pump
ss	Sub sea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
TVD	True vertical depth
US$	United States Dollar
WI	Working Interest
%	Percentage
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resources
3C	High estimate of Contingent Resources
2D	Two-dimensional
3D	Three-dimensional
2H	Second half (of year)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
3Q	Third quarter (of year)
1U	Low estimate of Prospective Resources
2U	Best estimate of Prospective Resources
3U	High estimate of Prospective Resources

PART IX

COMPETENT PERSON'S REPORT – ERC EQUIPOISE LTD

29th October 2019

The Directors
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Executive Summary of the Evaluation of certain Contingent and Prospective Resources of United Oil & Gas Plc.

Dear Sirs,

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a competent person's report ("CPR") in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM Guidance Note"). Accordingly, ERCE has independently assessed certain Contingent and Prospective Resources associated with assets owned by United Oil & Gas Plc ("United Oil & Gas", "UOG" or the "Company") in licences PL090 onshore UK, P1918 offshore UK, P2366 offshore UK and the Walton-Morant licence offshore Jamaica and reports herein said Contingent and Prospective Resources as at 31st August 2019, being the date to which ERCE assessed the data made available to them. This is the effective date of the report (the "Effective Date"), and ERCE is not aware of any material change in the status of the UOG assets in the period between the receipt of the data and the completion of the CPR. ERCE hereby consents to its inclusion in the Admission Document and also to using references to the CPR in any applicable disclosure document, provided that no portion be used out of context or in such a manner as to convey a meaning which differs from that set out in the whole. The CPR may not be used for any other purpose without the prior written approval of a Director of ERCE.

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This CPR provides an update to the report prepared for UOG in February 2019, specifically to resources within the Colter area, licence P1918. ERCE has also reviewed its assessment of the Colibri prospect, Walton-Morant licence and the Crown discovery, licence P2366, as additional data have been acquired since our last review. ERCE has carried out this work using the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Section 4 of the attached report. The full text can be downloaded from https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf. Nomenclature that may be used in this letter and the enclosed report is summarised in Section 5.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. No site visit was undertaken in the preparation of this report. ERCE has relied upon information provided by UOG for the preparation of its estimates of Contingent and Prospective Resources.

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR or on Admission and ERCE will receive no other benefit for the preparation of this CPR. ERCE does not have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the resources and reserves and the projections and assumptions included in the various technical studies completed by the Company, opined upon by ERCE and reported herein.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in the Company, the Mineral Assets or Beaumont Cornish Limited ("Beaumont"), or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. ERCE is not a group, holding or associated company of the Company or Beaumont. None of ERCE's partners or officers are officers or proposed officers of any group, holding or associated company of the Company or Beaumont.

The Competent Person involved in the preparation of this CPR is not an officer, employee or proposed officer of the Company or any group, holding or associated company of the Company or Beaumont. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of the Company, its directors, senior management and Beaumont.

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. In the case that material is delivered in digital format, ERCE does not accept any responsibility for edits carried out after the product has left the company's premises.

Contingent Resources

The Waddock Cross oil field, in which UOG has a 26.25% interest (Table 3), is located in licence PL090, in the Wessex Basin onshore UK, to the west of the Wytch Farm oil field. It contains oil within the Jurassic Bridport Sandstone reservoir, and has historically undergone production, which ceased due to high water cut. The field is currently shut in. The operator, Egdon Resources UK Limited ("Egdon"), is in the process of investigating the restoration of production, via the drilling of one or more horizontal wells in a structurally higher area of the field. ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. Development is contingent on the preparation and the commitment to a commercial development plan. ERCE agrees with UOG's estimate of the Chance of Development ("Pd") of 75%. Development would likely involve the drilling of two new wells with any water being reinjected. There are no identified Reserves.

The Colter discovery (formerly referred to as Colter East), in which UOG has a 10% interest (Table 3), is located in licence P1918 (Block 98/11a) in the Wessex Basin offshore UK, to the south of the Wytch Farm oil field. The licence is operated by Corallian Energy Limited ("Corallian"). Interpretation of the top reservoir structure is challenging and there is uncertainty associated with the location of the faults that bound the accumulation.

Colter was discovered by Well 98/11-3 in 1986. The well encountered a 10.5 m section of the Sherwood Sandstone reservoir with oil saturations from logs up to 60%, underlain by water-bearing Sherwood Sandstone. A DST was performed on Well 98/11-3, with 8.5 stb of oil produced at surface out of 109 bbl total fluid influx, including water. The well test straddled the oil water contact (OWC) of the discovery.

Well 98/11a-6 was drilled to appraise the Colter discovery in February 2019. The well encountered the Sherwood Sandstone reservoir deeper than prognosed and is interpreted to have penetrated the reservoir on the southern side of the Colter bounding fault. Wireline log interpretation indicates elevated hydrocarbon saturations above a depth of 1780.5 m TVDss. However, the well was not tested and the presence of moveable hydrocarbons has not been demonstrated. ERCE attributes Prospective Resources to the structures on the southern side of the Colter bounding fault.

Well 98/11a-6z was a side-track to the north from Well 98/11a-6 designed to further appraise the Colter discovery. The well penetrated the northern side of the Colter bounding fault but found the Sherwood Sandstone reservoir below the Colter OWC 1740 m TVDss defined by Well 98/11-3. This results in a reduction in the Contingent Resources estimates for the Colter discovery.

The results from Well 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area.

ERCE attributes Contingent Resources (sub-classification Development Unclarified) to the Colter discovery, made by Well 98/11-3. Development of Colter would be contingent on successful exploration drilling of the Colter South prospect. ERCE agrees with UOG's estimate of the Chance of Development of 30%.

The Crown discovery, in which UOG has a 95% interest (Table 3) and is licence administrator, is located in licence P2366 and straddles Blocks 15/18d and 15/19b located at the north west margin of the

Witch Ground Graben, offshore the United Kingdom. Crown was discovered by Well 15/19-9 in 1998. The well encountered in excess of 200 ft of good quality Balmoral Sandstone reservoir of Palaeocene age. The discovery has an oil rim of thickness between 35 and 55 ft overlain by gas and underlain by water-bearing sandstone. Wireline log oil saturations of up to 80% are encountered. Reprocessing of the seismic data and an associated rock physics study has recently been completed, satisfying the Phase A work commitments.

ERCE attributes Contingent Resources (sub-classification Development Unclarified) to the Crown discovery. Development is contingent on the preparation and the commitment to a commercial development plan. ERCE agrees with UOG's estimate of the Chance of Development of 60%.

UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on the 17th July 2019 and the sale and purchase agreement ("SPA") was signed on 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence, regulatory Oil and Gas Authority ("OGA") approval and definitive documentation.

ERCE's estimates of the unrisked oil Contingent Resources in the Waddock Cross, Colter and Crown discoveries, both gross and net to UOG, are shown in Table 1.

Table 1: Unrisked Oil Contingent Resources, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%
PL1918	Colter	Corallian Energy Limited	0.44	0.69	1.06	10.00%	0.04	0.07	0.11	30%
P2366	Crown	United Oil & Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	60%

Notes:

1) *"Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.*
2) *"Net Contingent Resources" are UOG's working interest fraction of the gross Contingent Resources*
3) *Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.*
4) *The volumes reported here are unrisked in that they have not been multiplied by a chance of development (Pd).*
5) *In accordance with SPE PRMS*
6) *UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. See additional notes under Table 3.*

Prospective Resources

The PL090 partnership is maturing prospectivity within the greater licence area and identifies a number of undrilled exploration prospects and leads. The licence is located in Wessex Basin onshore UK, to the west of the Wytch Farm oil field. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil Prospective Resources and Geological Chance of Success for the Broadmayne prospect, which is currently the most mature. Part of the Broadmayne structure is mapped as extending outside licence PL090. Reprocessing of the 3D seismic survey covering the Broadmayne prospect has recently been completed and preliminary interpretation supports the overall trapping mechanism and lateral extent of the historical mapping. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has reduced the element of trap risk, which results in a higher chance of success, compared to the assessment presented in 2017.

The results from Wells 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area. The new interpretation has led to a revised evaluation of the prospectivity to the south of the Colter discovery bounding fault; Colter South.

ERCE has assessed the Prospective Resources and Geological Chance of Success for the Colter South prospect, up-dip of Well 98/11-1, and also around Well 98/11-6.

The Walton-Morant licence in which UOG holds a 20% interest (Table 3) is situated offshore Jamaica and covers an area of 32,065 km^2. Historically, exploration in Jamaica focused on Cretaceous targets and to date nine onshore wells and two offshore wells have been drilled, the most recent of which was drilled in 1983. All but one of these wells exhibited hydrocarbon shows, which coupled with observed onshore and offshore seeps, suggests an active source kitchen.

The principal offshore exploration target identified by the operator, Tullow Jamaica Ltd ("Tullow"), is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20% porosity at outcrop. The Guy's Hill formation is a fluvio-deltaic-shallow marine succession of up to 320 m gross thickness onshore and is capped by regional shales and marls. Well Arawak-1 is the nearest offshore penetration of the Guy's Hill formation located approximately 70 km to the west of the Calibri prospect. Tullow has identified a number of undrilled prospects and leads, of which the Colibri prospect is currently the most mature. The prospect lies in water depths of approximately 750 m and is a fault-bounded structure prognosed to contain Guy's Hill formation reservoir. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data, including coverage of the Colibri prospect. These data have been reprocessed, and a number of stacked volumes and derived attributes have been generated. Since the last CPR an anisotropic PSTM and PSDM has been completed and made available. However, this has not altered the interpretation (time or depth structure), the uncertainty (gross rock volume estimates), or the Geological Chance of Success associated with the prospect. These volumes form the basis for the interpretation and ERCE's updated estimation of Prospective Resources.

ERCE's estimates of the gross unrisked oil Prospective Resources in Broadmayne, Colibri, Colter South and Colter South (Well#6) and the net unrisked and risked Prospective Resources attributable to UOG based on its working interest are shown in Table 2, including estimates of Geological Chance of Success.

A summary of UOG's licence interests are presented in Table 3.

Conclusions

ERCE's conclusions are included within this Executive Summary section.

Table 2: STOIIP and Oil Prospective Resources, Gross and Net Attributable to UOG

Licence	Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest	Net Unrisked Prospective Resources (MMstb)				COS	Net Risked Prospective Resources (MMstb)			
			Low	Best	High	Mean	1U	2U	3U	Mean		1U	2U	3U	Mean		1U	2U	3U	Mean
Walton Morant	Colibri	Tullow Jamaica Ltd	129.0	498.2	1790.6	805.3	30.3	127.5	512.6	229.1	20%	6.06	25.51	102.53	45.82	20%	1.19	5.00	20.08	8.97
PL1918	Colter South	Corallian Energy Limited	10.4	23.8	52.3	28.7	3.9	9.2	21.0	11.3	10%	0.39	0.92	2.10	1.13	65%	0.25	0.59	1.37	0.74
PL1918	Colter South(Well#6)	Corallian Energy Limited	0.5	1.9	7.0	3.2	0.2	0.7	2.7	1.3	10%	0.02	0.07	0.27	0.13	62%	0.01	0.05	0.18	0.08
PL090	Broadmayne	Egdon Resources UK Limited	5.0	11.1	24.5	13.4	1.5	3.3	7.4	4.0	18.95%	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

**Broadmayne's Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimates to lie within the PL090 block boundary (50%).*

Notes:

1) *Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.*
2) *"Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from an accumulation.*
3) *"Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources.*
4) *"Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).*
5) *The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.*
6) *Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the Chance of Development (Pd).*
7) *In accordance with SPE PRMS.*

Table 3: Summary of United Oil and Gas Licence Interests

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19 km^2	
		UOG PL090 Ltd	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	183 km^2	
		UOG PL090 Ltd	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				
P1918 (Colter)	Corallian Energy Limited	Corallian Energy Limited	74.00%	Extant	31/1/2020 (Second Term) 31/1/2038 (Licence End Date)	36.2 km^2	
		UOG Colter Ltd	10.00%				
		Baron Oil	8.00%				
		Resolute Oil & Gas	8.00%				
Walton Morant (Colibri)	Tullow Jamaica Ltd	Tullow Jamaica Ltd	80.00%	Extant	2024	32,065 km^2	60% relinquishment, drill or drop Q1 2020
		UOG Jamaica Ltd	20.00%				
P2366 (Crown)	United Oil & Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/09/2021 (Phase A) 30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)	13.6 km^2	Phase A work commitments including the reprocessing of 40km^2 of 3D seismic and an associated Rock Physics study have now been completed. Phase C will start on the condition that there is a firm commitement to drilling a well.
		Swift Exploration Limited	5.00%				

Notes:

1) *UOG also hold interests in UK onshore licences PEDL330 and PEDL345 with the same equities as licence P1918. However, evaluation is at an early stage and no leads have yet been identified, therefore these licences have not been addressed as part of this document.*
2) *Since the last CPR Corallian Energy Limited has acquired Corfe Energy's 25% interest in licence P1918.*
3) *Since the last CPR UOG has released its option associated with Licence P2264 which is located offshore UK in the Southern North Sea (Block 49/29c).*
4) *UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on the 17th July 2019 and the sale and purchase agreement ("SPA") was signed on 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence, regulatory Oil and Gas Authority ("OGA") approval and definitive documentation.*

Confirmations and Professional Qualifications

In accordance with UOG's instructions to us ERCE confirms that:

- Mr Simon McDonald, Founder Director of ERCE, a Chartered Engineer and the Past President of The Society of Petroleum Evaluation Engineers (SPEE), who has over 40 years' experience information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information.

Consent

We hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;
- the filing of this report with the AIM UK stock exchange and
- the electronic publication of this report on websites accessible by the public, including a website of the Company.

Yours faithfully

ERC Equipoise Limited

Simon McDonald
Founder Director, ERC Equipoise Ltd.

Evaluation of Certain Contingent and Prospective Resources of United Oil & Gas Plc

(Source: Egdon)

PREPARED FOR: United Oil & Gas Plc

BY: ERC Equipoise Limited

Month: October

Year: 2019

Approved by: Simon McDonald

Date released to client: 29th October 2019

ERC Equipoise Ltd ("ERCE") has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. This report is produced solely for the benefit of and on the instructions of ERCE's client named in the contract, and not for the benefit of any third party. The client agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and the client shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE. In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by ERCE to the client.

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1. Introduction

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a competent person's report ("CPR") with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM Guidance Note").

Accordingly, ERCE reviewed certain Contingent and Prospective Resources associated with assets owned by United Oil & Gas Plc ("United Oil & Gas" or "UOG") in licence PL090 onshore UK, licence P1918 offshore UK, licence P2366 offshore UK and the Walton-Morant licence offshore Jamaica. ERCE reports herein said Contingent and Prospective Resources as at 12th August 2019, being the date to which ERCE reviewed data made available to us. This is the effective date of this report, and ERCE is not aware of any material change in the status of the UOG assets in the period between the receipt of the data and the completion of the CPR.

The licence interests assessed in this report are summarised in Table 1.1.

UOG acquired its interest in the PL090 licence through the acquisition of the assets of First Oil's subsidiaries in August 2016. UOG holds a 26.25% working interest in the Waddock Cross field area (approximately 19 km^2) and a working interest of 18.9541% in the remainder of the licence (approximately 183 km^2). Both areas are operated by Egdon Resources UK Limited ("Egdon") and expire on the 31 March 2024. There are no outstanding work commitments on the PL090 licence.

UOG acquired a 10% stake in the P1918 licence (approximately 36 km^2) from the operator Corallian Energy Limited ("Corallian") in January 2018. The licence contains the Colter discovery.

Colter was recently appraised by the drilling of Well 98/11-6 and sidetrack Well 98/11-6z. The results from Wells 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area. The new interpretation has led to a reduction in the Contingent Resources attributable to the Colter discovery, and a revised assessment of prospectivity to the south of the Colter discovery.

In August 2018 as part of the UK 30th offshore licencing round, UOG was awarded a 95% stake of offshore Blocks 15/18d and 15/19b, Licence P2366. The remaining 5% interest is owned by Swift. The reprocessing of 50 km^2 of 3D seismic and a rock physics study to help de-risk the Crown discovery has recently been completed satisfying the Phase A work commitments. The initial phase of the licence will expire on 30 September 2021. A further phase can be entered into subject to the condition that a firm commitment to drilling a well has been made. If entered into, this subsequent phase will expire on the 30 September 2023.

UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on the 17th July 2019 and the sale and purchase agreement ("SPA") was signed on the 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence, regulatory Oil and Gas Authority ("OGA") approval and definitive documentation.

In March 2018 the Petroleum Corporation of Jamaica ("PCJ") approved a deal between UOG and Tullow Jamaica Limited ("Tullow") for UOG to farm-in to the Walton-Morant Licence which covers an area of 32,065 km^2, offshore Jamaica at a 20% equity interest. In May 2018, the acquisition of 2250 km^2 of 3D seismic data was successfully completed. Processing has recently been completed (2019) with the generation of an anisotropic PSTM and PSDM volume. However, the recent anisotropic PSTM and PSDM volumes have not altered the existing interpretation (time or depth structure), the uncertainty (gross rock volume estimates), or the Geological Chance of Success associated with the prospect. The partnership faces a drill or drop decision in Q1 2020, licence expiry occurs 2024.

Table 1.1: Summary of UOG Licence Interests

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19 km^2	
		UOG PL090 Ltd	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	183 km^2	
		UOG PL090 Ltd	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				
P1918 (Colter)	Corallian Energy Limited	Corallian Energy Limited	74.00%	Extant	31/1/2020 (Second Term) 31/1/2038 (Licence End Date)	36.2 km^2	
		UOG Colter Ltd	10.00%				
		Baron Oil	8.00%				
		Resolute Oil & Gas	8.00%				
Walton Morant (Colibri)	Tullow Jamaica Ltd	Tullow Jamaica Ltd	80.00%	Extant	2024	32,065 km^2	60% relinquishment, drill or drop Q1 2020
		UOG Jamaica Ltd	20.00%				
P2366 (Crown)	United Oil & Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/09/2021 (Phase A) 30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)	13.6 km^2	Phase A work commitments including the reprocessing of 40km^2 of 3D seismic and an associated Rock Physics study have now been completed. Phase C will start on the condition that there is a firm commitement to drilling a well.
		Swift Exploration Limited	5.00%				

Notes:

1) *UOG also hold interests in UK onshore licences PEDL330 and PEDL345 with the same equities as licence P1918. However, evaluation is at an early stage and no leads have yet been identified, therefore these licences have not been addressed as part of this document.*
2) *Since the last CPR Corallian Energy Limited has acquired Corfe Energy's 25% interest in licence P1918.*
3) *Since the last CPR UOG has released its option associated with Licence P2264 which is located offshore UK in the Southern North Sea (Block 49/29c).*
4) *UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. The heads of terms was signed on the 17th July 2019 and the sale and purchase agreement ("SPA") was signed on the 7th October 2019. The deal is subject to completion of satisfactory due diligence, including geological, legal and financial due diligence, regulatory Oil and Gas Authority ("OGA") approval and definitive documentation.*

1.1. Data Provided

ERCE has relied upon data and information made available by UOG in the preparation of this report.

1.1.1. Waddock Cross and Broadmayne (PL090)

UOG provided two 3D seismic data sets, the Waddock Cross 3D (which covers the extent of the Waddock Cross field) and the Broadmayne 3D which covers the Broadmayne structure and several additional leads. In addition to seismic data ERCE has also received well results, wireline logs and CPIs thereof, well test reports, MDT and PVT data and production and pressure data for the Waddock Cross field.

The Waddock Cross 3D has recently been reprocessed and ERCE has been provided with a PSTM (time domain) and PSDM (depth domain) seismic volume. In addition, ERCE has taken receipt of revised time and depth interpretation from both UOG and the operator Egdon.

1.1.2. Colter (P1918)

Our review was undertaken using primary geotechnical data supplied by UOG. These comprise 3D seismic data, including structural interpretation in time and depth, together with open-hole logs. ERCE has taken receipt of data from Wells 98/11a-6 and 6z and revised depth interpretations from both UOG and the operator, Corallian.

1.1.3. Colibri (Walton-Morant)

ERCE has been given access to a Petrel Project containing both well and seismic data through a data room in Tullow's offices. The seismic contained Tullow's recently acquired 2D lines and a mix of other vintage 2D lines. The project also contained a velocity model and time and depth interpretations performed by both Tullow and UOG.

Subsequent to the successful acquisition of 2250 km^2 of 3D seismic data in May 2018, ERCE has been provided with derived 3D time domain seismic volumes. In addition, ERCE has taken receipt of revised time and depth interpretations from both UOG and Tullow.

Following the completion of processing of the 3D volume (March 2019) ERCE has taken receipt of anisotropic PSTM, PSDM and associated velocity volumes.

1.1.4. Crown (P2366)

ERCE has been given access to a Kingdom Project containing both well and seismic data. In addition, a well database has also been provided. This primarily contains scanned or digital reports, but several wells also have digital log data.

Following the completion of the reprocessing and rock physics study ERCE has taken receipt of various derivative 3D seismic volumes and updated interpretation performed by UOG.

No site visit was undertaken in the preparation of this report.

1.2. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes.

1.2.1. Contingent Resources

1.2.1.1. Waddock Cross Field (PL090)

The Waddock Cross field is located in the Wessex Basin, onshore UK, to the west of the Wytch Farm and Wareham oil fields. The field contains 29^o API oil within the Jurassic Bridport Sandstone reservoir, and has historically undergone oil production, which was suspended due to a high water cut. The field is currently shut in.

The Waddock Cross 3D has recently been reprocessed with a focus on addressing apparent near-surface statics issues. This has given rise to both PSTM (time domain) and PSDM (depth domain) seismic volumes. The new volumes have only recently been interpreted and further studies are being undertaken to determine the viability and optimal location for any new well(s).

ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. The contingencies include the preparation and commitment to a commercial development plan. ERCE's estimates of the unrisked oil Contingent Resources in the Waddock Cross field, both gross and net to UOG, are shown in Table 1.2. ERCE agrees with UOG's assessment of Chance of Development (Pd) at 75%.

Table 1.2: Unrisked Oil Contingent Resources of the Waddock Cross Field, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%

Notes:

1) *"Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.*
2) *"Net Contingent Resources" are UOG's working interest fraction of the gross contingent resources.*
3) *Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.*
4) *The volumes reported here are unrisked in that they have not been multiplied by the Chance of Development (Pd).*
5) *In accordance with SPE PRMS.*

1.2.1.2. Colter Discovery (P1918)

Licence P1918 is located offshore southern UK, south of the Wytch Farm oil field and contains the Colter oil discovery. The licence is operated by Corallian and UOG holds a 10% working interest.

Colter was discovered by Well 98/11-3 in 1986. The well encountered a 10.5 m section of the Sherwood Sandstone reservoir with oil saturations from logs up to 60%, underlain by water-bearing Sherwood Sandstone. A DST was performed on Well 98/11-3, with 8.5 stb of oil produced at surface out of 109 bbl total fluid influx, including water. The well test straddled the oil water contact (OWC) of the discovery.

Well 98/11a-6 was drilled to appraise the Colter discovery in February 2019. The well encountered the Sherwood Sandstone reservoir deeper than prognosed and is interpreted to have penetrated the reservoir on the southern side of the Colter bounding fault. Wireline log interpretation indicates elevated hydrocarbon saturations above a depth of 1780.5 m TVDss. However, the well was not tested and the presence of moveable hydrocarbons has not been demonstrated. ERCE attributes Prospective Resources to the structures on the southern side of the Colter bounding fault.

Well 98/11a-6z was a side-track to the north from Well 98/11a-6 designed to further appraise the Colter discovery. The well penetrated the northern side of the Colter bounding fault but found the Sherwood Sandstone reservoir below the Colter OWC 1740 m TVDss defined by Well 98/11-3. This results in a reduction in the Contingent Resources estimates for the Colter discovery.

ERCE attributes unrisked Contingent Resources (sub-classification Development Unclarified) to the Colter discovery (Table 1.3). Development of Colter would be contingent on further successful exploration drilling of the Colter South prospect. ERCE agrees with UOG's assessment of the Chance of Development of 30%.

Table 1.3: Unrisked Oil Contingent Resources of Colter Discovery, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL1918	Colter	Corallian Energy Limited	0.44	0.69	1.06	10.00%	0.04	0.07	0.11	30%

Notes:

1) *Refer to notes under Table 1.2*

1.2.1.3. Crown Discovery (P2366)

Licence P2366 is located offshore UK at the northwest margin of the Witch Ground Graben and contains the Crown oil and gas discovery. The licence is operated by UOG who hold a 95% interest. The remaining 5% is owned by Swift.

Reprocessing of 50 km^2 of 3D seismic data and an associated rock physics study have recently been completed satisfying Phase A work commitments. The work has led to revised interpretations of the Crown structure and inferred reservoir and hydrocarbon distribution.

Well 15/19-9 penetrates the Crown discovery, a four-way dip closed anticline. The well found an oil rim of thickness 35 to 55 ft underlying a gas cap in the Balmoral reservoir, a deep marine sandstone turbidite. Production of the gas is at detriment to recovery of oil and as such development plans will aim to minimise any gas production. ERCE attributes unrisked oil Contingent Resources (sub-classification Development Unclarified) to Crown as shown in Table 1.4. ERCE agrees with UOG's assessment of the Chance of Development of 60%.

Table 1.4: Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	60%

Notes:

1) *Refer to notes under Table 1.2*
2) *UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. See additional notes under Table 1.1*

1.2.2. Prospective Resources

1.2.2.1. Broadmayne Prospect (PL090)

The PL090 partnership is maturing prospectivity within the greater licence area, and identifies a number of undrilled exploration prospects and leads. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil Prospective Resources and Geological Chance of Success for the Broadmayne prospect, which is currently the most mature. Part of the Broadmayne structure is mapped as extending outside licence PL090. Reprocessing of the 3D seismic survey covering the Broadmayne prospect has recently been completed and preliminary interpretation supports the overall trapping mechanism and lateral extent of the historical mapping. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report.

ERCE's estimates of the gross unrisked oil Prospective Resources in Broadmayne and the net unrisked and risked Prospective Resources attributable to UOG based on the mapped area of the prospect in Licence PL090 are shown in Table 1.5.

Table 1.5: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Broadmayne Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Broadmayne	Egdon Resources UK Limited	5.0	11.1	24.5	13.4	1.50	3.30	7.40	4.00	18.95%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**1U**	**2U**	**3U**	**Mean**
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimates to fall within the PL090 block boundary (50%).*

Notes:

1) *Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.*
2) *"Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from an accumulation*
3) *"Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources*
4) *"Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).*
5) *The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.*
6) *Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).*

1.2.2.2. Colter South Prospect (P1918)

The results from Wells 98/11a-6 and 98/11a-6z have led to a revised structural interpretation of Colter and the surrounding area.

The Colter South prospect is mapped to extend to the southeast up dip from Well 98/11-1. Log interpretation of the Sherwood Sandstone reservoir in Well 98/11-1 indicates elevated hydrocarbon saturations, but well testing flowed water only, defining a water up to for the prospect at 1780 m TVDss. A smaller structure is also mapped around Well 98/11-6 to which Prospective Resources are also attributed. Petrophysical interpretation of Well 98/11-6 wireline logs indicates elevated hydrocarbon saturations, but movable hydrocarbons have not been sufficiently demonstrated in this well. This prospect has been designated "Colter South (Well#6)".

ERCE's estimates of the gross unrisked oil Prospective Resources and Geological Chance of Success for Colter South and the net unrisked and risked Prospective Resources attributable to UOG in the P1918 Licence are shown in Table 1.6.

Table 1.6: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Colter South Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter South	Corallian Energy Limited	10	24	52	29	3.9	9.2	21.0	11.3	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**1U**	**2U**	**3U**	**Mean**
Colter South	Corallian Energy Limited	0.39	0.92	2.10	1.13	65%	0.25	0.59	1.37	0.74

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter South *(Well#6)*	Corallian Energy Limited	0.52	1.92	7.00	3.21	0.20	0.75	2.74	1.27	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**1U**	**2U**	**3U**	**Mean**
Colter South *(Well#6)*	Corallian Energy Limited	0.02	0.07	0.27	0.13	62%	0.01	0.05	0.18	0.08

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the P1918 Licence (10.00%).*

Notes:

1) Refer to notes under Table 1.5

1.2.2.3. Colibri Prospect (Walton-Morant)

The Walton Morant licence block, offshore Jamaica, contains a number of prospects and leads. The primary target reservoir is the Middle Eocene sands of the Guy's Hill formation. ERCE has independently estimated Prospective Resources for the Colibri prospect, which is the most mature in the current portfolio. ERCE's estimates of the gross unrisked oil Prospective Resources for Colibri and the net unrisked and risked Prospective Resources attributable to UOG in the Walton Morant Licence are shown in Table 1.7.

Table 1.7: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Colibri Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**1U**	**2U**	**3U**	**Mean**
Colibri	Tullow Jamaica Ltd	6	26	103	46	20%	1.19	5.00	20.08	8.97

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the Walton-Morant Licence (20.00%)*

Notes:

1) Refer to notes under Table 1.5

1.2.3. Leads

1.2.3.1. PL090

Preliminary mapping of seismic data has defined a number of other potential structural traps at Sherwood Sandstone level that are partially or wholly within licence PL090. These include the Casterbridge, Owermoigne East and West and Winfrith structures. UOG's evaluation of these leads is still at an early stage and further technical work is required to mature these to drillable prospects.

1.2.3.2. Walton-Morant

The Walton-Morant licence covers an area of 32,065 km^2 and Tullow has defined a number of potential structural and stratigraphic traps in both the Walton and Morant basins. Interpretation of the recently acquired 3D data has high graded Oriole and Tody to be the most attractive. The viability of these will be further assessed based on the results of drilling the Colibri prospect.

2. Contingent Resources

2.1. Waddock Cross Field (PL090)

2.1.1. Introduction

The Waddock Cross field is located in licence PL090 and is operated by Egdon Resources UK Limited ("Egdon"). The licence is located within the Wessex Basin in the county of Dorset, onshore UK (Figure 2.1).

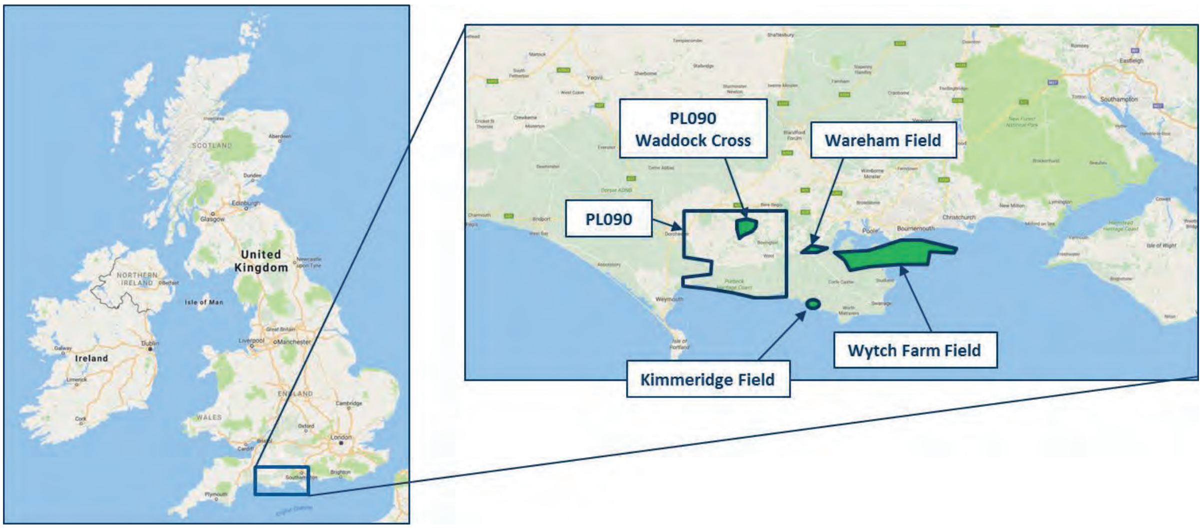

Figure 2.1: PL090 Licence Location and Neighbouring Oil Fields (Source UOG)

Waddock Cross is located in rural farmland close to woodlands approximately 11.5 km east of Dorchester and 21.6 km west of Poole. The Grid Reference (UK National Grid) for the site is SY805912. When the field was previously in production in 2013/14, oil was exported via road tanker to Holybourne Oil Terminal in Hampshire, power was supplied via mains electricity, and water was reinjected through the WX-2 well.

Neighbouring oil fields include the Wareham and Wytch Farm oil fields. The Wytch Farm field produces oil predominantly from the Triassic Sherwood Sandstone reservoirs, with subordinate production from the younger Jurassic Bridport Sandstone reservoir. The Wareham field also produces oil from the Bridport Sandstone reservoir.

The Waddock Cross field was discovered by British Gas in 1982 with Well WX-1. The primary objective was the Triassic Sherwood Sandstone, which did not contain hydrocarbons. A 22 m thick oil column (oil gravity of 29° API) was encountered in the shallower Jurassic Bridport Sandstone at a depth of ca 610 m TVDSS. The oil bearing reservoir can be subdivided into two units; the upper unit Cycle 3 has slightly poorer reservoir qualities than the underlying unit Cycle 2 which possesses better porosity and permeability. Cyclicity within the Bridport Sandstone can be correlated to the Wytch Farm oil field and also to outcrop. An extended well test was conducted in Well WX-1 over a period of 90 days at liquid rates of ~70-80 bbl/d during which the water-cut increased to 80% and the well was plugged and abandoned.

Egdon acquired operatorship in 2003 and drilled Well WX-2 which was completed in January 2004. The well was drilled in close proximity to Well WX-1 and also encountered a 22 m thick oil column.

Several drill stem tests were conducted in Well WX-2. Cycle 2 and Cycle 3 were tested both independently, and as a commingled production stream. Cycle 2 and Cycle 3 both independently produced oil, however in all cases the stabilised water-cut was at ~90% or above.

After the acquisition and interpretation of a 3D seismic survey over the area, Well WX-3 was designed and drilled as a horizontal appraisal well in 2005. The Bridport Sandstone was encountered approximately 9 m deep to prognosis and the well was completed in Cycle 3 to stay above the oil water contact and did not penetrate the better-quality Cycle 2 as originally intended.

Two extended well tests were conducted in Well WX-3 in 2005/6 which flowed oil rates of 53 stb/d and 40 stb/d respectively, both at a water-cut of ~90% over a total period of 22 days. A final extended well test was conducted in 2011-12 with intermittent periods of production from both Wells WX-2 and WX-3. The average combined oil rate was 17 stb/d at a water-cut of 95% over a total period of 59 days. In December 2011, a diesel squeeze was carried out in Well WX-3. However, the workover impacted the oil rate negatively (WX-3 water-cut increased from 90% to 99.5%) and the well test was abandoned shortly after.

The field was put into production through WX-2 in 2013 however results were disappointing. The average oil rate was ~8 stb/d at a water-cut of ~98% and the field was shut-in in 2014.

In late 2014, a workover was carried out with the objective of identifying and isolating the higher water-cut zone in Well WX-3. However, having isolated what was believed to be the higher water-cut zone, it was not possible to establish flow again in Well WX-3.

Egdon advises that there are currently two suspended wells on site, along with two fluid storage tanks that are contained with a purpose-built masonry bund. Other facilities still on site are the concrete tanker loading bay; anti-vandal site office and separate anti-vandal toilet block; constructed mains electricity sub-housing and surface water interceptor. The site area is 1.6ha which includes the access track from the road and is fenced with livestock post and wire fencing. Access from the road is secured with two palisade fence gates, and security is maintained by daily mobile patrol visits. End of life abandonment would require the recovery of the two downhole completions (one is a dual completion used for reinjection), abandonment and capping of the two wells, removal of existing facilities, and restoration using the existing sub soil and topsoil bunds. ERCE has reviewed the activities required to return the site to its former state and believe that the gross costs could range between a low and high estimate of £230,000 and £330,000 respectively.

There is no committed work programme on Waddock Cross. However, reservoir modelling and well costing is being undertaken ahead of well-planning.

2.1.2. Regional and Reservoir Geology

The Wessex Basin comprises four north-dipping half graben sub-basins, with northerly thickening sediments originally controlled by south dipping normal faults. The basin has undergone later tectonism and inversion as a result of (Tertiary) Alpine compression. It is believed that this inversion led to the breaching of a number of hydrocarbon bearing traps.

The stratigraphy of the Wessex Basin is summarised in Figure 2.2. Permian red bed strata containing mudstones, sandstones and basal breccias unconformably overly the deformed Carboniferous-Devonian Basement. The Triassic sediments are comprised of further red bed strata, sandstones, mudstones and conglomerates with halite and mudstone development in the upper part, which provides an intraformational seal. The Sherwood Sandstone was deposited at this time. The overlying Jurassic is formed of an alternating mudstone and carbonate sequence, and contains a number of potential source rock intervals, including the Kimmeridgian and Oxfordian shales. However, much of the oil that has migrated through the basin is sourced from the earlier Liassic shales, with a kitchen area centred to the south of the Wytch Farm field.

Sandstones, including the Bridport Sandstone, are developed in the Lower Jurassic section as the basin filled. Early Cretaceous strata are only preserved in a few basinal areas, with the area eventually covered by mid-late Cretaceous Chalk and Tertiary sediments. Alpine inversion has resulted in later structural modification, and the erosion of Tertiary and Upper Cretaceous strata over the area.

The Lower Jurassic Bridport Sandstone consists of very fine to medium grained shallow marine sandstones varying in thickness from 60 to 130 m. Reservoir quality is variable, with permeability in the range of 0.1 – 400 md, and net to gross ratio varying between 15 to 80%. The sandstones contain tightly cemented calcareous layers which form vertical permeability barriers. The thickly developed mudstones of the Middle Jurassic Fullers Earth Formation provide the top seal for the Bridport Sandstone reservoir.

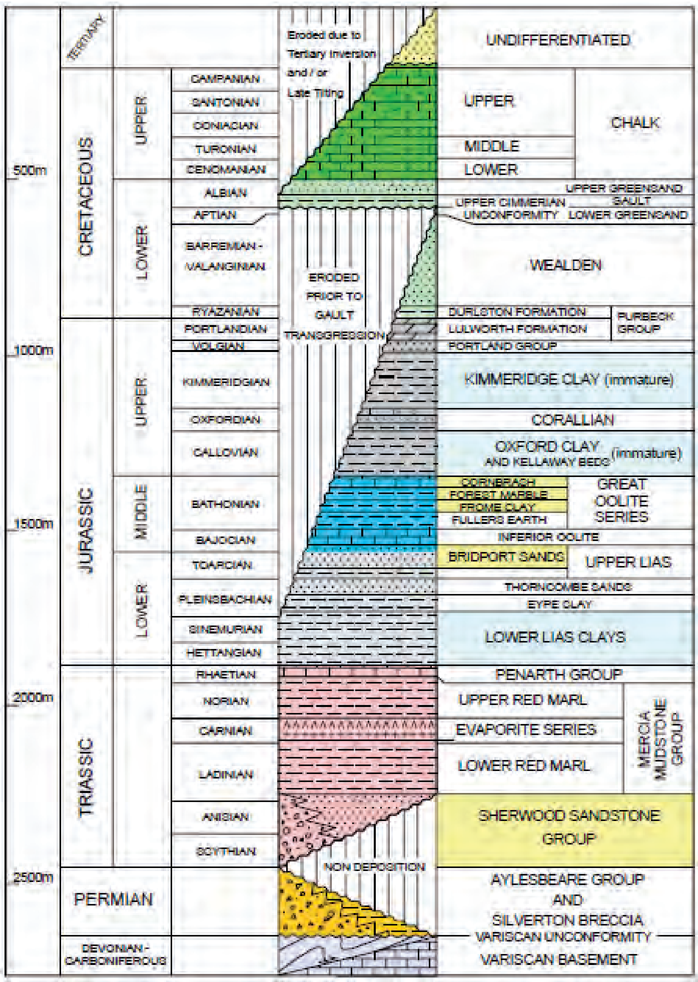

Figure 2.2: Stratigraphic Position of the Principal Source Rocks and Reservoirs of the Wessex Basin (source DTI).

2.1.3. Seismic Data and Structure

A further round of reprocessing has recently been completed which focused on addressing the apparent near surface statics issues. The reprocessing has resulted in both PSTM (time domain) and PSDM (depth domain) seismic volumes.

ERCE has assessed both the PSTM and PSDM 3D seismic data and acknowledges an improvement in imaging associated with the PSTM volume.

A representative seismic section from the PSTM volume across the Waddock Cross field is shown in Figure 2.3.

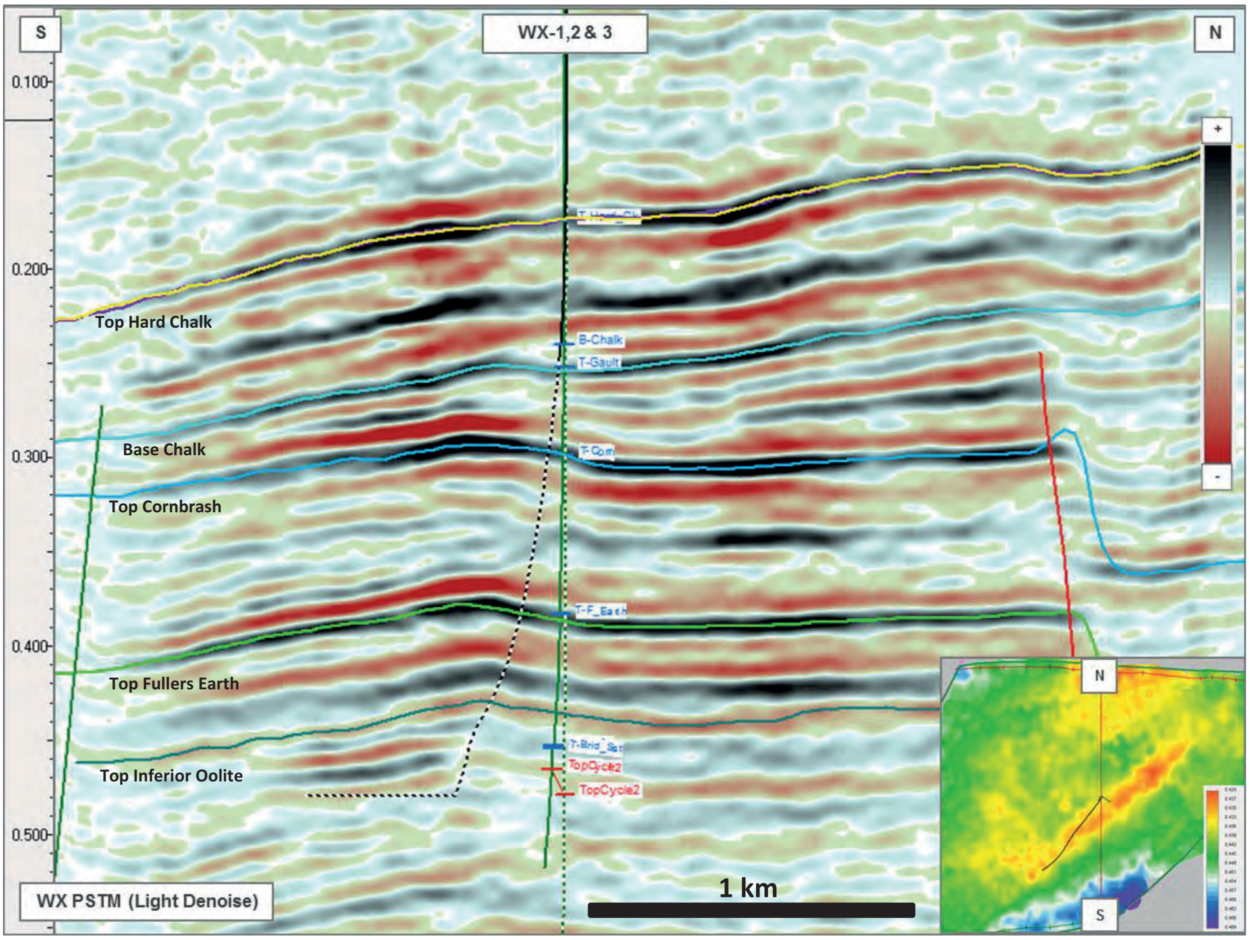

Figure 2.3: N-S Seismic Line Through the Waddock Cross Field

The field is defined by a three-way closure, fault sealed to the north and dip closed to the south, east and west.

2.1.4. Overburden Velocities and Depth Conversion

Overburden geology is complex above the Waddock Cross field, and structural relief is sensitive to depth conversion.

ERCE has assessed all available velocity data and generated independent depth conversion models to explore structural and volumetric uncertainty for the Waddock Cross field. ERCE's best technical case velocity model and the range of velocities explored through multi-realisation modelling is illustrated by Figure 2.4. This plot displays both sonic log velocities from Wells WX-1 and -2 and Well Wareham-3, derived best technical case velocity functions (green lines) and the range of velocities (dashed red lines) explored through multi-realisation modelling. The sonic log from Well Wareham-3 has been shifted to tie at Base Chalk for comparison purposes.

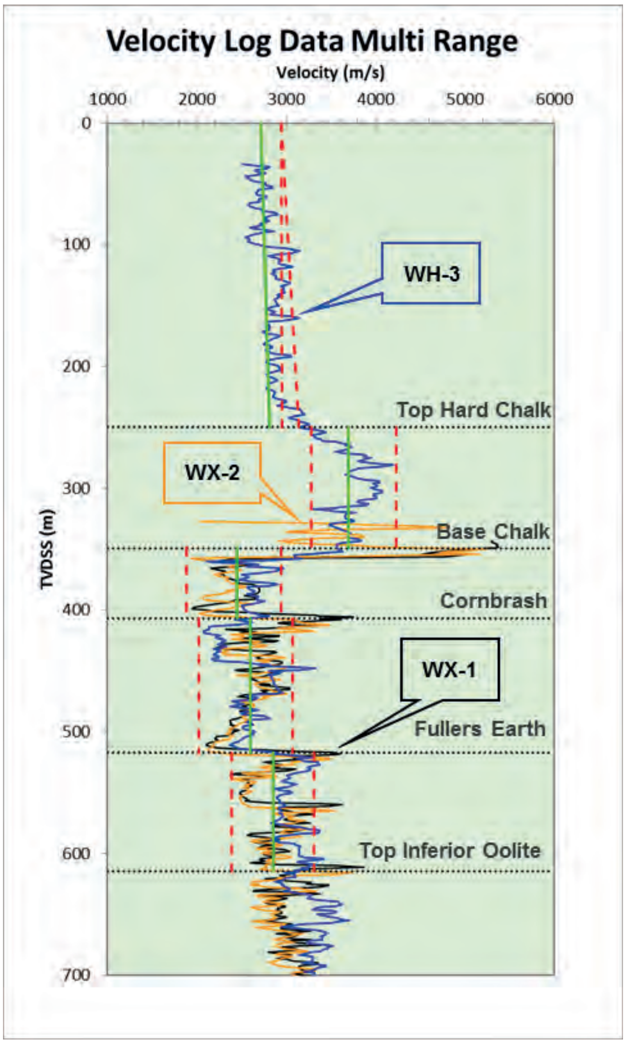

Figure 2.4: Log Velocity Plot - Waddock Cross Velocity Model
(Waddock Cross-1, 2 & Wareham-3)

2.1.5. Petrophysical Review

A petrophysical review of the Waddock Cross wells and Wareham Well C3WP was carried out by PGL in 2006 (the PGL Report). ERCE has carried out an audit of this interpretation and agrees with the results. We therefore adopt this petrophysical analysis as our basis for the evaluation of the Waddock Cross Bridport Sandstone reservoir.

Figure 2.5 presents CPIs of Wells WX-1 and WX-2 from the PGL Report. Cycle 3 is oil bearing in both wells, and an oil water contact (OWC) is encountered in Cycle 2 in both wells at 638.5 m TVDSS. Cycle 2 has better reservoir quality than Cycle 3, with higher net to gross ratios and slightly higher porosity (29% compared to 26%). Water saturation is high in both reservoirs, due to the proximity of the OWC.

Figure 2.6 presents a CPI of horizontal Well WX-3. This well was drilled approximately 10 metres above the OWC. The CPI shows that high water saturations generally greater than 60% are encountered throughout the horizontal section.

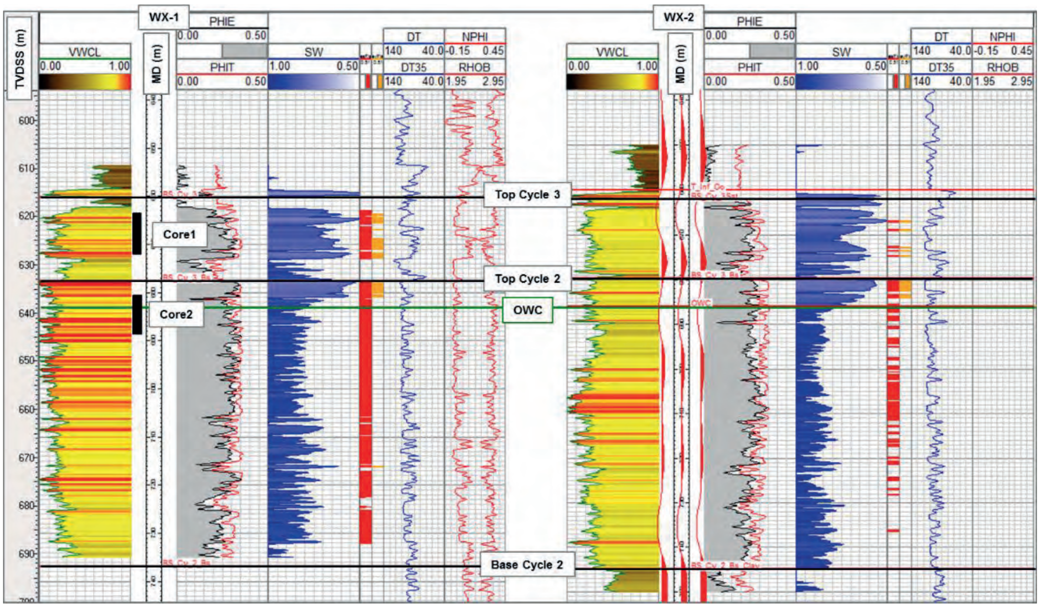

Figure 2.5: CPI Images of Wells WX-1 and WX-2
(Source PGL Report, 2006)

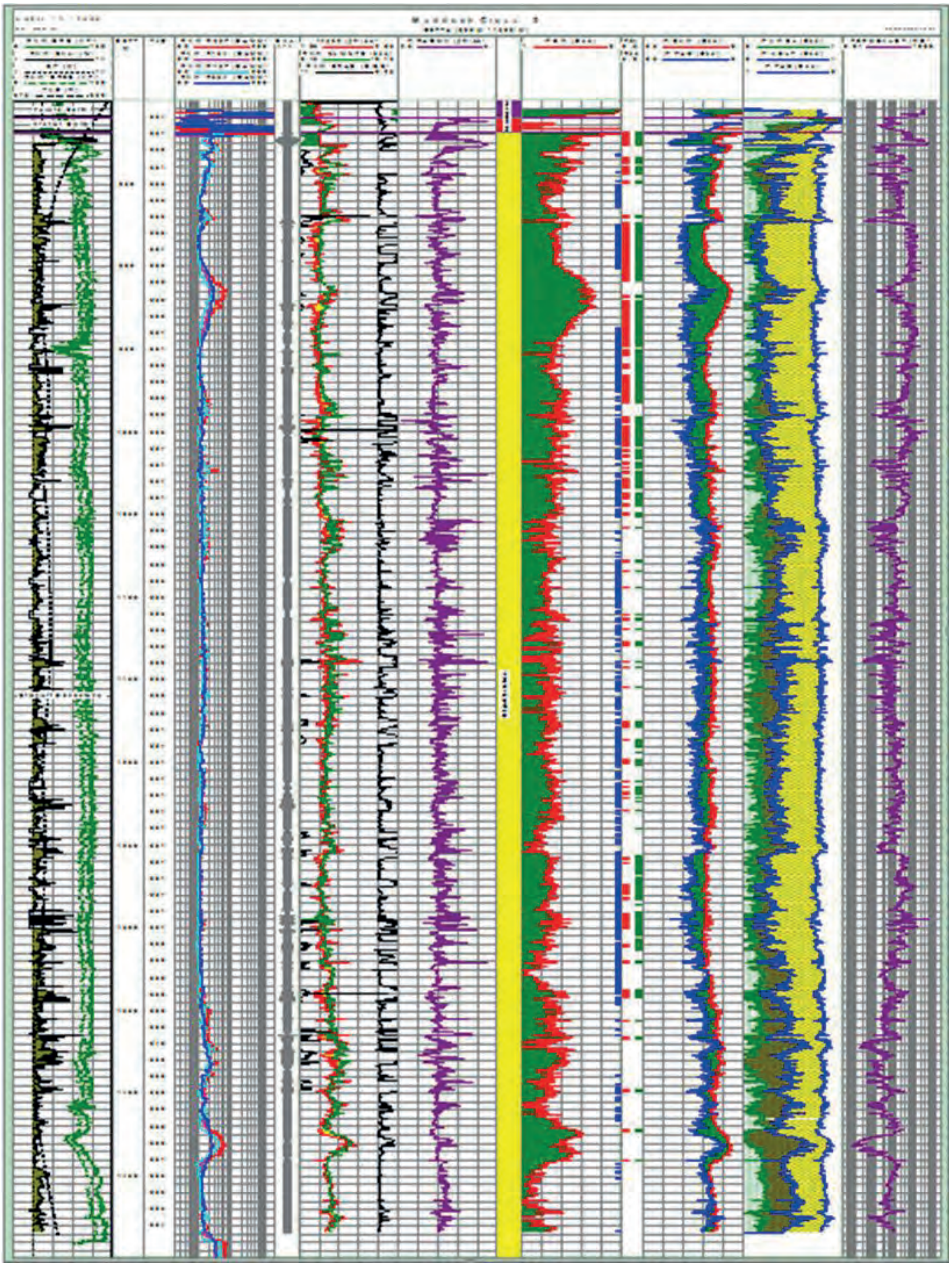

Figure 2.6: CPI Image of Well WX-3
(Source PGL Report, 2006)

2.1.6. Fluid Analysis

Downhole reservoir fluid samples were not made available for review. Reservoir fluid properties have been estimated using surface fluid samples, gas-oil ratio from production tests and standard engineering correlations. Surface oil sample density was measured at 29 °API and it is expected that reservoir fluid has a moderately high viscosity and a formation volume factor close to one.

2.1.7. Well Test Review

The field was discovered by Well WX-1 in 1982 which encountered oil in the Bridport Sandstone. An extended well test was conducted over a period of 90 days however the well was plugged and abandoned due to low oil rates (<10 stb/d) and a high water-cut (~70-80%).

Appraisal Well WX-2 was drilled in 2004 at an offset of 120 m from the discovery well WX-1 and completed in the Bridport Sandstone. Several drill stem tests ("DSTs") were conducted on the WX-2 well. The first DST was over a two metre perforated interval in Cycle 2 and produced oil at 40 stb/d with a water-cut of ~90% over a 24 hour period. The second test was carried out over a 13 metre perforated interval in Cycle 3 and flowed at an oil rate of 60 stb/d with a water-cut of ~95% over a 30 hour period. A further two DSTs were carried out in Well WX-2 later in 2004 which again flowed at high water-cuts.

In December 2005, horizontal development Well WX-3 was drilled. The well was intended to target Cycle 2 however the reservoir came in nine metres deep to prognosis and the well was instead completed in Cycle 3. The total horizontal section was 690 m. Two extended well tests were conducted in WX-3 in 2005/6 which flowed oil rates of 53 stb/d and 40 stb/d respectively, both at a water-cut of ~90% over a total period of 22 days.

Another extended well test was conducted in 2011-12 with intermittent periods of production from both Wells WX-2 and WX-3. The average combined oil rate was 17 stb/d at a water-cut of 95% over a total period of 59 days. In December 2011, a diesel squeeze was carried out in Well WX-3. However, the workover impacted the oil rate negatively (WX-3 water-cut increased from 90% to 99.5%) and the well test was abandoned shortly after.

The field was put into production through WX-2 in 2013 however results were disappointing. The average oil rate was ~8 stb/d at a water-cut of ~98% and the field was shut-in in 2014.

In late 2014, a workover was carried out with the objective of identifying and isolating the higher water-cut zone in Well WX-3. However, having isolated what was believed to be the higher water-cut zone, it was not possible to establish flow again in Well WX-3.

All well tests conducted in the field have been characterised by high water-cuts. Water-cut development is exacerbated by the relatively high viscosity of the oil. All wells to date have been completed with relatively little offset from the oil water contact and hence have encountered high water saturations. The proposed development plan therefore intends to target areas of the discovery with greater relief where lower water saturations may lead to oil production with less associated water.

2.1.8. Hydrocarbons Initially In Place

ERCE uses probabilistic methods to estimate hydrocarbons in place for the Waddock Cross field. Firstly, we develop a mid case gross-rock volume, using our best technical estimate depth conversion (Section 2.1.4), and an OWC at 638.5 m TVDSS. Top Bridport Sandstone is derived by adding well based isopachs to the overlying top Inferior Oolite – the seismic marker closest to the Bridport Sandstone.

We then perturb velocity model structure and seismic pick uncertainty to generate low and high case estimates of gross rock volume (GRV).

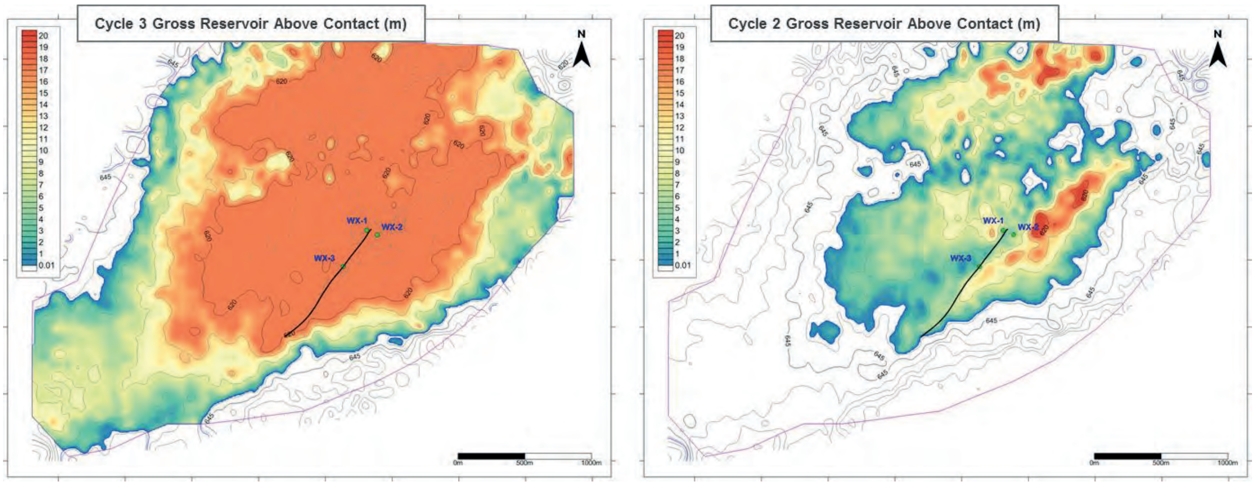

Figure 2.7: Gross Reservoir Thickness Above OWC – Mid Case
(Grey contours represent depth to top reservoir TVDss, blue contour highlights contact depth and the colourfill represents the gross reservoir thickness above contact).

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the field where a shallower structure has been interpreted. A summary of input parameters used in our calculation of stock tank oil initially in place (STOIIP) is presented in Table 2.1.

Table 2.1: Input Parameters – Waddock Cross

Block	Field	Reservoir	GRV (MMm3)			NTG (frac)			Porosity (frac)		
			Low	Best	High	Low	Best	High	Low	Best	High
PL090	Waddock Cross	Cycle3	84	98	114	0.21	0.33	0.47	0.23	0.26	0.28
		Cycle2	11	20	40	0.51	0.63	0.74	0.26	0.29	0.31

Block	Field	Reservoir	HC Saturation (frac)			Bo (rb/stb)		
			Low	Best	High	Low	Best	High
PL090	Waddock Cross	Cycle3	0.40	0.48	0.55	1.01	1.02	1.03
		Cycle2	0.40	0.48	0.55	1.01	1.02	1.03

The results of our STOIIP estimates, separated as Cycle 2 and Cycle 3, are presented in Table 2.2.

Table 2.2: Waddock Cross STOIIP

Block / Concession	Field	Operator / Administrator	Reservoir	STOIIP (MMstb)		
				Low	Best	High
PL090	Waddock Cross	Egdon Resources UK Ltd	Cycle 3	14.1	23.8	36.8
			Cycle 2	5.1	10.5	21.0
			Total	**19.2**	**34.3**	**57.8**

2.1.9. Recovery Factor and Oil Contingent Resources

The partners are reviewing the revised interpretation to determine the viability and optimal location to drill a new well.

Reservoir simulation modelling was undertaken by Egdon prior to the drilling of Well WX-3. Our estimates of recovery factor have been guided by the results of this simulation modelling. We assume that two wells with horizontal sections of some 1000 m each will be drilled in structurally shallow areas of the field, allowing a greater offset from the oil water contact. We are of the view that if the reservoir is encountered deeper than prognosis, reflecting the Low case mapping, then a low recovery factor is likely to prevail. In a similar manner, if the reservoir is encountered higher than encountered in the current wells, a higher recovery factor is likely. We have therefore applied recovery factor ranges deterministically to our STOIIP estimates. We have assigned a higher recovery factor range to Cycle 2 to reflect the higher reservoir quality.

ERCE agrees with UOG’s assessment of Chance of Development of 75%.

Table 2.3 presents our estimates of STOIIP, recovery factor and oil Contingent Resources (sub-classification Development Pending).

Table 2.3: Waddock Cross STOIIP, Recovery Factor and Oil Contingent Resources

Block / Concession	Field	Operator / Administrator	Reservoir	STOIIP (MMstb)			Recovery Factor (%)			Gross Contingent Resources (MMstb)		
				Low	Best	High	Low	Best	High	1C	2C	3C
PL090	Waddock Cross	Egdon Resources UK Ltd	Cycle 3	14.1	23.8	36.8	1.5%	2.1%	3.0%	0.21	0.50	1.10
			Cycle 2	5.1	10.5	21.0	5.0%	10.0%	20.0%	0.25	1.05	4.20
			Total	**19.2**	**34.3**	**57.8**	-	-	-	**0.46**	**1.55**	**5.30**

Notes:

1) *Refer to notes under Table 1.2*
2) *Waddock Cross carries a 75% Chance of Development.*

2.2. Colter Discovery (P1918)

2.2.1. Introduction

The Colter discovery is located in licence P1918 and is operated by Corallian Energy Limited. The licence is located offshore southern UK, south of Wytch Farm oil field (Figure 2.8).

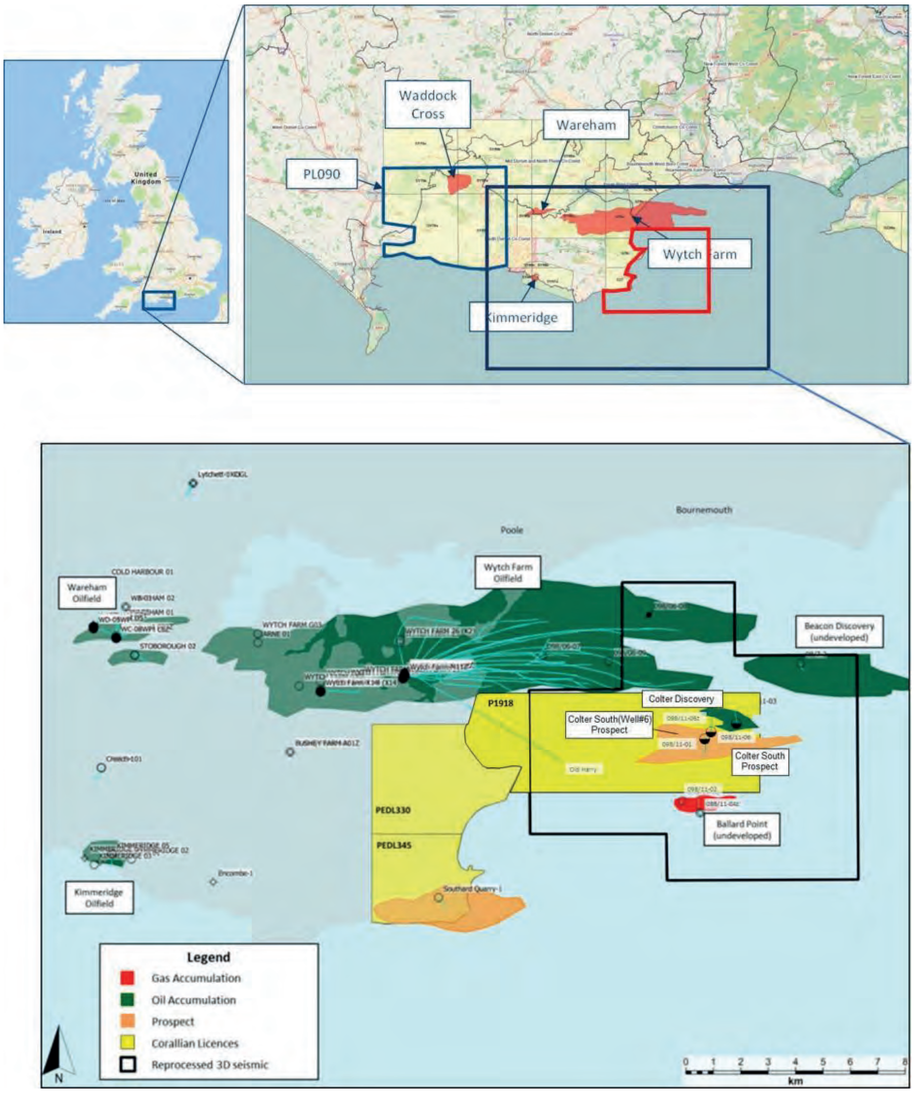

Figure 2.8: Colter Discovery Location Map
(Source: United Oil & Gas Summary Presentation)

The Colter discovery lies within the Wessex Basin, and so shares a geological history with Waddock Cross, as described in Section 2.1.2 and Figure 2.2.

The Sherwood sandstone is the principal reservoir for the Colter accumulation, deposited in the Triassic in a fluvial environment, and sealed by Jurassic Mercia mudstones. The Bridport sands, deposited in a shallow marine setting in the Lower Jurassic are a potential secondary target at Colter.

The Colter accumulation is trapped within a tilted fault block, analogous to Wytch Farm.

There have been five wells drilled in the Colter area. Two of the wells, drilled in the 1980s, sought to test fault structures to the south of the Wytch Farm field. Well 98/11-1 was drilled in 1983 to test a tilted fault block mapped at Bridport and Sherwood Sandstone level. Elevated hydrocarbon saturations are interpreted from wireline logs over the Sherwood Sandstone interval. A DST of the Sherwood Sandstone was performed over an interval between 1779 m and 1785 m TVDss. The DST recovered 74.1 bbls of water in a period of just over five hours.

The Colter discovery was made by Well 98/11-3 in 1986. The well encountered a 10.5 m section of Sherwood Sandstone reservoir with oil saturations from logs up to 60%, underlain by water-bearing Sherwood Sandstone.

A DST was performed on Well 98/11-3 over this Sherwood Sandstone interval, with 8.5 stb of oil produced at surface out of 109 bbl total fluid production, including water. An oil-water contact is indicated on logs at 1740 m TVDss. Average porosity is 18% in the pay interval and overall the reservoir quality is very similar to Wytch Farm.

The Old Harry extended reach exploration well was drilled in 2000 from an onshore Wytch Farm pad, to the west of Well 98/11-3. Log analysis indicates the presence of thin potentially hydrocarbon-bearing sands near the top of the Sherwood Sandstone reservoir, underlain by water. No tests were undertaken. Reservoir quality at the top of the Sherwood Sandstone is poor, and a possible contact is identified at c. 1750 m TVDss. Below the top 18 m of poor quality reservoir, a further 105 m gross reservoir was encountered, with 73% net to gross, and average porosity of 17%. This section represents good quality Sherwood Sandstone reservoir similar to Wytch Farm and Well 98/11-3.

Well 98/11a-6 was drilled to appraise the Colter discovery in February 2019. The well encountered the Sherwood Sandstone reservoir deeper than prognosed and is interpreted to have penetrated the reservoir on the southern side of the Colter bounding fault, within the same fault block as Well 98/11-1. Wireline log interpretation indicates elevated hydrocarbon saturations above a depth of 1780.5 m TVDss. However, the well was not tested and the presence of moveable hydrobcarbons has not been demonstrated.

Well 98/11a-6z was a side-track to the north from Well 98/11a-6 designed to appraise the original target, the updip section of the Colter discovery. The well penetrated to the northern side of the Colter bounding fault but found the Sherwood Sandstone reservoir below the OWC 1740 m TVDss defined by Well 98/11-3.

Top Sherwood Sandstone penetration of these wells is shown on the top reservoir depth structure map in Figure 2.9.

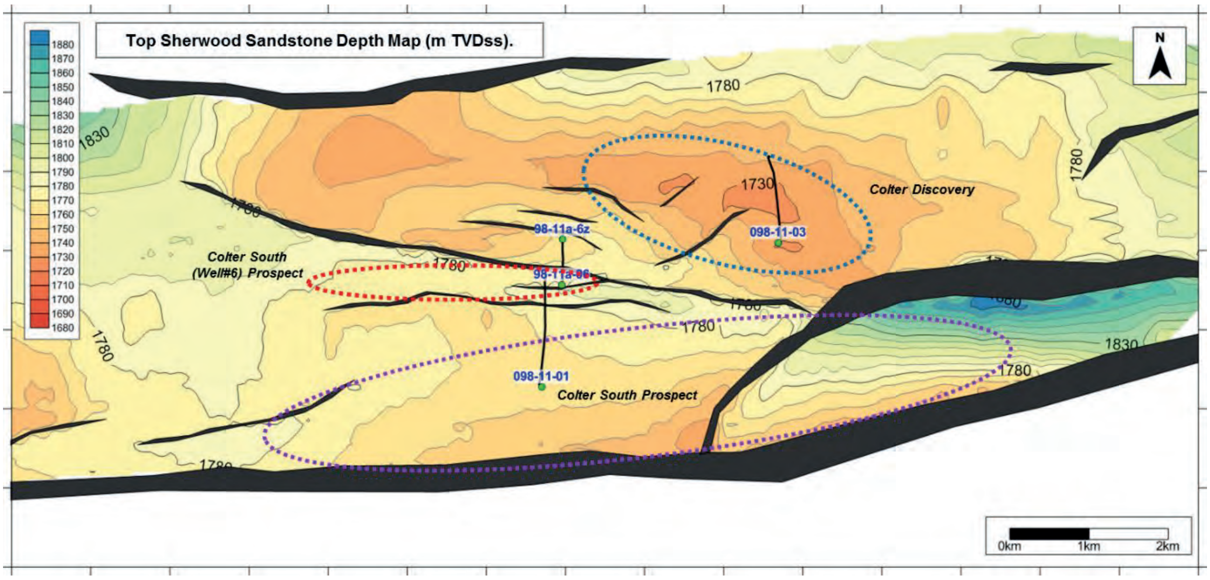

Figure 2.9: Well Locations and Corallian's Top Sherwood Sandstone Depth Map (m TVDss)
(Top Sherwood Sandstone penetration in each of the wells is shown by the green dot. The dashed coloured ellipses highlight the locations of the Colter Discovery, Colter South prospect and Colter South (Well#6) prospect.)

There is uncertainty in the correlation of interpreted elevated hydrocarbon saturations from wireline logs within the Sherwood Sandstone and the results of well tests, as Well 98/11-1 flowed water and Well 98/11-3 flowed oil from Sherwood Sandstone sections with similar elevated oil saturations. ERCE attributes oil Contingent Resources to the Colter discovery made by Well 98/11-3, and Prospective Resources to structures interpreted to the south of the Colter discovery fault block, as movable oil has not been demonstrated.

The Colter discovery and associated Contingent Resources are discussed in this section, and the Colter South prospect is discussed in Section 3.1.3.

2.2.2. Seismic Data and Structure

The interpretation of the Top Sherwood event on the available seismic data is challenging due to structural complexity and poor seismic signal below fast and steeply dipping chalk sediments at the surface. The Top Penarth event is therefore used as a proxy for Top Sherwood through application of a well isochron. Reprocessing of the seismic survey was completed in April 2018. However, the resultant seismic image does not materially reduce uncertainty in seismic interpretation. Figure 2.10 shows a north to south seismic section through Wells 98/11-1, 11a-6 & 11a-6z.

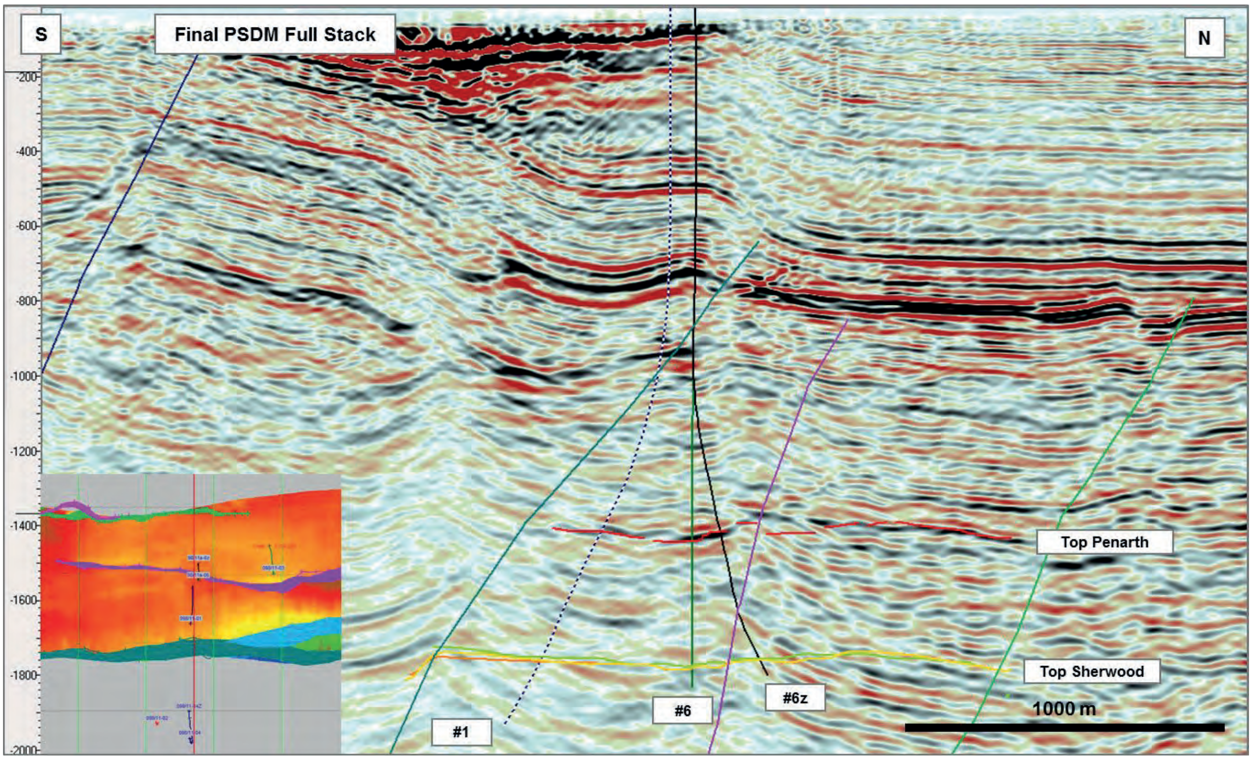

Figure 2.10: S-N Seismic Section through Wells 98/11-1, 11a-6 & 11a-6z

ERCE has assessed both the operator's and UOG's seismic interpretation for the Top Sherwood respectively over the Colter structure. Although these interpretations differ, they both bracket the uncertainty in structural interpretation in the area, and we adopt both as the basis for estimating volumetric uncertainty.

2.2.3. Depth Conversion

ERCE has reviewed the operator's approach used to depth convert the Top Sherwood and the PSDM depth structures. All methods reveal a velocity trend that increases to the south where uplift has removed the slower tertiary sediments and left the faster underlying formations including the chalk which outcrops to surface above the Colter South prospect.

Given the poor seismic signal and challenging interpretation depth conversion is felt to be a subsidiary control on GRV sensitivity. However, ERCE has reviewed and adopted both the operator's and UOG's structural interpretation to assess the range of gross rock volume, as these use both the PSDM and a layered velocity model. A representative depth map is presented in Figure 2.9.

2.2.4. Petrophysical Review

ERCE has carried out an independent petrophysical interpretation for Wells 98/11-1, 98/11-3, 98/11a-6 and 98/11a-6z. Well 98/11a-6 was only logged over the upper 25 m of Sherwood, and Well 98/11-6z did not acquire neutron or density logs and only has gamma ray and resistivity. Therefore, the results from Well 98/11a-6z have not been used quantitatively.

A CPI for Well 98/11-3 is shown in Figure 2.11. Reservoir quality in the Sherwood is typically good, with moderate hydrocarbon saturations in the upper Sherwood. An apparent OWC is encountered at around 5708 ft TVDss (1940 mTVDss). The composite log notes strong fluorescence in sands and gas shows.

A CPI for Well 98/11a-6 is shown in Figure 2.12. The reservoir quality is poorer than Well 98/11-3 with thinner sands that are interbedded with shales, resulting in a lower net to gross ratio (NTG). Interpreted saturation curves show elevated hydrocarbon saturations above a depth of 1780.5 m TVDss, below which water saturations of 100% are interpreted. Cuttings descriptions record the presence of shows above 1780.5 m TVDss, however, an absence of staining was also noted.

However, cuttings descriptions state poor shows and the absence of staining over above 1780.5 m TVDss.

Well 98/11-1, drilled in the fault block to the south of Well 98/11-3, exhibits similar reservoir properties to Well 98/11-3, and similar elevated hydrocarbon saturations. Good fluorescence is noted, with bleeding oil observed in core, but no gas shows were observed. A DST on the Sherwood over a depth interval of 1779 to 1785 m TVDss flowed water.

A well correlation between Wells 98/11-3, 98/11a-6 and 98/11-1 is displayed in Figure 2.13.

ERCE's petrophysical averages show good agreement with the range of petrophysical averages used in UOGs volumetric cases. Given the uncertainty in maximum potential hydrocarbon saturations from these wells, Wytch Farm has been used as a nearby analogue for our estimation of hydrocarbon saturations.

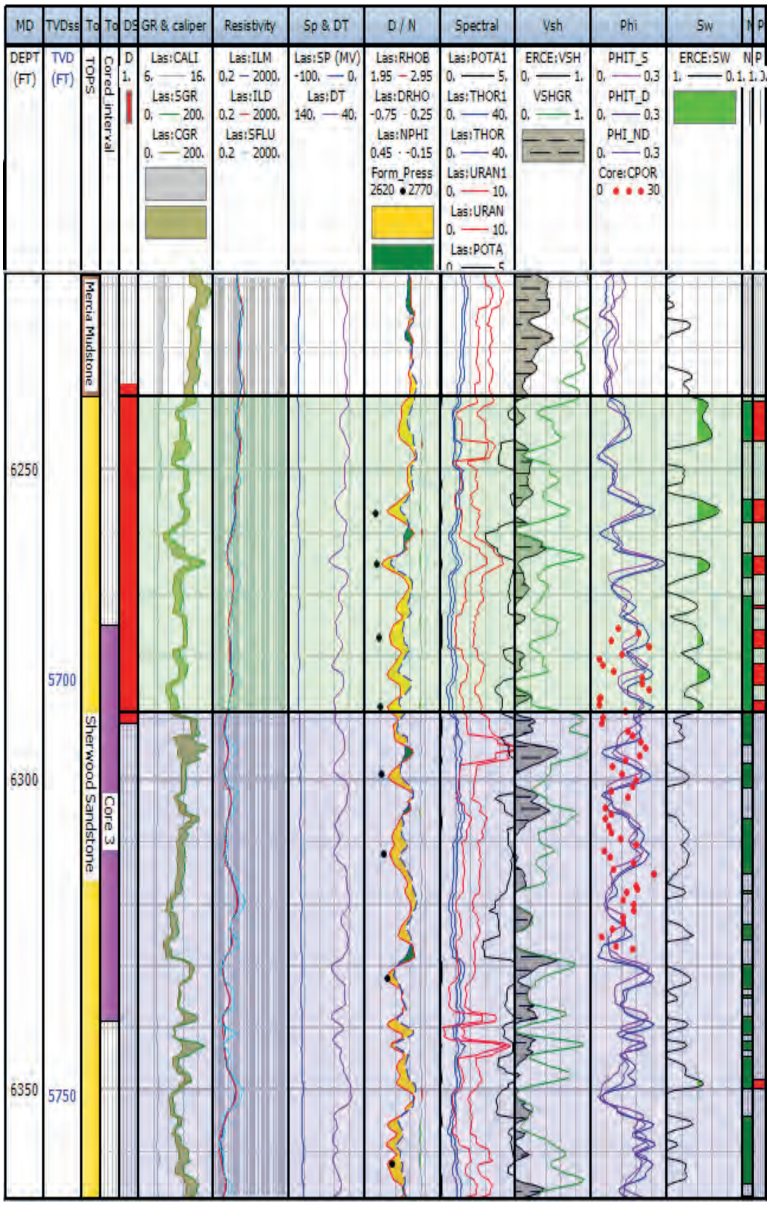

Figure 2.11: CPI for Well 98/11-3

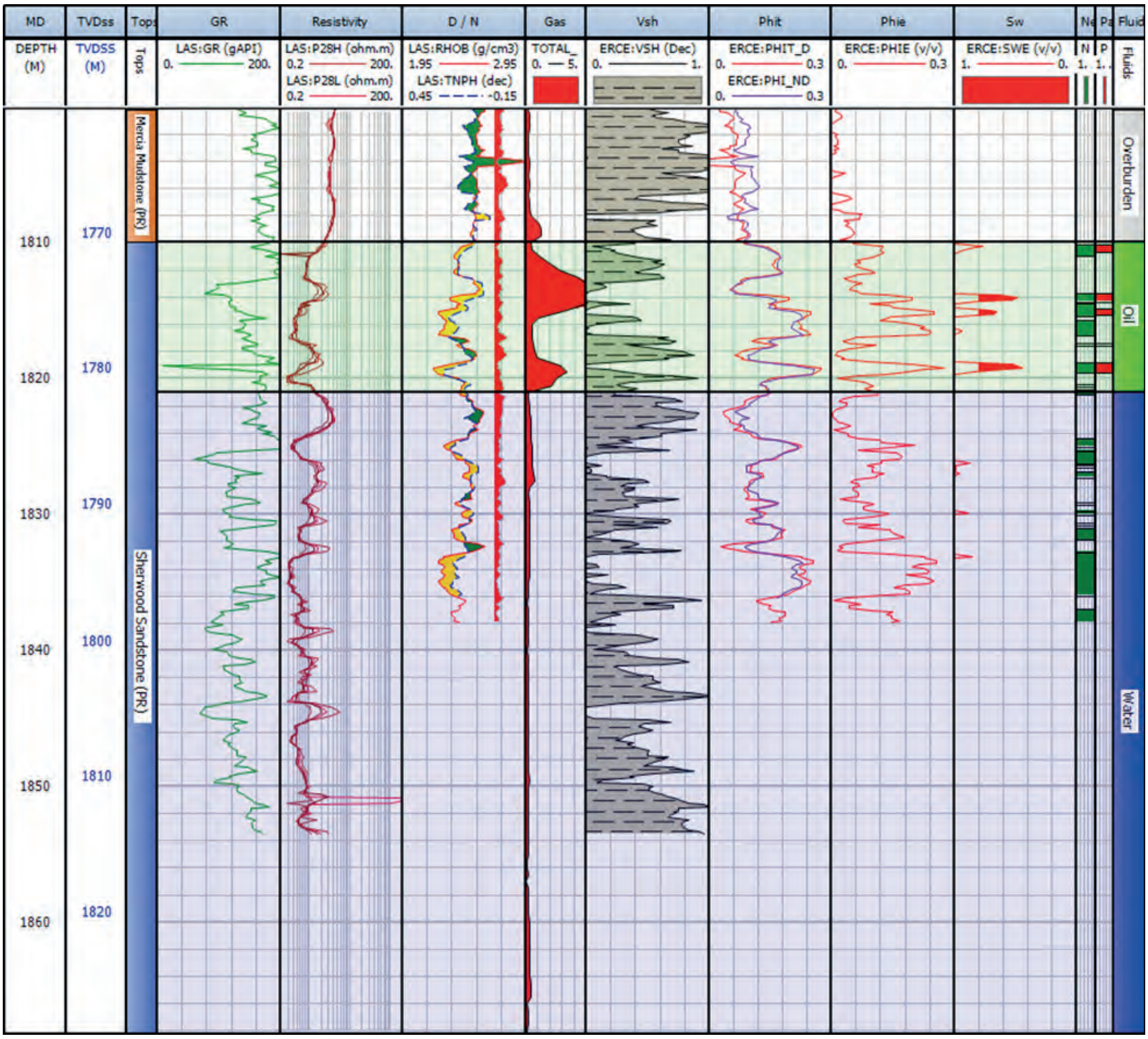

Figure 2.12: CPI for Well 98/11a-6

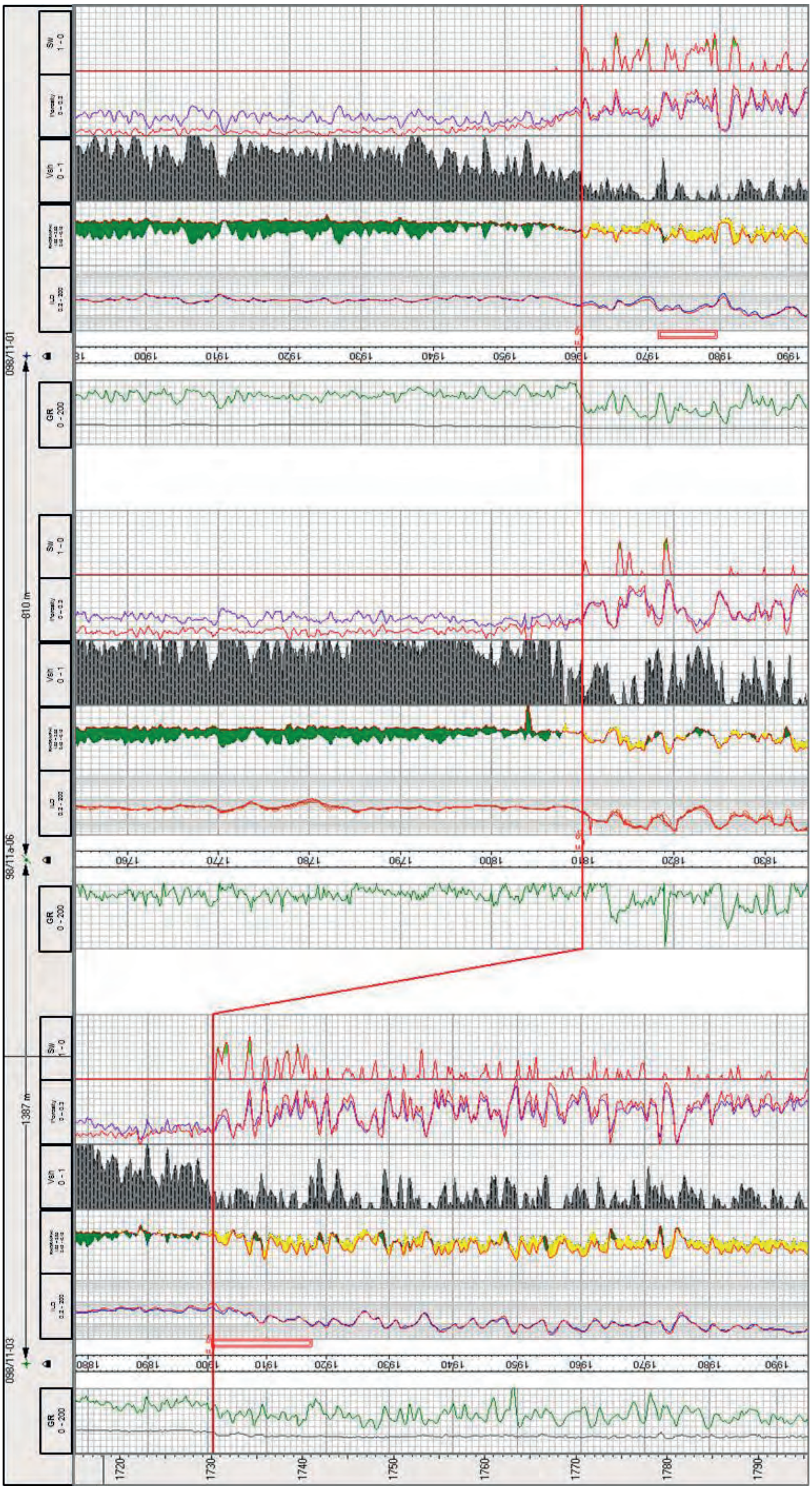

Figure 2.13: Well correlation panel between Wells #3, #6 & #1

2.2.5. Well Test Review

DSTs were carried out over the Sherwood Sandstone intervals in Wells 98/11-1 and 98/11-3.

The interval tested in Well 98/11-3 is shown in Figure 2.11. The well test report documents 8.5 bbl of oil were flowed to surface, out of 109 bbl total production, over a period of 3.5 hours. The flow rate declined rapidly on test due to water ingress and lack of gas to lift the liquids. The DST straddles the oil water contact interpreted from wireline logs, which probably explains the high water cut.

Figure 2.13 shows the depth range of the tested interval in Well 98/11-1. Despite the interpretation of elevated hydrocarbons saturations over the tested interval, Well 98/11-1 flowed water only, with 74 bbl of water recovered in a period of just over five hours. The tested interval is between 1779 and 1785 m TVDss (upper perforation set at 1780 m TVDss). Log interpretation suggests that the test targeted the most porous interval.

2.2.6. Hydrocarbons Initially In Place and Contingent Resources

ERCE uses probabilistic methods to estimate hydrocarbons in place and Contingent Resources for the Colter discovery.

The principal volumetric uncertainty at Colter is the structural interpretation which is a combination of both top depth surface and bounding faults. ERCE has reviewed depth and fault interpretation from both UOG and the operator Corallian and has adopted both as valid models. We adopt the OWC at 1740 m TVDss interpreted from wireline logs.

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the structure, based on analogue saturations in the nearby Wytch Farm field. A summary of input parameters used in our calculation of STOIIP is presented in Table 2.4.

Table 2.4: Input Parameters - Colter

Block	Field	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
PL1918	Colter	Sherwood	Oil	4.4	6.0	8.0	0.60	0.70	0.80	0.15	0.18	0.21
Block	**Field**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
PL1918	Colter	Sherwood	Oil	0.50	0.60	0.70	1.15	1.20	1.25	0.25	0.30	0.35

Our Gross and Net Contingent Resources (sub-classification Development Unclarified) estimates are presented in Table 2.5. ERCE agrees with UOG's assessment of Chance of Development of 30%.

Table 2.5: Unrisked Oil Contingent Resources of Colter, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL1918	Colter	Corallian Energy Limited	0.44	0.69	1.06	10.00%	0.04	0.07	0.11	30%

Notes:

1) *Refer to notes under Table 1.2*
2) *Colter carries a 30% Chance of Development.*

2.3. Crown Discovery (P2366)

2.3.1. Introduction

The Crown discovery is located in Block 15/19, offshore UK. UOG was awarded a 95% interest in the block in August 2018 as part of the UK offshore 30th Licensing Round. The licence is located offshore UK at the northwest margin of the Witch Ground Graben (Figure 2.14).

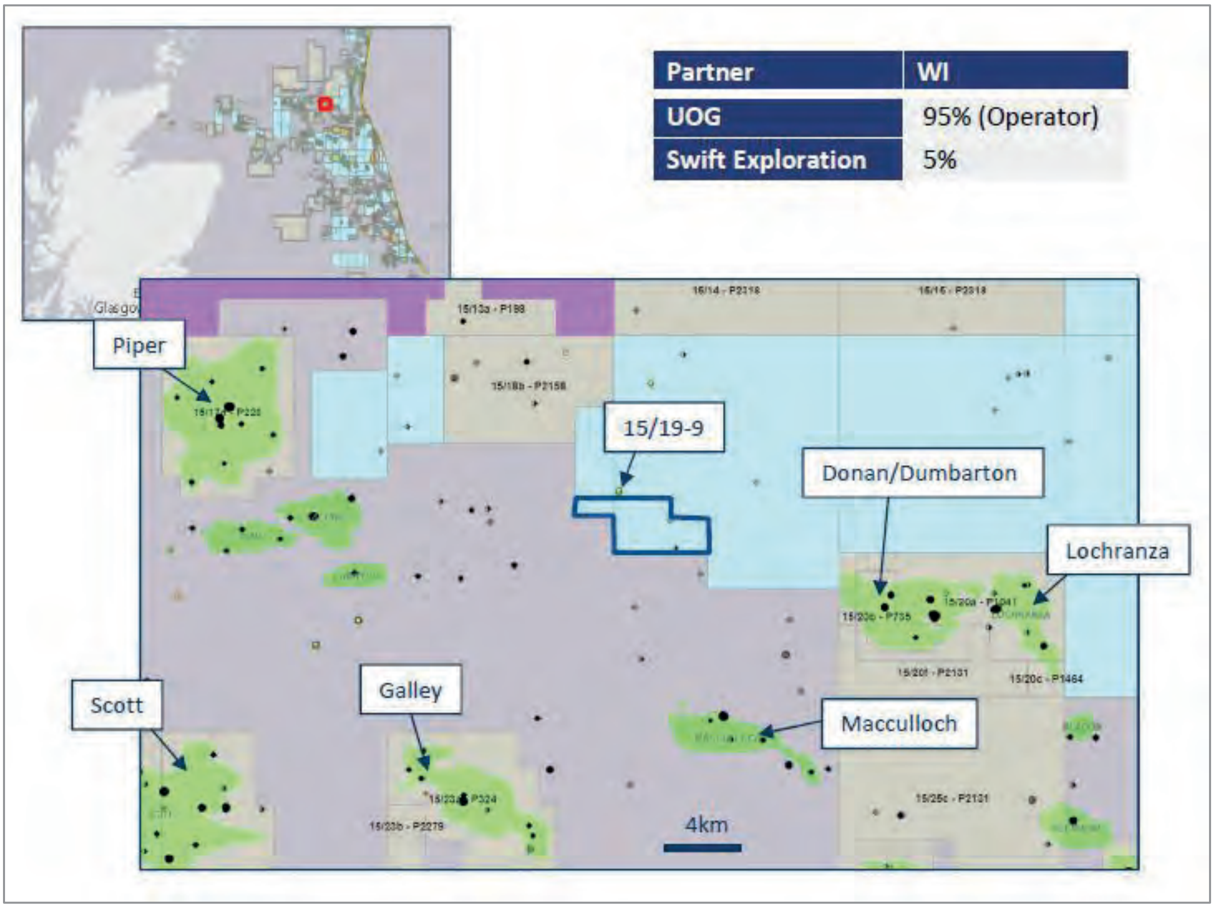

Figure 2.14: Crown Discovery Location Map
(Source: UOG Presentation)

Twelve wells have been drilled in the block. Wells 15/19-1, 2 & 3 were dry holes drilled through 1974 to 1976, testing tilted fault blocks at Jurassic level. Well 15/19-1 was a dry hole drilled in 1974 by Conoco to evaluate a structural-stratigraphic trap in the Upper Jurassic sandstones approx. 15 miles ESE of the Piper field. Well 15/19-2, drilled in 1974, evaluated a prospective structural closure at Base Tertiary/Top Danian and a structural stratigraphic trap in pre-Upper Cretaceous chalk beds. The Palaeocene sandstones were the primary objective and these were found to be dry. Well 15/19-3 was drilled in 1976 to test the Upper Jurassic Piper sandstones which were found to be absent, but the top of the Lower Palaeocene sands were oil bearing. The well was plugged and abandoned as a dry hole.

A second phase of exploration was undertaken in 1984 to 1986 to test the Jurassic Piper Sands, during which a further two dry holes were drilled (Wells 15/19-4 & 5). In 1993 to 1996 Wells 15/19-6 & 7 to tested the Piper and Palaeocene sands and Well 15/19-6 encountered an oil column in the Piper. Drilling in 1998 focussed on the Balmoral sand channel play and with Wells 15/19-8 and 15/19-9 which discovered Crown . Well 15/19-10b drilled the Stag discovery in 2007, encountering oil in Balmoral sands.

The southern part of the Block 15/19c was awarded to Maersk in 2009 in pursuit of the Balmoral play following its successful redevelopment of the Donan field renamed Dumbarton. Maersk subsequently drilled Wells 15/19c-11 in 2010 and 15/19c-12 in 2014 to test AVO anomalies on the Balmoral channel fairway.

Well 15/19-9 encountered in excess of 200 ft of the Palaeocene Balmoral Sandstone reservoir with an oil column between ~35 to ~55 ft and a gas column of ~30 ft, underlain by water-bearing Balmoral Sandstone. Core was cut and shows favourable reservoir properties with an average porosity of 27% and permeability mostly between 500 mD and 1500 mD. No DSTs were performed. An attempt was made to run a pipe conveyed MDT but this was unsuccessful.

2.3.2. Regional and Reservoir Geology

The Crown discovery is a four-way dip closure located at the northwest margin of the Witch Ground Graben. The Witch Ground Graben and Fladen Spur were a result of extension and associated fault movement during the Late Jurassic. These structural elements had a major influence on the later deposition of deep marine sand rich turbidites sourced from the Scottish mainland and Shetland Platform which form the Palaeocene Balmoral reservoir sands at Crown.

A chronostratigraphic column showing the principal source rocks and reservoir units is shown in Figure 2.15.

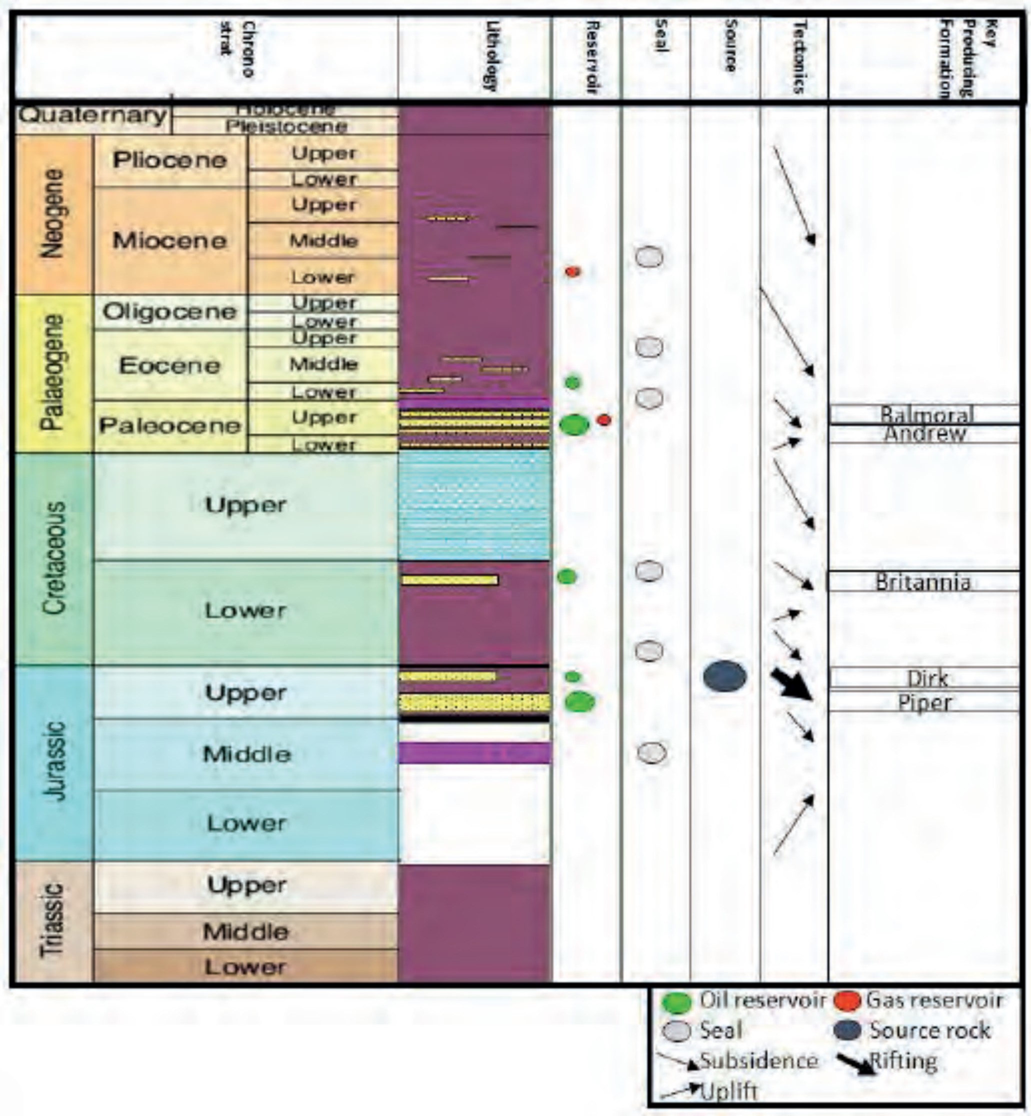

Figure 2.15: Stratigraphic Column, Witch Ground Graben and Fladen Spur.
(Source: United Oil & Gas Summary Presentation)

2.3.3.Seismic Data and Structure

The 3D seismic data over the Crown discovery were released in 1993, are of good quality, and allow for mapping of the key seismic events used to define the velocity model and top reservoir structure (Figure 2.16).

The data has subsequently been reprocessed by Shearwater in March 2019, further data conditioning and a rock physics study leading to a “JiFi” inversion volume was completed by Ikon in May 2019 satisfying the Phase A work commitments.

The newly reprocessed data has been reviewed by ERCE and supports our historical assessment of in-place volumes and Contingent Resources.

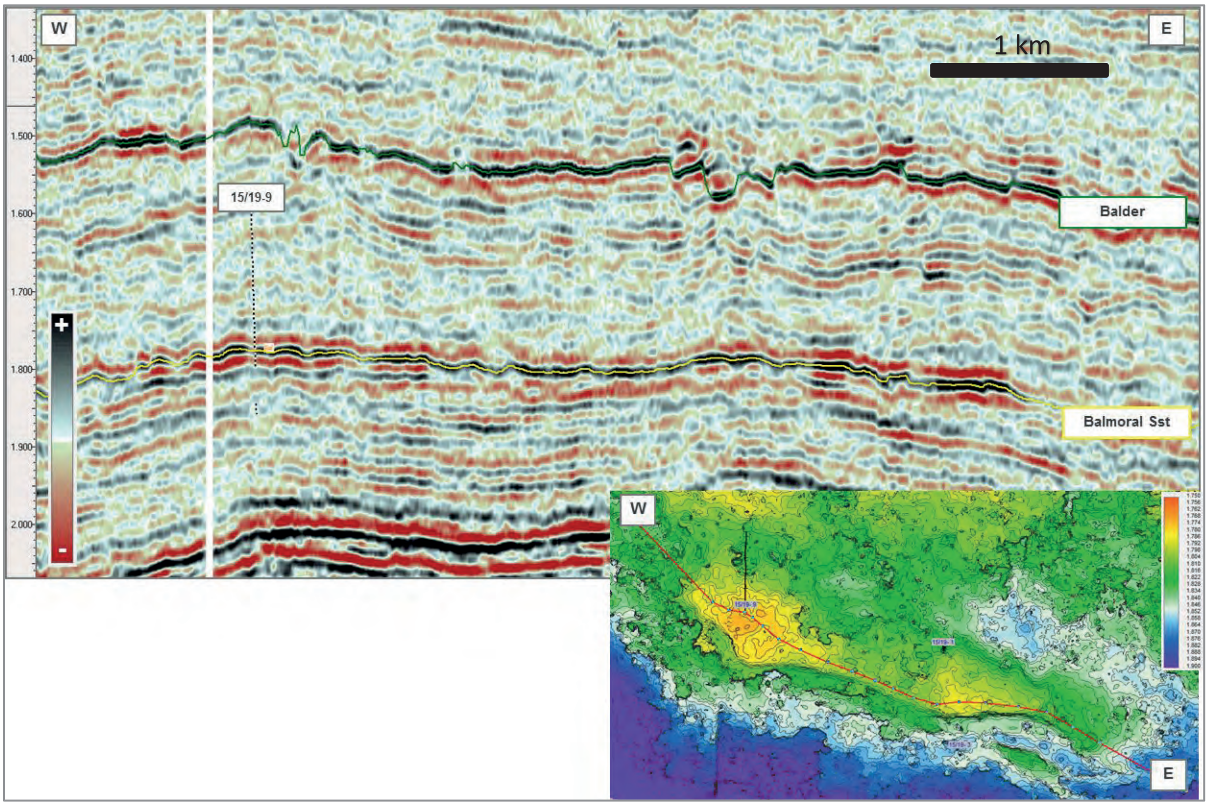

Figure 2.16: Arbitrary seismic line from running West to East along the crest of the Crown discovery

The Top Balmoral Sandstone event can be mapped from Well 15/19b-10 (Stag) which has been tied to the seismic through synthetic matching work, to the Crown discovery (Figure 2.17).

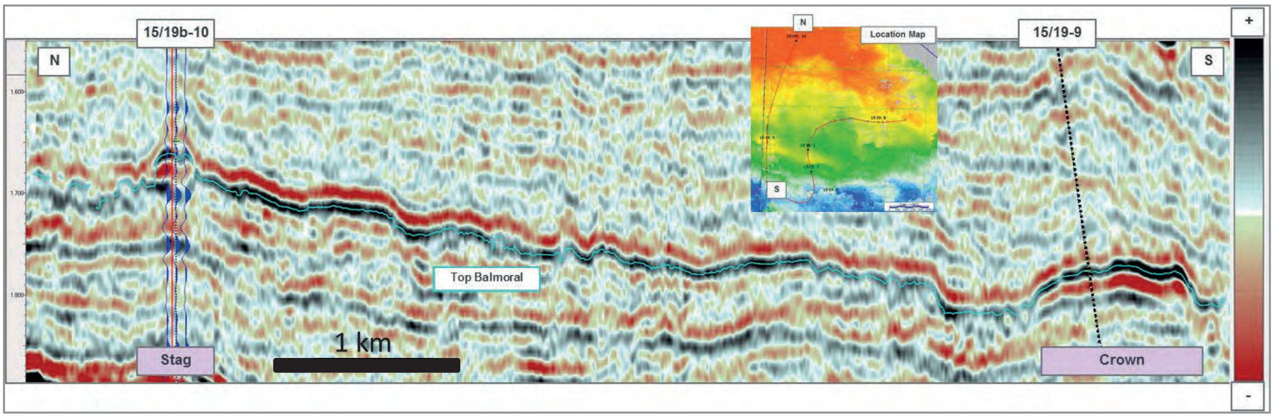

Figure 2.17: Arbitrary seismic line from Stag to Crown

The structure is a well-defined four-way dip closure which is fault bound to the south. ERCE has performed its own independent seismic interpretation for the Top Balder and Top Balmoral and which is in agreement with that provided by the operator.

2.3.4. Depth Conversion

ERCE has assessed all available velocity data and generated independent depth conversion models to explore the structural and volumetric uncertainty of the Crown discovery. ERCE has reviewed both alternative layering schemes and approaches to depth conversion. ERCE has further performed structural sensitivity testing by perturbing the velocity functions through multi-realisation modelling.

Velocity control is provided by sonic log velocities from wells proximal to the field (Figure 2.18) in conjunction with pseudo velocities calculated from formation top depths and associated time grid interpretation. ERCE used optimisation techniques to derive velocity function parameters that minimise residual error between predicted depths and well formation tops.

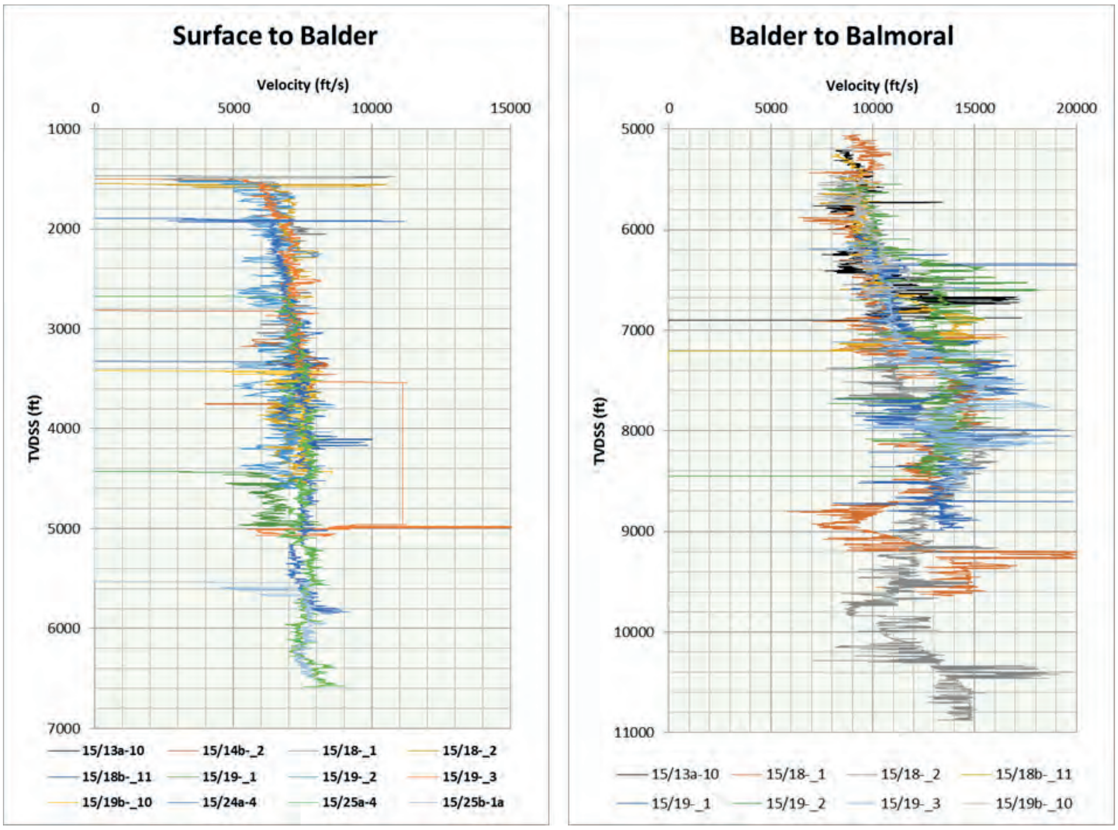

Figure 2.18: Sonic log velocities from proximal well control

2.3.5. Petrophysical Review

ERCE has performed an independent petrophysical review of Well 15/19-9, the Crown discovery well (Figure 2.19). The well is a deviated well with good log coverage and core data. The key uncertainty is water resistivity (Rw), as no water samples have been taken.

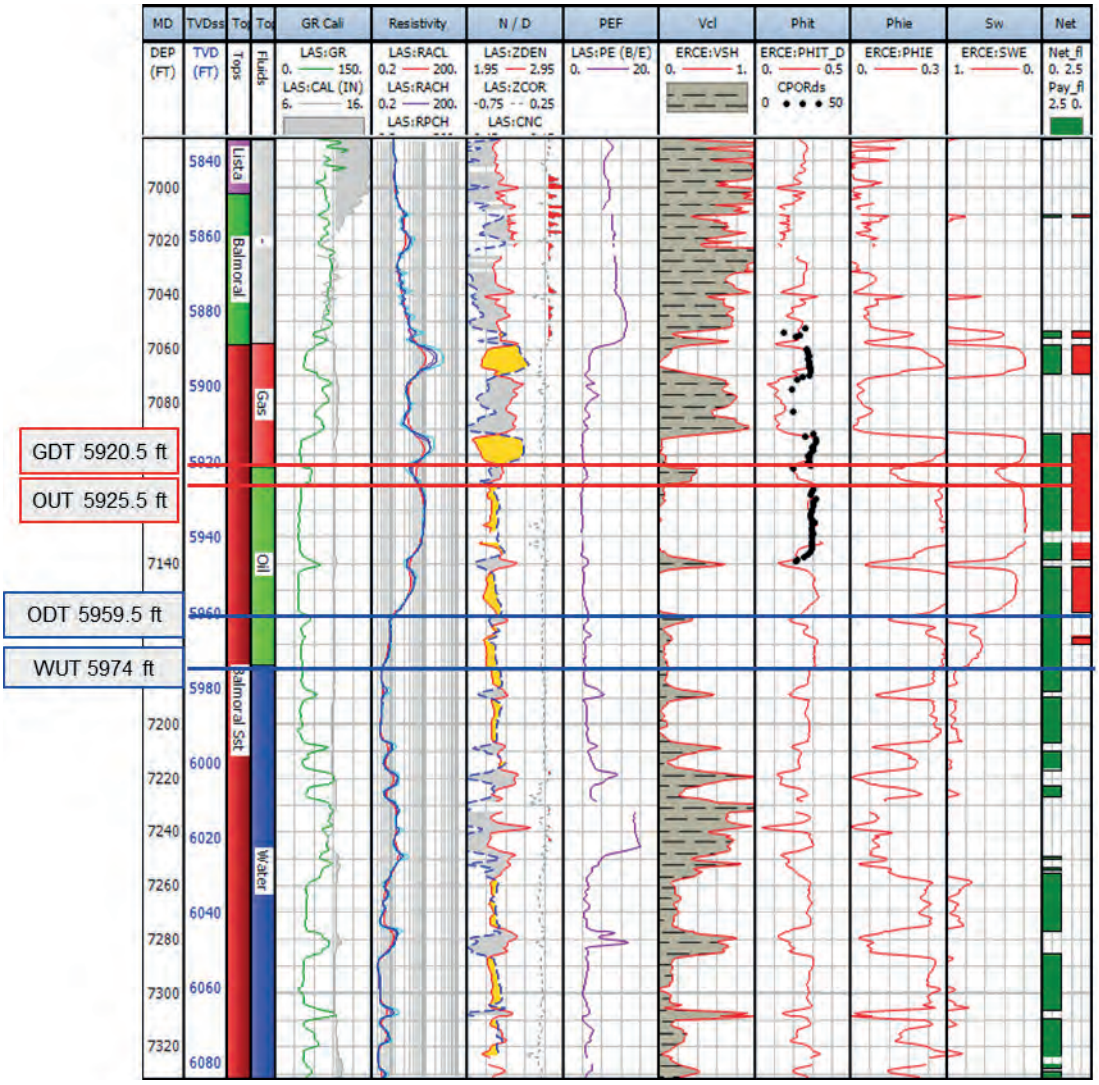

Figure 2.19: CPI Image of Well 15/19-9

The gas oil and oil water contacts as interpreted by ERCE are shown in Figure 2.19. These are also presented in Table 2.6.

Table 2.6: Crown Fluid Contacts

Contacts	TVDss (ft)
GDT	5920.5
OUT	5925.5
ODT	5959.5
WUT	5974.0

Figure 2.20 presents a cross plot of core porosity versus core permeability. The core data show good reservoir quality in the oil and gas leg with porosities of up to 32% and permeability of up to 2 D. There is no obvious difference in reservoir quality between the gas and oil legs.

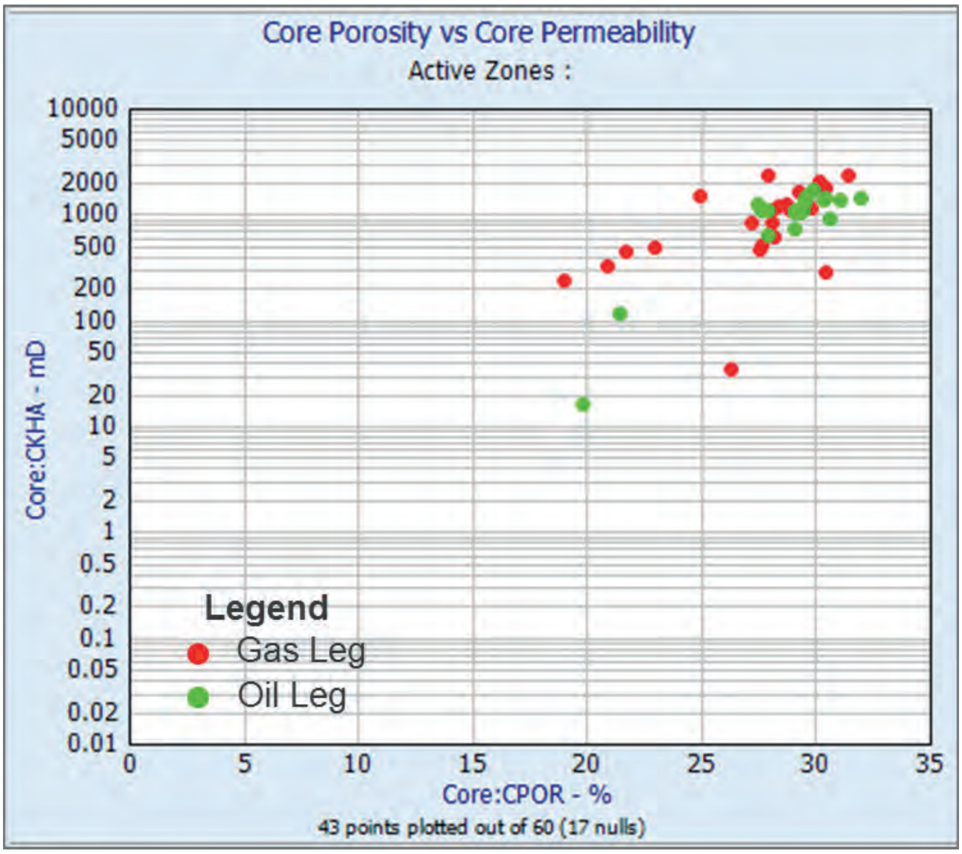

Figure 2.20: Plot of Core Porosity vs Core Permeability Well 15/19-9

ERCE has computed average reservoir properties across the different hydrocarbon zones in the reservoir using cut-offs of >10%phie, <40%Vsh and <60% Sw.

Table 2.7: Petrophysical Sums and Averages, Well 15/19-9

							Net			Pay			
Well	Zone Name	Top	Bottom	Top	Bottom	Gross	Net	N/G	Av Phi	Pay	P/G	Av Phi	Av Sw
		ft MD	ft MD	ft TVDss	ft TVDss	ft TVDss	ft TVDss	v/v	v/v	ft TVDss	ft TVDss	v/v	v/v
15/19- 9	BalmoralGas	7,059.25	7,101.75	5,889.33	5,919.62	30.28	14.07	0.465	0.256	14.07	0.465	0.256	0.259
15/19- 9	BalmoralOil	7,101.75	7,160.25	5,919.62	5,961.32	41.7	37.42	0.897	0.257	33.77	0.81	0.266	0.32
15/19- 9	BalmoralWater	7,160.25	7,381.50	5,961.32	6,120.13	158.82	95.34	0.6	0.223	0	0	---	---
15/19- 9	BalmoralRes	7,059.25	7,381.50	5,889.33	6,120.13	230.8	146.84	0.636	0.235	47.84	0.207	0.263	0.302

2.3.6. **Fluid Analysis**

Fluid samples were not taken from Well 15/19-9; the only estimate of oil API is from core samples. There are no measurements of gas properties. The core samples, which were likely already contaminated with drilling fluids, were transported in clingfilm, with chippings in a plastic bag, and as a result likely suffered some loss of light ends during transportation. Any resulting API estimate is therefore more uncertain than those from regular fluid samples.

Both the oil and gas leg residual oil samples showed moderate biodegradation, with the gas leg sample predicting a lower API (28 vs 35 °API). It is unclear whether the oils are different or this is just indicative of uncertainty in samples/measurements. Furthermore, it is unclear from the available samples whether the heavier components in the gas are due to residual oil or wet gas.

The laboratory which undertook the biochemical analysis was uncomfortable with the resulting API predictions, given the compositions and indication of light ends loss, deeming them high, so reduced its predicted ranges to 20-25 °API for the gas leg sample and 30-35 °API for the oil leg sample.

Both pressure and fluid samples were collected from Well 15/19-10 (Stag discovery to the north) but only the MDTs were available for ERCE's review. These data may be indicating a lighter fluid based on the suggested fluid gradient (>30 °API) however Well 15/18b-14 has reported a lower API fluid (20-25 °API).

ERCE has therefore used this information, in conjunction with other known field analogues, and estimates a formation volume factor range of 1.075 / 1.15 / 1.225.

2.3.7. Recovery Factor, Hydrocarbons Initially In Place and Oil Contingent Resources.

ERCE uses probabilistic methods to estimate hydrocarbons in place and Contingent Resources for the Crown discovery.

The principal volumetric uncertainty at Crown is the gross oil leg thickness above contact. ERCE has explored low and high cases for GRV using depth structure sensitivity analysis in combination with low and high case fluid contacts observed in Well 15/19-9. Low and high case gross oil legs maps are illustrated in Figure 2.21

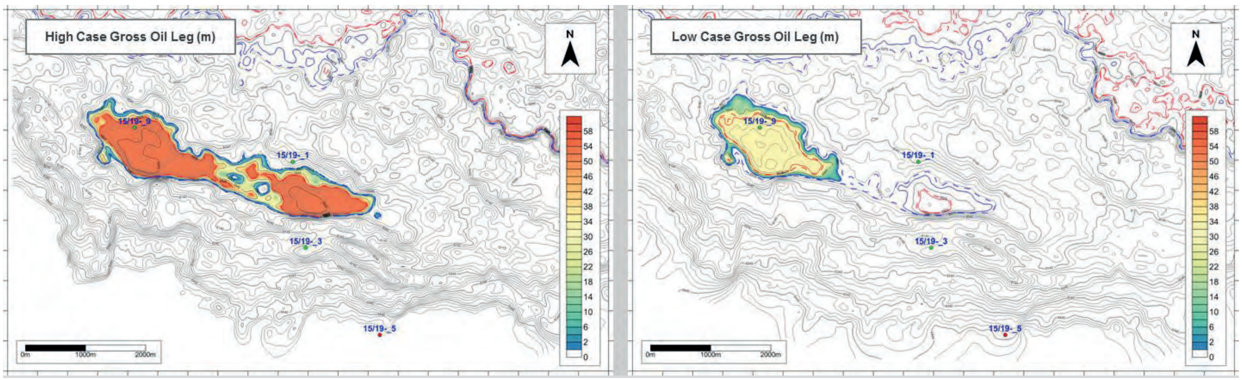

Figure 2.21: Low and High Case Oil Legs (m)

(Grey contours represent depth to top reservoir TVDss, solid blue contour highlights the ODT, dashed blue contour highlights the WUT, red contour highlights GDT and dashed red contour represents OUT. The colourfill represents the gross oil thickness).

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the petrophysical analysis across the different reservoir zones. ERCE is mindful of the impact that varying zone proportions modelled in the low, mid and high case will have on average water saturation and accounts for this. ERCE also applies a range of net to gross ratio (NTG) values to account for how structural variation may have the apparent effect of moving the oil leg to better or worse reservoir zones.

Seismic reprocessing and rock physics studies are part of the work commitments designed to help delineate and de-risk the Crown discovery. This work will also help form the optimal development strategy which at present is undecided. ERCE has considered nearby analogue fields to determine an appropriate range of recovery factors.

A summary of input parameters used in our calculation of STOIIP is presented in Table 2.8.

Table 2.8: Input Parameters - Crown

Licence	Field	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
P2366	Crown	Balmoral	Oil	14	23	40	0.55	0.65	0.75	0.25	0.27	0.29
Licence	**Field**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
P2366	Crown	Balmoral	Oil	0.65	0.70	0.75	1.075	1.150	1.225	0.20	0.28	0.40

Our STOIIP and Contingent Resources (sub-classification Development Unclarified) estimates are presented in Table 2.9. ERCE has reviewed UOG's assessment of Chance of Development and feel 60% is an appropriate estimation.

Table 2.9: Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	60%

Notes:

1) *Refer to notes under Table 1.2*
2) *Crown carries a 60% Chance of Development.*
3) *UOG is currently in the process of selling North Sea Blocks 15/18d and 15/19b ("Licence P2366") to Anasuria Hibiscus UK Limited. See additional notes under Table 1.1.*

3. Exploration Prospectivity

3.1. Wessex Basin

3.1.1. Introduction

The PL090 and P1918 licence areas within the Wessex basin contain Prospective Resources which have been assessed by ERCE in this report.

The PL090 licence block contains a number of prospects and leads in addition to the contingent resources of the Waddock Cross field discussed in Section 2.1. The licence contains two 3D surveys; the Waddock Cross 3D seismic survey acquired in 2004 and the larger Broadmayne 3D survey, which was acquired in 2013 and lies to the southwest of Waddock Cross. The data have been reprocessed a number of times and the third vintage of reprocessing has been used by UOG and partners in the mapping and identification of leads and prospects (Figure 3.1), including the Broadmayne prospect, which is currently the most mature and to which ERCE has restricted its assessment of Prospective Resources. The data have recently been reprocessed for a fourth time and provisional interpretation performed by UOG over the Broadmayne prospect supports historical mapping and the presence of dip and fault-closure. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report. It is anticipated that mapping and prospect maturation will continue using the results of this recent reprocessing.

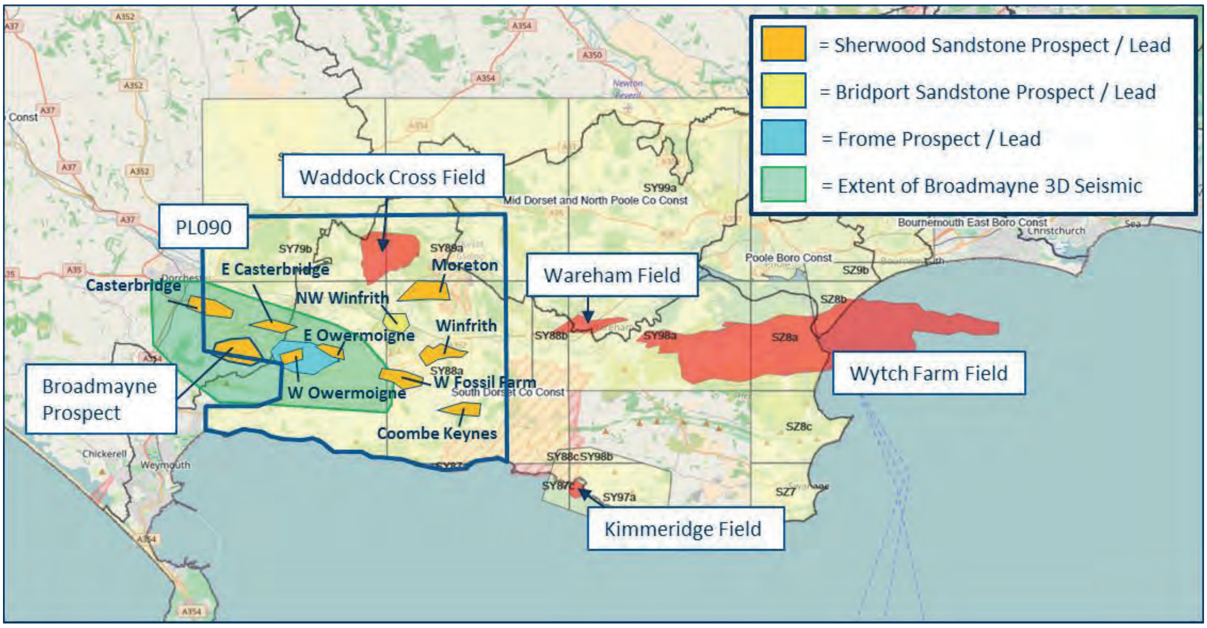

Figure 3.1: Locations of Wessex Basin leads
(Source – Oil & Gas Authority)

The nearby P1918 licence to the south of Wytch farm contains further prospectivity, including the Colter South prospect, which lies in the fault block immediately to the south of the Colter discovery discussed in Section 2.2.

A description of the regional geology and petroleum systems of the Wessex basin is given in Section 2.1.2. The primary exploration play for both prospects is that of the Sherwood Sandstone, charged by long distance migration from the main source kitchen to the east, and trapped within horsts or tilted fault blocks that provide counter dip closure (the regional dip is from west to east).

3.1.2. Broadmayne Prospect (PL090)

The Broadmayne prospect is situated to the southwest of the Waddock Cross field, and is mapped as straddling the PL090 license block at Sherwood Sandstone level.

The Sherwood Sandstone has been penetrated by eight wells within PL090 and the adjacent PEDL072 to the west. All of the wells encountered the Sherwood Sandstone but none encountered hydrocarbons. However, the majority were drilled on poor quality 2D seismic data. Although dry hole analysis is ongoing, the Broadmayne 3D suggests that a number of the wells did not have a valid structural closure, were positioned downdip from the crest, or drilled traps that had evidence of later breach.

The interpretation of the Top Sherwood event is challenging due to structural complexity and poor seismic signal below fast chalk sediments at the surface. The structure is less well defined in the west, in the direction of spill. Reprocessing of the seismic survey has recently been completed and provisional interpretation supports historical mapping and the presence of dip and fault-closure. Figure 3.2 shows a north to south seismic section over the prospect.

ERCE has assessed UOG's seismic interpretation over the Broadmayne structure and has adopted it for our volumetric assessment. A representative depth map is presented in Figure 3.3.

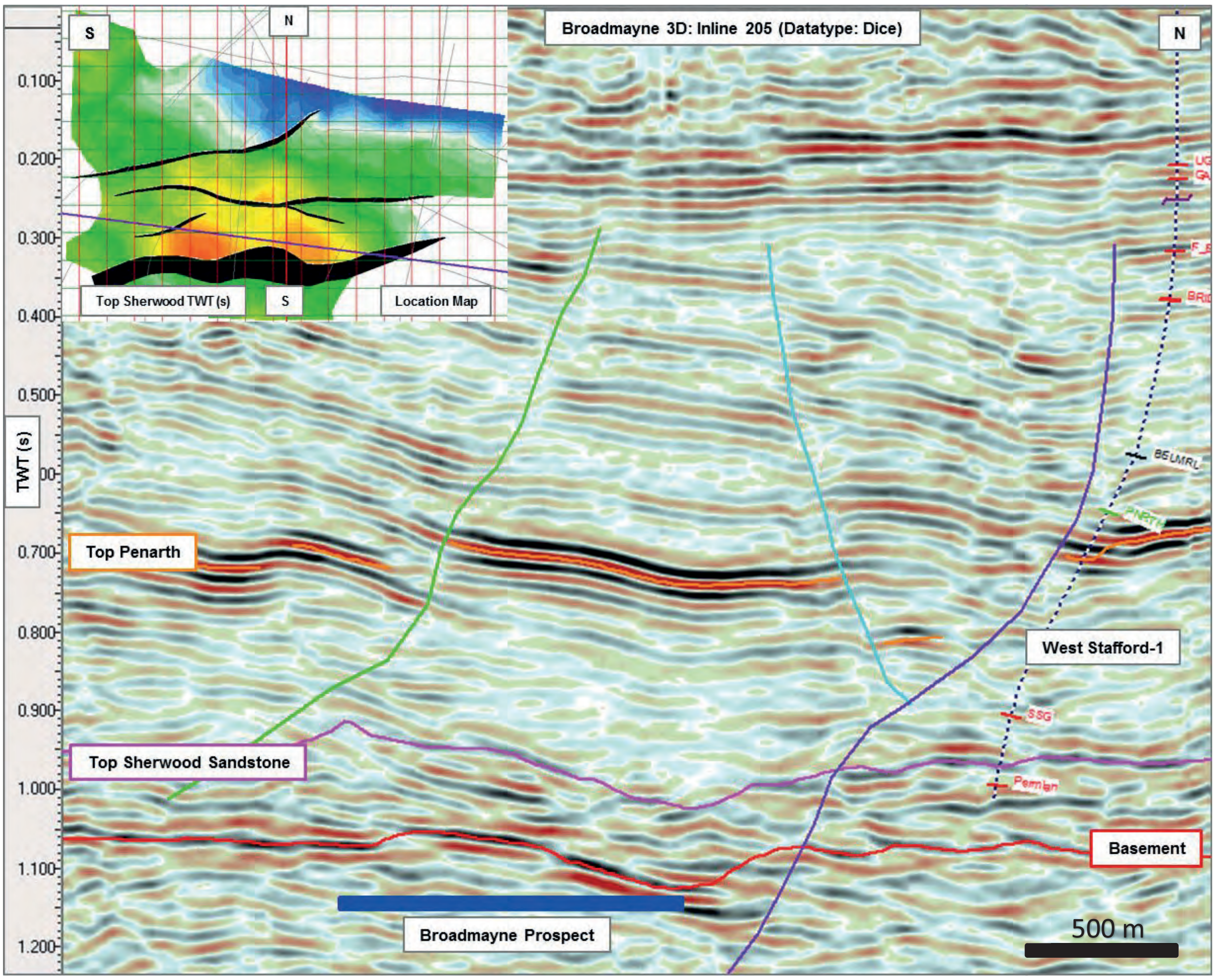

Figure 3.2: N-S Seismic Section Over the Broadmayne Prospect

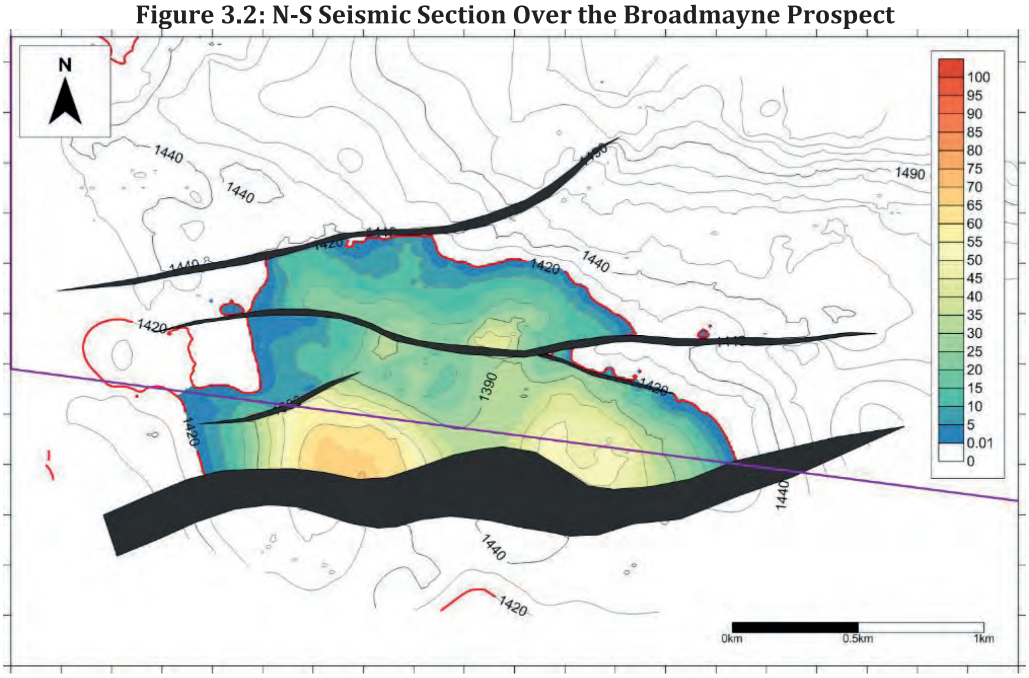

Figure 3.3: Broadmayne Prospect Depth Structure Map (m TVDSS)

(Grey contours represent depth to top reservoir TVDss, red contour highlights the depth at which structural spill occurs and the colourfill represents the gross reservoir thickness above spill depth).

3.1.3.Colter South Prospect (P1918)

The Colter South prospect in licence P1918 lies in the fault block immediately to the south of the Colter discovery, up-dip of Well 98/11-1. Additional closure is mapped around Well 98/11a-6. The geological history, seismic interpretation and depth structure are identical to Colter, so are not repeated here. A description of the drilling results in Licence P1918 can be found in Sections 2.1.1 and 2.1.7.

ERCE has assessed Prospective Resources for the Colter South structure, up -dip of Well 98/11-1, and the Prospective Resources associated with the closure around Well 98/11-6, which we have named the Colter South (Well#6) prospect.

3.1.4.Prospective Resources and Geological Chance of Success

ERCE has assessed the undiscovered hydrocarbons in place and oil Prospective Resources for the Broadmayne and Colter South prospects (Figure 2.9) using identical methodology to that used in our assessment of the Waddock Cross field and Colter discovery respectively.

For the Broadmayne prospect, offset wells Martinstown-1, Chickerell-1 and Coombe Keynes have been used to guide the potential thickness and reservoir properties of the Sherwood. Only the top 100 m of Sherwood Sandstone has been considered in each of the wells as this is the maximum mapped oil column thickness. Estimates of hydrocarbon saturation in the Broadmayne prospect have been made by treating the Wytch Farm Sherwood Sandstone as an analogue.

A summary of input parameters used in ERCE's estimation of the STOIIP for the Broadmayne prospect is presented Table 3.1.

Table 3.1: Input Parameters – Broadmayne Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
PL090	Broadmayne	Sherwood	Oil	20	42	85	0.4	0.5	0.6	0.14	0.18	0.21
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
PL090	Broadmayne	Sherwood	Oil	0.50	0.60	0.70	1.150	1.200	1.250	0.25	0.30	0.35

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources for Broadmayne is presented in Table 3.2.

Table 3.2: Broadmayne Prospect - STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Broadmayne	Egdon Resources UK Limited	5.0	11.1	24.5	13.4	1.50	3.30	7.40	4.00	18.95%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**1U**	**2U**	**3U**	**Mean**
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimate to fall within the PL090 block boundary (50%).*

Notes:
1) Refer to notes under Table 1.5

ERCE has adopted a four component risk matrix in our assessment of Geological Chance of Success (COS) for the Broadmayne Prospect, comprising source, reservoir (presence and efficacy), trap and seal

ERCE sees no material risk associated with reservoir presence, efficacy and top seal, based on the results of the offset wells. The dominant risk factors for the Broadmayne prospect are source/migration and trap integrity.

Source encompasses both the presence of source rock material and migration. The presence of producing oil fields in the area confirms the presence of source rocks. Success for Broadmayne relies upon a migration pathway existing to the west of the main source area of the basin into Licence PL090

Trap embraces all the components that define the competency of the closure. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

Our assessment of the COS for the Broadmayne prospect is 30%, as presented in Table 3.3.

Table 3.3: Broadmayne Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Broadmayne	0.50	1.00	0.60	1.00	0.30

For the Colter South prospect ERCE generated low and high GRV cases based on the different structural models from UOG and the operator Corallian in conjunction with a range of fluid levels. Our high case contact is chosen as the WUT at the top of the shallowest perforation in the DST of Well 98/11-1. We choose the base of the elevated hydrocarbon saturations which lie above the tested net interval as our low case contact, of 1775 m TVDss.

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the field where a shallower structure has been interpreted, based on analogue saturations in the nearby Wytch Farm field. A summary of input parameters used in our calculation of STOIIP is presented in Table 3.4.

Table 3.4: Input Parameters – Colter South & Colter South (Well#6) Prospects

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
PL1918	Colter South	Sherwood	Oil	28	61	130	0.60	0.70	0.80	0.15	0.18	0.21
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
PL1918	Colter South	Sherwood	Oil	0.50	0.60	0.70	1.15	1.20	1.25	0.30	0.39	0.50

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
PL1918	Colter South W#6	Sherwood	Oil	1.4	4.9	17.3	0.60	0.70	0.80	0.15	0.18	0.21
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	Best	High	Low	Best	High	Low	Best	High
PL1918	Colter South W#6	Sherwood	Oil	0.50	0.60	0.70	1.15	1.20	1.25	0.30	0.39	0.50

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources for Colter South and the 98/11-6 well closure is presented in Table 3.5.

Table 3.5: Colter South and Colter South Well#6 Prospect – STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter South	Corallian Energy Limited	10	24	52	29	3.9	9.2	21.0	11.3	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	2U	3U	Mean		1U	2U	3U	Mean
Colter South	Corallian Energy Limited	0.39	0.92	2.10	1.13	65%	0.25	0.59	1.37	0.74

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter South *(Well#6)*	Corallian Energy Limited	0.52	1.92	7.00	3.21	0.20	0.75	2.74	1.27	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	2U	3U	Mean		1U	2U	3U	Mean
Colter South *(Well#6)*	Corallian Energy Limited	0.02	0.07	0.27	0.13	62%	0.01	0.05	0.18	0.08

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the P1918 Licence (10.00%).*

Notes:
1) *Refer to notes under Table 1.5*

ERCE sees reservoir presence, efficacy source and migration as low risk based on the results of the offset wells. The dominant risk factor for the Colter South prospects is trap integrity, as a potential fault seal breach across the southern bounding structural faults.

Our assessment of the COS for the Colter South prospect and the 98/11-6 well closure is 65% and 62% respectively, as presented in Table 3.6.

Table 3.6: Colter South Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Colter South	1.00	1.00	0.65	1.00	0.65
Colter South (Well#6)	1.00	0.95	0.65	1.00	0.62

3.2. Jamaica

3.2.1. Introduction

The Walton-Morant licence area is situated offshore Jamaica and covers a large area of 32,065 km^2 (Figure 3.4). The PSA became effective on 1st November 2014 and Tullow is the operator. UOG has signed an agreement with Tullow to farm-in to the Walton-Morant Licence at a 20% equity interest. This will involve paying a 20% share of costs. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data which was designed to concentrate on the Colibri prospect. Since the acquisition the data have been reprocessed and a number of 3D seismic volumes and derived attributes have been generated. One of the most recent products is an anisotropic PSTM, PSDM and an associated velocity volume.

The licence contains the Pedro Bank carbonate platform and the Walton and Morant Basins, of which the Walton Basin is the primary exploration focus as this contains siliciclastic reservoirs located within a thermally mature kitchen area.

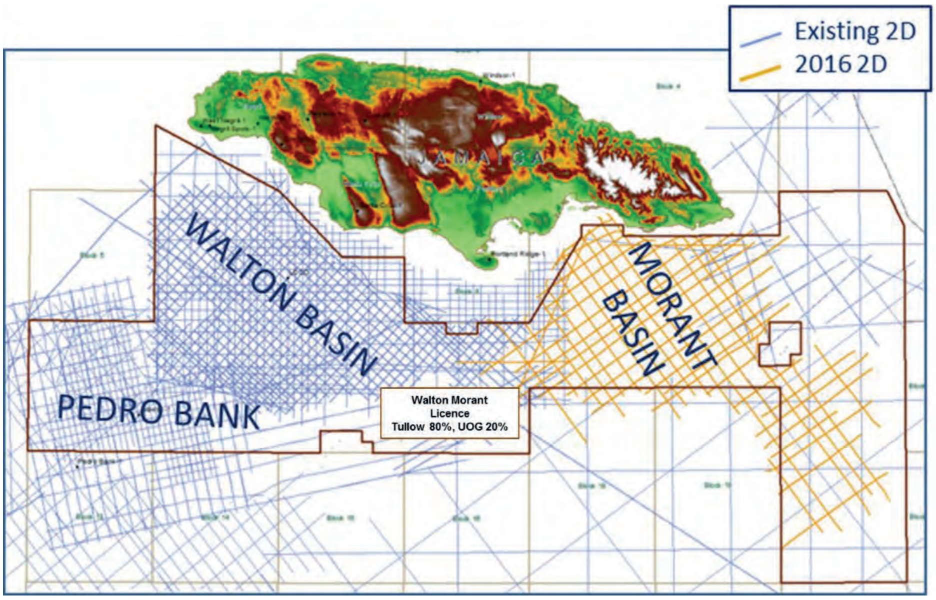

Figure 3.4: The Walton Morant Licence, offshore Jamaica
(Source: Tullow)

The Walton Basin is an Early Tertiary rift basin situated on the eastern margin of the Nicaragua Rise.

The principal reservoir target is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20% porosity at outcrop. The Guy's Hill Formation comprises a fluvio-deltaic-shallow marine succession in stacked parasequences which have been observed to reach up to 320 m gross thickness onshore. Well Arawak-1 is the nearest offshore penetration of potential Guy's Hill correlatives located approximately 70km to the west of the prospect, this is interpreted to contain a gross thickness in excess of 220m. A potential lack of continental clastic input has been a concern for reservoir quality and extent in the region. However, evidence of southerly directed palaeocurrents and palaeontological data suggest Jamaica was receiving sediment from the Maya – Chortis continental block in the Eocene epoch. This implies the presence of delta mouth, shoreface and/or submarine fan sands with good reservoir properties in offshore areas.

The proposed source rocks in the region are Eocene prodelta-marine shales and Cretaceous marine shales, which are observed onshore and at outcrop. Sedimentological models and analogues predict thicker and more oil prone marine shales offshore. Seeps have been observed onshore, and there have been two positive offshore seep surveys. Although a definitive correlation to a particular source rock is yet to be achieved, this suggests an effective and mature regional source. Extensive maturity modelling suggests significant oil would have been expelled from Eocene kitchens in both the Walton and Morant basins.

The recently acquired and processed 3D seismic data covering the Colibri prospect better images faults which could provide migration pathways from source to reservoir. The 3D seismic also reveals features which are positive indications that fluid movement has taken place within the basin. These include pock marks at seabed and bright amplitude abutting deep seated faults. This additional information has allowed ERCE to reduce the risk associated with source and migration.

Seal is provided by the widely distributed transgressive shales, marls and tight limestones of the Chapelton formation, which directly overlies the Guy’s Hill Formation.

Structurally, the area sits within an extensional horst and graben-style basinal setting with large tilted fault blocks and basement highs as trapping mechanisms.

The regional stratigraphy of the area is summarised in Figure 3.5.

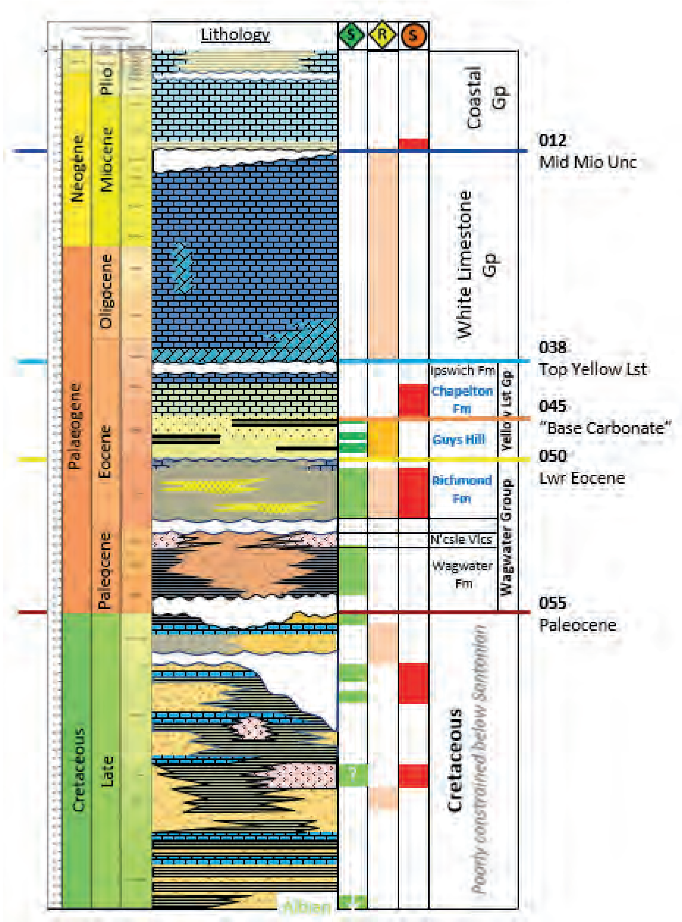

Figure 3.5: Regional Stratigraphy, offshore Jamaica
(Source: Tullow)

Historically, exploration focused on Cretaceous targets and to date eleven wells have been drilled, of which nine wells were onshore and two were offshore. Many of the targets were defined only by surface geology whilst others were based on poor data and UOG's current interpretation is that the wells were not valid structural tests. However, all but one of the wells exhibited hydrocarbon shows.

Well Arawak-1 was one of the last wells drilled in Jamaica in 1982 and exhibited wet gas shows. The well targeted Cretaceous carbonates in a four way dip closed anticline structure, but the reservoir was not encountered as prognosed and the well was plugged and abandoned at a depth of 4,588 metres. The well did intersect over 200 m of sands possibly belonging to the Guy's Hill formation with a net to gross ratio of 46% and a log derived porosity of 14%, at a depth of around 4000 m MD, near TD.

3.2.2. Colibri Prospect (Walton-Morant)

The Colibri prospect is situated in the Walton Basin in water depths of approximately 750 m (Figure 3.6). The prospect is a well-defined fault-bounded structure with onlap and drape. The basinal position suggests overlying pelagic shales and marls will likely form a seal. The 3D seismic data demonstrate that some faulting propagates to seabed, implying the possibility of trap breach. The prospect is well positioned to receive charge from surrounding Eocene and/or Cretaceous kitchens, and is located close to the Blower Rock oil seep. The improved imaging provided by the 3D seismic data provides positive evidence for migration pathways and fluid movement through the Walton Basin. The area has also been interpreted by Tullow to sit within the Guy's Hill Formation depositional fairway.

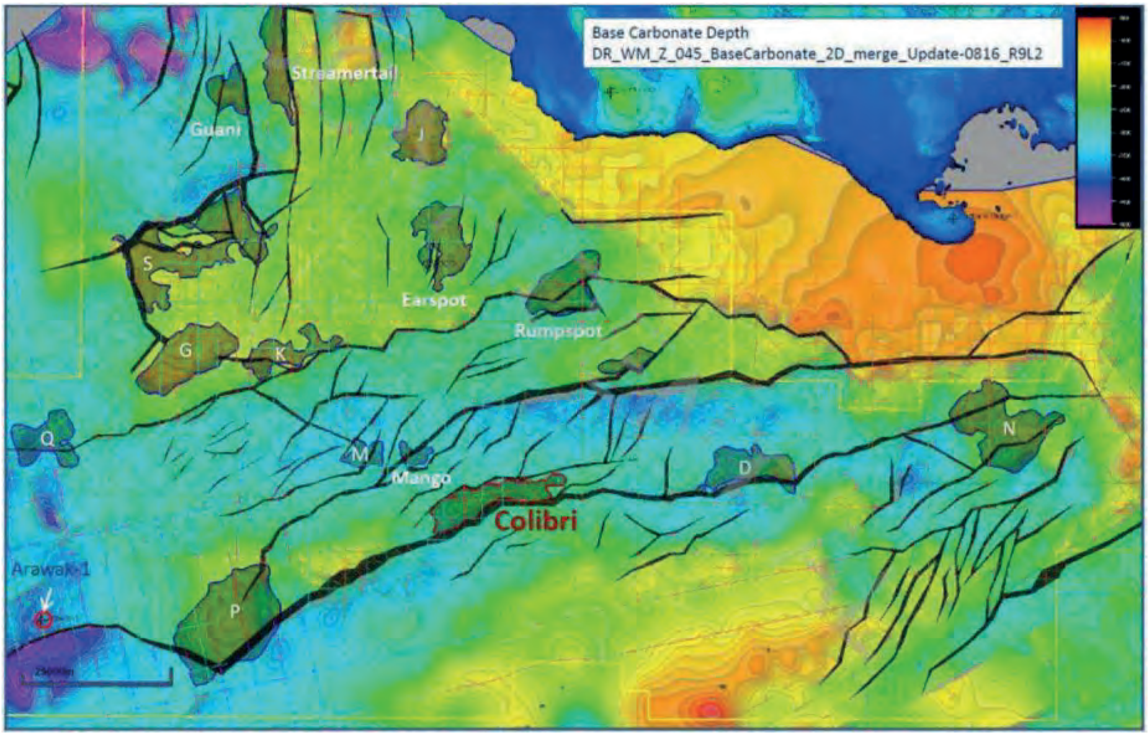

Figure 3.6: Location of Colibri and associated leads in the Walton Basin
(Source: Tullow)

ERCE has reviewed both Tullow's and UOG's revised 3D seismic interpretation over the Colibri structure and following audit has adopted interpretations as valid models from which to derive a volumetric range. A west to east and south to north seismic section across the Colibri prospect illustrating these interpretations for comparison are shown in Figure 3.7 and Figure 3.8 respectively.

ERCE has assessed the Tullow processing velocity depth conversion model and performed comparisons against independent layer cake models that predicts an increase in velocity with increasing depth below seabed. The rate of velocity increase ($0.7s^{-1}$) was determined from regressions of sonic log velocities from Well Arawak-1. However, it is noted that this well is located on the Pedro Bank and encountered different lithologies than prognosed for the more basinal location of the Colibri prospect. ERCE have therefore calibrated the layer cake model to a crestal depth predicted by the processing velocities. ERCE used both the linear model and processing velocity model as alternative base cases for further stochastic sensitivity analysis for the Colibri prospect.

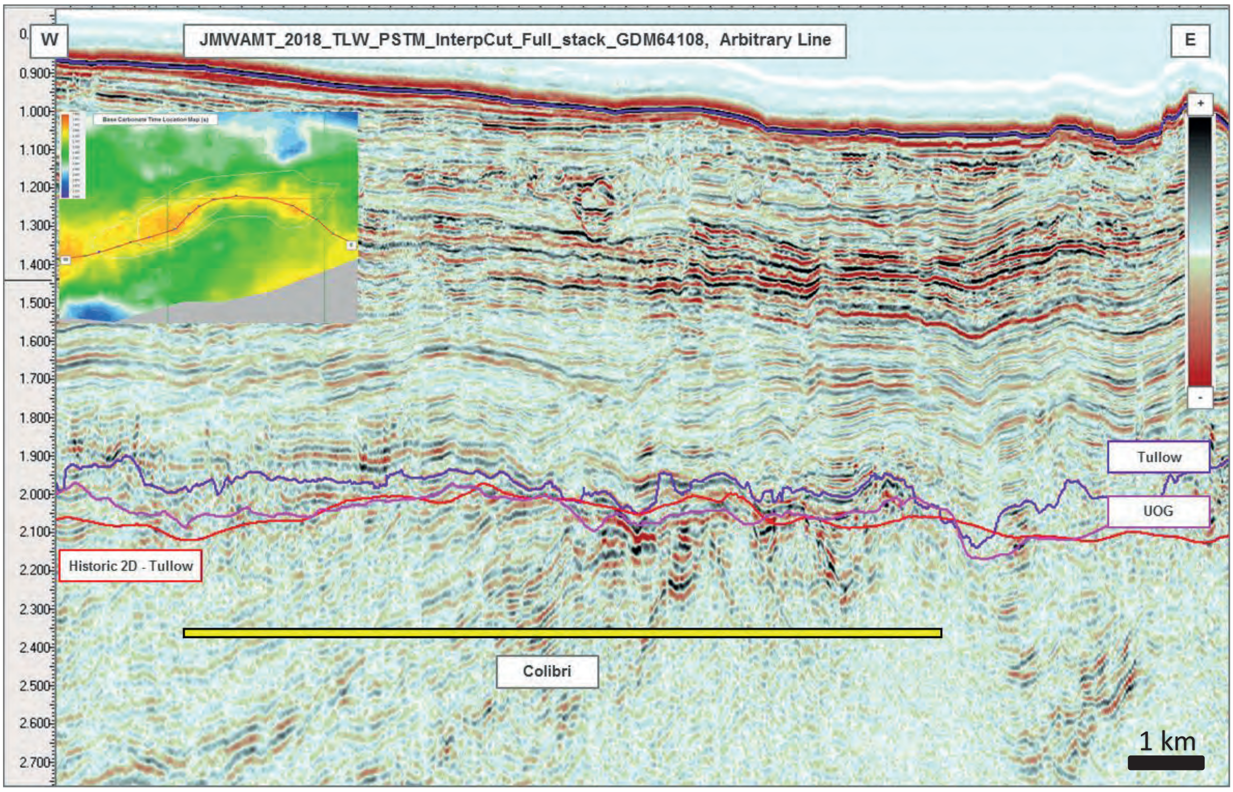

Figure 3.7: W-E Seismic Section Over the Colibri Prospect

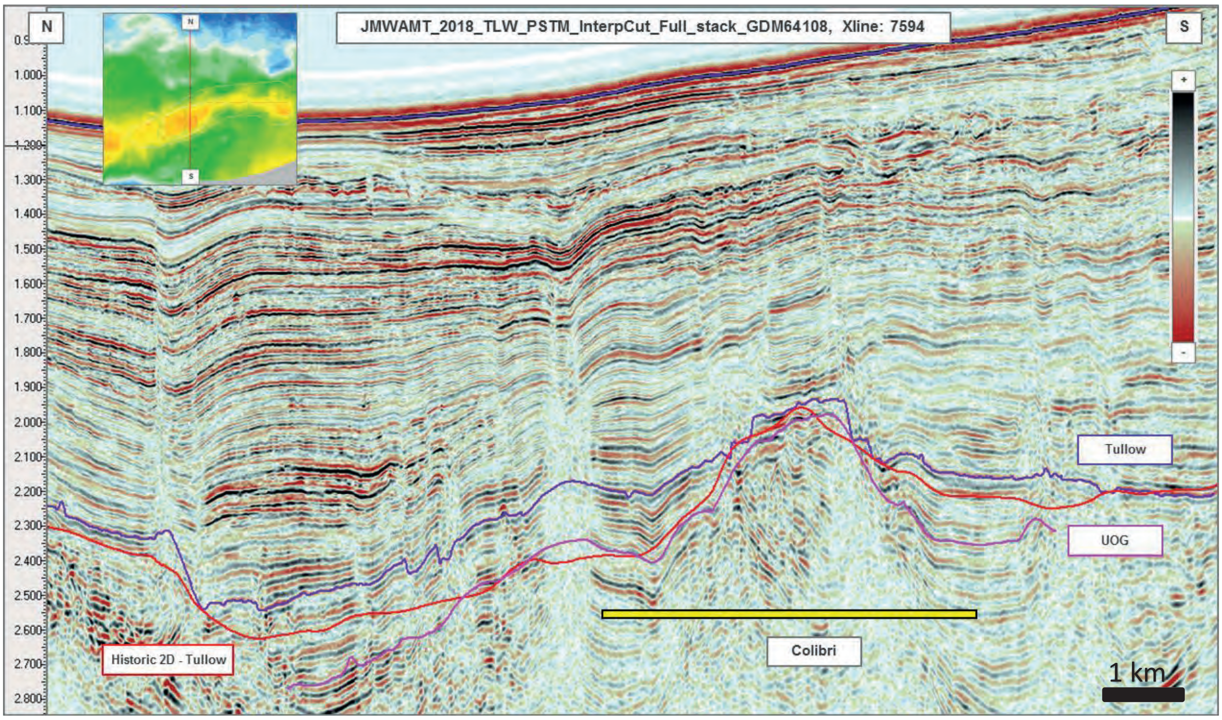

Figure 3.8: S-N Seismic Section Over the Colibri Prospect

Since the above review, the operator has undertaken PSTM and PSDM seismic reprocessing. ERCE has reviewed the existing interpretation against the new data. ERCE agrees with UOG's and the operator's view that there is little change to the time domain seismic image and there is no reason to alter the existing time interpretation.

3.2.3. Prospective Resources and Geological Chance of Success

ERCE uses probabilistic methods to estimate hydrocarbons in place and oil Prospective Resources for the Colibri prospect.

ERCE has applied stochastic uncertainty modelling to our base case depth structures to assess the GRV range of the Colibri prospect. An uncertainty of up to 5% in depth below mudline has been assumed and used to condition the sequential gaussian simulation (SGS) surfaces. The resulting high and low case closures are shown in Figure 3.9.

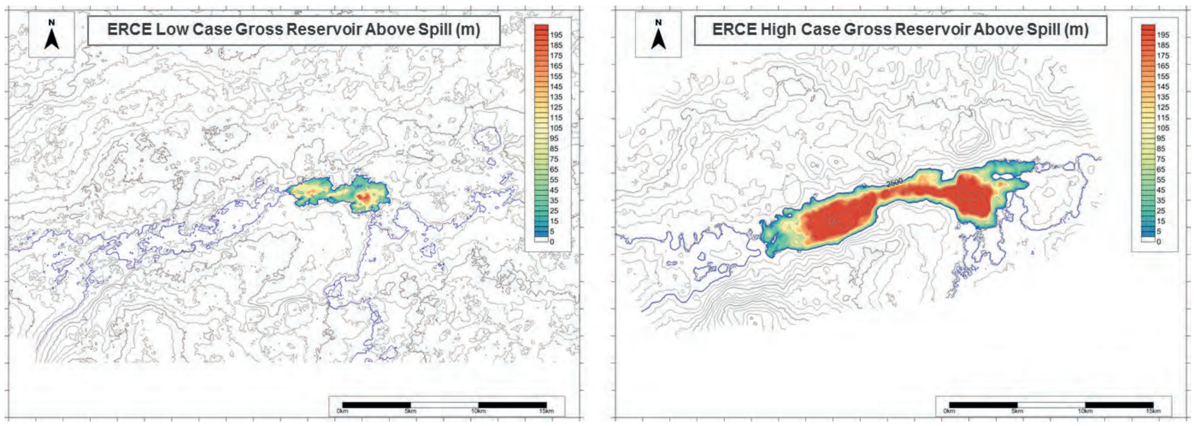

Figure 3.9: Colibri Prospect, Reservoir Height Above Contact Maps (m TVDss)
(Grey contours represent depth to top reservoir TVDss, blue contour highlights the depth at which structural spill occurs and the colourfill represents the gross reservoir thickness above spill depth).

Offset Well Arawak-1 together with outcrop studies and analogues have been used to guide the potential thickness and reservoir properties of the Guy's Hill Formation over the Colibri prospect. Estimates of hydrocarbon saturation in the Colibri prospect have been made by using an industry analogue database. A summary of input parameters used in ERCE's estimation of the STOIIP for the Colibri prospect is presented in Table 3.7.

Table 3.7: Input Parameters – Colibri Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
Walton Morant	Colibri	Guy's Hill	Oil	772	2259	6608	0.20	0.40	0.60	0.12	0.19	0.25
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	Best	High	Low	Best	High	Low	Best	High
Walton Morant	Colibri	Guy's Hill	Oil	0.50	0.65	0.80	1.12	1.21	1.30	0.15	0.25	0.45

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources is presented in Table 3.8.

Table 3.8: Colibri Prospect - STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%
Prospect	Operator/ Administrator	Net Unrisked Prospective Resources (MMstb)				COS	Net Risked Prospective Resources (MMstb)			
		1U	2U	3U	Mean		Low	Best	High	Mean
Colibri	Tullow Jamaica Ltd	6	26	103	46	20%	1.19	5.00	20.08	8.97

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the Walton-Morant Licence (20.00%)*

Notes:

1) Refer to notes under Table 1.5

Our assessment of the risk for the Colibri play is 54%, with the prospect risk at 36%, leading to a Geological chance of success as 20%, as presented in Table 3.9. The recently acquired 3D seismic data shows positive evidence of fluid movement and hydrocarbon presence in the basin and ERCE have therefore reduced the risk associated with play source and prospect migration since the last assessment. The dominant prospect risk is reservoir efficacy and presence, given the sparsity of wells and uncertain reservoir distribution in the basin.

Table 3.9: Colibri Play and Prospect Risk Matrix

Play Element	Risk
Source	0.85
Reservoir Presence	0.80
Seal	0.80
Combined Play Risk	0.54

Prospect Risk	Colibri
Trap	0.80
Reservoir efficacy (presence)	0.50
Migration	0.90
Combined Prospect Risk	0.36

Geological Chance of Success (GCOS)	0.20

4. SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, Version 1.01, as revised in June 2018 and updated in November 2018 (PRMS).

The full text of the PRMS document can be viewed at:

https://secure.spee.org/resources/reserves-definitions-committee-rdc

PRMS classifies resources into discovered and undiscovered, and defines the recoverable resources classes of; Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

A graphical representation of the PRMS resources classification framework can be seen below in Figure A. The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, which is the chance that a project will be committed for development and reach commercial producing status.

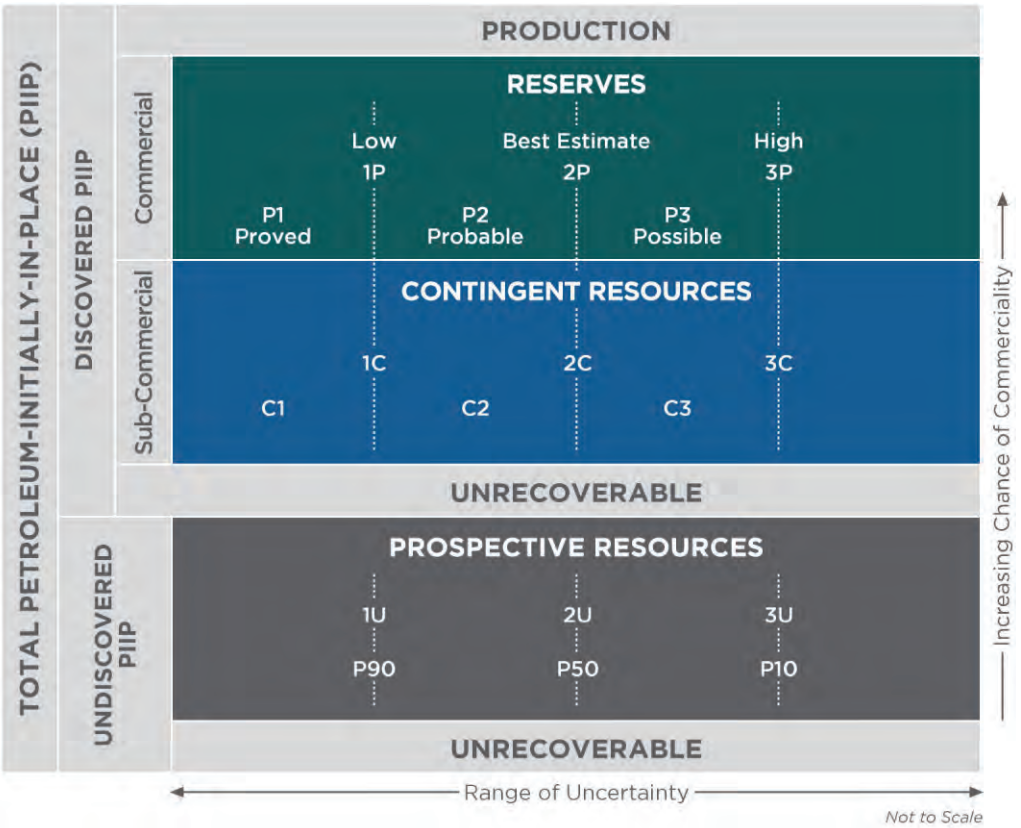

Figure A: PRMS Resources classification framework
(Source: PRMS, Version 1.01; page 1, Figure 1.1)

As illustrated below in Figure B, development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

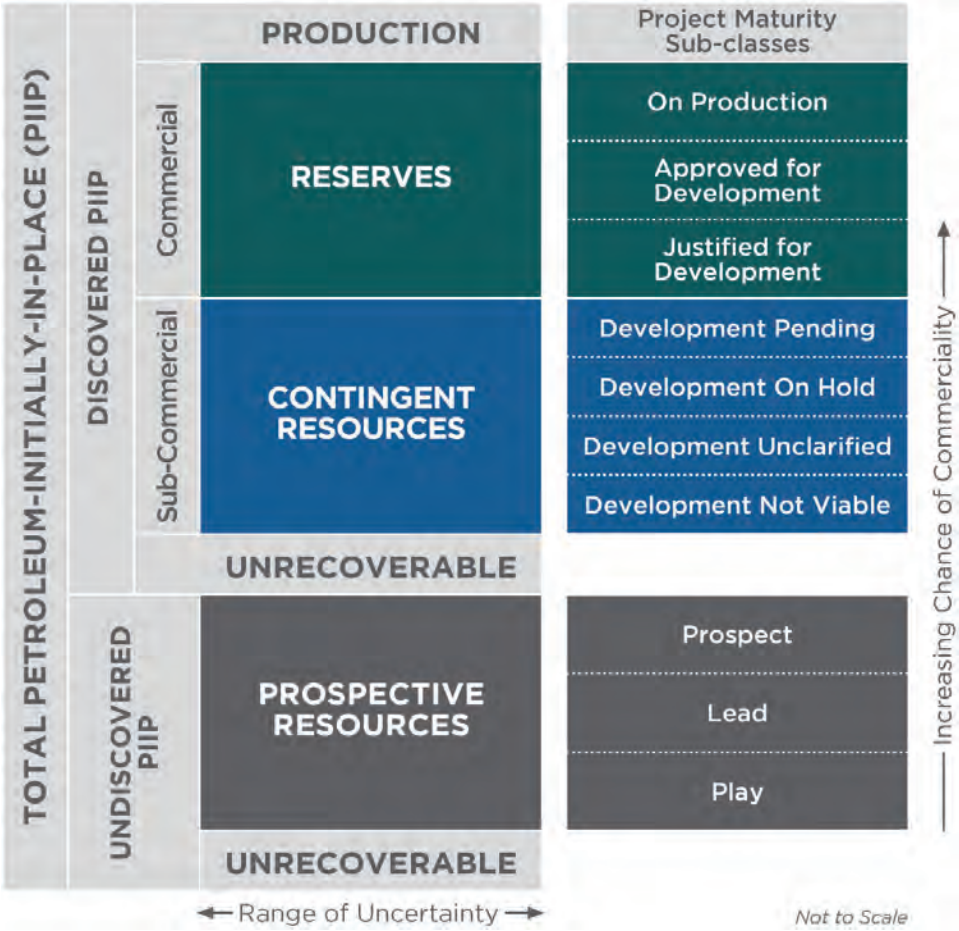

Figure B: PRMS Resources sub-classes
(Source: PRMS, Version 1.01; page 8, Figure 2.1)

A summary of key definitions of the PRMS Reserves and Resource categories, classes and sub-classes can be found in Tables 1-3 and a glossary of selected PRMS terms can be found in Table 4, below:

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see PRMS Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see PRMS Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Classes/Sub-classes	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Selected Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Low/Best/High Estimate	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an accumulation or project.

5. Nomenclature

5.1. Units and their abbreviations

bbl	barrel
bbl/d	barrels per day
ft	feet
ftTVDSS	feet subsea
km	kilometres
m	metres
M or MM	thousands and millions respectively
md	millidarcy
mTVDSS	metres subsea
rcf	cubic feet at reservoir conditions
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb/d	stock tank barrels per day

5.2. Terms and their abbreviations

Bo	oil shrinkage factor or formation volume factor, in stb
CPI	computer processed information log
DST	drill stem test
GEF	gas expansion factor
GIIP	gas initially in place
GRV	gross rock volume
GWC	gas water contact
NTG	net to gross ratio
OWC	oil water contact
Phi	porosity
PSDM	post stack depth migration
PSTM	post stack time migration

PVT	pressure volume temperature experiment
STOIIP	stock tank oil initially in place
Sw	water saturation
TVD	true vertical depth

PART X

COMPETENT PERSON'S REPORT – CGG SERVICES (UK) LIMITED

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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 and its employees who worked on preparation of this report, are independent of United Oil & Gas plc (UOG) and their directors, senior management and other advisers; have no economic or beneficial interest (present or contingent) in the company or in any of the mineral assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG have 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.

In undertaking this valuation CGG have used data supplied by UOG in the form of geoscience reports, seismic data and engineering reports. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that UOG will have in the Properties, as communicated by UOG. CGG has not verified nor do CGG make any warrant as to UOG'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 reserve; (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 UOG.

CGG affirm that from 27th June (the cut-off date for inclusion of data) to the date of issue of this report, 20th August 2019, 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 UOG.

The report has been prepared and is presented in accordance with the requirements of the AIM Rules for Companies and the Guidance Note for Mining and Oil & Gas Companies issued by AIM in June 2009 (AIM Guidance Note). This report conforms with the guidelines and definitions of the Petroleum Resources Management Systems (PRMS) (2007 and 2011) as published by the Society of Petroleum Engineers (SPE). Further details of these definitions are included in Appendix A of the CPR.

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If substantive new data or facts become available or known after the date of issue of this report, then this report should be updated to incorporate all relevant new information.

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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: BP521				
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1 EXECUTIVE SUMMARY

This report has been prepared for the Directors of:-

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CGG is acting as UOG's Competent Person as defined by the rules made by the London Stock Exchange, governing the admission of securities to AIM (the AIM Rules) and the AIM Guidance Note in relation to the Company's interest in the Podere Gallina exploration licence, located in the Po Valley, northern Italy. In accordance with the engagement letter between CGG and UOG dated 16th June 2019, CGG has updated the previously prepared independent Competent Person's Report in respect of the Company's interest in the Podere Gallina exploration licence in connection with the proposed application for admission to trading on the AIM Market (AIM) of the London Stock Exchange plc (London Stock Exchange) of the enlarged issued share capital of the Company (Re-admission) following a reverse takeover of Rockhopper Egypt Pty Ltd and the issue of an admission document (Re-admission Document) prepared in accordance with the AIM Rules and the AIM Guidance Note.

In January 2019, CGG was commissioned to prepare a Competent Person's Report on the Podere Gallina licence for UOG in connected with UOG AIM Admission and this report was published in the Company's AIM Admission Document dated 22 February 2019. This report has now been updated with new contingent and perspective resources based on new mapping and incorporating the latest development schedule received from the operator

1.1 Location

The Po Basin runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years. The Podere Gallina Licence is located approximately 10 km to the east of Bologna, and about 30 km from the coast in the Ferrara and Bologna provinces of the Emilia-Romagna region.

Figure 1.1 Location map for Podere Gallina licence

1.2 Data sources

In completing this evaluation, CGG have independently reviewed information and checked the validity of interpretations provided by UOG and the operator, Po Valley Operations Pty Ltd (PVO), as well as utilising complementary information from the public domain. CGG have produced several previous CPRs on the three fields over the last four years for the operator, PVO, and UOG, and as a result are familiar with the geology. Much of the data supplied by UOG for this report was in the form of updates to existing data previously provided to and reviewed by CGG. In conducting their evaluation, CGG have accepted the accuracy and completeness of data supplied by UOG, and have not performed any new interpretations, simulations or studies. Resource volumes presented in this report have been worked up independently by CGG.

1.3 Licence Description

The Podere Gallina Licence is located in the Po Valley plain, and covers an area of 506 square kilometres. The currently shut-in Selva gas field lies within this licence area. This field, operated by ENI, the Italian oil and gas multinational, produced 83 Bcf over a 35 year period from 15 wells. Production ceased in 1984.

As a result of a farm-in agreement between PVO and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well that was drilled in Q4 2017. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Table 1-1 Podere Gallina licence details

Operator	UOG Interest (%)	Status	Licence expiry date	Licence Area
PVO	20%	Exploration	3rd February 2018*	506 km^2

** In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorization time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from February 3, 2018. The application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law.*

1.4 Reserves

A summary of the reserves and resources associated with the Podere Gallina Licence, both gross and net, in accordance with the 2007 Petroleum Resource Management System (PRMS) published by the SPE, are shown in the tables below.

The volumes associated with the “Selva Stratigraphic” redevelopment opportunity now incorporate the results of the Podere Maiar-1 well. This well confirmed the presence of undrained gas in the structure, and has further de-risked the progression towards a commercial development. A development plan dated May 2018 was submitted to Italian authorities and application was made to convert to a Production Concession, allowing gas production to commence from the PM-1 well after tie-in to the gas network pipeline nearby. CGG has reviewed the relevant application documents in detail and reports the following Reserves and Resources for the assets.
In light of the preliminary award of the Production Concession which was awarded in January 2019 by the Italian authorities, the “Selva Stratigraphic” redevelopment is clarified as reserves.

These volumes have been based on integrating all of the geological and historic production data, including the well test results, to arrive at a range of reserves that reflects the uncertainties that exist in the Selva field.
Once production has started, over time it is expected that this range of reserves will narrow as the production history gives certainty to the recoverable volumes.

Table 1-2 Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG

Selva Stratigraphic Trap	Gross (MMscm)			20% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	10	26	42	PVO
C2 Sand	69	250	637	14	50	127	
Total	**117**	**379**	**846**	**23**	**76**	**169**	

** The net attributable may not add due to rounding error.*

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project for a 100% field interest and respective net interests. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

Table 1-3 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	9.0	26.2	45.0	1.8	5.2	9.0	PVO
Low	6.5	20.1	35.2	1.3	4.0	7.0	
High	11.5	32.2	54.9	2.3	6.4	11.0	

CGG's gas price assumption follows the forward Italian PSV spot gas price curve until 2025, and thereafter escalates at 2% per year. Low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards.

1.5 Contingent Resources

The following table presents the contingent resources on a gross and a UOG net attributable basis deriving from the licences.

Table 1-4 Summary of Contingent Resources and Net Attributable to UOG

	Gross			Net attributable				
Asset	1C	2C	3C	1C	2C	3C	Risk factor	Operator
Gas MMscm								
Level B North	99.8	252.3	504.5	20.0	50.5	100.9	70%	PVO
Level B South	27.5	96.6	264.5	5.5	19.3	52.9	60%	PVO
Level A South	29.3	51.2	102.1	5.9	10.2	20.4	60%	PVO
Total	156.6	400.1	871.1	31.3	80.0	174.2	70%	PVO

Notes:-

1. *Contingent Resources are the volumes estimated to be potentially recoverable if the appraisal well is successful and the opportunity is then fully developed.*
2. *Volumes are stated before the application of 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. *Full definitions of the Contingent Resource categories can be found in Appendix A*
5. *The risk factor means the estimated chance that the volumes will be commercially extracted*
6. *Conversion factor used for cubic metres to cubic feet is 35.31*

1.6 Prospective Resources

With the commerciality of the field demonstrated, an application for an exploitation concession was submitted in May 2018. 3D seismic acquisition over the field is also being planned. Acquisition is expected in 2020, and this will help delineate any further opportunities for undrained gas within the Selva structure.

Table 1-5 Summary of Gas Prospective Resources by Prospect and Net Attributable to UOG

	Gross (MMscm)			Net (MMscm)				
Name	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Risk factor**	**Operator**
Cembalina	59.5	93.5	133.1	11.9	18.7	26.6	51%	PVO
Fondo Perino	288.9	413.5	580.6	57.8	82.7	116.1	34%	PVO
East Selva	824.1	985.6	1149.8	164.8	197.1	230.0	30%	PVO
Riccardina	367.2	1097.8	3651.5	73.4	219.6	730.3	21%	PVO

Notes:-

1. *Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Prospective resources have both an associated chance of discovery and a chance of development*
3. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates*
4. *Prospective Resources are stated before the application of a risk factor and an economic cut-off*
5. *Full definitions of the Prospective Resource categories can be found in Appendix A*
6. *The risk factor means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*

1.7 Conclusion

CGG have reviewed the available information on the Podere Gallina licence in the Po Valley in northern Italy and conclude that UOG has performed a reasonable interpretation of the available data. CGG believe that the figures in this report reflect the potential for the field, given current knowledge. It should be noted that the reserves classification is subject to the award of a Production Concession. Although preliminary approval by the Italian Government was granted in January 2019, it should be noted that the award of the final production licence may be affected by the new law of February 11th 2019 that relates to upstream oil and gas activities.

2 INTRODUCTION

This independent Competent Person's Report (CPR) was prepared by CGG at the request of United Oil & Gas plc (UOG). The report evaluates reserves and resources associated with the Podere Gallina licence in the Po Valley in northern Italy, which is operated by PVO.

This report is based on CGG's previous CPR on the Podere Gallina licence for UOG issued in February 2019, and is updated with new contingent and perspective resources based on new mapping and incorporating the latest development schedule received from the operator.

As a result of a farm-in agreement between PVO and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Details of the licence are summarised below.

Table 2-1 Podere Gallina licence details

Operator	UOG Interest (%)	Status	Licence expiry date	Licence Area
PVO	20%	Exploration	3rd February 2018*	506 km^2

** In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorization time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from February 3, 2018. The application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law.*

The report contains descriptions of the licence area, and evaluates the range of gas volumes that could be present in the identified assets and the associated risk factors.

2.1 Sources of Information

In completing this evaluation, CGG have reviewed information and interpretations provided by UOG and PVO, as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR included:-

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data
- AFE's and budgets
- Well logs (Podere Maiar well)
- Well testing reports (Podere Maiar well, latest interpretations)
- Contents of Field Development Plan dated May 2018

In conducting their evaluation, CGG have accepted the accuracy and completeness of information supplied by UOG, and have not performed any new interpretations, simulations or studies.

As the assets in question are still to be developed, no site visits have been conducted by CGG.

2.2 Evaluation methodology

In estimating the reserves and resource volumes, 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 deterministic methods.

PVO staff demonstrated and reviewed the seismic workstation interpretations during a CGG visit to PVO in 2013. At the same time, maps and geological issues were discussed face to face with senior PVO staff. The seismic picks, reservoir structure and gross rock volume, according to these interpretations, was demonstrated to CGG. PVO interpretations have not changed since that time. Estimates of reservoir properties have been checked by CGG, and these are thought to be reasonable.

2.3 Principal contributors

CGG employees and consultants involved technically in the drafting of this CPR have between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

CGG confirms that itself and the authors of this report are independent of UOG, its directors, employees and advisers, and has no interest in the assets that are the subject of this report.

The following personnel were involved in the drafting of the CPR.

Andrew Webb

Mr Andrew Webb has supervised the preparation of this CPR. He is the Manager of the Petroleum Reservoir & Economics Group at CGG, having 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 acquisition 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

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 including onshore northern and southern Italy.

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 several technical papers, published by GSTT and SPE.

Peter Wright

Has 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 Requirements

In accordance with UOG's instructions, CGG confirm that:

- CGG personnel working on this CPR are professionally qualified and members in good standing of self-regulating organisations of engineers and/or geoscientists as appropriate;
- CGG personnel working on this CPR have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;

- CGG are independent of UOG "the Company", its directors, senior management and advisers;
- CGG will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of the Company;
- CGG are not a sole practitioner; and
- CGG have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

2.5 Consent

CGG hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;
- the filing of this report with any stock exchange and other regulatory authority;
- the electronic publication of this report on websites accessible by the public, including a website of the Company; and
- the inclusion of CGG's name in documents prepared in connection to commercial or financial activities.

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3 GEOPHYSICS AND GEOLOGY

The Exploration Licence that is the subject of this report is located in the Po Valley onshore northern Italy. The Po Valley runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years.

3.1 Regional Context

The Po Basin is a major hydrocarbon province which was estimated by the US Geological Survey to have approximately 16 TCF of ultimately recoverable gas (Lindquist, USGS, 1999, on-line review paper). The basin occurs on the margins of the Alpine mountain chain to the North and the Apennine chain to the South. The basin opens into the Adriatic Sea to the East. Compression associated with the building of these mountain belts created a large deep basin (or "foredeep") into which large thicknesses of sediment were shed from the surrounding uplands. As the basin deepened, turbidite sands were created and the high sediment supply began to fill the basin. Many of these turbidite sands are now gas-bearing, including long-established reservoirs discovered and developed by ENI, as well as thin-bedded reservoirs that are becoming new targets at the present time. Pliocene reservoirs include marine sands of significant lateral extent, which are folded over faulted structures that were formed during the compressional phases. At least 6km of Pliocene sediments were deposited in the foredeep, and as this was filled, the Po River drainage system became established, depositing marine sands in a delta-front environment. These may be overlain by fluvial sands as subsidence slowed and the basin filled.

The source of the gas is Miocene and Pliocene shales that are interbedded with turbidites and other sediments; the gas is predominantly biogenic rather than associated with deep burial of the shales. Biogenic gas may be generated at shallower depths than is required for the generation of gas by burial, and is related to the activity of bacteria acting on organic matter buried with the shales. However, the deepest known bacterial gas generation is recorded in the Po Basin at a depth of 4500 metres. As such, the process can generate large gas volumes throughout a basin, and the source may continue to be active at the present time. These aspects have led directly to the hydrocarbon richness of the Po Basin. Many structures and many reservoirs have proven to be gas-bearing, which explains the 263 developed fields in the Po Basin. Much potential for new discoveries remains, as do many opportunities for field re-development (missed pays and remaining gas in old fields).

The assets under consideration here include Miocene and Pliocene reservoir sands, stacked vertically, and including both thick, good quality gas sands and thin-bedded gas reservoirs. Reservoir sands are interbedded with shaley and marly fine-grained sediments. In many cases, the sands are pressure isolated from each other and may be drained in succession according to well designs and completion strategies employed.

3.2 Selva Stratigraphic Reserves

The Selva Stratigraphic redevelopment opportunity represents a part of the former ENI-operated Selva gas field. The extension of the Selva Field into the Podere Gallina Licence was interpreted by Po Valley Operations Ltd. mainly using isopach mapping from well data at Upper Mid Pliocene level. Recent modelling (DREAM 2013) was based on the conservative assumption that the initial GWC of the Selva Field at 1336m TVDSS had risen to 1235m (top level C in the Selva-6 well) leaving a potential undrained updip gas volume.

Seismic and well data show the Selva Stratigraphic redevelopment to be an Upper Middle Pliocene onlap to a Lower Pliocene thrust-bounded anticline. However, interpretation of seismic lines suggests the reservoir is also displaced by reactivated thrust splays which detach onto the main thrust fault. Although the depth structure map is quite well constrained by existing well penetrations, the 2D seismic (in terms of line spacing and vintage) is imperfect for imaging small features and part of the Operator's plan is to revise the structure mapping using additional data in the near future. The Podere Maiar-1 well was drilled in late 2017 and tested in early 2018. It targeted the updip volume based upon a new interpretation of the position of the lapout edge towards the Selva-3 well. The latest interpretation of the well test and its implications are fully incorporated into this CPR and into CGG's consideration of Reserves.

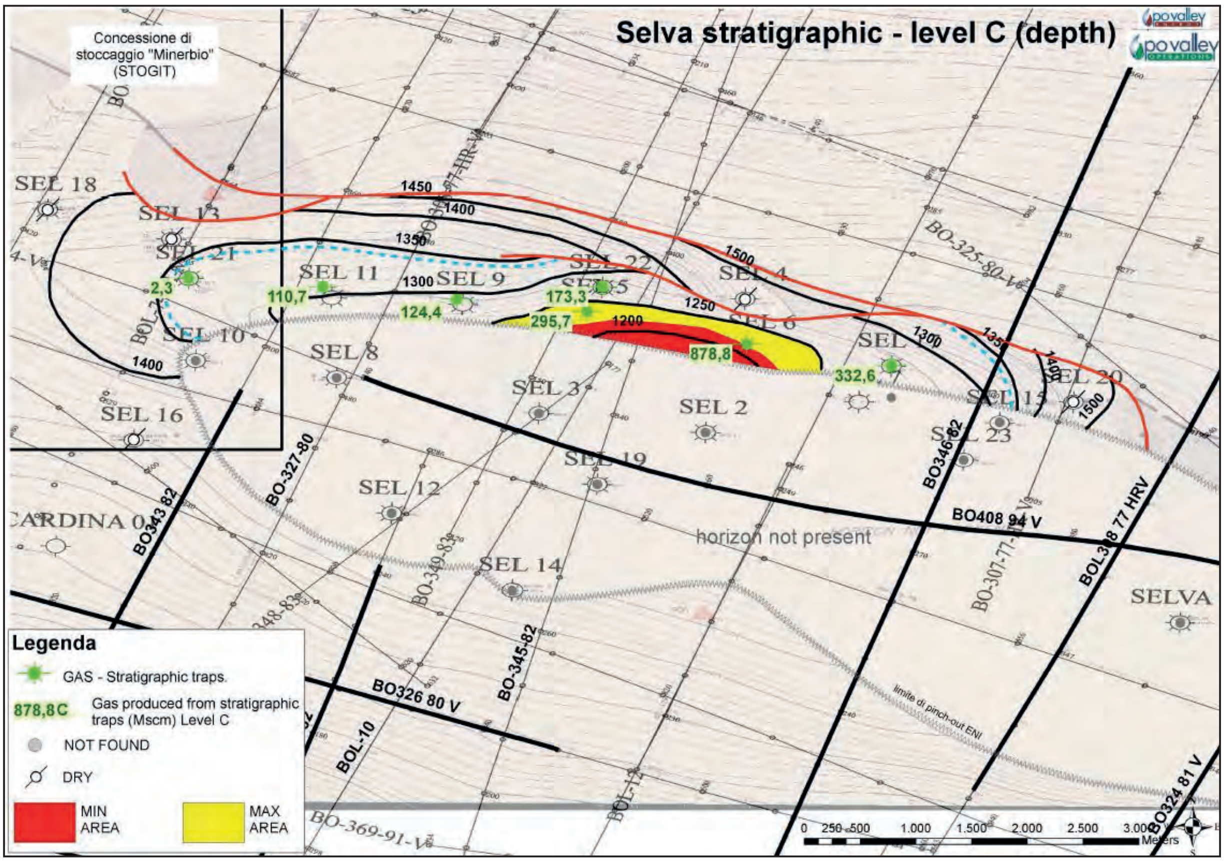


Figure 3.1 Selva stratigraphic structure map

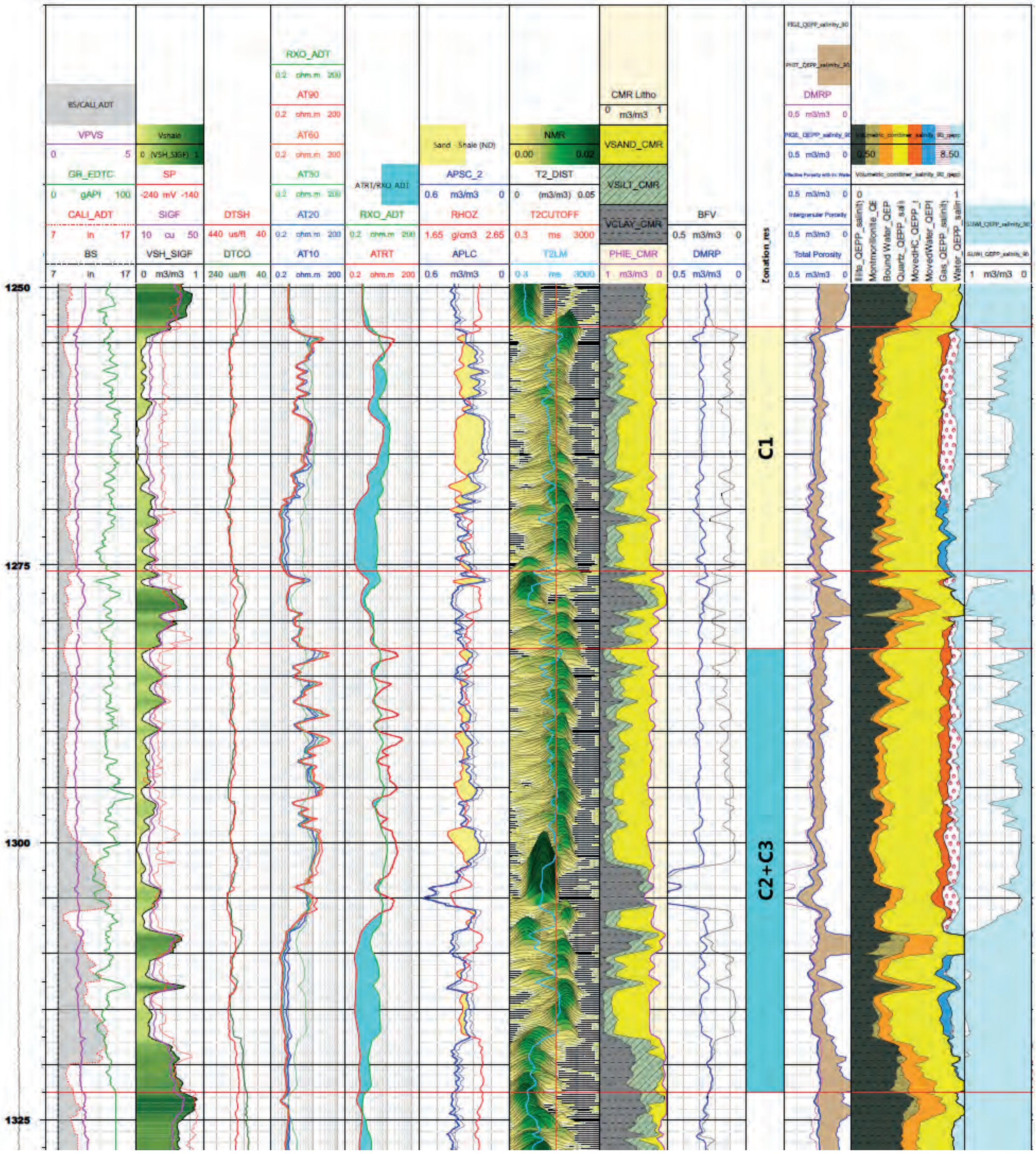


Figure 3.2 Podere Maiar-1: C1 and C2 Sand Reservoirs, Extract from ELAN Interpretation Plot

The ELAN log and interpretation plot is provided as Figure 3.2, above.

Podere Maiar-1 penetrated a gross thickness of 62.5 metres of Lower Pliocene (C1 and C2) gas sands of the old Selva field. Petrophysical analysis has indicated average properties in each sand as follows:

<u>C1 Sand</u>

22 metres gross thickness, 70% net-to-gross, 22-26% porosity and 65% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 case.

<u>C2 Sand</u>

40.5 metres gross thickness, 63% net-to-gross, 21-25% porosity and 70% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 cases.

The logging tools deployed for the assessment of the reservoirs were high quality and comprehensive, including a CMR (Figure 3.2). Porosity estimation is considered reliable as the CMR-Density technique was used (ideal for gas-filled shaly sandstones), and the CMR also clearly distinguishes sand from shale. The ELAN interpretation has been checked and appears to be reliable, showing long reservoir sections with good gas saturations. The quality of the reservoir section encountered by the well appears good and reliably defined.

Pressure data taken over the reservoir section has established a separate gas-water-contact in C1 and C2 sands which are separated by a shale. In both sands, the contact derived from pressure data points falls close to the GWC identified on the petrophysical interpretation plot. The location of the water, therefore, is quite well established from independent evidence.

Gas initially in place estimates have been reviewed and the following parameters are considered fair estimates:

Table 3-1 Parameters used in the estimation of gas-initially-in-place (GIIP)

Sand	Case	GWC	NtG	Phi	Sg	Bg	GIIP (MMscm)
C1	min	1,237.0	0.66	0.22	0.65	140	81
C1	max	1,239.6	0.75	0.26	0.65	144	299
C2	min	1,274.5	0.58	0.21	0.7	140	261
C2	max	1,277.8	0.68	0.25	0.7	144	910
Total	min						342
	max						1,208

The mid-case GIIP is taken as the average of low and high.

As a proposed re-development of an old field, this appears relatively low risk; the major geological risk component is the location of the reservoir zero thickness line (pinch-out) and the shape of the pinch-out as drawn on the structure map (currently the zero line is drawn as a smooth, straight line which could be correct or could be substantially incorrect). Lack of high-resolution structural definition means Gross Rock Volume remains the greatest geological uncertainty. At this stage, post appraisal well but prior to production start-up, there is remaining uncertainty regarding the interpretation of the well test, in particular the meaning and significance of the “boundaries” seen in C1 and C2 sands. These boundaries are the result of non-unique interpretations of well test data, although the slope of the derivative is a clear reservoir signature for both sands. At the present time, CGG considers that the derivative signature from the C2 sand flow test may be significant in terms of a geological feature that limits the contacted gas volume or accelerates water coning. The major risk to recoverable gas volumes is considered to be the timing of water breakthrough. In the Po Valley region, accurately predicting the timing of water breakthrough in comparable reservoirs has been a source of uncertainty in the past. The well test and production risks will be discussed in Chapter 4.

3.3 Selva North and South Prospects

Following the successful Podere Maiar-1 well drilled in late 2017, PVO have firmed up a further two prospects on the North and South crest of the old Selva gas field (Figure 3.3). Both prospects rely on the same stratigraphic pinch-out concept successfully proved viable by the Podere Maiar-1 well.

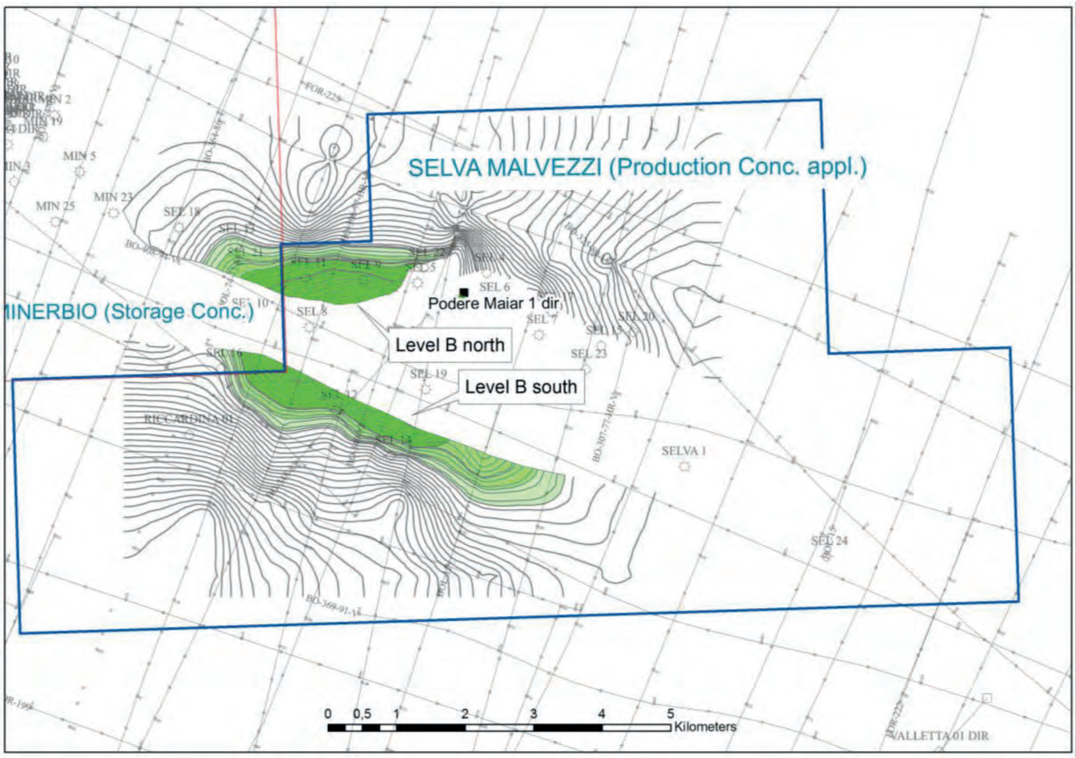


Figure 3.3 Level B North and South Prospects, Selva Malvezzi Production Concession

Although these are named as Prospects, they fall into the Contingent Resource category because they have already produced gas to surface in commercial quantities leaving a remaining updip gas volume.

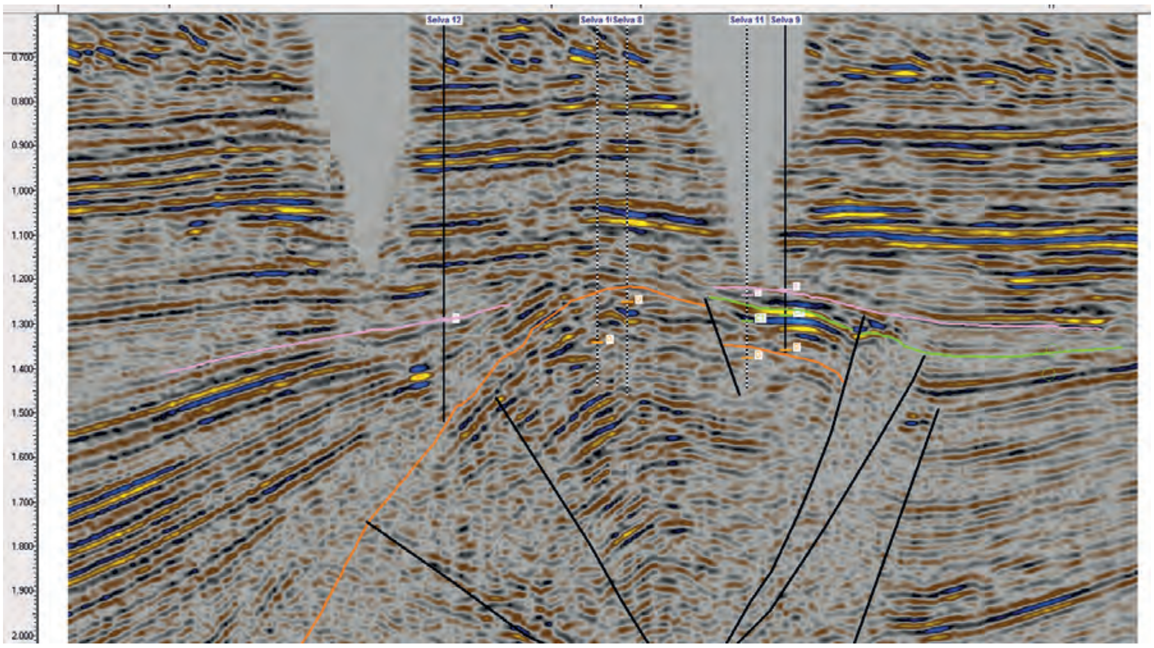


Figure 3.4 Seismic line BO327-80 showing Selva Level B North and South Prospects

After proof of concept was established by means of the successful Podere Maiar-1 well, similar updip pinch-out prospects have been worked up by PVO. The Level A and Level B sands, productive in the main Selva gas field, pinch out onto the underlying thrust fold structure in the same way that Level C sands do (drilled and proven to be good quality sands and gas-bearing by PM-1 well). Comparable reservoir properties are anticipated, and the sand thickness is known from some of the old Selva producing wells, particularly Selva-9 for North Prospect and Selva-12 for South Prospect. For the North Prospect, only Level B sand is expected, whereas for the South Prospect Level B plus slightly shallower Level A sands are taken into account.

PVO have used eleven reprocessed 2D seismic lines and information from old Selva gas wells to work up these prospects. CGG has reviewed the information supplied by PVO and have validated their presence. Level B sands were formerly exploited by ENI in Selva gas field in the period from 1959 to 1971 and 1977 to 1982. During this time, Level B in the north flank produced 248 MMScm of gas and 0.94 MMScm from the south flank leaving undrained gas updip from these producers.

The definition of the potential volumes remaining in the updip pinchout is dependent upon the location of the pinch-out (zero sand thickness) line, which is difficult to determine using the available 2D seismic lines. Nevertheless, CGG believes that there is good potential for success in pursuing the concept in this area.

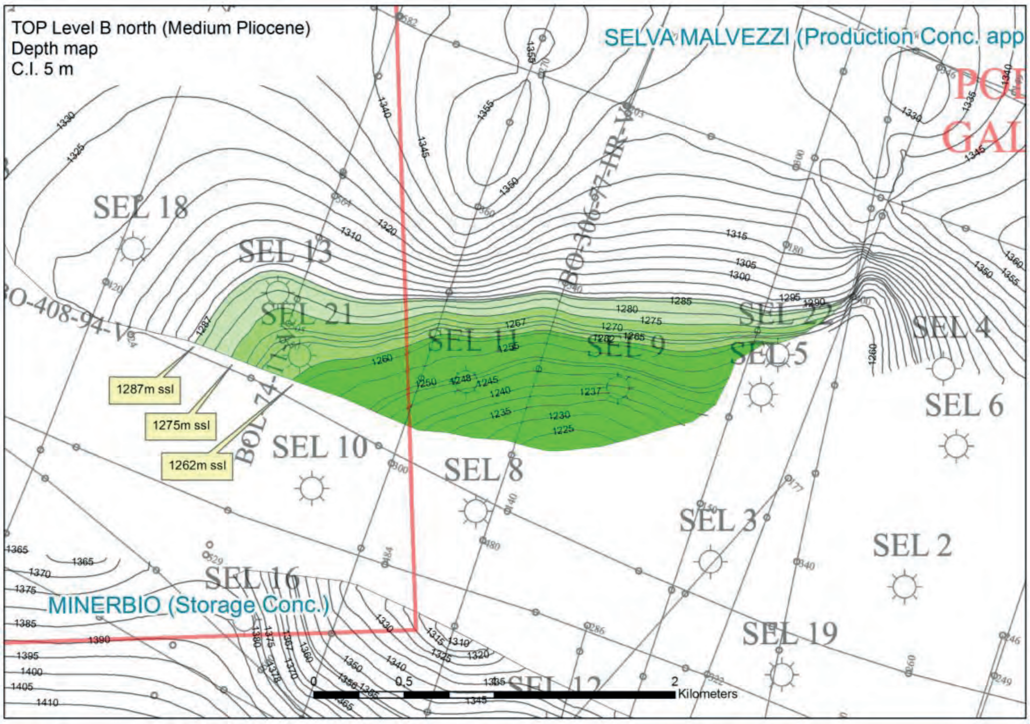


Figure 3.5 Level B North Prospect, Depth Structure Map showing Low, Mid and High Case contacts

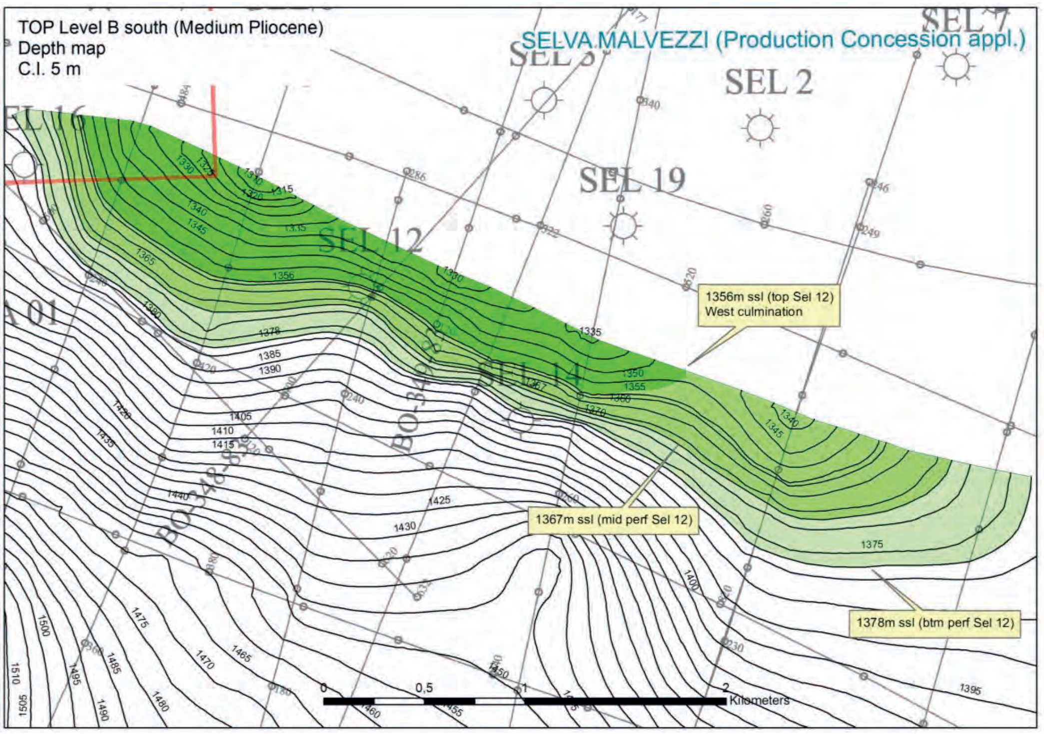


Figure 3.6 Level B South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

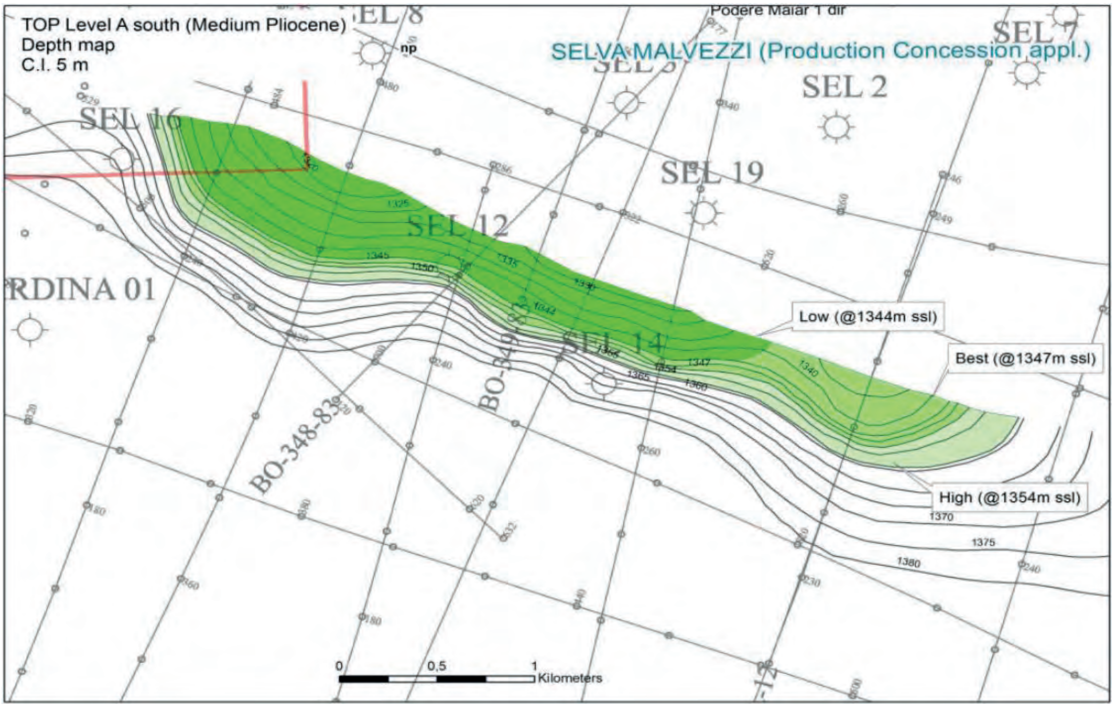


Figure 3.7 Level A South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

Information from nearby wells is limited to old log plots and very limited log coverage (SP and resistivity). In spite of this, a thick sand package appears to be present on the Northern side of the structure. The assessment presented by PVO appears to present a reasonable reflection of the available data. CGG consider that the values presented in Table 3-2 below provide a balanced view of uncertainty range and likely resource potential:

Table 3-2 Level B North Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1262	18.0	0.55	0.2	0.40	0.008333	143	70	99.8
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1275	35.0	0.6	0.22	0.35	0.008333	360	70	252.3
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1287	55.0	0.65	0.24	0.30	0.008333	721	70	504.5

Concerning Level B South Prospect, available well data suggests a much thinner sand package, having an estimated thickness range of 4 – 6.5 – 9 metres. CGG has used these and the area-thickness method to estimate volume and applies the reservoir parameters in Table 3-3 below. The Level A sand package is also evaluated from sand thickness information in the Selva-12 well where it appears to be a little over 3 metres thick and of good quality. An average thickness range of 2.5 – 3.25 – 4 metres for the whole area is assumed, with the reservoir parameters shown in Table 3-4.

Table 3-3 Level B South Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE 1C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1356	5.6	0.55	0.2	0.40	0.008065	46	60	27.5
BEST CASE 2C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1367	14.0	0.6	0.22	0.35	0.008065	149	65	96.6
HIGH CASE 3C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1378	27.9	0.65	0.24	0.30	0.008065	378	70	264.5

Table 3-4 Level A South Contingent Resource; Parameters used in the estimation of gas volumes

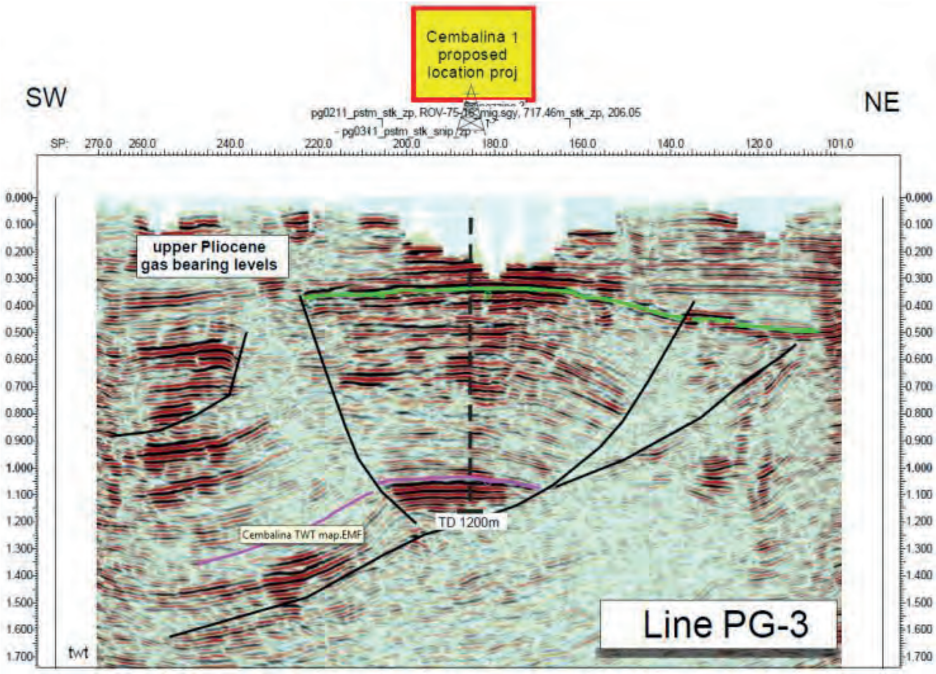
LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1344	2.75	1	0.22	0.35	0.008065	49	60	29.3
BEST CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1347	4.06	1	0.23	0.32	0.008065	79	65	51.2
HIGH CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1354	7	1	0.24	0.30	0.008065	146	70	102.1

A risk factor has been estimated for these two opportunities (the risk factor is the estimated chance that the volumes will be commercially extracted). Level B North Prospect is the better prospect having a project risk factor of 70% whereas the less well defined South Prospect is assigned a project risk factor of 60%. The main uncertainties exerting an effect on project risks are the current situation in terms of gas water contact elevation and sand architecture, both of which can be established by the drilling and flow testing of a well.

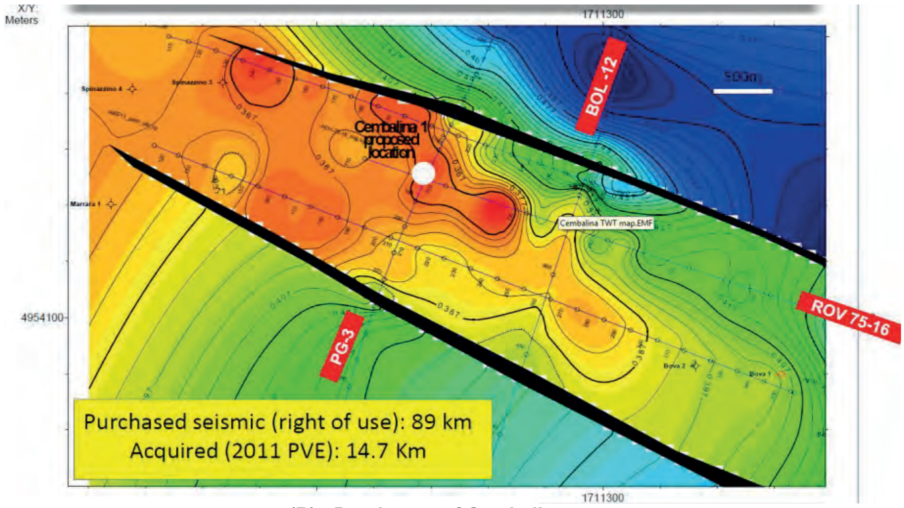
3.4 Cembalina Prospective Resource

The Cembalina prospect is defined on five seismic lines at Upper Pliocene level. Lines are oriented NNE-SSW 1.2km to 3.4km apart and WNW-ESE 0.4km to 7km apart. The structure is a WNW-ESE oriented hanging-wall anticline with associated back thrust at Early Pliocene level with fold drape above the structure at Upper Pliocene level. The seismic interpretation of horizons has been checked and validated.

Additional seismic lines purchased by PVO in 2011 resulted in a revised structural interpretation which had the effect of increasing the size of the Cembalina prospect as compared to pre 2011.



(A) Cross-section through Cembalina structure



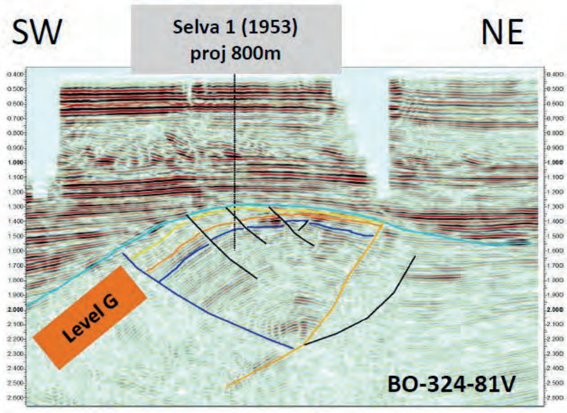
(B) Depth map of Cembalina structure

Figure 3.8 Cembalina structure

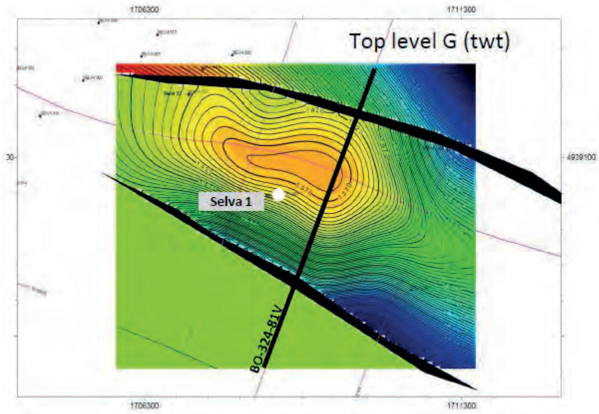
Prospective reservoirs are the Early Pliocene marine sands which, in nearby wells, exhibit up to 30% porosity with 70% average gas saturation. The thickness of these sands is expected to be about 20 metres with a net-to-gross of about 50%. In a success case, then, we concur with the prospective resource estimates given by PVO. These are a P90 of 60 MMscm, a P50 of 94 MMscm and a P10 of 133 Mscm. The CoS relating to these resources is 51% due to the proximity of gas fields producing from these Early Pliocene sands.

3.5 Fondo Perino Prospective Resource

The Fondo Perino prospect is the dip closed cap of a hanging-wall anticline located between the Selva-1 and Selva-23 wells. The trap is interpreted on two NNE-SSW oriented seismic lines located 1.3km apart and a WNW-ESE line. The limits of the prospect closure exist between smaller faults in the core of the anticline.



(A) Fondo Perino seismic cross-section



(B) Fondo Perino depth structure map

Figure 3.9 Fondo Perino structure

The reservoirs are Lower Pliocene sandstones of the Selva gas field; the prospect is the updip gas bearing level tested on Selva-1 well. The CoS is good at 34% for prospective resources of 289, 413 and 581 MMscm at P90, 50 and P10 cases respectively.

3.6 Riccardina Prospect

The prospect lies within the Selva Malvezzi Production Concession approximately 5km distant from the Podere Maiar-1 well. Already identified by ENI, the Riccardina-1 well tested the prospect in 2004 but encountered water-bearing sands and was abandoned. PVO have re-interpreted the available seismic data (ten 2D lines) and have come to the opinion that this well just missed the prospect, coming in on the wrong side of a thrust fault and lying outside of the high amplitude area that is interpreted to signify gas presence. Target reservoirs are sands of the lower Pliocene Canopo Formation, which is a silty-sandy succession offering some 250m of section in the target area. PVO are planning to acquire a small 3D survey over the area.

The structure is reasonably well defined by means of the available 2D seismic lines (Figure 3.10, Figure 3.11).

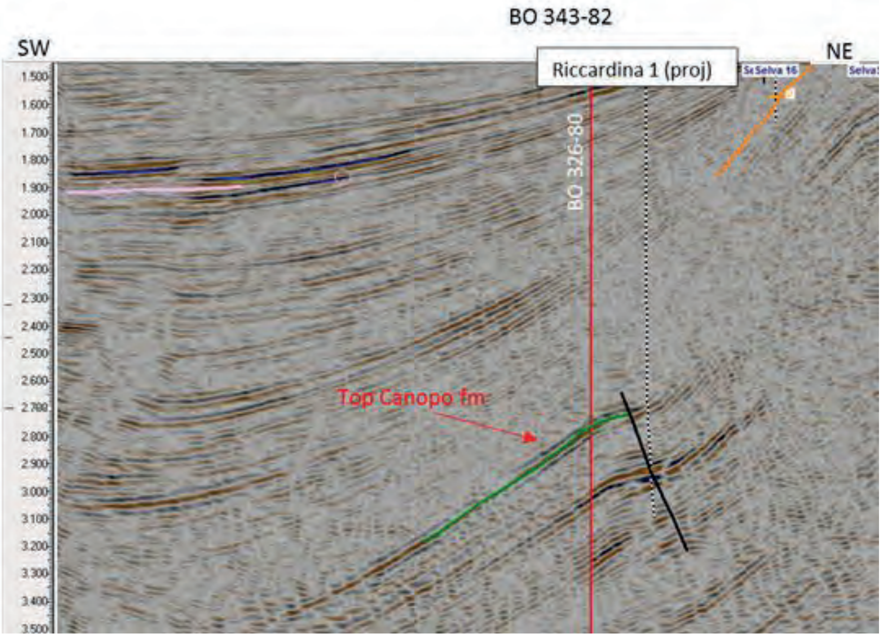


Figure 3.10 Riccardina Prospect: Seismic Line BO343-82 shows gas prospect in Canopo Formation

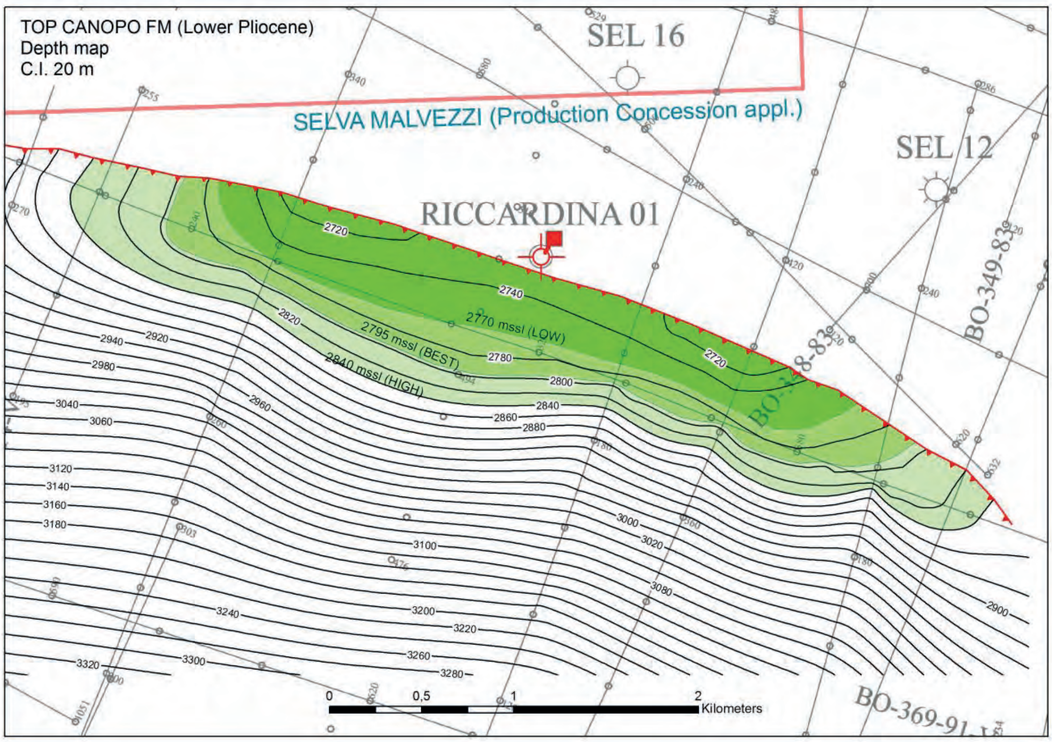


Figure 3.11 Riccardina Prospect; PVO depth structure map at top Canopo Formation (metres subsea)

CGG has inspected the Riccardina-1 well logs. The Upper Canopo Formation consists of alternating sands-silts with fairly thick and permeable sands ranging from 1 – 10 metres. There is separation between shallow and deep resistivity logs indicating invasion and SP suggests permeable formation. Resistivity readings confirm the presence of saline formation water in this well. The reservoir geology appears positive but there is chance of encountering sand of less than 20% porosity at this depth. CGG has made an independent assessment of reservoir parameters based on evidence provided by PVO (Table 3-5).

PVO have made the following assumptions regarding gas fill for this prospect:

- Low: contact at 2770 m ssl
- Best: contact at 2795 m ssl
- High: contact at spill point of the structure (@2840 m ssl)

Table 3-5 Selva Riccardina Prospect; Parameters used in the estimation of gas-initially-in-place (GIIP)

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -2770	34	0.45	0.18	0.40	0.0027	612	60	367.2
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -2795	76	0.5	0.2	0.35	0.0027	1830	60	1097.8
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
Spill Point -2840	194	0.55	0.22	0.30	0.0027	6086	60	3651.5

Table 3-6 Selva Riccardina Prospect; Risk Assessment

RISK ELEMENTS		RISK SCORE (probability)	
CLOSURE	Interpretation	0.9	0.85
	Depth Conversion	0.85	
SEAL	Top Seal	0.85	0.425
	Base / Side Seal	0.5	
RESERVOIR	Presence	0.8	0.8
	Quality	0.8	
CHARGE	Source Rock	0.85	0.7225
	Migration	0.85	
	RISK TOTAL		**0.21**

Risk score for closure and reservoir is the lowest of two assigned values but for seal and charge it is the product of the two assigned values.

The primary risk is considered to be the seal capacity of the fault that defines the northern margin of the trap. Overall chance of success for the Riccardina Prospect is estimated to be 21%.

3.7 East Selva Prospective Resource

The East Selva structure is identical in concept in the Selva Stratigraphic structure but has not previously been drilled. PVO reinterpreted the mapped closure area of this structure using available seismic data and CGG review of this work indicates that it presents a fair and reasonable view of the prospect.

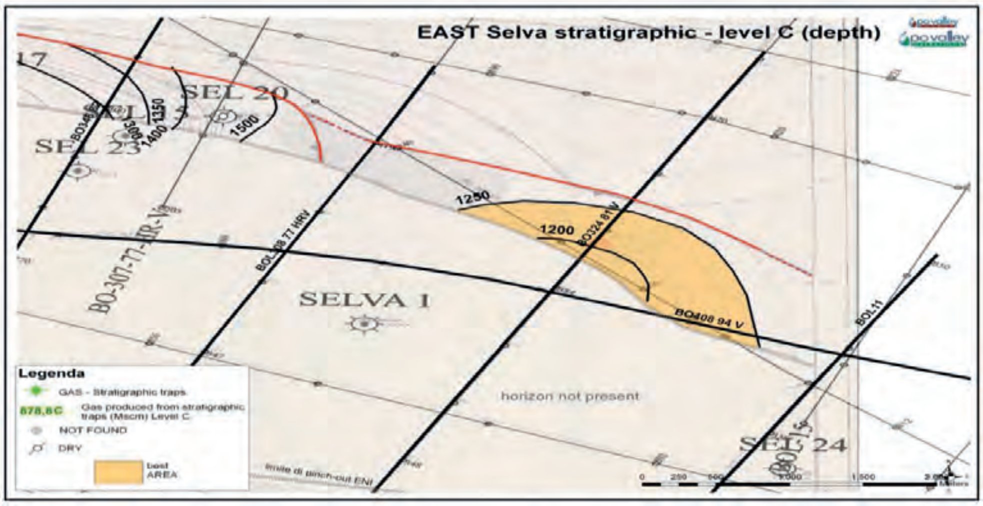


Figure 3.12 East Selva structure map

The East Selva reservoirs are expected to be as good as those in the Selva field itself. CGG's review of the Operator's work has concluded that the stated prospective resources are very reasonable. Given the proof of concept demonstrated by the success of the Podere Maiar-1 well, the Chance of Success at East Selva has been upgraded. The prospect could hold recoverable resources of 824, 986 and 1150 MMscm in Low, Best and High cases respectively for a CoS of 30%. The primary risk is the definition of the gross rock volume based on only a small number of seismic lines.

Table 3-7 Summary of Gas and Net to UOG Prospective Resource by Prospect (MMscm)

	Gross (MMscm)			Net (MMscm)		
Prospect	**Low**	**Best**	**High**	**Low**	**Best**	**High**
Cembalina	59.5	93.5	133.1	11.9	18.7	26.6
Fondo Perino	288.9	413.5	580.6	57.8	82.7	116.1
East Selva	824.1	985.6	1149.8	164.8	197.1	230.0
Riccardina	367.2	1097.8	3651.5	73.4	219.6	730.3

4 RESERVOIR ENGINEERING

4.1 Selva Stratigraphic Trap

4.1.1 Historical production of the Selva Gas Field

The Selva gas field was previously on production during the 1950s-1980s. Total historical production from the C level is shown in Table 4-1 below:

Table 4-1 Summary of Total Gas Recovered from Selva Stratigraphic Trap (MMscm)

Well	Total Gas Recovered, MMscm
Selva-5-C	295.74
Selva-6-C	878.80
Selva-9-C	124.38
Selva-11-C	124.05
Selva-17-C	332.58
Selva-21-C	2.31
Selva-22-C	173.33
Total	**1,931.19**

Figure 4.1 shows the total gas produced from each historical well. CGG has no records of perforation intervals of Level C, only well tops. Therefore, we consider "height of sand top above Gas-Water Contact (GWC)". The height above contact of each historical well is as follows:

- Selva-21 was watered-out when GWC was at ~1,340 mTVDss, assuming this is the original water contact
- Selva-11's Top C is at 1,315 mTVDss, 25 m above contact. Produced 124 MMscm
- Selva-9's Top C is at 1,296 mTVDss, 44 m above contact. Produced 124 MMscm
- Selva-22's Top C is at 1,295 mTVDss, 45 m above contact. Produced 173 MMscm
- Selva-17's Top C is at 1,281 mTVDss, 59 m above contact. Produced 333 MMscm
- Selva-5's Top C is at 1,246 mTVDss, 94 m above contact. Produced 296 MMscm
- Selva-6's Top C is at 1,235 mTVDss, 105 m from the contact. Produced 879 MMscm

CGG postulates that the PM-1dir well will perform within the range of the posted cumulative produced gas values at historical wells. We consider that height of perforations above water is a key indicator of when water breaks through.

- In the C1 sand, PM-1's GWC is estimated at 1239 mTVDss; PM-1's Top C1 is at 1222 mTVDss, that is, 17 m above contact.
- In the C2 sand, PM-1's GWC is estimated at 1278 mTVDss; PM-1's Top C2 is at 1251 mTVDss which is 27 m above contact.

Therefore, the most closely analogous wells are Selva-11 (124 MMscm cumulative), Selva-9 (124 MMscm) and Selva-22 (173 MMscm). The PM-1dir well could perform as well as Selva-5 (296 MMscm) and Selva-17 (333 MMscm). In the high case, the PM-1dir could possibly produce as much as Selva-6 (879 MMscm cumulative). On the basis that the new well is closer to the water than most Selva wells on the map prior to the well being put on production, and there being some production history, we do not expect PM-1dir to out-perform these prior to suffering water breakthrough.

It is based on these historic production histories that the reserves volumes for the PM-1dir have been bench marked against.

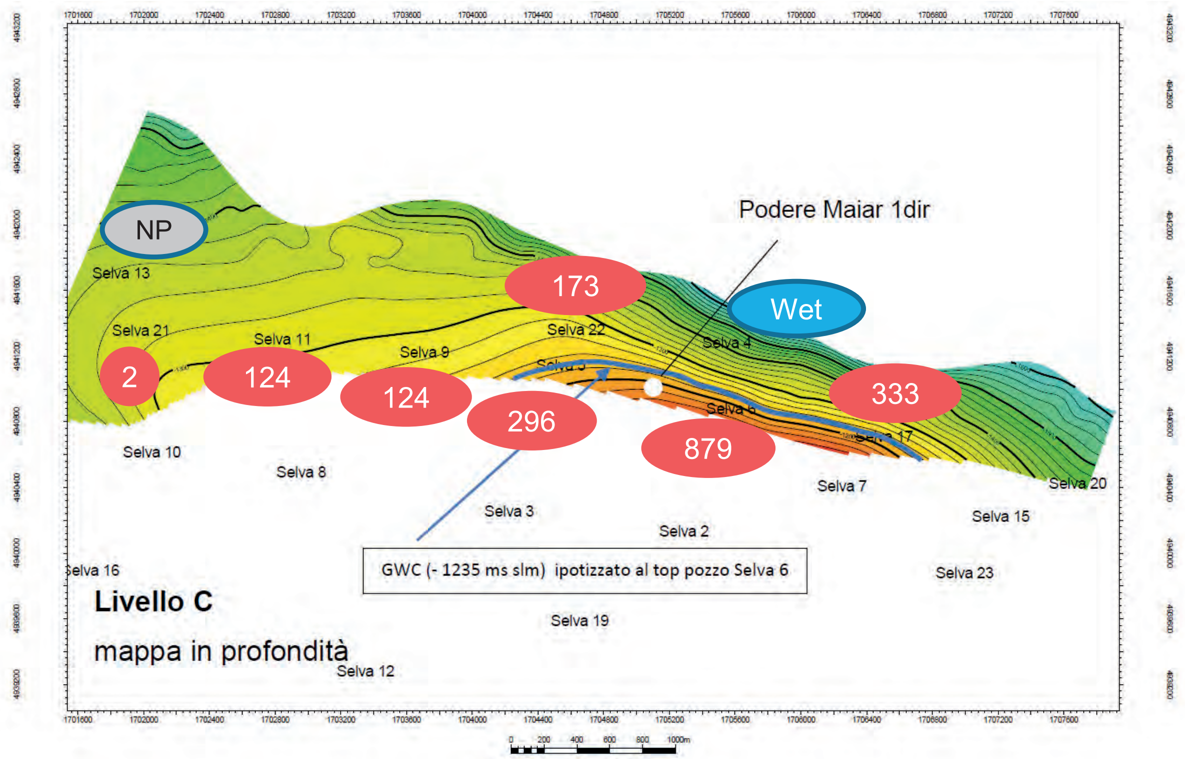


Figure 4.1 Historical Well Locations in Selva Stratigraphic Trap and Well Total Gas Production in MMscm

4.1.2 Podere Maiar-1dir well test results

Podere Maiar-1 was drilled targeting remaining updip gas of the C Level in the Selva Stratigraphic Trap. The new pressure data taken over the C level has established a separate GWC in C1 and C2 sands. In both C1 and C2 sands, the GWC has been identified. The depths of C1 and C2 sands are tabulated in Table 4-2. The bottom perforation is over 13 m above the contact.

Table 4-2 Podere Maiar-1dir – Depths of C1 and C2 Sands

Podere Maiar-1dir (RT 22.71 m)		
C1	Top, m MD RT (m SSL)	1253.5 (1221.9)
	Bottom, m MD RT (m SSL)	1275.5 (1244.4)
	GWC, m MD RT (m SSL)	1270.5 (1239)
	Perforation, m MD RT	1253.5-1256
C2	Top, m MD RT (m SSL)	1282.5 (1251)
	Bottom, m MD RT (m SSL)	1318.5 (1286.5)
	GWC, m MD RT (m SSL)	1309.5 (1277.8)
	Perforation, m MD RT	1282.5-1296

The well has been completed by a conventional completion with sliding side door (see Figure 4.2). Each sand can produce individually or co-mingle.

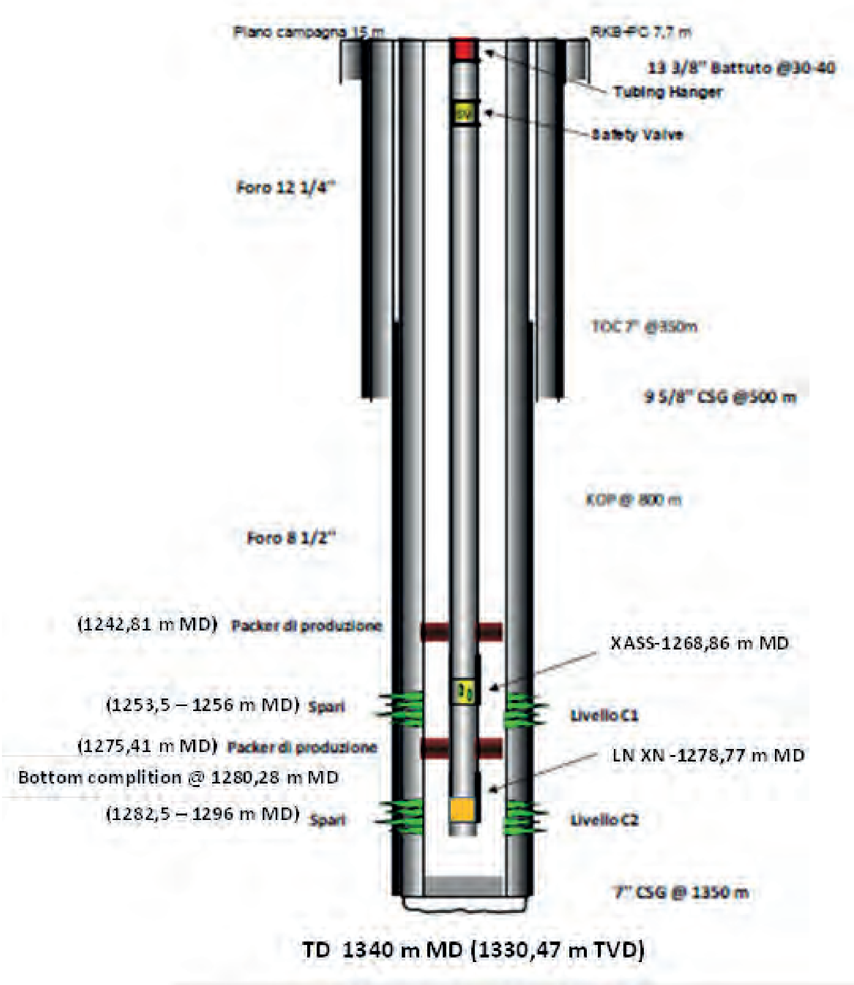


Figure 4.2 Podere Maiar-1dir – Well Schematic

The initial flow test performed in January 2018 by testing each sand individually indicates good initial gas flow rates as shown below. Although both sands have high well deliverability, the perforations of the Podere Maiar 1dir well are sited at over 13 m above the gas-water-contacts encountered in both the C1 and C2 reservoirs. An appropriate production flow rate will be required to prevent water coning and early breakthrough into the well.

Table 4-3 Summary of Flow Test Results of C1 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 132.9 bara at 1253.5 m MD RT, STHP 120.7 bara			
8	119.3	14,300	6
16	115.0	64,000	6
18	113.2	77,400	6
Build up			30
24	105.0	127,000	3
Build up			1

Table 4-4 Summary of Flow Test Results of C2 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 135.5 bara at 1275 m MD RT, STHP 122.9 bara			
8	122.7	17,800	6
16	120.7	64,800	6
18	119.5	78,000	6
Build up			50
24	104.6	142,000	4
Build up			6

The build-up tests have been interpreted by Po Valley's consultant (DREAM, Dedicated Reservoir Engineering And Management, based in Torino). Figure 4.3 to Figure 4.8, Table 4-5, and Table 4-6 are extracted from DREAM's interpretation in the submission document to the Italian authorities.

C1 sand's well test interpretation indicates that the well sees two no-flow boundaries. In Figure 4.3 during the late time i.e. after 3 hours, the pressure derivative shows positive slope indicating no-flow behaviour. In this case, DREAM interprets it as two parallel no-flow boundaries. CGG accepts DREAM interpretation of the C1 sand. The two no-flow boundaries can be interpreted as the pinch-out (South) and the structural closure (North). Pressure builds up to the pre-test pressure suggesting that the well has some pressure support and good connectivity. CGG therefore considers that the Podere Maiar-1dir is capable of draining the whole area of the updip gas.

For the C2 sand, DREAM interprets the well test as three boundaries and mentions that one of the boundaries might be the aquifer. In Figure 4.6, during the late time (i.e. after 1 hour), the pressure derivative starts to divert from radial flow (zero slope) to slightly positive slope and the pressure derivative continues to show positive slope indicating no-flow behaviour. The boundaries could be leaking, although we have not observed this during the short test. This could not be an aquifer effect as the derivative of pressure would have shown a negative slope in the late time. We agree with DREAM that the C2 sand has encountered three boundaries. Two of the boundaries are no-flow and can be interpreted as the pinch-out (South) and the structural closure (North). The shortest boundary, at a distance of 80 m, could indicate that there is a boundary that could not be seen in the existing seismic data. However, the well test data does not identify if the boundary at 80 m is to the East or the West of the well. The hypothesis of a third boundary is supported by the fact that the final build-up reservoir pressure that does not reach the pre-test value. This may indicate some depletion of a limited connected gas volume. Although the pressure loss during the test is very small (1/10th bar after 50 hours of shut-in), the pressure did not build-up back to the pre-test value as observed in C1 (in which the pressure returned to the pre-test value after 30 hours of shut-in, as we would expect in high quality reservoir with a longer shut-in time). CGG therefore has taken into consideration that the Podere Maiar-1dir well may only drain a limited area of the updip gas and assigns only 44% (considering the boundary is located to the West of the well) of the total drainage area of the low in-place volumes in the 1P reserves. For the 2P reserves, only 63% (considering the boundary is located to the East of the well) of the total drainage area of the mid in-place volumes is assigned. However, the 80 m no-flow boundary may not fully seal (i.e. leaking) and the whole area could possibly be drained by the Podere Maiar-1dir well. We therefore assign 100% of the high drainage area in our 3P reserves.

For the C2 sand, CGG recognises that the three no-flow boundaries interpretation may not be a unique solution. Alternative interpretations are possible. This has been taken into consideration of our reserves uncertainty i.e. 44%, 63%, and 100% drainage area.

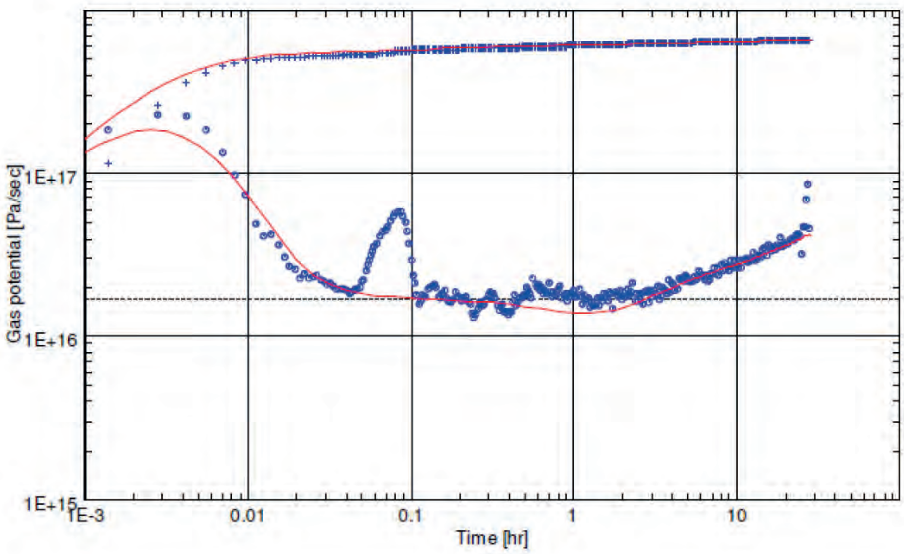


Figure 4.3 Log-log Plot of Pressure and Pressure Derivative of C1 Sand

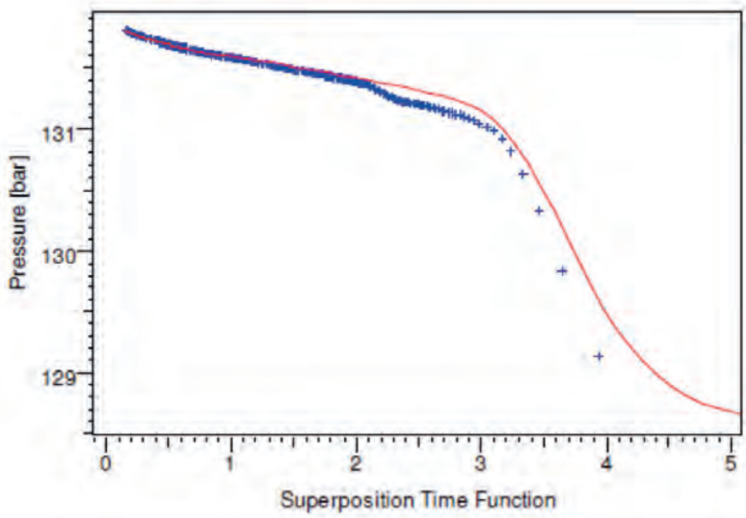


Figure 4.4 Horner Plot of C1 Sand

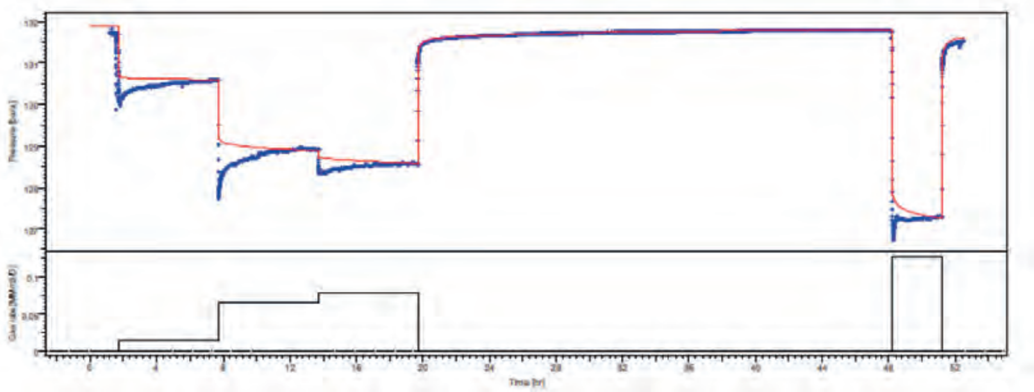


Figure 4.5 Pressure and Gas Rate of C1 Sand

Table 4-5 Well Test Interpretation Result of C1 Sand

P_i	131.9	bar
kh	949	mD m
h	2.5	m
k	380	mD
S_m	decreasing	
d1	120	m
d2	190	m

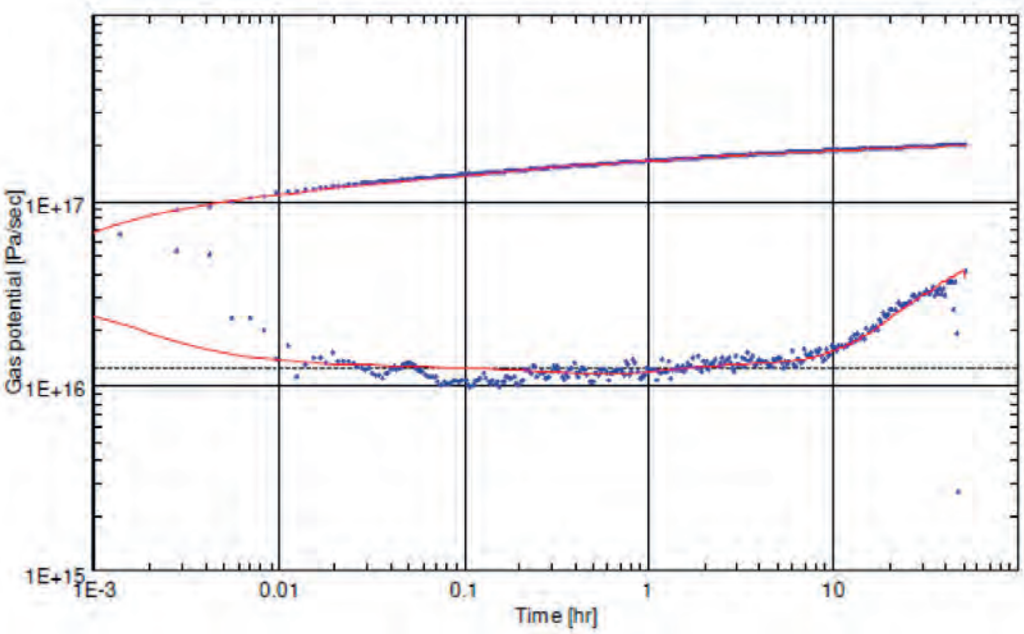


Figure 4.6 Log-log Plot of Pressure and Pressure Derivative of C2 Sand

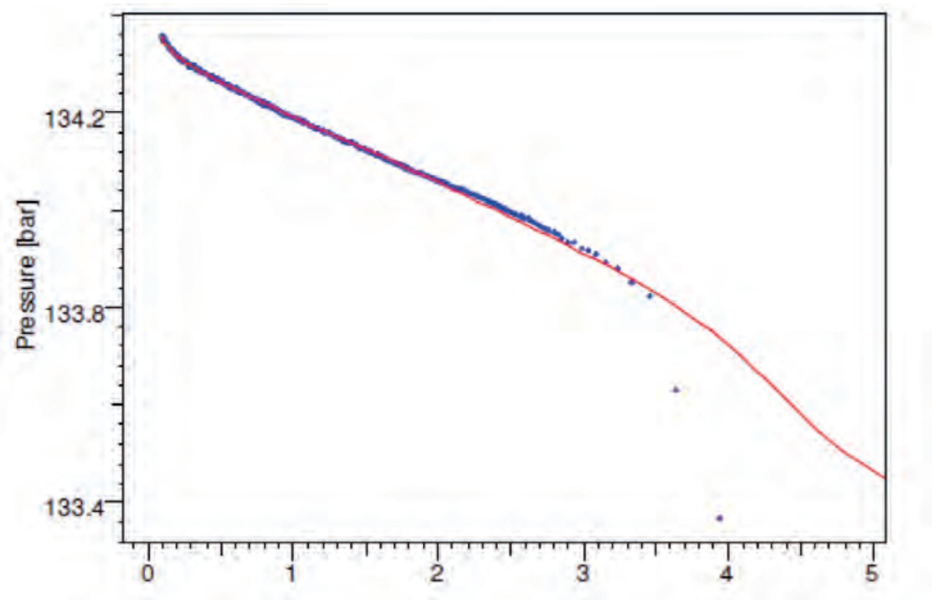


Figure 4.7 Horner Plot of C2 Sand

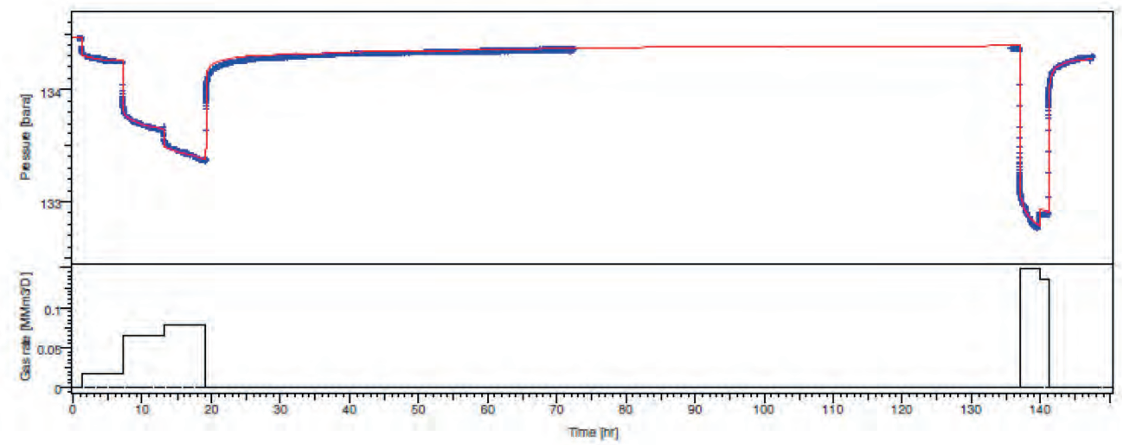


Figure 4.8 Pressure and Gas Rate of C2 Sand

Table 4-6 Well Test Interpretation Result of C2 Sand

P_i	134.5	bar
kh	1440	mD m
h	8.5	m
k	169	mD
d1	80	m
d2	120	m
d3	170	m

4.1.3 Reserves

Selva gas consists of approximately 99.5% methane and has low hydrocarbon liquids content, and as such will require minimal surface processing when the field is redeveloped. The Italian gas grid (SNAM) is also located approximately one kilometer in the South-West direction from the proposed field facilities. The field re-development plan is currently under review by the Italian authorities.

CGG has reviewed both historical well production and the Podere Maiar-1dir well test results. We have estimated 1P, 2P and 3P reserves used parameters tabulated in Table 4-7. The 1P, 2P and 3P reserves are summarized in Table 4-8.

- For 1P reserves, with low in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 44% of the area. The recovery factor of 60% is assigned for both sands.

- For 2P reserves, with mid in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 63% of the area. The recovery factor of 68% is assigned for both sands.

- For 3P reserves, with high in-place volumes, both C1 and C2 sands can drain 100% of the area. The recovery factor of 70% is assigned for both sands.

This range covers the uncertainties in the volumes, taking into consideration the uncertainty of the location and presence of “boundaries”.

Table 4-7 Summary of Parameters Used for Reserves Calculation

Sand	Case	GIIP (MMscm)	% Area Contacted by PM-1	Contacted GIIP (MMscm)	Recovery Factor (%)	Reserves (MMscm)*
C1	1P	81	100	81	60	48
	2P	190	100	190	68	129
	3P	299	100	299	70	209
C2	1P	261	44	115	60	69
	2P	585	63	369	68	250
	3P	910	100	910	70	637
Total	1P	342	N/A	195	N/A	117
	2P	775	N/A	558	N/A	379
	3P	1,208	N/A	1,208	N/A	846

** The numbers may not add due to rounding error.*

In light of the preliminary award of the Production Concession which was awarded in January 2019 by the Italian authorities, the “Selva Stratigraphic” redevelopment is clarified as reserves.

As water breakthrough is the major risk to recoverable gas volumes, PVO proposes to produce at a maximum gas rate of around 80,000 scm/day, solely from C2 sand then switch to C1 sand. In the event of earlier than expected water breakthrough, it would have a major impact on the project and as such could require an additional well.

Table 4-8 Summary of Technical Reserves (both Gross and Net) for the Selva Redevelopment Project

Selva Stratigraphic Trap	Gross (MMscm)			Net (MMscm)		
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible
C1 Sand	48	129	209	9.6	25.8	41.8
C2 Sand	69	250	637	13.8	50.0	127.4
Total	**117**	**379**	**846**	**23.4**	**75.8**	**169.2**

**The reserves classification is subject to the award of a production concession.*

CGG has compared the reserves to the historical production as shown in Figure 4.9. We find the reserves are in the reasonable range of low, mid, and high historical well performance. Our 1P, 2P and 3P reserves are based on producing with the minimum WHP of 70 barg and lower to 30 barg towards the end of well life. Therefore, it is reasonable to see slightly higher 2P reserves comparing to the historic wells that were limited at 80 barg WHP.

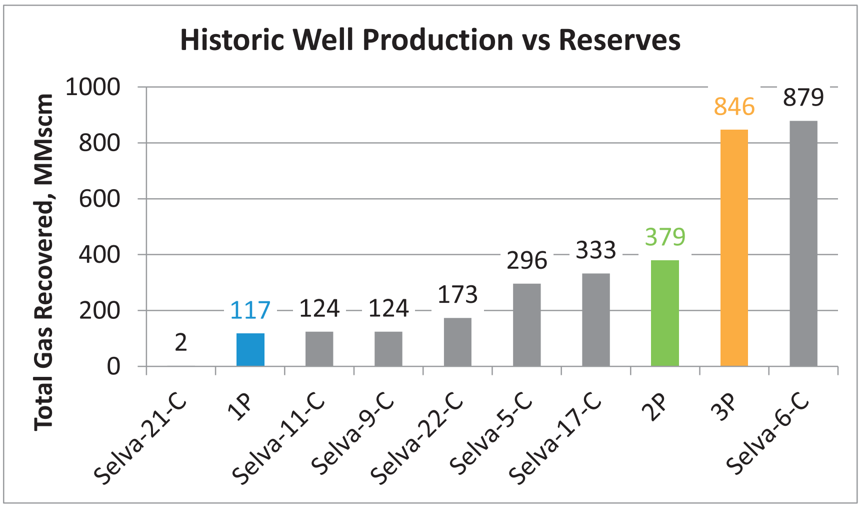


Figure 4.9 Comparison between historical production and reserves

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.10. Table 4-9 shows the annual production and cumulative production.

Figure 4.10 Technical Production Profiles of Selva 1P, 2P and 3P (before Economic Cut-off)

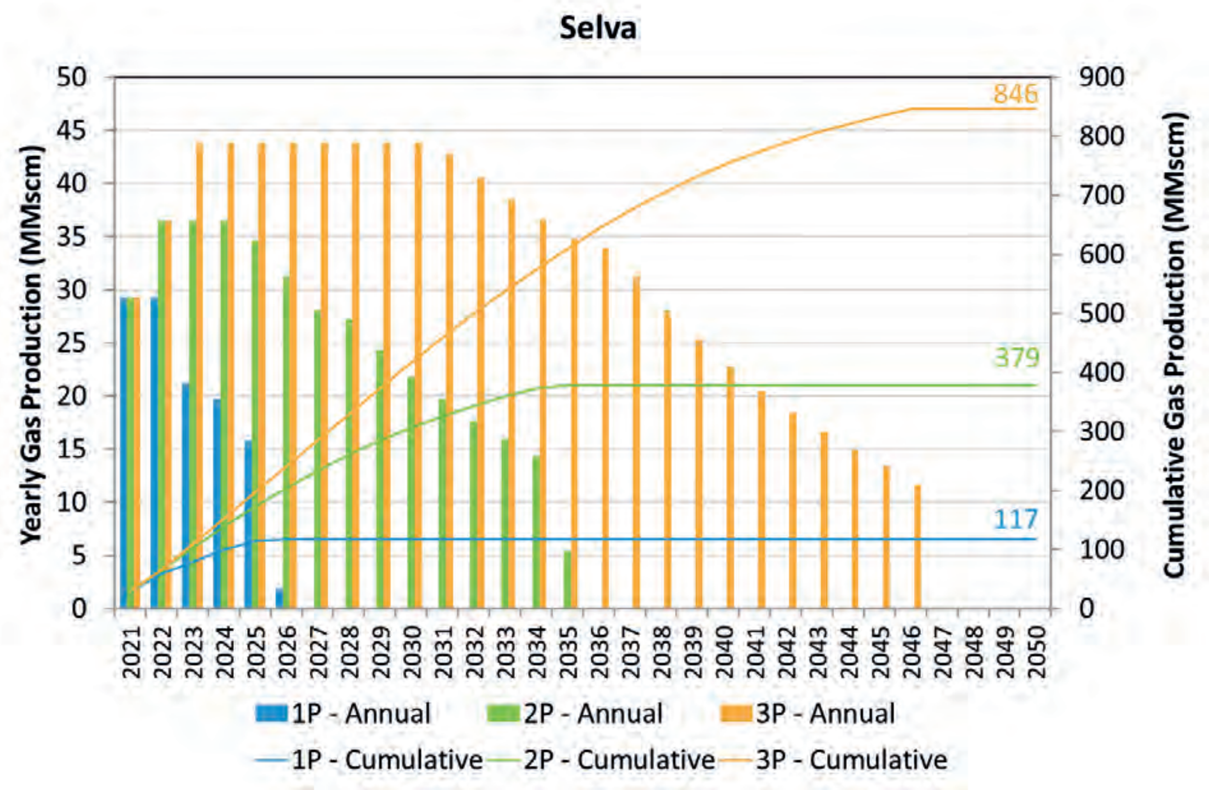


Table 4-9 Annual Production and Cumulative Production of Selva (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2021	29.20	29.20	29.20	29.20	29.20	29.20
2022	29.20	58.40	36.50	65.70	36.50	65.70
2023	21.25	79.65	36.50	102.20	43.80	109.50
2024	19.71	99.36	36.50	138.70	43.80	153.30
2025	15.77	115.12	34.68	173.38	43.80	197.10
2026	1.88	117.00	31.21	204.58	43.80	240.90
2027	0.00	117.00	28.09	232.67	43.80	284.70
2028	0.00	117.00	27.19	259.86	43.80	328.50
2029	0.00	117.00	24.27	284.13	43.80	372.30
2030	0.00	117.00	21.85	305.97	43.80	416.10
2031	0.00	117.00	19.66	325.63	42.71	458.81
2032	0.00	117.00	17.69	343.33	40.57	499.37
2033	0.00	117.00	15.93	359.25	38.54	537.92
2034	0.00	117.00	14.33	373.59	36.61	574.53
2035	0.00	117.00	5.41	379.00	34.78	609.31
2036	0.00	117.00	0.00	379.00	33.89	643.21
2037	0.00	117.00	0.00	379.00	31.21	674.41
2038	0.00	117.00	0.00	379.00	28.09	702.50
2039	0.00	117.00	0.00	379.00	25.28	727.78
2040	0.00	117.00	0.00	379.00	22.75	750.53
2041	0.00	117.00	0.00	379.00	20.48	771.00
2042	0.00	117.00	0.00	379.00	18.43	789.43
2043	0.00	117.00	0.00	379.00	16.58	806.02
2044	0.00	117.00	0.00	379.00	14.93	820.94
2045	0.00	117.00	0.00	379.00	13.43	834.38
2046	0.00	117.00	0.00	379.00	11.62	846.00
2047	0.00	117.00	0.00	379.00	0.00	846.00
2048	0.00	117.00	0.00	379.00	0.00	846.00
2049	0.00	117.00	0.00	379.00	0.00	846.00
2050	0.00	117.00	0.00	379.00	0.00	846.00

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4.2 Cembalina, Fondo Perino and East Selva

There are currently no firm plans to drill wells on the Cembalina, Fondo Perino or the East Selva prospects located within the licence area.

The 3D seismic that is planned across the Selva Field in 2020 will also cover the East Selva and Fondo Perino prospects. It should help to de-risk these structures, and progress them towards drill-ready status.

5 ECONOMIC ANALYSIS

5.1 Methodology

Net Present Values (NPVs) have been calculated using industry standard discounted cash flow analysis. CGG have created an after-tax economic model in Excel™ for this purpose. The estimated production profiles and costs have then been input in order to calculate NPVs for each of the reserve categories.

The tax benefit of any brought forward losses and/or undepreciated capex arising from trading activities and expenditure prior to the effective date has not been included in the valuation. Corporate overhead costs not specifically allocated to the operating costs and any payments relating to the farm-in agreements have also not been included.

5.2 Assumptions

5.2.1 Gas prices

It is assumed that future gas production is sold at the Italian spot gas price – the Punto di Scambio Virtuale (PSV) price. CGG have assumed that the PSV price will follow the forward curve for the Dutch TTF spot price plus Euro 1.9/Mwh, which was the average difference between the two prices in 2018. Beyond the end of the current quoted forward curve in 2025, it is further assumed that the price escalates at 2% per year. The PSV price assumption used in the economic evaluation, which is based on the TTF forward curve on 23rd November 2018, is tabulated below.

Table 5-1 PSV gas price assumption

Year	Base price (Euro/m^3)
2019	0.260
2020	0.241
2021	0.228
2022	0.220
2023	0.210
2024	0.203
2025	0.200
2026+	+2% pa

In order to capture gas price uncertainty, low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

The calorific value of gas from the field is assumed to be 38MJ/m3. No condensate production has been assumed.

5.2.2 Fiscal System

Italy's upstream oil and gas industry operates under a concessionary royalty and taxation system. Concessions are granted by the state through the National Office of Mining, Hydrocarbons and Geothermal Resources (UNMIG).

Royalty is paid on the wellhead value of production, with certain volumes exempt depending on the region and type of development. The applicable royalty rate for Selva is assumed to be 10%, with an annual royalty free allowance of 25 million cubic metres.

Profits are subject to standard Italian corporate income tax (IRES), for which the current rate is 24.0%. Tax losses can be carried forward indefinitely, and allowances are as follows:

- Exploration and Appraisal costs at 100 percent as incurred.
- Non-Well Capital costs depreciated at 15 percent, on a straight line basis (10% in the 7th year).
- Well Capital costs depreciated on a unit of production basis.
- Abandonment expenditure depreciated on a unit of production basis.
- Operating expenditure at 100 percent as incurred.
- Royalty payments at 100 percent as incurred.

In addition to IRES, companies with onshore production are also subject to a regional income tax (IRAP). The IRAP rate is assumed to be 3.9%, and is calculated in a similar way to IRES.

5.2.3 Other assumptions

The following assumptions have also been used by CGG.

Table 5-2 Economic Parameters

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost /Price Inflation	2% per annum
Discount Date	1st January 2019

5.3 Facilities and costs

The proposed development plan for Selva consists of surface processing facilities and a 1 km export pipeline to the SNAM grid. The surface facilities will include skid mounted separation and dehydration units, fiscal metering and produced water storage tanks. An allowance has also been made to add compression later in field life. The estimated development costs are as follows:

Table 5-3 Development Costs (Gross 100%)

Item	€ MM
Surface facilities	1.420
Compressor	0.230
Pipeline to grid	0.180
Project Management	0.137
Environmental	0.350
Insurance	0.023
Total	**2.339**

Table 5-4 Development Costs (Net to UOG)

Item	€ MM
Surface facilities	0.284
Compressor	0.0460
Pipeline to grid	0.036
Project Management	0.027
Environmental	0.070
Insurance	0.005
Total	**0.469**

Operating costs are estimated to be approximately €0.3MM per year with an additional charge of €0.015/M^3 for compression when required.

Abandonment costs at the end of field life are estimated to be €1.363MM
The schedule to first gas from receiving a Production Concession is assumed to be 9 months, with first gas planned for end 2020.

CGG have reviewed these assumptions, which are deemed to be reasonable.

5.4 Results

NPVs are presented for the Proven, Proven plus Probable, and Proven, Probable and Possible reserve cases for a 100% field interest and respective net interests.

It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project.

Table 5-5 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	9.0	26.2	45.0	1.8	5.2	9.0	PVO
Low	6.5	20.1	35.2	1.3	4.0	7.0	
High	11.5	32.2	54.9	2.3	6.4	11.0	

Capital and operating cost sensitivities to NPV have been performed at the base gas price and are presented in the table below.

Table 5-6 NPVs cost sensitivities (100% field)

Gas price	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	9.0	26.2	45.0
Capex +25%	8.5	25.6	44.5
Capex -15%	9.4	26.5	45.4
Opex +25%	8.7	25.6	44.4
Opex -15%	9.2	26.5	45.4

Table 5-7 NPVs cost sensitivities (Net to UOG)

Gas price	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	1.8	5.2	9.0
Capex +25%	1.7	5.1	8.9
Capex -15%	1.9	5.3	9.1
Opex +25%	1.7	5.1	8.9
Opex -15%	1.8	5.3	9.1

6 APPENDIX A: DEFINITIONS

6.1 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 1998, 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 (2007) are presented in the following sections.

Source: SPE Petroleum Resources Management System 2007

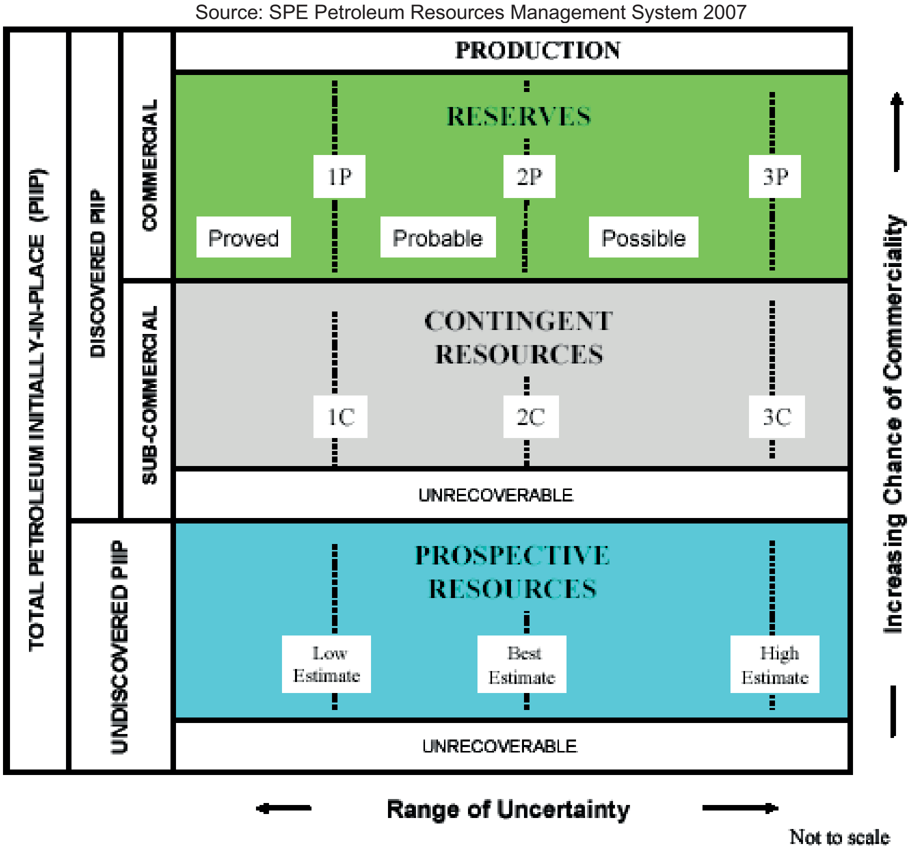
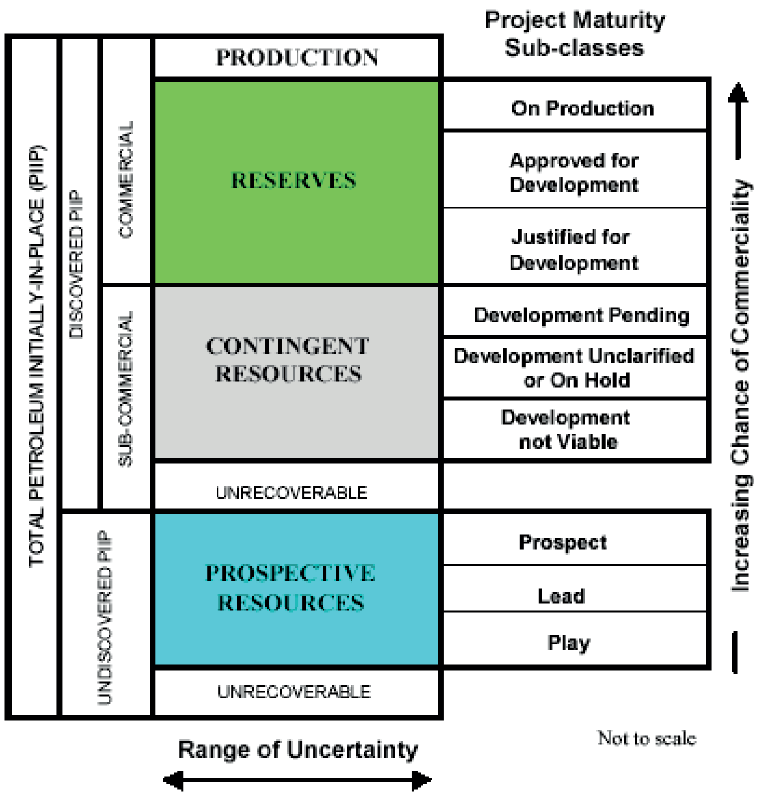


Figure 6.1 Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 6.2 Resources Classification Framework: Sub-classes based on Project Maturity

6.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

6.1.2 Discovered Petroleum Initially-In-Place

Discovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

6.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

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6.2 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

6.3 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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- A project must be sufficiently defined to establish its commercial viability
- There must be a reasonable expectation that all required internal and external approvals will be forthcoming
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The “decision gate” whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

6.3.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

6.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

6.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

6.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

6.3.5 Probable Reserves

Probable Reserves are those additional reserves that 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 + Probable Reserves (2P).

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.

6.3.6 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 + Probable + Possible (3P), 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.

6.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. 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.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

6.4.1 Contingent Resources: Development Pending

Contingent Resources (Development Pending) are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

6.4.2 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 eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

6.4.3 Contingent Resources: Development Not Viable

Contingent Resources (Development Not Viable) are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to 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 recognised in the event of a major change in technology or commercial conditions.

6.5 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

6.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

6.5.2 Lead

A Lead is classified as a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

6.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

6.6 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

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7 APPENDIX B: NOMENCLATURE

acre	43,560 square feet	ESP	Electrical Submersible Pump
AOF	absolute open flow	et al.	and others
API	American Petroleum Institute (ºAPI for oil gravity, API units for gamma ray measurement)	EUR	estimated ultimately recoverable (reserves)
		FPSO	Floating production storage unit
av.	Average	ft/s	feet per second
AVO	Amplitude vs. Off-Set	G & A	general & administration
BBO	billion (10^9) barrels of oil	G & G	geological & geophysical
bbl, bbls	barrel, barrels	g/cm^3	grams per cubic centimetre
BCF	billion cubic feet	Ga	billion (10^9) years
bcm	billion cubic metres	GIIP	gas initially in place
BCPD	barrels of condensate per day	GIS	Geographical Information Systems
BHT	bottom hole temperature	GOC	gas-oil contact
BHP	bottom hole pressure	GOR	gas to oil ratio
BOE	barrel of oil equivalent, with gas	GR	gamma ray (log)
	converted at 1 BOE = 6,000 scf	GWC	gas-water contact
BOPD	barrels of oil per day	H_2S	hydrogen sulphide
BPD	barrels per day	ha	hectare(s)
Btu	British thermal units	HI	hydrogen index
BV	bulk volume	HP	high pressure
c.	circa	Hz	hertz
CCA	conventional core analysis	IDC	intangible drilling costs
CD-ROM	compact disc with read only memory	IOR	improved oil recovery
cgm	computer graphics meta file	IRR	internal rate of return
CNG	compressed natural gas	J & A	junked & abandoned
CO_2	carbon dioxide	km	kilometres (1,000 metres)
COE	crude oil equivalent	km^2	square kilometres
1-D, 2-D, 3-D	1-, 2-, 3-dimensions	kWh	kilowatt-hours
DHI	direct hydrocarbon indicators	LoF	life of field
DHC	dry hole cost	LP	low pressure
DPT	deeper pool test	LST	lowstand systems tract
DROI	discounted return on investment	LVL	low-velocity layer
DST	drill-stem test	M & A	mergers & acquisitions
DWT	deadweight tonnage	m	metres
E	East	M	thousands
E & P	exploration & production	MM	million
EAEG	European Association of Exploration	m^3/day	cubic metres per day
	Geophysicists	Ma	million years (before present)
e.g.	for example	mbdf	metres below derrick floor
EOR	enhanced oil recovery	mbsl	metres below sea level

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MBOPD	thousand bbls of oil per day
MCFD	thousand cubic feet per day
MCFGD	thousand cubic feet of gas per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
Mscm	thousand cubic metres
MMscm	million cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFGD	million cubic feet of gas per day
MMTOE	million tons of oil equivalent
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P90 or 1P	proved
P50 or 2P	proved + probable
P10 or 3P	proved + probable + possible
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability

PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
Ø	porosity
plc	public limited company
por.	porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SCF/STB	standard cubic feet per stock tank barrel
SCM	standard cubic metres
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
STB	stock tank barrels
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TCF	trillion (10^{12}) cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
VDR	virtual dataroom
W	West

WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

*1 SCM= 35.3147 SCF

Created by
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PART XI

NOTICE OF GENERAL MEETING OF UNITED OIL & GAS PLC

("Company")

(incorporated in England and Wales with registered number 09624969)

NOTICE IS HEREBY GIVEN that a General Meeting of the Company will be held at 200 Strand, London, England, WC2R 1DJ at 10.00 a.m. on 23 December 2019 for the purpose of considering and, if thought fit, passing the following resolutions of which, resolutions numbered 1 and 2 will be proposed as ordinary resolutions and resolution 3 as a special resolution:

Terms used in this notice shall have the same meanings as defined in the circular to shareholders of the Company dated 6 December 2019 ("**Admission Document**"), unless the context requires otherwise.

ORDINARY RESOLUTIONS

1 **THAT** the proposed acquisition by the Company of the entire issued share capital of Rockhopper (Egypt) Pty Limited (the "**Rockhopper Acquisition**") on the terms summarised in the Admission Document of which this notice forms part be and is hereby approved and that the directors of the Company, or a duly constituted committee of the directors, be and are hereby authorised to waive, amend, vary or extend any of the terms and conditions of the Rockhopper Acquisition or the agreement for the Rockhopper Acquisition or any related agreements (but not to a material extent) and do all such things that they may consider necessary or desirable in connection with the Rockhopper Acquisition.

2 **THAT**, subject to the passing of Resolution 1, the directors of the Company be generally and unconditionally authorised under section 551 of the Companies Act 2006 (the "**Act**") to exercise all the powers of the Company to allot shares in the Company and to grant rights to subscribe for, or to convert any security into such shares in the Company ("**Allotment Rights**"):

(a) up to an aggregate nominal amount of £1,145,038.17 in respect of the 114,503,817 new Ordinary Shares pursuant to the Rockhopper Acquisition on the terms set out in the Admission Document (the "**Consideration Shares**");

(b) up to an aggregate nominal amount of £1,506,166.69 in respect of the 150,616,669 new Ordinary Shares pursuant to the terms of the Placing (the "**Placing Shares**");

(c) up to an aggregate nominal amount of £84,194.98 in respect of the 8,419,498 new Ordinary Shares pursuant on the terms of the Subscription (the "**Subscription Shares**");

(d) up to an aggregate nominal amount of £11,416.67 in connection with the Cenkos December 2019 Warrants;

(e) up to an aggregate nominal amount of £63,891.67 in connection with the Optiva December 2019 Warrants; and

(f) otherwise than pursuant to paragraphs (a) to (e) above, up to an aggregate nominal amount of £2,063,847 (being equal to one-third of the nominal value of the Company's enlarged issued share capital immediately following Admission);

such authority shall expire (unless previously revoked by the Company) at the conclusion of the next Annual General Meeting of the Company and the Company may, before such expiry, make an offer or agreement which would or might require shares to be allotted or Allotment Rights to be granted after the authority has expired and the directors may allot such shares or grant such Allotment Rights in pursuance of any such offer or agreement notwithstanding that this authority has expired.

SPECIAL RESOLUTION

3 **THAT** the directors of the Company be generally and unconditionally empowered under section 570 of the Act to exercise all the powers of the Company to allot equity securities (as defined in section 560 of the Act) for cash pursuant to the authorisation conferred by resolution 2 above as if section 561 of the Act did not apply to such allotment, provided that this power shall be limited to:

(a) the allotment and issue of the Consideration Shares;

(b) the allotment and issue of the Placing Shares;

(c) the allotment and issue of the Subscription Shares;

(d) the allotment of equity securities up to an aggregate nominal amount of £11,416.67 in connection with the Cenkos December 2019 Warrants;

(e) the allotment of equity securities up to an aggregate nominal amount of £63,891.67 in connection with the Optiva December 2019 Warrants;

(f) the allotment of equity securities in connection with an offer by way of a rights issue to:

(i) ordinary shareholders in proportion (as nearly as may be) to their existing holdings; and

(ii) holders of other equity securities, if this is required by the rights of those securities or, if the directors consider it necessary, but subject to such exclusions and other arrangements as the directors may consider necessary or appropriate in relation to fractional entitlements, record dates, legal, regulatory or practical problems nor under the laws of any territory (including the requirements of any regulatory body or stock exchange) or any other matter; and

(g) otherwise than pursuant to paragraphs (a) to (f) above, the allotment of equity securities up to an aggregate nominal amount of £2,063,847 (being one third of the nominal value of the Company's Enlarged Issued Share Capital immediately following Admission);

such power shall expire (unless previously revoked by the Company) at the conclusion of the next annual general meeting of the Company and in each case the Company may, before such expiry, make an offer or agreement which would or might require equity securities to be allotted after such expiry and the directors may allot equity securities in pursuance of any such offer or agreement as if this power had not expired.

By Order of the Board

Registered Office:

200 Strand
London
WC2R 1DJ

David Quirke
Company Secretary
Dated: 6 December 2019

Notes

1. A member entitled to attend and vote at the above meeting is entitled to appoint one or more proxies to exercise all or any of their rights to attend, speak and vote at the meeting. A proxy need not be a member of the Company. You may appoint more than one proxy provided each proxy is appointed to exercise rights attached to different shares, in which case you should specify the number of shares in respect of which each proxy is entitled to exercise their rights. You may not appoint more than one proxy to exercise the rights attached to any one share. A corporate member is also entitled to authorise a person or persons to act as its representative or representatives at the meeting with the entitlement to exercise on behalf of the member the same powers as the member could exercise, if it were an individual member of the Company.
2. A form of proxy is enclosed for use at the above meeting. Completion and return of the form of proxy will not prevent a member from attending the meeting and voting in person. To be effective, the form of proxy, duly executed, must be lodged at the address shown on the form of proxy not later than 48 hours before the time of the meeting (excluding non-business days).
3. The right to vote at the meeting is determined by reference to the Company's register of members ("**Register**") as at 10.00 a.m. on 19 December 2019. Changes to entries on the Register after that time will be disregarded in determining the rights of any member to attend and vote at the meeting.
4. It is possible for you to submit your proxy votes online. Further information on this service can be seen below under the heading "**Electronic voting**".
5. As at 5.00 p.m. on 5 December 2019, being the latest practicable date prior to the publication of this Notice, the Company's issued share capital comprised 345,613,985 ordinary shares of £0.01 each. Each ordinary share carries the right on a poll to one vote at a general meeting of the Company and, therefore, the total number of voting rights in the Company as at 5.00 p.m. on 5 December 2019 is 345,613,985. Voting on the resolutions will be conducted by way of a show of hands.
6. As a member, you have the right to put questions at the meeting relating to the business being dealt with at the meeting. Any joint holder may vote at the meeting, either personally or by proxy, and if more than one holder is present the one whose name stands first in the Register shall be entitled to vote.
7. CREST members who wish to appoint a proxy or proxies by utilising the CREST electronic proxy appointment service may do so for the meeting and any adjournment(s) thereof by utilising the procedures described in the CREST Manual which can be viewed at www.euroclear.com. CREST personal members or other CREST sponsored members, and those CREST members who have appointed a voting 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.
8. In order for a proxy appointment made or instructions 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 ("**EUI**") 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 issuer's agent ID (7RA36) by the latest time for the receipt of proxy appointments specified in note 3 above. 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 Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST.
9. CREST members and, where applicable, their CREST sponsors or voting service providers should note that EUI does not make available special procedures in CREST for any particular messages. 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 service providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.
10. 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 (as amended).

Electronic voting

The Company actively encourages Shareholders to cast their vote electronically. You can do so by visiting www.shareregistrars.uk.com and following the online instructions. Through the website Shareholders will be able to access the Registrars' Portal, on which they will be able to register to be able to vote. For security reasons, registration is a two-stage authentication process. Once registered, Shareholders will be able to vote online via the platform. Alternatively, Shareholders can submit their completed Form of Proxy electronically by emailing the same to voting@shareregistrars.uk.com.