THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the Acquisition, the contents of this document, or as to the action you should take, you are recommended to seek your own independent financial advice immediately from your stockbroker, bank, solicitor, accountant, fund manager or other appropriate independent financial adviser authorised under the Financial Services and Markets Act 2000 if you are resident in the United Kingdom or, if not, from another appropriately authorised independent professional adviser in the relevant jurisdiction.

If you sell, have sold or otherwise transferred all of your SOCO Shares you should send this document and the accompanying documents, together with the accompanying Form of Proxy, as soon as possible to the purchaser or transferee or to the stockbroker, bank or other agent through whom the sale or transfer was effected for delivery to the purchaser or the transferee. However, the distribution of this document, any accompanying documents and/or the Form of Proxy into certain jurisdictions other than the United Kingdom may be restricted by law. Therefore, persons into whose possession this document and any accompanying documents come should inform themselves about, and observe, any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. If you have sold only part of your holding of SOCO Shares you should retain these documents.

SOCO INTERNATIONAL PLC

(Incorporated and registered in England and Wales with Registered No. 03300821)

PROPOSED ACQUISITION OF MERLON PETROLEUM EL FAYUM COMPANY

Circular to SOCO Shareholders and Notice of SOCO General Meeting

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Your attention is drawn to the letter from the Chairman of SOCO International plc ("SOCO" or the "Company") which is set out on pages 9 to 18 of this document and which contains the unanimous recommendation of the SOCO Directors that you vote in favour of the Resolutions to be proposed at the SOCO General Meeting referred to below. Please read the whole of this document and, in particular, the risk factors set out in Part II (*Risk Factors*).

Notice of the SOCO General Meeting to be held at Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ at 10.00 a.m. on 21 December 2018 is set out at the end of this document. A Form of Proxy for use in connection with the SOCO General Meeting is enclosed with this document. Whether or not you intend to be present at the SOCO General Meeting, you are requested to complete and sign the Form of Proxy in accordance with the instructions printed on it so as to be received by SOCO's registrar, Equiniti Limited, at Aspect House, Spencer Road, Lancing, BN99 6DA, as soon as possible, and in any event, no later than 10.00 a.m. on 19 December 2018 (or, in the case of an adjournment, not later than 48 hours (excluding non-working days) before the time fixed for the holding of the adjourned meeting). If you hold SOCO Shares in CREST, you may appoint a proxy by completing and transmitting a CREST Proxy Instruction to SOCO's registrar, Equiniti Limited, (CREST participant ID RA19). Alternatively, you may give proxy instructions by logging on to www.sharevote.co.uk and following the instructions. Proxies sent electronically must be sent as soon as possible and, in any event, so as to be received by not later than 10.00 a.m. on 19 December 2018 (or, in the case of an adjournment, not later than 48 hours (excluding non-working days) before the time fixed for the holding of the adjourned meeting). The completion and return of a Form of Proxy (or the electronic appointment of a proxy) will not preclude you from attending and voting in person at the SOCO General Meeting or any adjournment thereof, if you wish to do so and are so entitled.

This document is a circular relating to the Acquisition which has been prepared in accordance with the Listing Rules. This document has been approved by the FCA. This document does not constitute or form part of any offer or invitation to purchase, otherwise acquire, subscribe for, sell, otherwise dispose of or issue, or any solicitation of any offer to sell, otherwise dispose of, issue, purchase, otherwise acquire or subscribe for, any security. The information provided in this document is provided solely in compliance with the Listing Rules for the purpose of enabling SOCO Shareholders to consider the Resolutions.

Evercore Partners International LLP ("**Evercore**"), is authorised and regulated by the FCA. Evercore is acting as sponsor and financial adviser exclusively for SOCO in connection with the matters set out in this document and the Acquisition. Evercore is not, and will not be, responsible to anyone other than SOCO for providing the protections afforded to its clients or for providing advice in relation to the Acquisition or any other matters referred

to in this document. Apart from the responsibilities and liabilities, if any, which may be imposed on it by the FSMA or the regulatory regime established thereunder, or under the regulatory regime of any jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, neither Evercore nor any of its subsidiaries, branches or affiliates owes or accepts any responsibility whatsoever (whether direct or indirect, whether in contract or in tort, under statute or otherwise) and makes no representation or warranty, express or implied, for the contents of this document, including its accuracy, fairness, sufficiency, completeness or verification or for any other statement made or purported to be made by it, or on their behalf, in connection with SOCO or the Acquisition, and nothing in this document is, or shall be relied upon as, a promise or representation in this respect, whether as to the past or the future. Evercore and any of its subsidiaries, branches or affiliates accordingly disclaims to the fullest extent permitted by law all and any responsibility and liability whether arising in tort, contract or otherwise (save as referred to above) which they might otherwise have in respect of this document or any such statement contained therein.

The distribution of this document in jurisdictions other than the United Kingdom may be restricted by law. No action has been taken by SOCO to obtain any approval, authorisation or exemption to permit the possession or distribution of this document (or any other publicity material relating to the Acquisition) in any jurisdiction, other than in the United Kingdom.

Overseas SOCO Shareholders may be affected by the laws of other jurisdictions in relation to the distribution of this document. Persons into whose possession this document comes should inform themselves about and observe any applicable restrictions and legal, exchange control or regulatory requirements in relation to the distribution of this document. Any failure to comply with such restrictions or requirements may constitute a violation of the securities laws of any such jurisdiction.

This document does not constitute an offer of securities for sale in the United States or an offer to acquire or exchange securities in the United States. No offer to acquire securities or to exchange securities for other securities has been made, or will be made, and no offer of securities has been made, or will be made, directly or indirectly, in or into, or by the use of the mails, any means or instrumentality of interstate or foreign commerce or any facilities of a national securities exchange of, the United States of America or any other country in which such offer may not be made other than (i) in accordance with the requirements under the US Securities Exchange Act of 1934, as amended, a registration statement under the US Securities Act of 1933, as amended, or the securities laws of such other country, as the case may be, or (ii) pursuant to an available exemption therefrom.

The contents of this document should not be construed as legal, business or tax advice. Each SOCO Shareholder should consult his, her or its own legal adviser, financial adviser or tax adviser for legal, financial or tax advice.

Any reproduction or distribution of this document, in whole or in part, and any disclosure of its contents or use of any information contained in this document for any purpose other than considering the Acquisition is prohibited. By accepting delivery of this document, each SOCO Shareholder agrees to the foregoing.

Without limitation, the contents of the website of the SOCO Group and the Merlon Group do not form part of this document.

Dated: 5 December 2018

IMPORTANT INFORMATION

Information regarding forward-looking statements

This document (including the information incorporated by reference into this document) includes forward-looking statements. The words "believe", "anticipate", "expect", "intend", "aim", "plan", "predict", "continue", "assume", "positioned", "may", "will", "should", "shall", "risk" and other similar expressions that are predictions of or indicate future events and future trends or identify forward-looking statements. These forward-looking statements include all matters that are not current or historical facts. In particular, the statements regarding the SOCO Group's and the Merlon Group's strategy, future financial position and other future events or prospects are forward-looking statements.

SOCO Shareholders should not place undue reliance on forward-looking statements because they involve known and unknown risks, uncertainties and other factors that are in many cases beyond the control of SOCO or Merlon. By their nature, forward-looking statements involve risks and uncertainties because such statements relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements are not indicative of future performance and the actual results of operations and financial condition of the SOCO Group or the Merlon Group, and the development of the industry in which the SOCO Group or the Merlon Group operates, may differ materially from those made in or suggested by the forward-looking statements contained in this document. Important risk factors which may cause actual results to differ include, but are not limited to, those described in Part II (*Risk Factors*) of this document. The cautionary statements set out above should be considered in connection with any subsequent written or oral forward-looking statements that SOCO or Merlon, or persons acting on their behalf, may issue.

These forward-looking statements reflect SOCO's and Merlon's judgement at the date of this document and are not intended to provide any representations, assurances or guarantees as to future events or results. To the extent required by the Listing Rules, the Prospectus Rules, the Market Abuse Regulation, the Disclosure Guidance and Transparency Rules and other applicable regulation, SOCO will update or revise the information in this document. Otherwise, SOCO undertakes no obligation to update or revise any forward-looking statements or other information and will not publicly release any revisions it may make to any forward-looking statements or other information that may result from events or circumstances arising after the date of this document. SOCO Shareholders should note that this paragraph is not intended to qualify the statement as to working capital set out in Part VII (*Additional Information*) of this document.

No statement in this document is intended to constitute a profit forecast or profit estimate for any period, nor should any statement be interpreted to mean that earnings or earnings per share will necessarily be greater or lesser than those for the relevant preceding financial periods for either SOCO or Merlon as appropriate.

Currency presentation

Unless otherwise indicated, all references in this document to "**pence**", "**pounds sterling**", "**sterling**", "**£**" or "**p**" are to the lawful currency of the United Kingdom, all references to "**cents**", "**US$**", "**US dollars**" or "**$**", are to the lawful currency of the United States and all references to "**Egyptian Pounds**" are to the lawful currency of Egypt.

The following tables set forth, for the periods indicated, the period end, period average, high and low London Composite Rate expressed in US$ per £1.00. The London Composite Rate is a "best market" calculation in which, at any point in time, the bid rate is equal to the highest bid rate of all contributing bank indications and the ask rate is set to the lowest ask rate offered by these banks. The London Composite Rate is a mid-value rate between the applied highest bid rate and the lowest ask rate. The London Composite Rate of US$ on the Latest Practicable Date was US$1.2741 per £1.

	Period End	Average	High	Low
Year				
2015	1.4734	1.5283	1.5872	1.4654
2016	1.2345	1.3554	1.4810	1.2158
2017	1.3524	1.2886	1.3582	1.2068
Period				
January (through the Latest Practicable Date) 2018	1.2741	1.3408	1.4325	1.2700

The above rates differ from the actual rates used in the preparation of the financial statements and other financial information appearing in this document. These exchange rates have been provided solely for the convenience of SOCO Shareholders. The inclusion of exchange rates is not meant to suggest that the pound sterling amounts actually represent US$ amounts or that these amounts could have been converted into US$ at any particular rate, if at all.

Market, economic and industry data

Unless the source is otherwise stated, the market, economic and industry data in this document constitute the SOCO Directors' estimates, using underlying data from independent third parties. While the SOCO Directors are not aware of any misstatements regarding their estimates presented herein, their estimates involve risks, assumptions and uncertainties and are subject to change based on various factors, including those discussed in Part II (*Risk Factors*) in this document.

SOCO obtained market data and certain industry forecasts used in this document from internal surveys, reports and studies, where appropriate, as well as market research, publicly available information and industry publications, including Wood Mackenzie's report entitled "Egypt's 2018 EGPC licensing round: improving outlook tempered by tough terms" dated 21 June 2018. These and other industry publications generally state that while the information they contain has been obtained from sources believed to be reliable, the accuracy and completeness of such information is not guaranteed. SOCO believes that these industry publications, surveys and forecasts are reliable but it has not independently verified them and cannot guarantee their accuracy or completeness. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications and uncertainties as the other forward-looking statements in this document.

SOCO confirms that all such third party data contained in this document has been accurately reproduced and, so far as SOCO is aware and able to ascertain from information published by the relevant third party, no facts have been omitted that would render the reproduced information inaccurate or misleading.

Where third-party information has been used in this document, the source of such information has been identified.

Reserves information and Competent Person's Report

Unless otherwise indicated, Lloyd's Register has, in compiling its Merlon Group CPR concerning the Merlon Group's hydrocarbon reserves and resources as of 30 June 2018 contained in Part VI (*Competent Person's Report in respect of the Merlon Group*) to this document, used the definitions and guidelines set out by the PRMS Standards as the standard classification and reporting (details of which are set out in Appendix I of the Merlon Group CPR).

SOCO Shareholders should not place undue reliance on the forward-looking statements in the Merlon Group CPR or on the ability of the Merlon Group CPR to predict actual reserves or resources. Prospective and contingent resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. A possibility exists that the prospects will not result in the successful discovery of economic resources in which case there would be no commercial development.

Except where otherwise indicated, all reserves and resources information in this document is presented on the basis of the PRMS Standards. The PRMS Standards are different than the standards used by other jurisdictions. SOCO Shareholders should not assume that the data found in the Merlon Group CPR is directly comparable to a similar report prepared in accordance with the reserve and resource reporting standards of other jurisdictions. SOCO Shareholders should read the Merlon Group CPR for more information on the Merlon Group's reserves and resources and the reserves and resources definitions that the Merlon Group uses.

The information on reserves and resources in this document and in the Merlon Group CPR is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the Merlon Group CPR is set out in more detail in such report contained in Part VI (*Competent Person's Report in respect of the Merlon Group*).

Presentation of financial information

Unless otherwise stated:

- financial information relating to the SOCO Group has been extracted without material adjustment from the SOCO Audited Financial Statements and the SOCO Interim Financial Statements; and

- financial information relating to the Merlon Group has been extracted without material adjustment from the historical financial information relating to the Merlon Group set out in Part III (*Financial Information on Merlon*) of this document.

Unless otherwise indicated, financial information in this document relating to SOCO and Merlon has been prepared in accordance with IFRS and in accordance with the accounting policies adopted by SOCO in preparing the audited financial statements for the year ended 31 December 2017.

Rounding

Certain data in this document, including financial, statistical and operating information, have been rounded. As a result of rounding, the totals of data presented in this document may vary slightly from the actual arithmetic totals of such data. Percentages have also been rounded and accordingly may not add to 100 per cent.

Pro-Forma Financial Information

In this document, any reference to pro-forma financial information is to information which has been extracted without material adjustment from the unaudited pro-forma financial information contained in Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group*).

The unaudited pro-forma financial information consists of a pro-forma net assets statement relating to the Enlarged Group. This has been prepared: (i) in accordance with Annex II to the Prospectus Directive Regulation (No 2004/809/EC), (ii) in a manner consistent with the accounting policies and presentation adopted by the SOCO Group in relation to the consolidated financial statements for the year ended 31 December 2017 and (iii) based on the consolidated net assets of the SOCO Group as at 31 December 2017 and the consolidated net assets of the Merlon Group as at 31 December 2017. The unaudited pro-forma statement of net assets has been prepared to illustrate the impact of the Acquisition and the draw down under the new RBL Facility.

Due to its nature, the unaudited pro-forma net assets statement addresses a hypothetical situation. It does not represent the SOCO Group's actual financial position or results, or what the Enlarged Group's actual financial position or results would have been if the Acquisition and the draw down under the new RBL Facility had completed on the date indicated.

CONTENTS

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

The dates and times given in the table below in connection with the Acquisition are indicative only and are based on SOCO's current expectations and may be subject to change (including as a result of changes to the regulatory timetable and/or the process for implementation of the Acquisition). If any of the times and/or dates above change, the revised times and/or dates will be notified by SOCO to SOCO Shareholders through a Regulatory Information Service.

References to a time of day are to London time.

Event	Time and/or Date
Announcement of the Acquisition	20 September 2018
Publication of this Circular	5 December 2018
Latest time for lodging Forms of Proxy	10.00 a.m. on 19 December 2018[(1)]
SOCO General Meeting	10.00 a.m. on 21 December 2018
Completion of the Acquisition	A date expected to be in H1 2019 ("**D**")[(2)]
Issue of Consideration Shares to the Seller	By 8.00 a.m. on D+1 Business Day
Admission and commencement of dealings in the Consideration Shares on the London Stock Exchange	By 8.00 a.m. on D+1 Business Day
Crediting of the Consideration Shares in uncertificated form to CREST accounts	Within 2 Business Days of Admission
Despatch of definitive share certificates for Consideration Shares in certificated form	Within 10 Business Days of Admission
Backstop Date for Completion of the Acquisition	20 September 2019[(3)]

NOTES:

(1) Forms of Proxy for the SOCO General Meeting must be lodged no later than 10.00 a.m. on 19 December 2018 in order to be valid, or, if the SOCO General Meeting is adjourned, not later than 48 hours (excluding non-working days) before the time appointed for holding the adjourned meeting.

(2) Subject to the satisfaction or waiver of the Conditions.

(3) This is the date by which the Acquisition must be completed, unless otherwise agreed in writing by SOCO and the Seller in accordance with the terms of the Share Purchase Agreement.

SOCO DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

SOCO Directors	Rui de Sousa (*Non-Executive Chairman*) Ed Story (*President and Chief Executive Officer*) Dr. Mike Watts (*Managing Director*) Jann Brown (*Managing Director and Chief Financial Officer*) Rob Gray (*Deputy Chairman and Senior Independent Non-Executive Director*) John Martin (*Independent Non-Executive Director*) Ambassador António Monteiro (*Non-Executive Director*) Ettore Contini (*Non-Executive Director*)
Company Secretary	Tony Hunter
Registered Office	48 Dover Street London W1S 4FF United Kingdom
Sponsor and Financial Adviser	Evercore Partners International LLP 15 Stanhope Gate London W1K 1LN United Kingdom
Legal Adviser to SOCO	Clifford Chance LLP 10 Upper Bank Street Canary Wharf London E14 5JJ United Kingdom
Legal Adviser to the Sponsor	Simmons & Simmons LLP 1 Ropemaker Street London EC2Y 9SS United Kingdom
Registrar	Equiniti Limited Aspect House Spencer Road Lancing BN99 6DA United Kingdom
Auditor and Reporting Accountant to the SOCO Group	Deloitte LLP 1 New Street Square London EC4A 3HQ United Kingdom
Competent Person Reporting to the SOCO Group	Lloyd's Register (Senergy (GB) Limited) Kingswells Causeway Prime Four Business Park Kingswells Aberdeen AB15 8PU United Kingdom

PART I

LETTER FROM THE CHAIRMAN OF SOCO

SOCO INTERNATIONAL PLC

(*Incorporated and registered in England and Wales with registered number 03300821*)

SOCO Directors:

Rui de Sousa (*Non-Executive Chairman*)
Ed Story (*President and Chief Executive Officer*)
Dr. Mike Watts (*Managing Director*)
Jann Brown (*Managing Director and Chief Financial Officer*)
Rob Gray (*Deputy Chairman and Senior Independent Non-Executive Director*)
John Martin (*Independent Non-Executive Director*)
Ambassador António Monteiro (*Non-Executive Director*)
Ettore Contini (*Non-Executive Director*)

Registered Office:

48 Dover Street
London W1S 4FF
United Kingdom

5 December 2018

Dear Shareholder

PROPOSED ACQUISITION OF MERLON PETROLEUM EL FAYUM COMPANY

1. Introduction

On 20 September 2018, SOCO announced that it had reached an agreement with Merlon International on the terms of the proposed Acquisition by SOCO of Merlon for approximately US$215 million, to be satisfied through the payment of approximately US$136 million in cash and the issue of 65,561,041 new SOCO Shares, representing 19.75 per cent. of SOCO's current issued share capital (excluding treasury shares). SOCO will also arrange for the repayment of Merlon's net debt, which was approximately US$15.1 million as at 30 September 2018 (based on Merlon's unaudited financial statements for the period ending 30 September 2018) and approximately US$22.2 million as at 31 December 2017. The Acquisition is subject to shareholder and regulatory approvals.

Merlon is a private oil and gas exploration and production company incorporated in the Cayman Islands, headquartered in Houston, Texas and has been engaged in oil and gas exploration and production with assets in Egypt since 1997. It has a 100 per cent. participating interest in the El Fayum Concession, which is located in the low-cost and highly prolific Western Desert in Egypt, c.80 km south west of Cairo and in proximity to local energy infrastructure. Merlon was awarded the Concession Agreement in 2004, which granted Merlon and the Egyptian General Petroleum Corporation ("EGPC") the joint exclusive right to explore for and develop oil and gas in the El Fayum Concession Area. Further information on Merlon is set out in paragraph 6 (Information on the Merlon Group) below.

Owing to its size, the Acquisition constitutes a Class 1 transaction for the purposes of the Listing Rules and therefore requires the approval of SOCO Shareholders. Accordingly, the SOCO General Meeting has been convened for 10.00 a.m. on 21 December 2018 at Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ. The notice convening the SOCO General Meeting is set out at the end of this document and an explanation of the Resolutions to be proposed at the meeting is set out in paragraph 15 (*SOCO General Meeting and the Resolutions*) below.

I am writing to give you further details of the Acquisition, including the background to and reasons for the proposed transaction, to explain why the SOCO Board considers the proposed transaction to be in the best interests of SOCO, the SOCO Group and SOCO Shareholders as a whole and to seek your approval of the Resolutions.

2. Summary of the terms of the Acquisition

The Acquisition will be structured as an acquisition of the entire issued and to be issued share capital of Merlon for approximately US$215 million, to be settled through the payment of approximately US$136 million in cash and the issue to the Seller of 65,561,041 Consideration Shares (representing 19.75 per cent. of SOCO's current share capital (excluding treasury shares) and a value of approximately US$79 million based on the arithmetic average of the daily volume-weighted average price for a SOCO ordinary share for the 20 trading days ended 17

September 2018, the latest practicable date prior to the date of the Announcement). The Consideration Shares represent 16.5 per cent. of SOCO's share capital (excluding treasury shares) immediately following Admission. The Seller will transfer the Consideration Shares, subject to the terms of the Share Purchase Agreement, to the Seller's shareholders.

As part of the Acquisition, SOCO will arrange for the repayment of Merlon's existing debt facility. Merlon's net debt was approximately US$15.1 million as at 30 September 2018 (based on Merlon's unaudited financial statements for the period ending 30 September 2018) and approximately US$22.2 million as at 31 December 2017.

Completion of the Acquisition is subject to the satisfaction or waiver of, amongst other things, conditions relating to certain regulatory approvals from EGPC and/or the Minister of Petroleum in Egypt. Under the terms of the Concession Agreement an Assignment Fee of 10 per cent. of the value of the Acquisition may be due and payable by Merlon to EGPC upon its approval of any deemed indirect assignment of Merlon's rights, duties or obligations under the Concession Agreement to SOCO. Under the terms of the Share Purchase Agreement, the Parties have agreed that, upon Completion, Merlon or SOCO, on behalf of Merlon, will fund any such Assignment Fee that may be due and payable by Merlon up to US$21,500,000, and the Seller will pay all costs charges and expenses in connection with any such Assignment Fee in excess of US$21,500,000. In addition, under the terms of the Share Purchase Agreement, certain leakage from Merlon will be permitted to occur without a reduction in the consideration payable by SOCO, including the payment of monitoring fees to the Seller or its associated persons of up to US$3,500,000. Further details on the Assignment Fee and permitted leakage are set out in paragraph 4 of Part V (Principal Terms of the Share Purchase Agreement).

Merlon's President and Chief Executive Officer, Jason Stabell, will join SOCO and will continue to have responsibility for managing the Egyptian business within SOCO, alongside the existing Merlon team. The Merlon team has extensive knowledge and experience of operating in Egypt, and strong relationships with relevant regional regulatory authorities. Their experience will be invaluable to ensure operational continuity and support SOCO's future growth efforts in-country and within the broader Middle East and North Africa ("**MENA**") region. SOCO is reviewing the existing organisational structure of Merlon with a view to developing a detailed integration plan by the time of Completion.

As part of the Acquisition, Mr. Stabell will receive a portion of his consideration entitlement in Consideration Shares that will be subject to staggered lock-ups over a 12-month period. The remaining Consideration Shares will, subject to the terms of the Share Purchase Agreement, be distributed pro-rata amongst the remaining shareholders of the Seller. The individual funds managed by Yorktown Partners LLC, which collectively are currently the largest shareholders of the Seller with a combined c.72 per cent. ownership interest, will retain a combined c.12 per cent. ownership interest in SOCO at Completion.

3. Background to and reasons for the Acquisition

The Acquisition is a significant step forward in SOCO's stated objective of expanding and diversifying its resource base to create a full-cycle, growth orientated exploration and production company of scale. Merlon has a 100 per cent. participating interest in the El Fayum Concession, which is located in the low-cost and highly prolific Western Desert, c.80 km south west of Cairo and in proximity to local energy infrastructure. The Acquisition is expected to add immediate cash generative production and incremental 2P gross reserves of 24 mmbbls and 2C gross resources of 37 mmbbls (Merlon has 100 per cent. participating interest in the Concession Area). Merlon's average gross production in 2017 was 7,859 bopd and has the potential to increase production levels to a target in excess of 15,000 bopd by 2023 through the recovery of its discovered 2P reserves and 2C resources. In addition, the El Fayum Concession will provide SOCO with nearly 1,570km^2 of exploration acreage (of which c.70 per cent. is covered by existing 3D seismic) with multiple, identified exploration prospects in proven petroleum systems, as well as a large underexplored area in the northern portion of the concession.

SOCO believes Merlon offers a highly strategic platform to enable future organic and inorganic growth in Egypt and the wider MENA region. The Merlon team expected to be retained by SOCO after Completion has a proven ability to create and realise value. Under their management, Merlon has evolved from being an exploration-focused entity into a production and development business. The Merlon team's experience in Egypt and wider regional relationships are anticipated to be significant assets for, and highly complementary to, SOCO.

SOCO will finance the cash component of the Consideration and the redemption of Merlon's net debt through its existing cash and liquid investments (US$129 million as of 30 June 2018) and unutilised capacity under its new RBL Facility. Merlon is free cash flow positive on a standalone basis and SOCO anticipates that the growth investment required for developing Merlon's 2C resources will be primarily funded by the cash flows generated

from the El Fayum Concession. SOCO therefore expects that it will continue to maintain a robust balance sheet and free cash flow outlook following completion of the Acquisition, which will allow SOCO to maintain and further underpin its policy of regular distributions of excess free cash flow to its shareholders.

4. Key benefits of the Acquisition

The Acquisition will:

- Complement and diversify SOCO's existing Vietnamese portfolio and add a material hub of operated onshore oil production in the prolific Western Desert in Egypt
- Increase scale through incremental 2P gross reserves of 24 mmbbls, 2C of 37 mmbbls and expected average gross production of 6,500 – 7,000 bopd in 2018 (Merlon has a 100 per cent. participating interest in the Concession Area)
- Improve SOCO's through-cycle financial resilience through Merlon's low cost resource base
  - Opex/bbl of US$6/bbl (2017)
  - Full-cycle 2P + 2C NPV10 breakeven of c.US$34/bbl
- Enhance SOCO's organisational capabilities through the addition of Merlon's team
  - Jason Stabell, Merlon's President and CEO, will join SOCO and will continue to have responsibility for managing the Egyptian business within SOCO, alongside the Merlon team
  - An operating platform for further growth in Egypt and the wider MENA region
- Provide tangible production growth, re-setting SOCO's growth trajectory
  - Targeting over 15,000 bopd gross production by 2023, from existing discovered reserves and resources
  - Scalable, low-risk development profile: infill drilling, workovers and waterflood expansion
- Enhance exploration optionality and upside potential within SOCO's portfolio
  - Multiple prospects and leads with un-risked OIIP conventional resource potential of >500 million boe
  - An additional untested potentially significant unconventional resource play
  - Historic exploration success rate in the Concession Area in excess of 50 per cent.
- Be immediately accretive to SOCO's operating cash flow per share

5. Financial effects of the Acquisition

On a pro-forma basis and assuming completion of the Acquisition on 31 December 2017, the Enlarged Group would have had net assets of approximately US$544.8 million (based on the net assets of the SOCO Group and the Merlon Group as at 31 December 2017) as more fully described in Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group*).

On a pro-forma basis and assuming completion of the Acquisition on 31 December 2017, the Enlarged Group would have had loans and borrowings of US$100 million, cash and cash equivalents of US$50.6 million and liquid investments of US$25.3 million (based on the loans and borrowings, cash and cash equivalents and liquid investments of the SOCO Group and the Merlon Group as at 31 December 2017) as more fully described in Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group)*. Prior to the Acquisition SOCO had a net cash position.

The Merlon Group has historically been loss making but has recognised a reduction in the loss for the year over the last three financial years, moving from a loss for the year ended 31 December 2015 of US$21.3 million to a loss for the year ended 31 December 2017 of US$2.8 million. This trend in reduced losses for the Merlon Group over the last three financial years has principally been driven by stable revenues combined with a reduction in production operating costs.

The SOCO Group made a loss for the year ended 31 December 2017 of US$157.3 million. As the Merlon Group was also loss making in the year ended 31 December 2017, it would have increased the loss for the year of the SOCO Group had it been part of the SOCO Group for the same period. The SOCO Directors believe that expected future growth in production will drive growth in revenue for the Merlon Group.

6. Information on the SOCO Group

Incorporated in 1997, SOCO is an international oil and gas exploration and production company, headquartered in London and listed on the London Stock Exchange. The Company has a production-oriented business model focused on low cost, cash generative conventional oil assets in Vietnam. The SOCO Group predominantly focuses on rift basins with proven petroleum systems and selectively pursues opportunities in untested plays, such as basement reservoirs, or seeks to uncover frontier plays through the application of new technology.

The SOCO Group's two principal assets are the Te Giac Trang ("**TGT**") and the Ca Ngu Vang ("**CNV**") fields in Vietnam, located in the oil rich Cuu Long Basin. The SOCO Group has been present in Vietnam for almost two decades and has invested over US$1 billion into its oil and gas projects located offshore southern Vietnam. Average net working interest production for the SOCO Group for the year ended 31 December 2017 was 8.3 kboepd. As of 31 December 2017, the SOCO Group had net working interest Proved Reserves and Probable Reserves of 28.1 mmboe and 2C resources of 20.8 mmboe.

The TGT field is situated in Block 16-1, offshore Vietnam in the shallow water Cuu Long Basin, approximately 100 kilometres from Vung Tau. Block 16-1 was awarded to SOCO in 1999. Production from TGT began in 2011 and to date 41 wells have been drilled and an estimated 78 mmboe produced. Oil from TGT is transported by a subsea pipeline to a nearby Floating Production Storage and Offloading vessel where it is processed and then exported by tanker. Gas from TGT is processed at nearby facilities and transported by pipeline to shore to supply the Vietnamese domestic market.

The CNV field is situated in Block 9-2, offshore Vietnam, in the shallow water Cuu Long Basin. Block 9-2 was awarded to SOCO in 2000. The CNV field was first discovered in 2002 by the CNV-1X well and production began in July 2008. The oil and gas produced from CNV are transported by a subsea pipeline to a nearby central processing platform where the oil and gas are separated. Gas is transported via pipeline to an onshore gas facility. The crude oil is held in a storage vessel prior to sale.

PetroVietnam, the national oil company of Vietnam, and PTTEP, the national oil company of Thailand, have been long term partners of SOCO in Vietnam. The partners hold their interests in the TGT and CNV projects through non-profit joint operating companies.

Since its inception in 1997, SOCO has distributed US$499 million of cash to its shareholders, compared with US$231 million of equity raised. Shareholder distributions have been funded through a combination of free cash flow from operations and realising value from asset sales.

7. Information on the Merlon Group

Merlon is a private exploration and production company incorporated in the Cayman Islands, headquartered in Houston, Texas.

Merlon was formed in 1997, and was an indirect subsidiary of Merlon Petroleum Company ("**MPC**"). In 1997, MPC was the successful bidder on several concessions in Egypt, including the Siwa Concession which was awarded by EGPC directly to Merlon (then named Merlon Petroleum Siwa Company). On 22 December 2000, the Siwa Concession was relinquished back to EGPC and Merlon remained dormant until 2004 when its name was changed from Merlon Petroleum Siwa Company to Merlon Petroleum El Fayum Company, its current name. In July 2004, MPC was the successful bidder on the El Fayum Concession and the concession was awarded directly to Merlon.

Merlon is part of a wider group of entities using the Merlon name that have, over several decades, been conducting business in the oil and gas industry. MPC was formerly part of such group but was sold in 2006 to Melrose Resources. The current holding company to such entities is Merlon International, a Delaware limited liability company formed in 2007, headquartered in Houston, Texas, USA. Merlon International is the sole shareholder of Merlon, and the Seller under the Share Purchase Agreement The management team members of the various Merlon named entities have been engaged in oil and gas operations in the USA and internationally collectively for many decades, predominantly in Egypt and in the US.

Merlon International or its wholly owned subsidiaries historically owned and/or controlled other oil and gas producing properties in the State of Texas, but the last of those properties was sold in 2013.

Merlon International is owned 72 per cent. by funds managed by Yorktown Partners LLC ("**Yorktown**"), 12 per cent. by Richmond Peach Associates LLC ("**Richmond Peach**"), 9 per cent. by management and directors of the Seller and 7 per cent. by other high net worth individuals. Yorktown is an independently owned and operated asset management firm headquartered in New York, New York, USA dedicated to making private equity investments in the energy sector, and predominantly in businesses focussed on oil and gas production and pipe lines, gathering systems and processing and/or fractionation plants. Richmond Peach is an investment vehicle for South Eastern US high net worth individuals headquartered in Richmond, Virginia, USA.

Yorktown's investments in Merlon named entities began in 2001 with an investment in MPC. A small percentage of Yorktown's current ownership in the Seller came from Yorktown's original investments in MPC. Starting in 2006 and continuing for over ten years, Yorktown made additional capital investments in the Merlon named entities through its various funds. Thus, Yorktown and the management of the Seller have had a long-term business relationship for over 17 years.

Through the Concession Agreement, Merlon owns a 100 per cent. participating interest in the Concession Area in the Western Desert in Egypt. The Concession Area is operated via Petrosilah, a joint stock company incorporated in Egypt, being the joint venture vehicle for the Concession Area, with each of Merlon and the EGPC holding one half of its capital stock, as contemplated by the Concession Agreement. The Concession Area covers 1,827km^2 and is located c.80 km south west of Cairo.

Other than its interest in Petrosilah, Merlon does not own an interest in any other body corporate or other entity. As a result, the only entities that form part of the Acquisition perimeter are Merlon and its interest in Petrosilah. The El Fayum Concession is the only oil and gas exploration and production asset that Merlon owns. Merlon owns no other material assets which are not related to oil and gas exploration and production.

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 that the basin still holds one billion boe (83 per cent. oil) of risked prospective resources. Further, 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.

El Fayum is located in the Gindi Basin geologic province in close proximity to several other large productive fields. A total of 11 Development Leases have been awarded within the Concession Area covering 15 distinct oil fields. The first field discovery (Silah) came onstream in 2009 followed by 11 additional field opening exploration discoveries over 2009 to 2010. The majority of development is concentrated in the Greater Silah Area. The Concession Area is expected to have remaining 2P gross reserves of 24 mmbbls and 2C gross resources of 37 mmbbls. Daily production from the Concession Area averaged approximately 7,859 bopd in 2017. Production from the Concession Area is trucked c.70 km to the Tebbeen pumping station, where it enters the pipeline network and is transported to the Cairo refinery.

Under the terms of the Concession Agreement, EGPC has a preferential right to purchase a percentage share of Merlon's production from the Concession Area to satisfy domestic market requirements. This percentage share can vary and is calculated by dividing (i) the total amount of Merlon's crude oil production in the Concession Area by (ii) total crude oil production (from all production companies) in all of the concession areas in Egypt in which EGPC has a preferential right to purchase a share of production.

Any portion of Merlon's production which is (i) specified by the EGPC to be designated for cost recovery as a set-off against Merlon's exploration costs (at the EGPC's discretion); (ii) over which EGPC has not exercised its preferential right; or (iii) the portion of production over which the EGPC does not have a preferential right, can under the terms of the Concession Agreement, be freely exported and sold by Merlon in the market. However in practice, EGPC typically purchases 100 per cent. of Merlon's production. Although EGPC receivables for production volumes have reduced over the last four years, historically EGPC has remitted payments due to the Merlon Group several months in arrears. Further details of EGPC receivables due to Merlon are set out at Part II (*Risk Factors*) of this document.

Merlon retains a significant prospect inventory with identified exploration targets in the southern and northern parts of the Concession Area.

8. Summary financial information on Merlon

The historical financial information of the Merlon Group for the three years ended 31 December 2017, 31 December 2016 and 31 December 2015 as reported on by Deloitte is set out in Part III (*Financial Information on Merlon*) of this document.

As at 31 December 2017, the value of the gross assets included in the Acquisition totalled US$231 million. The profit before tax attributable to the assets included in the Acquisition totalled a loss of US$2.8 million in the twelve months to 31 December 2017.

In the twelve months to 30 September 2018, Merlon received payments in lieu of oil sales from EGPC totalling c.US$65 million, and had an outstanding receivables balance of c.US$43 million as of 30 September 2018 (based on Merlon's unaudited financial statements for the period ending 30 September 2018). The outstanding receivables balance, net of payables, was c.US$18 million as of 30 September 2018 (based on Merlon's unaudited financial statements for the period ending 30 September 2018).

SOCO Shareholders should read the whole of this document and not rely solely on summarised financial information in this section. Further financial information is contained in Part III (*Financial Information on Merlon*).

9. Current trading, trends and prospects

SOCO current trading, trends and prospects

SOCO released its interim results for the six months ended 30 June 2018 on 20 September 2018. The performance of the Company was described in the Chief Executive Officer's statement as follows:

"The first half of the year has seen the team focused on execution of our strategy of portfolio rationalisation and finding new growth projects, whilst returning cash to shareholders and strengthening the board. The new debt facility and the proposed acquisition of Merlon are exciting steps forward for SOCO and provide the platform to expand and diversify the Company's resource base to create a full-cycle, growth orientated E&P company. As we look to the future, we are well positioned financially and, with a dedicated and capable team, continue to look for opportunities to grow the business

Operational Highlights

- *Production during 1H 2018, averaged 26,773 BOEPD gross and 7,748 BOEPD net to SOCO's working interest (1H2017: 29,600 BOEPD and 8,606 BOEPD, respectively)*
  - *TGT production averaged 6,177 BOEPD net (1H2017: 7,056 BOEPD)*
  - *CNV production averaged 1,571 BOEPD net (1H2017: 1,550 BOEPD)*
- *Successful extension of two key operational contracts, resulting in significant cost savings for the TGT Field: the FPSO Operations and Maintenance Agreement and the Bare Boat Charter for the FPSO Armada TGT 1*
- *Two rigs are currently operating, one on each of the TGT and CNV Fields. The drilling programme has been delayed as a result of operational and weather related issues*
- *Production guidance for 2018 is revised to 7,000 -7,400 BOEPD.*
- *Portfolio rationalisation through:*
  - *Completion of the sale of SOCO's interests in Congo (Brazzaville) for a cash consideration of up to $10m and an overriding royalty on all future gross oil and condensate production sold from the interests*
  - *Agreement to sell SOCO's interests in Cabinda, Angola for a total cash consideration of up to $5m*

Financial Highlights

- *Agreement for $125m Reserve Based Lending Facility ("RBL") signed on 15 September 2018, secured against the Group's producing assets in Vietnam*
- *Strong balance sheet; half year-end cash and liquid investments balance of $128.8m with no debt ($137.7m at 31 December 2017)*

- *Low cash operating costs just under $14/bbl (1H 2017: $13/bbl)*
- *Average realised crude oil price up at $74.08/bbl, a $3.46 premium to Brent (1H 2017: $53.90/bbl)*
- *Cash capital expenditure down to $3.6m (1H 2017: $13.2m restated) due to delays in drilling*
- *Revenues up 26% at $93.2m (1H 2017: $74.0m)*
- *Net operating cash flow down to $24.9m (1H 2017: $27.1m), including cash used in discontinued operating activities of $1.7m*
- *Net operating cash flow (before working capital) of $56.5m (1H 2017: $42.0m)*
- *2017 full year dividend of $23.3m (1H 2017: $21.0m) paid 15 June 2018, up 5% on prior year"*

The outlook for SOCO was described in the interim results press release as follows:

- *"Production guidance for 2018 is modified to 7,000 - 7,400 BOEPD, reflecting the additional delays to the drilling programme resulting from the requirement to redrill the CNV-5P sidetrack, which occurred subsequent to the revision in production guidance announced on 31 July 2018.*
- *Cash capital expenditure in 2018 is expected to come in under $30m reflecting the delay in the drilling campaign and the deferral to 2019 of seismic acquisition on exploration Blocks 125 & 126 in Vietnam.*
- *Continued focus on financial discipline, sustainable cash flow generation and commitment to cash returns to shareholders.*
- *The Proposed Transaction is a significant step forward in SOCO's stated objective of expanding and diversifying its resource base to create a full-cycle, growth orientated E&P company of scale."*

There has been no material change in the SOCO Board's assessment of the matters described above since 20 September 2018.

Since the issue of SOCO's interim results for the six months ended 30 June 2018:

- On 5 October 2018, SOCO announced completion of the sale of the Group's entire 80 per cent. shareholding in SOCO Cabinda Limited as previously announced on 2 July 2018 and the receipt of the total cash consideration of US$5 million in cleared funds together with a minor further payment to cover funding requirements after 30 June 2018; and
- The rig that was previously operating on the TGT H1-WHP platform has been released following completion of the TGT-16AP well. The rig operating on CNV for the drilling of the CNV-5PST2 well has been moved to the TGT H5-WHP platform to drill two further wells.

Merlon current trading, trends and prospects

In the period since 31 December 2017, the Merlon Group has continued to trade in line with management expectations.

Production from the Concession Area averaged 6,671 bopd through the first nine months of 2018, which is consistent with the 31 December 2017 average of 6,897 bopd. The SOCO Directors believe that the maintenance of production levels is the result of continued development drilling throughout 2018, under a one drilling rig programme. During the first nine months of 2018, seven new development wells have been drilled in the Concession Area, five of which are currently on production, one of which was a dry hole and one which is currently pending completion (which is currently expected by year end 2018). Current production levels are in line with Merlon management expectations for 2018, with average production of 7,135 bopd during September 2018.

Crude sales from the Concession Area were US$51.6 million gross in the first nine months of 2018, which represented a 19 per cent. increase over the same period in 2017. The SOCO Directors believe that the increase was due to higher realised oil prices (US$68.37 per barrel for the first 9 months of 2018 versus US$47.46 for the first 9 months of 2017), offsetting lower production. The September 2018 realised sales price, of US$74.40 per barrel, represents a 23 per cent. increase over the equivalent figure as at 31 December 2017. These figures are based on Merlon's unaudited financial statements for the period ending 30 September 2018.

Sales receivables from EGPC were US$43.3 million as at 30 September 2018, representing approximately 7 months of outstanding revenues due from EGPC. The equivalent figure as at 31 December 2017 was US$47.6 million and represented 10 months of outstanding revenues due from EGPC to December 2017. These figures are based on Merlon's unaudited financial statements for the period ending 30 September 2018.

Based on Merlon's unaudited management accounts as of 30 September 2018, operating costs are currently 24 per cent. higher compared to 30 September 2017. The SOCO Directors believe that this is due to lower production levels, increased fuel prices (which track oil prices) and increased well-maintenance activity. Based on Merlon's unaudited management accounts, Merlon incurred US$10 million of well write-off costs in the nine months to 30 September 2018 compared to no well write-off cost in the comparable period in 2017.

10. Financing of the Acquisition

SOCO will finance the cash portion of the Consideration payable in connection with the Acquisition through a combination of existing cash and liquid investments and unutilised capacity under its RBL Facility. The Consideration will be financed as described below:

(a) *Existing debt facilities*

SOCO intends to finance part of the cash Consideration payable under the terms of the Acquisition from its RBL Facility, announced 17 September 2018. It is currently anticipated that US$100 million will be drawn under the RBL Facility for the purposes of financing the Acquisition.

For more information on the SOCO Group's RBL Facility see paragraph 10.2 of Part VII (*Additional Information*).

(b) *Cash reserves*

The remaining portion of the cash Consideration payable under the terms of the Acquisition will be funded from SOCO's cash reserves. SOCO's cash reserves (including cash equivalents and liquid investments) totalled approximately US$129 million as at 30 June 2018.

11. Regulatory Conditions

Completion of the Acquisition is conditional upon, amongst other things, waiver or satisfaction of the following Conditions which are contained in the Share Purchase Agreement:

- the written waiver, or non-exercise, in accordance with the El Fayum Concession, of the pre-emptive rights of EGPC; and
- EGPC and/or the Minister of Petroleum in Egypt (as applicable) approving or consenting in writing to the Acquisition, to the extent such approval or consent (as applicable) is required under the laws of Egypt or the El Fayum Concession.

Written notification of the Acquisition was provided to the Minister of Petroleum in Egypt on 14 October 2018 and to EGPC on 17 October 2018. The Parties are continuing to engage with EGPC, for itself and on behalf of the Egyptian Government, for the purposes of clarifying whether or not the Acquisition is deemed an assignment for the purposes of the Concession Agreement and otherwise in respect of satisfying such Conditions.

In the event that the Acquisition is deemed to be an assignment for the purposes of the Concession Agreement, the Acquisition would require the written approval of the Egyptian Government to such assignment and a deed of assignment would need to be approved by EGPC, in each case in advance of Completion. In addition, in such circumstances, EGPC would have a period of 90 days from written notification of the Acquisition to exercise its pre-emption right in respect of the El Fayum Concession otherwise that right is deemed waived. Further details of the Concession Agreement are set out in paragraph 11.2 of Part VII (*Additional Information*).

12. Irrevocable undertakings

The SOCO Directors who beneficially hold SOCO Shares, each listed below, have irrevocably undertaken to vote (or procure the voting) in favour of the Resolutions at the SOCO General Meeting in respect of their (and their connected persons') SOCO Shares, which amount in aggregate to 53,105,540 SOCO Shares, representing approximately 16 per cent. of the issued ordinary share capital of SOCO (excluding treasury shares) on the Latest Practicable Date.

SOCO director	Number of SOCO shares	Per cent. of issued share capital of SOCO (excluding treasury shares)
Rui de Sousa	9,178,572	2.77 per cent.
Ed Story	14,073,747	4.24 per cent.
Dr. Mike Watts	478,559	0.14 per cent.
Jann Brown	344,662	0.10 per cent.
Ettore Contini	29,000,000	8.74 per cent.
John Martin	30,000	0.01 per cent.

13. Settlement, listing and dealings in Consideration Shares

The Consideration Shares will be issued at Admission, credited as fully paid and will rank *pari passu* in all respects with the SOCO Shares, including the right to receive all dividends, distributions or any return of capital declared, made or paid after Admission.

Applications will be made to the FCA and the London Stock Exchange for the Consideration Shares to be admitted to the Official List and to trading on the London Stock Exchange's Main Market respectively. It is expected that Admission will become effective and that dealings for normal settlement in the Consideration Shares will commence on the London Stock Exchange at 8.00 a.m. on the Business Day following Completion.

The Consideration Shares will be issued in registered form and will be capable of being held in certificated or uncertificated form.

14. Dilution

Upon the issue of the Consideration Shares, the existing SOCO Shares at the date of this document will represent 83.5 per cent. of the total issued SOCO Shares (excluding treasury shares) immediately following Admission (assuming that no other SOCO Shares are issued by the Company between the Latest Practicable Date and the date of Admission).

15. Risk factors

For a discussion of certain risk factors which should be taken into account when considering whether or not to vote in favour of the Resolutions, see Part II (*Risk Factors*).

16. SOCO General Meeting and the Resolutions

Completion of the Acquisition is conditional upon, among other things, SOCO Shareholders' approval being obtained at the SOCO General Meeting. Accordingly, you will find, set out at the end of this document, a notice convening a general meeting to be held at Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ at 10.00 a.m. on 21 December 2018 at which the Resolutions will be proposed to approve the Acquisition and other matters. A summary of the Resolutions is below. The full text of the Resolutions is set out in the notice. Resolution 2 is conditional on Resolution 1 being passed.

Resolution 1

Resolution 1 will be proposed as an ordinary resolution requiring a simple majority of votes in favour of the Resolution. The Acquisition will not proceed if the Resolution is not passed. The Resolution proposes that: (i) the Acquisition be approved, and (ii) the SOCO Directors be authorised to take all such steps as may be necessary or desirable in connection with, and to implement, the Acquisition and to agree such modifications, variations, revisions, waivers or amendments to the terms and conditions of the Acquisition (provided such modifications, variations, revisions, waivers or amendments are not material), and to any documents relating thereto, as they may in their absolute discretion think fit.

Resolution 2

Resolution 2 will be proposed as an ordinary resolution requiring a simple majority of votes in favour of the Resolution. The Resolution proposes that the SOCO Directors be authorised to allot SOCO Shares, credited as fully paid, and to take all such other steps as it may deem necessary, expedient or appropriate to implement such allotment in connection with the Acquisition up to an aggregate nominal amount of £3,278,052.05.

If granted, the authority conferred by Resolution 2 will expire on the 20 September 2019 and is in addition to any subsisting authorities to allot shares in SOCO. As at the Latest Practicable Date, SOCO held 9,122,268 shares in treasury representing approximately 2.7 per cent. of the total issued ordinary share capital of SOCO (excluding treasury shares) as at the Latest Practicable Date. The authority conferred by Resolution 2 will enable the Company to allot sufficient Consideration Shares to implement the Acquisition.

The authority conferred by Resolution 2 is in addition to the authority to allot shares in SOCO which was granted to the SOCO Board at SOCO's annual general meeting held on 7 June 2018, which the SOCO Board has no present intention of exercising, and which will expire at SOCO's annual general meeting in 2019. Accordingly, the Consideration Shares to be issued in connection with the Acquisition will be created, allotted and issued pursuant to the authority to be granted under Resolution 2 proposed at the SOCO General Meeting.

Action to be taken

You will find enclosed with this document a Form of Proxy for use at the SOCO General Meeting or any adjournment thereof. Whether or not you intend to be present at the SOCO General Meeting, you are requested to complete and sign the Form of Proxy in accordance with the instructions printed on it so as to be received by SOCO's registrar, Equiniti Limited at Aspect House, Spencer Road, Lancing, BN99 6DA, as soon as possible, and in any event no later than 10.00 a.m. on 19 December 2018 (or, in the case of an adjournment, not later than 48 hours (excluding non-working days) before the time fixed for the holding of the adjourned meeting).

If you hold SOCO Shares in CREST you may appoint a proxy by completing and transmitting a CREST Proxy Instruction to ID number RA19 in accordance with the procedures set out in the notice convening the SOCO General Meeting at the end of this document.

Alternatively, you may give proxy instructions by logging on to www.sharevote.co.uk and following the instructions. Proxies sent electronically (either via the CREST system or online) must also be sent as soon as possible and, in any event, so as to be received no later than 10.00 a.m. on 19 December 2018 (or, in the case of an adjournment, not later than 48 hours (excluding non-working days) before the time fixed for the holding of the adjourned meeting).

The completion and return of a Form of Proxy (or the electronic appointment of a proxy) will not preclude you from attending and voting in person at the SOCO General Meeting or any adjournment thereof, if you so wish.

17. Further information

Your attention is drawn to the further information contained in Part II (*Risk Factors*), to the information incorporated by reference into this document as listed in Part VIII (*Information Incorporated by Reference*) and the information set out in Part VII (*Additional Information*).

18. Financial advice

The SOCO Board has received financial advice from Evercore in relation to the Acquisition. In providing such financial advice to the SOCO Board, Evercore has relied upon the SOCO Board's commercial assessment of the Acquisition.

19. Recommendation

The SOCO Board considers the Acquisition and the Resolutions to be in the best interests of SOCO and SOCO Shareholders as a whole. Accordingly, the SOCO Board recommends that SOCO Shareholders vote in favour of each of the Resolutions to be put to the SOCO General Meeting as SOCO Directors have irrevocably agreed to do in respect of their own beneficial holdings of 53,105,540 SOCO Shares in aggregate, representing approximately 16 per cent. of SOCO's issued ordinary share capital (excluding treasury shares).

Yours faithfully,

Rui de Sousa
Chairman
SOCO International plc

PART II

RISK FACTORS

SOCO Shareholders should consider the following risks and uncertainties together with all the other information set out in, or incorporated by reference into, this document prior to making any decision as to whether or not to vote in favour of the Acquisition.

The risks described below are based on information known at the date of this document, but may not be the only risks to which the SOCO Group, the Merlon Group or, following completion, the Enlarged Group is or might be exposed. Additional risks and uncertainties, which are currently unknown to SOCO or that SOCO does not currently consider to be material, may materially affect the business of the SOCO Group, the Merlon Group and/or the Enlarged Group and could have material adverse effects on the business, financial condition, results of operations and prospects of the SOCO Group, the Merlon Group and/or the Enlarged Group. If any of the following risks were to occur, the business, financial condition, results of operations and prospects of the SOCO Group, the Merlon Group and/or the Enlarged Group could be materially adversely affected and the value of the SOCO Shares could decline and shareholders could lose all or part of the value of their investment in SOCO Shares.

1. MATERIAL RISKS RELATED TO THE ACQUISITION

1.1 ***The implementation of the Acquisition is subject to the satisfaction of certain conditions and the conditions might not be satisfied or waived.***

The implementation of the Acquisition is subject to the satisfaction of the following conditions:

- the Consideration Shares having been issued and allotted to the Seller subject only to Admission;
- the UKLA having acknowledged that its requirements for listing have been complied with in respect of the Consideration Shares, and the London Stock Exchange having acknowledged that its requirements in respect of the Consideration Shares being admitted for trading on the Main Market have been complied with, in each case, conditional upon Completion;
- written waiver, or non-exercise, in accordance with the terms of the El Fayum Concession, of the pre-emptive rights of EGPC;
- EGPC and/or the Minister (as applicable) approving or consenting in writing to the transactions contemplated by the Share Purchase Agreement, to the extent such approval or consent (as applicable) is required under the laws of Egypt or the El Fayum Concession; and
- approval of the Resolutions by SOCO Shareholders at the SOCO General Meeting.

There is no guarantee that these conditions will be satisfied. Failure to satisfy or obtain waiver of any of these conditions may result in the Acquisition not being completed.

As a condition to their clearance of the Acquisition, regulatory authorities may impose requirements, limitations or costs or place restrictions on the conduct of the business of the SOCO Group, the Merlon Group or, following completion, the Enlarged Group. These requirements, limitations, costs, or restrictions could jeopardise or delay the consummation of the Acquisition or may reduce the anticipated benefits of the Acquisition.

If Completion were not to occur, the SOCO Group would, in certain circumstances set out in the Share Purchase Agreement, be required to pay the Break Fee to the Seller.

1.2 ***The Enlarged Group's success will be dependent upon its ability to integrate the two businesses; there will be numerous challenges associated with the integration and the benefits expected from the Acquisition may not be fully achieved.***

While SOCO believes that the business growth opportunities, cost savings and synergies expected to arise from the Acquisition have been reasonably estimated, unanticipated events or liabilities may arise which result in a delay or reduction in the benefits derived from the Acquisition, or in costs significantly in excess of those estimated, including as a result of any additional and unexpected challenges and/or costs associated with integrating Merlon into the SOCO Group. Such challenges and/or costs could arise from

the redeployment of resources in different areas of operations to improve efficiency; the diversion of management attention from ongoing business concerns to the Merlon business (and their integration within the existing SOCO Group); and addressing possible differences between the SOCO Group's business culture, processes, controls, procedures and systems and those of the Merlon Group. The Acquisition significantly increases the SOCO Group's interests in production and development assets in Egypt, where it does not currently operate, thereby changing the balance of its portfolio. This could place additional demands on the SOCO Group's management team and require additional skills and resources within the Enlarged Group. Under any of these circumstances, the business growth opportunities, cost savings and other synergies anticipated by SOCO to result from the Acquisition may not be achieved as expected, or at all, or may be delayed materially. To the extent that the Enlarged Group incurs higher integration costs or achieves lower synergy benefits than expected, its and the Enlarged Group's results of operations, financial condition and/or prospects may be adversely affected.

1.3 ***There is a risk that, as a result of the Acquisition, governmental authorities in certain of the jurisdictions in which the SOCO Group and the Merlon Group operate may seek to impose taxes or other transactional levies on the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group.***

The tax regimes in certain jurisdictions in which the SOCO Group and the Merlon Group operate are not clearly codified and therefore can be subject to varying or inconsistent interpretation and legislative or administrative change in those jurisdictions. Accordingly, there is a risk that governmental authorities in certain of the jurisdictions in which the SOCO Group and the Merlon Group operate may seek to impose taxes or other levies on the Enlarged Group as a result of the Acquisition taking place. Should this occur, there can be no assurance that the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will be able to negotiate an appropriate settlement in the future or that any such governmental authority will not enforce the original claim for tax or other transactional levy payable which could be material and consequently have a material adverse effect on the business, prospects, financial condition and results of operations of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as applicable.

1.4 ***SOCO Shareholders will own a smaller percentage of the Enlarged Group than they currently own of SOCO.***

After Admission, the SOCO Shareholders will own a smaller percentage of the Enlarged Group than they currently own of SOCO Group. Assuming that there are no other issues of SOCO Shares (including under the SOCO Share Plans) between the Latest Practicable Date and the date of Admission, the SOCO Shareholders will own approximately 83.5 per cent. of the outstanding shares of the Enlarged Group (excluding treasury shares). As a consequence, the number of voting rights which can be exercised and the influence which may be exerted by shareholders in respect of the Enlarged Group will be reduced.

1.5 ***The Acquisition is being funded from existing cash resources and SOCO's existing debt which will reduce the Group's financial flexibility.***

The Acquisition is being funded from SOCO's existing cash resources and its RBL Facility. The RBL Facility has an accordion mechanism that will allow the SOCO Group to borrow up to an additional US$125 million, subject to bringing additional petroleum assets into the borrowing base for the facility and securing funding for the increase from the existing and new lenders via the agreed mechanism under the RBL Facility Agreement. SOCO expects to move the assets acquired as part of the Acquisition into the borrowing base post Completion and, following such inclusion, increase amounts available for drawdown in accordance with this accordion mechanism. The RBL Facility also contains customary financial covenants including a leverage test which provides that the net borrowings of the SOCO Group shall not exceed 3.5 times the EBITDAX of the SOCO Group in respect of each twelve-month period ending on 31 December and 30 June.

The Acquisition will reduce the Group's cash balances and increase the overall indebtedness and financial leverage of the Enlarged Group, which will result in increased repayment commitments and borrowing costs. This could limit the Enlarged Group's commercial and financial flexibility in the longer term, causing SOCO to reprioritise its uses of capital to the potential detriment of its business prospects, the value of its assets and its ability to finance future dividends. Therefore, depending on the level of the Enlarged Group's borrowings, prevailing interest rates and exchange rate fluctuations, this could result in reduced funds being available to fund future growth, future acquisitions, dividend payments and other

general corporate purposes, which could have a material adverse impact on the Enlarged Group's results of operations, financial condition and prospects in the longer term.

1.6 ***The Share Purchase Agreement reflects a competitive auction process with limited protections provided to the Company by the Seller.***

The disposal of Merlon by the Seller was carried out by means of a competitive auction process involving the Company and, the Company understands, other bidders. Accordingly, the warranties and other purchaser protections given by the Seller in the Share Purchase Agreement are limited and may not cover all potential liabilities associated with the Merlon Group, whether identified or unidentified. The liability of the Seller is also limited in time and amount. Accordingly, the Company may not have recourse against, or otherwise be able to recover from, the Seller in respect of material losses which it may suffer in respect of a breach of those warranties or otherwise in respect of liabilities of Merlon or Petrosilah. The Company would also be dependent on the financial position of the Seller, in the event that it were able and sought to recover amounts, in respect of claims brought under such warranties. If such material liabilities arose and it was not possible to make a claim under the warranties in respect thereof, or if any losses could not be recovered in respect of claims under the warranties, this could adversely affect the Enlarged Group's business, results of operations, financial conditions and prospects.

2. MATERIAL RISKS RELATING TO THE ENLARGED GROUP WHICH RESULT FROM THE ACQUISITION

2.1 ***The Merlon Group is, and following Completion, the Enlarged Group will be, dependent on the Egyptian General Petroleum Corporation ("EGPC") for a significant portion of its revenues, profits and free cash flows, and receivables due from the Merlon Group's operations in Egypt under the Merlon Group's licence agreements are paid irregularly and may be subject to significant delay.***

The Merlon Group generates all of its revenues from sales of oil and gas in Egypt to EGPC under the terms of the El Fayum Concession Agreement. As a result, the Merlon Group is, and following Completion, the Enlarged Group will be, exposed disproportionately to counterparty risk in respect of EGPC.

Under the terms of the Concession Agreement, EGPC has a preferential right to purchase a percentage share of Merlon's production from the Concession Area to satisfy domestic market requirements. This percentage share can vary and is calculated by dividing (i) the total amount of Merlon's crude oil production in the Concession Area by (ii) the total crude oil production (from all production companies) in all of the concession areas in Egypt in which EGPC has a preferential right to purchase a share of production. Any portion of Merlon's production which is (i) specified by the EGPC to be designated for cost recovery as a set-off against Merlon's exploration costs (at the EGPC's discretion); (ii) over which EGPC has not exercised its preferential right; or (iii) the portion of production over which the EGPC does not have a preferential right, can under the terms of the Concession Agreement be freely exported and sold by Merlon in the market. EGPC has to date been purchasing all of Merlon's production.

EGPC has historically set a purchase price for its purchase of crude oil from Merlon based on the average price of mixed oil in the Western Desert officially announced by EGPC less a discount. Pursuant to a Crude Oil Pricing Letter issued by EGPC on 23 March 2017, EGPC has set a purchase price based on the average price of mixed oil in the Western Desert officially announced by EGPC for the shipment month minus 3.00 dollars/barrel effective 1st April 2017.

Historically EGPC has remitted payments due to the Merlon Group several months in arrears, resulting in significant fluctuations in the outstanding receivables due from EGPC to the Merlon Group in the past. As at 31 December 2017, the total amount of receivables due to the Merlon Group from EGPC was US$48 million, of which US$28 million were considered past due, but not impaired as at such date. As at 30 September 2018, receivables due to Merlon from EGPC were US$43.3 million (based on Merlon's unaudited management accounts as of 30 September 2018). EGPC's payments to the Merlon Group may continue to be received on an irregular and unpredictable basis that is outside the Merlon Group's ability to predict or control. Any remittance to the Merlon Group which serves to reduce the balance of receivables from EGPC will be partly or wholly offset by new receivable obligations incurred by EGPC due to new production by the Merlon Group in Egypt.

EGPC periodically arranges for the Merlon Group to receive the proceeds of certain volumes of oil sold via cargo payments, whereby EGPC sells oil to market purchasers who pay the Merlon Group directly, in US dollars, for oil sold by EGPC. There is no assurance that such US dollar cargo payments will continue

in the future. Furthermore, receipt of US dollar cash payments from EGPC may be subject to continued or increased delay in the future as a result of various factors, including the prevailing political and economic climate in Egypt, the availability of US dollars in Egypt, and trends in international oil prices. If EGPC's payments to the Merlon Group become irregular and significantly delayed again, this could result in the Merlon Group and, following Completion, the Enlarged Group, becoming more reliant on its available cash resources and debt facilities to meet its immediate and short-term obligations.

If receivables from EGPC remain outstanding for a prolonged period, if expected US dollar cargo payments arranged by EGPC are discontinued or are not received as planned, or if payments on existing or new receivables are substantially delayed, the Merlon Group and, following Completion, the Enlarged Group, may be required to impair or discount certain of its existing past due receivables, resulting in an impairment charge on the Merlon Group's and, following Completion, the Enlarged Group's consolidated income statement which would reduce or eliminate, as the case may be, the Merlon Group's and, following Completion, the Enlarged Group's net profits for the period in which the impairment was recognised.

The Merlon Group currently relies upon cash flows from the El Fayum Concession to fund a portion of its operations and capital expenditures. Given the Merlon Group's dependence on receipt of cash from EGPC for all of its operating cash flows, the execution of the Merlon Group's and, following Completion, the Enlarged Group's development and, in the case of the Enlarged Group, exploration and appraisal programmes (which are funded in part by these cash flows) may be adversely affected by the unpredictable nature of the timing and amounts eventually paid by EGPC. If substantial amounts of receivables from EGPC are outstanding for a prolonged period, or if EGPC alters its current practice of making periodic payments in a manner disruptive to the Merlon Group, the Merlon Group and, following Completion, the Enlarged Group, may be required to cancel or delay certain of its projects, and as a result, the Merlon Group and, following Completion, the Enlarged Group, may be unable to successfully implement, as applicable, its respective exploration, appraisal and development programmes. See the risk factor entitled "The SOCO Group's and the Merlon Group's exploration, appraisal and development programmes are capital intensive and the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will be unable to implement these programmes and fulfil their respective licensing commitments in the longer term without significant capital expenditure for which funding may not be available".

There can be no assurance that EGPC will meet its existing or future payment obligations to the Merlon Group or, following Completion, the Enlarged Group; that the political or economic situation in Egypt will not deteriorate; or that the Egyptian government will be successful in improving financial stability and maintaining domestic order. The Merlon Group and, following Completion, the Enlarged Group, may therefore be unable to collect some or all of its outstanding receivables, or may accrue increased amounts of outstanding receivables, either of which would have a material adverse effect on the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

2.2 ***The Merlon Group's, and following Completion, the Enlarged Group's operations in Egypt expose them to fluctuations in the value of the Egyptian Pound and high rates of inflation.***

Egypt's on-going shortage of foreign currency (in particular the US dollar) has, at times, been significant since the devaluation of the Egyptian Pound in late 2016 and may worsen if Egypt is unable to generate US dollar remittances. While EGPC's payments to the Merlon Group, which currently account for a significant portion of the Merlon Group's revenue, are sometimes made in US dollars, a continuing shortage of US dollars within the Egyptian government and EGPC may result in part of all of such payments being remitted to the Merlon Group and, following Completion, the Enlarged Group, in Egyptian Pounds rather than US dollars, subjecting the Merlon Group and, following Completion, the Enlarged Group, to the risk of currency fluctuations between the Egyptian Pound, pounds sterling and US dollars. For example, in the years ended 31 December 2017 and 2016, a total of US$30 million, or 80 per cent., and US$46 million, or 98 per cent., respectively, of the Merlon Group's US$37 million and US$47 million, respectively, received from EGPC was received in Egyptian Pounds. EGPC may increase the proportion of its payments in Egyptian Pounds and as a result the Merlon Group and, following Completion, the Enlarged Group may be subject to additional exposure to the value of the Egyptian Pound, or to higher levels of receivables from EGPC to the extent the Merlon Group or, following Completion, the Enlarged Group opts to await the availability of US dollars for payment. If the proportion of payments received from EGPC in Egyptian Pounds substantially increases going forward, the Merlon Group and, following Completion, the Enlarged Group, may receive more Egyptian Pounds than it needs to fund its operating expenses in Egypt, causing a decline in the US dollar value of its Egyptian revenues upon translation, and contributing to

increased exposure to the value of the Egyptian Pound. Furthermore, due to an increasingly constrained global foreign exchange market for Egyptian Pounds, the Merlon Group and, following Completion, the Enlarged Group, may be unable to convert certain quantities of its Egyptian Pounds to US dollars going forward, which could limit the Merlon Group's and, following Completion, the Enlarged Group's, ability to distribute cash to other jurisdictions within the Merlon Group and, following Completion, the Enlarged Group, as the case may be. There can be no assurance that EGPC will continue to have access to sufficient US dollars. If receivables from EGPC are settled in a currency other than the US dollar, the Merlon Group and, following Completion, the Enlarged Group may be required to impair or discount certain of its existing past due receivables, resulting in an impairment charge on the Merlon Group's or, following Completion, the Enlarged Group's, as applicable, consolidated income statement which would reduce or eliminate, as applicable, the Merlon Group's or, following Completion, the Enlarged Group's net profits for the period in which the impairment was recognised. Additionally, the devaluation of the Egyptian Pound has caused high inflation rates in Egypt, which has led to, and may continue to lead to, increases in the prices of obtaining services and products in Egypt. The Merlon Group and, following Completion, the Enlarged Group, may be unable to maintain the prices the Merlon Group and, following Completion, the Enlarged Group, charge for such services and products, or may be unable to increase the prices to levels sufficiently high in order to preserve operating margins, due to competitive pressures, regulatory requirements or other reasons. Furthermore, difficulties in obtaining foreign currencies in Egypt could cause difficulties in making contractor payments. Any of the above could have a material adverse effect on the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

2.3 ***The Merlon Group is, and following Completion, the Enlarged Group will be, dependent on its operations in Egypt for a significant portion of its revenues, profits and free cash flows.***

All of the Merlon Group's production for the year ended 31 December 2017, the year ended 31 December 2016 and for the year ended 31 December 2015 came from the El Fayum Concession, with total revenues from production at the El Fayum Concession amounting to 100 per cent. of the Merlon Group's revenues in the years ended 31 December 2017, 31 December 2016, and 31 December 2015. Whereas the SOCO Group's average production for the year ended 31 December 2017 was split with c.81 per cent. from the TGT field in Vietnam and c.19 per cent. from the CNV field in Vietnam.

As a result, the Merlon Group is, and following Completion, the Enlarged Group will be, exposed disproportionately to the impact of localised events or circumstances in Egypt. Such adverse conditions could include delays or interruptions to production from wells caused by transportation capacity constraints, scarcity of equipment, facilities, personnel or services, equipment failure, political or social unrest, significant adverse governmental regulation, natural disasters, adverse weather or tidal conditions, wars or terrorist attacks. The concentrated nature of the Merlon Group's and, following Completion, the Enlarged Group's producing asset portfolio results in such conditions having a relatively greater impact on the Merlon Group's and, following Completion, the Enlarged Group's as applicable, business, results of operations, financial condition and prospects than they might have if the Merlon Group had a more diversified portfolio of production assets with wider geographic exposure.

In addition, the SOCO Group has not previously carried out business in Egypt meaning that the risks to the Enlarged Group's operations in Egypt may be greater than those it faces in the existing markets in which the SOCO Group is more familiar.

2.4 ***Substantial future sales by significant shareholders or otherwise or issues by SOCO of shares of the Enlarged Group could impact their market price.***

SOCO cannot predict what effect, if any, future sales of shares of the Enlarged Group whether by significant shareholders or otherwise, or issues of shares of the Enlarged Group by SOCO, or the availability or perception of such future sales or issues of shares of the Enlarged Group, will have on the market price of the shares of the Enlarged Group.

As part of the Acquisition, only Mr. Stabell will receive a portion of his consideration entitlement in Consideration Shares that will be subject to staggered lock-ups over a 12-month period. The remaining Consideration Shares will, subject to the terms of the Share Purchase Agreement, be distributed pro-rata amongst the remaining shareholders of the Seller. The SOCO Group has not received lock-ups with respect to these remaining shares.

Sales of substantial amounts of shares of the Enlarged Group, whether by significant shareholders or otherwise, in the public market following Completion, or the issuance of a substantial number of shares of the Enlarged Group by SOCO, or the perception or any announcement that such sales or issuances could occur, could adversely affect the market price of the shares of the Enlarged Group and may make it more difficult for investors to sell their shares of the Enlarged Group at a time and price which they deem appropriate, or at all.

2.5 ***The Merlon Group's estimates of reserves and resources are inherently subjective and uncertain and may be subject to downward revision.***

As part of its business, the Merlon Group must, and following Completion, the Enlarged Group will be required to, estimate the quantity 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 the quantity of commercially recoverable oil and gas reserves, rates of production, net present value of future cash flows and the timing of development expenditures depend upon several variables and assumptions, including, among others, the following: (i) historical production from the area; (ii) interpretation of geological and geophysical data; (iii) effects of regulations adopted by governmental agencies; (iv) future percentages of domestic and international sales; (v) future oil and gas prices; (vi) capital expenditure; and (vii) 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. Moreover, reserves and resources estimates are inherently speculative and may require substantial 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 other economic factors which are beyond the Merlon Group's and, following Completion, the Enlarged Group's ability to predict or control. Any downward revisions may indicate lower future production, adversely affecting the Merlon Group's and, following Completion, the Enlarged Group's financial condition and prospects and the present value of its respective reserves and resources. Downward revisions in reserve levels may also result in impairment losses, impacting the Merlon Group's and, following Completion, the Enlarged Group's reported operating profit and asset value, as applicable.

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

In particular, potential investors should note the following:

(a) The reserves and resources estimates as at 30 June 2018 for the Merlon Group were calculated using forecast prices for hydrocarbons in effect as at that date. As a result, downward revisions in the future price of hydrocarbons could have a material adverse effect on the estimates of reserves and resources, as well as estimates of the net present value of future cash flows of the Merlon Group and, following Completion, the Enlarged Group.

(b) Evaluations of reserves and resources necessarily involve multiple uncertainties, and the accuracy of any reserves or resources evaluation depends on the quality of available information and on petroleum engineering and geological interpretation. Exploration and appraisal drilling, geophysical and geological interpretation and modelling, interpretation and testing, and production after the date of the estimates may require substantial downward revisions in the Merlon Group's and, following Completion, the Enlarged Group's reserves or resources data, for example as a result of geological features in hydrocarbon reservoirs which prove to be less favourable in terms of location, shape, size or in other respects than those which are estimated and assumed in the Merlon Group's model. Estimates of reserves and resources may also change because of acquisitions and disposals, new discoveries and extensions of existing fields as well as the application of improved recovery techniques. Poor data quality from certain fields, particularly when such data are old and in need of updating, will increase the uncertainty of reserve and resource estimates for a given field.

(c) Different reservoir engineers may make different estimates of reserves, resources and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources may vary from estimates, and the differences may be material.

(d) The Merlon Group's reserves and resources evaluations are based in part on the assumed success of development activities the Merlon Group intends to undertake in future years as part of its respective capital expenditure plans. The reserves and resources and estimated cash flows to be derived

therefrom contained in the Merlon Group's estimates will be reduced to the extent that the planned development activities do not achieve the level of success assumed in the evaluations.

(e) Certain categories of reserves (probable and possible reserves) are inherently less certain than other categories (proved reserves). Results of drilling, testing and production subsequent to the date of an estimate may result in revisions to the original estimates and, as a consequence, could have the effect of altering the Merlon Group's and, following Completion, the Enlarged Group's recoverable reserves, potentially leading to material unfavourable classification changes from proved to probable or possible or from probable to possible, or from possible to a contingent resource. The estimates underlying the categorisation of the Merlon Group's reserves include a number of assumptions related to factors such as initial production rates, production decline rates, the likelihood and amount of the ultimate recovery of reserves, timing and amount of capital expenditure, marketability of production, future prices of oil and gas and operating costs, among others. The Merlon Group's respective assumptions were based on price forecasts in use at 30 June 2018, the date the relevant evaluations were prepared, and many of these assumptions are subject to change according to factors which are beyond the control of the Merlon Group, respectively. Actual production, capital expenditure and cash flows derived therefrom will vary from these estimates and evaluations and such variations could be material.

(f) In estimating and/or auditing the Merlon Group's reserves and resources, Lloyd's Register has applied forecast discounts to the relevant benchmark oil price to account for product quality and local market conditions, the terms of the Merlon Group's various sales and marketing agreements and other factors. If actual production achieved and sold in Egypt is sold at a greater discount to the benchmark oil price than was used in these forecasts, the Merlon Group's and, following Completion, the Enlarged Group's reserves and resources could be subject to downward revision, which could be material.

(g) In estimating and/or auditing the Merlon Group's reserves and resources, Lloyd's Register has also applied an estimate of future increases in the Merlon Group's operating costs. If the Merlon Group's operating costs increase at a substantially higher rate than that which is reflected in these forecasts, the Merlon Group's and, following Completion, the Enlarged Group's reserves and resources could be subject to material downward revision.

As a result of the uncertainties described above, the Merlon Group's estimated reserves and resources data and the net present value information contained in the Merlon Group CPR prepared by Lloyd's Register should not be interpreted as a statement of the commercial viability or market value of the Merlon Group's and, following Completion, the Enlarged Group's present or future operations. Material differences between the Merlon Group's and/or, following Completion, the Enlarged Group's estimated and actual reserves and resources could have a material adverse effect on the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

The estimated reserves, resources and net present values set out by Lloyd's Register in the Merlon Group CPR represent estimates only and should not be relied upon as representing exact quantities. These estimates include a number of assumptions relating to factors such as production, revenues, operating expenses, capital expenditure forecasts, abandonment expenditure estimates, marketability of oil and gas, ultimate reserves recovery, future oil and gas prices, licence extensions, royalty rates and current fiscal policies and regulatory regimes. If the assumptions upon which the estimates of the Merlon Group's and/or, following Completion, the Enlarged Group's reserves and resources are inaccurate, this may indicate lower future production than projected, which in turn could have a material adverse effect on the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects and the net present value of its reserves.

Furthermore, the initial development period for each Development Lease is 20 years from the date of the Minister of Petroleum's approval of the Development Lease and thereafter the development period for each lease may be extended by two periods of five years each. However, every four years, EGPC has a right to carry out a periodic review of the blocks within each Development Lease for the purpose of auditing the acreage blocks within each such lease and identifying those blocks from which production has ceased (since either the initial approval of the Development Lease or the last formal review) or in respect of which production has not commenced. If EGPC deem that production has ceased, such Development Lease would be subject to immediate relinquishment. The estimated reserves, resources and net present values set out by Lloyd's Register in the Merlon Group CPR for each producing field assume there will be adequate

investment capital available to further develop the discovered reserves within the Development Leases. If production ceases, or fails to commence, within a Development Lease while reserves and resources remain in place and the necessary investment capital is not available to restore production prior to a periodic audit review by EGPC, blocks within any such Development Lease and the remaining reserves in place may be subject to compulsory relinquishment which in turn could have a material adverse effect on the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects and the net present value of its reserves.

2.6 ***Development of contingent resources will require successful implementation of complex technical extraction methods (e.g. waterflooding).***

Rate and ultimate recovery of reserves and resources from the El Fayum concession will be dependent on the expansion of water flood, which will require the drilling of additional water injector wells and construction of certain new facilities e.g. water storage, treatment facilities and flow lines. While water injection has been tested through a pilot scheme, with demonstrably positive results, there are currently only four injector wells active (all in the Greater Silah area) on the concession. Thus there is a risk that the reservoirs elsewhere will not respond as positively to water injection, which may have an adverse impact on the rate of production and ultimate recovery.

2.7 ***Petrosilah is jointly controlled with EGPC.***

As required by the Concession Agreement (and the standard Egyptian Concession model) Merlon's operations in Egypt are conducted through Petrosilah, a joint venture company established by Merlon and EGPC, whereby the shareholders each own 50 per cent. of the shares and have joint control over the exploration and development operations of the company. Under Petrosilah's charter, the board of directors consists of 4 directors appointed by Merlon and 4 directors appointed by EGPC.

Decisions of the board of Petrosilah require a vote in favour of at least 5. Petrosilah's Bylaws provide for resolution procedures in case of a deadlock, whether at a shareholders' or directors' meetings, if such deadlock is unresolved for a period of at least 30 consecutive days (a "**Deadlock Notice Period**"). Once a deadlock arises, the party who proposed the relevant matter the subject of the deadlock may submit the issue for agreement within 30 days from the lapse of the Deadlock Notice Period. The Concession Agreement then requires the parties to agree to meet to reach an amicable agreement. If agreement is reached, the content of such agreement shall be recorded in writing and signed by both representatives and shall be binding on both the shareholders and the company. If the parties fail to find amicable solution within 60 days of their first meeting, the matter should then be referred to arbitration in accordance to the provisions of the Concession Agreement.

As a result, the Merlon Group is, and following Completion, the Enlarged Group will be, exposed to counterparty risk in respect of EGPC failing to agree to operation or governance requests of Merlon with respect to the Merlon Group's El Fayum assets in Egypt and unresolved matters may be referred to arbitration proceedings.

2.8 ***The Merlon Group's IT systems and processes require investment to improve their suitability and resilience.***

The Merlon Group's IT systems and processes will require investment to improve their suitability and resilience in order to adequately support the business processes of the Merlon Group and, following completion of the Acquisition, the Enlarged Group. SOCO intends to make the required investments in the Merlon Group's IT systems and processes following completion of the Acquisition. The areas requiring investment and improvement include:

- Data recovery capabilities: the Merlon Group does not currently have a formal documented IT disaster recovery plan for the business. Whilst the Merlon Group has informal disaster recovery arrangements and planned additional future disaster recovery arrangements, these are not currently formally documented or aligned with the current SOCO Group processes. In the event of a systems or process failure, an inability to recover data to a suitable standard or a material deficiency in the Merlon Group's disaster recoverability capabilities could lead to significant costs and disruptions that could adversely affect the overall operational or financial performance of the business. This could have a material adverse effect on the Merlon Group's and, following completion of the Acquisition, the Enlarged Group's business, results of operations, financial condition or prospects;

- Cyber-security measures: the Merlon Group's IT function lacks formal cyber security documentation and IT penetration testing processes and will require the implementation of formally documented cyber security transformation programme designed to increase cyber security capability including incident detection and response. The SOCO Group, the Merlon Group, following completion of the Acquisition the Enlarged Group relies on IT and other operational systems for the proper functioning of its business and operations across the jurisdictions in which it operates. Cyber-based attacks and attempts by hackers and similar unauthorised users to gain access to or to corrupt or otherwise make unavailable the SOCO Group's, the Merlon Group's and, following completion of the Acquisition, the Enlarged Group's, as applicable, IT systems, and electrical or telecommunication systems, could impede its operations and may cause it to lose revenue, to incur liabilities or to fail to meet its regulatory and/or contractual and/or licence obligations. Whilst neither the SOCO Group nor the Merlon Group has incurred any material cyber-attacks or security breaches to date, a number of companies have disclosed cyber-attacks and security breaches, some of which have involved intentional attacks; and

The SOCO Directors expect to make the required investments and improvements in the six months following completion of the Acquisition, following which the probability of these risks crystallising would be significantly reduced.

3. EXISTING MATERIAL RISKS TO THE SOCO GROUP WHICH WILL BE IMPACTED BY THE ACQUISITION

3.1 ***The SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's ability to operate depends on its ability to obtain, retain or renew required drilling rights, licences, concessions, permits and other authorisations necessary for its operations, many of which are subject to change, and certain formalities of which may not always be satisfied.***

The SOCO Group and the Merlon Group conduct their respective exploration, appraisal and development operations pursuant to rights under petroleum contracts, production sharing agreements, service contracts and licences, concessions, permits and other authorisations and approvals (together, "**licences**"), as the case may be, from governmental and local authorities. The SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's ability to operate their respective business depends on the granting and continued validity of such licences, which are subject to the discretion of the relevant governmental authorities and cannot be assured. Each of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may face significant financial penalties and/or litigation or have existing and future licences suspended, terminated or revoked, or may fail to obtain approval for extensions or renewals for such licences, if it fails to fulfil the specific terms of any of its existing or future licences or if it operates its business in a manner that violates applicable laws or regulations, which could result in increased costs, reputational harm and failure to achieve its strategy. Government authorities may also, upon renewal or extension of a licence, or at any other time, impose unilateral changes to the key terms of any of the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as the case may be, licences, including terms relating to price, volume of production, cost recovery, and liability. Additionally, if governmental authorities or policies were to change, the validity of the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as the case may be, rights under such licences or concessions may be challenged. It may from time to time be difficult to ascertain whether the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as the case may be, has complied with obligations under production sharing contracts and licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as the case may be, does business may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

Furthermore, some of the SOCO Group's production licences are due to expire before the end of what it estimates to be the productive life of its licensed fields. In Vietnam, Block 16-1 is due to expire on 9 December 2024, with a 5 year extension subject to government approval and Block 9-2 expires on 17 December 2025, with a 5 year extension subject to government approval. The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, may be unsuccessful in its attempts to renew existing licences, and may be unable to gain approval for any applications for additional licences, at all or on terms and within a timeframe satisfactory to the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as the case may be.

The exploration period granted to Merlon and EGPC under the Concession Agreement for the remaining exploration area (being the original Concession Area which has not been relinquished or converted to a Development Lease) ends on 15 November 2020. The initial period for each Development Lease is 20 years from the date of the Minister of Petroleum's approval of the Development Lease. The development period for each Development Lease may be extended by two periods of five years each if Merlon provides a written request to EGPC six months prior to the end of the relevant expiration date of either the 20 year initial development period or the first five year extension period. Any extension is subject to the approval of EGPC and the Minister of Petroleum.

The Concession Agreement includes termination rights in favour of the Arab Republic of Egypt, including for material breach, submission of false statements, transfer contrary to agreed restrictions, bankruptcy and non-compliance with a final decision under the dispute provisions.

In the event that there is no regular production of crude oil from a Development Lease within four years of the lease approval date, Merlon is deemed to have automatically assigned all of its rights in respect of the area covered by the Development Lease back to EGPC. The same applies to individual blocks within a development lease; if there is no commercial production of oil within four years of the commencement of commercial production in the relevant Development Lease, any relevant blocks are deemed to be relinquished back to EGPC.

Every four years, EGPC further has a right to carry out a periodic technical review of the Development Blocks within each Development Lease for the purposes of auditing the areas which should be subject to relinquishment.

In addition, the nature of the jurisdictions in which the SOCO Group and the Merlon Group operates is such that certain formalities with regard to the execution of agreements may not, in a small number of cases, be satisfied, and government consents may not in all cases be formally received, or may be received with delay. Non-compliance with certain technical obligations under the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's licences may give rise to enforcement action by the relevant authorities, and the SOCO Group and the Merlon Group may not be successful in enforcing any or all of its rights under its respective agreements or defending against claims of licence invalidity, particularly against governmental authorities. Although governmental authorities may agree to waivers and extensions, such authorities are also generally entitled to revoke the SOCO Group's and the Merlon Group's, as the case may be, licences in such circumstances or refuse applications for further licences, extensions, permits or other approvals because of non-compliance. Moreover, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may, for commercial, legal, or other reasons, be unable to comply with certain specific terms or requirements of the licences it holds, including the meeting of specified deadlines for prescribed tasks, production quotas and other obligations set out in the work programmes attached to licences in circumstances that may entitle the relevant authority to suspend or withdraw the terms of such licences or impose material financial penalties.

Even where the SOCO Group and the Merlon Group, as the case may be, is in compliance with the terms of its licences and all applicable laws and regulations, any of its licences could be revoked, materially altered, or successfully challenged by the SOCO Group's or the Merlon Group's, as the case may be, licence counterparties or by third parties. In addition, administration and interpretation of the laws and regulations governing the SOCO Group's and the Merlon Group's licences by government authorities vary considerably and may be under-developed, untested and subject to change, challenge or invalidation. The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group therefore has limited control over whether or not such licences and other regulatory requirements (or renewals or extensions thereof, as the case may be) are granted, when such licences or renewals may be granted, the terms on which they are granted or renewed, any fees, levies, taxes, duties or other costs payable in connection therewith and the general tax regimes to which, assets in the relevant jurisdiction of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will be subject.

Finally, although all of the SOCO Group's and the Merlon Group's petroleum contracts may permit some form of cost recovery by the SOCO Group and the Merlon Group, as applicable, for its incurred exploration, appraisal and development costs, there may be disputes with governmental authorities with regard to whether a given cost was properly incurred and should be subject to the cost recovery mechanism. As a result, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may in some cases fail to recover substantial costs for its exploration, appraisal and development activities.

A portion of the licences pursuant to which the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group and its commercial partners conduct operations are solely exploration licences, and as such the assets which are the subject of those licences are not currently producing, and may never produce commercial quantities of, oil or gas. Typically, these licences have a limited life before the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group or its commercial partners (as the case may be) are obliged to seek to convert the licence to a production licence, extend the licence or relinquish the licence area. If hydrocarbons are discovered during the exploration licence term, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group or its commercial partners (as the case may be) may be required to apply for a production licence before commencing production. If the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group or its commercial partners (as the case may be) comply with the terms of the relevant exploration licence, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group would normally expect that a production licence would be issued; however, no assurance can be given that any necessary production licences will be granted by the relevant authorities on terms acceptable to the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group and/or its commercial partners (as the case may be), or at all, and the failure to obtain such a licence on acceptable terms could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

As a result of third party administration and interpretation of its licences, even for those assets in which the SOCO Group or the Merlon Group is acting as operator, the nature and timing of the SOCO Group's, the Merlon Group's and/or, following Completion, the Enlarged Group's exploration, appraisal, development, production and other activities, or its ability to execute its strategy according to plan or at all may be materially and adversely affected, including by substantial delays or material increases in costs. There can be no assurance that the views of the relevant government agencies regarding the development of the fields that the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group or its commercial partners operate or the compliance with the terms of the licences, permits, agreements or relevant legislation pursuant to which the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group conducts its operations will coincide with the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's views, which might lead to disagreements that may not be resolved and any such disagreement, if not resolved in a commercially acceptable way or at all, could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects. Any inability of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group to comply with the terms of its licences, successfully defend against claims, or obtain, retain or renew its licences on terms satisfactory to it, or at all, could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

3.2 ***The SOCO Group's and the Merlon Group's exploration, appraisal and development programmes are capital intensive and the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will be unable to implement these programmes and fulfil their respective licensing commitments in the longer term without significant capital expenditure for which funding may not be available.***

The SOCO Group incurred total cash capital expenditure of US$29.3 million during 2017 and US$40.1 million during 2016 and expects total cash capital expenditure for 2018 to be less than US$30 million reflecting the delay in the drilling campaign and the deferral to 2019 of seismic acquisition on exploration Blocks 125 & 126 in Vietnam. The Merlon Group incurred total capital expenditure of US$14.9 million during 2017 and US$23.3 million during 2016.

Given the Merlon Group's assets are at an earlier stage of development than the SOCO Group's assets, it is expected that the Merlon Group assets will require higher capital expenditure than the SOCO Group's assets over the medium term. The SOCO Directors expect that the Enlarged Group's development plan for the Concession Area will require US$245 million of investment through the financial year ended 2023. This will be directed towards, among other things, drilling wells, building and improving infrastructure and upgrading production facilities.

The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group intend to fund their respective planned capital expenditure from amounts available under borrowings, operating cash flows resulting from production and sale of oil, natural gas and condensate, the sale of certain assets or the agreement of farm out financing arrangements in respect of certain assets, and potentially from corporate

restructuring, refinancing of current debt, new borrowings or from capital markets funding, in the form of equity or debt.

In the longer term, the SOCO Group, the Merlon Group and/or, following Completion, the Enlarged Group may not be able to generate sufficient funds from operating cash flows or, particularly during periods of distress and limited capital availability in the global capital markets, to raise sufficient funds from asset sales, from farm out arrangements, and from borrowing or raising debt or equity to meet its respective future capital expenditure requirements, or to do so at commercially acceptable or reasonable terms and/or cost. The SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's ability to arrange future financing, and the cost of financing generally, depends on many factors, including:

(a) economic and capital markets conditions generally;

(b) investor confidence in the oil and gas industry and in the SOCO Group, the Merlon Group or, following Completion, the Enlarged Group, as the case may be;

(c) the business performance of the SOCO Group, the Merlon Group or, following Completion, the Enlarged Group, as the case may be;

(d) the success of exploration and appraisal efforts for a given asset;

(e) regulatory developments;

(f) receipt of permission from existing lenders (if applicable) or counterparties;

(g) credit available from banks and other lenders; and

(h) provisions of tax and securities laws that are conducive to raising capital.

It may therefore be difficult or impossible, in the longer term, for the SOCO Group, the Merlon Group and/or, following Completion, the Enlarged Group to obtain funding for existing or proposed capital expenditures on acceptable terms, or at all.

If the SOCO Group raises debt in the future, it will become more leveraged and subject to additional or more restrictive financial covenants and ratios, and/or may be required to extend security over its assets for the benefit of lenders, and if the Merlon Group and, following Completion, the Enlarged Group raises debt in the future, it may become more leveraged and subject to additional or more restrictive financial covenants and ratios, and/or may be required to extend security over its assets for the benefit of lenders.

Any inability of the SOCO Group, the Merlon Group and/or, following Completion, the Enlarged Group, as the case may be, to generate or procure sufficient financing for capital expenditures in the longer term could adversely affect its ability to expand its respective business and meet its stated reserve and production targets, could result in the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as the case may be, facing unexpected costs and delays in relation to the implementation of its exploration, appraisal and development plans and could adversely affect the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's ability to maintain its production at current levels, meet its commitments under certain of its exploration or development licences, and achieve its strategy. This could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

The SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's development plans may be unsuccessful if it is not possible to convert exploration licences into production licences.

Generally, the SOCO Group's and the Merlon Group's petroleum agreements grant a licence for the exploration and appraisal of hydrocarbons within defined areas and provide for certain commitments (for example, exploration and appraisal drilling commitments) to be completed within specified timeframes. If the SOCO Group, the Merlon Group and/or, following Completion, the Enlarged Group is unable to meet the specified requirements and/or deadlines for commitments set out in its respective exploration licences, it may be required to relinquish those licences or may otherwise fail to secure a waiver, amendment or extension of such requirements, which could result in premature termination, expiration, suspension or cancellation of any of its material exploration licences. In certain cases, each of the SOCO Group and/or the Merlon Group is required to provide letters of credit when it enters into minimum work commitments,

which it may have to write off if an asset is relinquished. Even if the terms of the SOCO Group's and/or the Merlon Group's exploration licences are met, the ability of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, to initiate production in respect of the hydrocarbon reserves for which it has exploration licences depends on its ability to convert its exploration licences into production licences. The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, as the case may be, may be unable to negotiate commercially reasonable terms for development and production, and its development plans may be subject to delays or difficulties arising from the political, environmental and other conditions in the areas where potential reserves and resources are located. Factors such as equipment or staff shortages, infrastructure problems, adverse weather conditions and, natural disasters may also make it uneconomical to develop potential reserves and resources. In addition, the conversion of exploration licences into development and production licences will require approval from central, regional or local governments, which may be delayed or altogether unavailable for reasons beyond the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as the case may be, ability to predict or control. The SOCO Group, the Merlon Group and/or following Completion, the Enlarged Group may also be required to raise debt or issue equity in order to successfully implement its exploration, appraisal and development programmes. See the risk factor entitled "The SOCO Group's and the Merlon Group's exploration, appraisal and development programmes are capital intensive and the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will be unable to implement these programmes and fulfil their respective licensing commitments in the longer term without significant capital expenditure for which funding may not be available".

Any inability of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group to convert its exploration licences in line with exploration, appraisal and development programmes, as applicable, could delay or prevent production, which would limit the growth of future reserves and revenues and could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's expected return on investment, as applicable, and could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

3.3 ***The SOCO Group and the Merlon Group are each dependent on the efforts of certain members of management and on its ability to attract and retain key technical and finance and administrative staff.***

The SOCO Group's and the Merlon Group's business is highly dependent upon skilled personnel and professional staff in the areas of oil and gas exploration, appraisal and development, operations, engineering, and business development, and in particular on the regional knowledge and relationships of senior management in the jurisdictions in which the SOCO Group and the Merlon Group operates.

In particular, Ed Story, who is currently the President and Chief Executive Officer of SOCO, Jann Brown, who is currently Managing Director and Chief Financial Officer of the SOCO Group, Dr Mike Watts, who is currently Managing Director of the SOCO Group, and Antony Maris, who is currently Chief Operating Officer of the SOCO Group, and Jason Stabell, President and Chief Executive Officer of Merlon, are expected to be important to the success of the Enlarged Group following Completion. These named SOCO Group individuals, with the exception of Jason Stabell, are employed on the basis of twelve months' notice periods, with covenants not to compete with the SOCO Group as well as customary confidentiality and non-solicitation obligations. Jason Stabell is employed on the basis of a six-month notice period and is bound by covenants not to compete with the SOCO Group and customary confidentiality and non-solicitation obligations. Any failure to retain key members of management could significantly delay or prevent the implementation of the respective strategy of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group, which could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

Certain Houston-based employees of the Seller who have historically provided services to Merlon in the areas of oil and gas exploration, appraisal and development, operations, engineering, business development and financial reporting will not transfer to the Enlarged Group following Completion, resulting in the loss of institutional, operational and financial knowledge, experience and expertise. This may cause a strain on the managerial, technical and administrative resources of the Enlarged Group relating to its business in Egypt and require the hiring of additional personnel. These resource constraints and any delays or difficulties in hiring additional personnel could adversely affect the Enlarged Group's ability to execute its business strategy successfully in Egypt.

Were any of the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's key members of management to depart, the SOCO Group and the Merlon Group, as applicable, and, following Completion, the Enlarged Group may not be able to locate suitable replacement personnel in a timely manner, or at all. The departure of any of these individuals, or any impediment to any of them performing their duties, may reduce the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's ability to successfully implement its respective strategy and could have a material adverse effect on SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as applicable, business, results of operations, financial condition or prospects.

Global competition in the oil and gas industry for management and technical personnel with relevant expertise and exposure to international best practices is intense due to the small number of qualified individuals in the labour market. The SOCO Group and the Merlon Group place, and, following Completion, the Enlarged Group will place a particular emphasis, as part of its strategy, on hiring local staff rather than expatriates wherever possible, and as a result may have difficulty hiring and retaining qualified management and technical personnel in countries which have a limited supply of such personnel available locally. The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may be unable to retain its existing senior management and technical personnel or attract additional qualified personnel as the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group grows its operations in existing and/or new jurisdictions. As a result, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may face significant costs in attracting and retaining specialist personnel necessary for the operation and expansion of its business, and there can be no assurance that it will be able to do so in every or any case. Any failure to attract, retain or replace qualified technical personnel or senior management could significantly delay or prevent the successful implementation of the respective strategy of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group which could have a material adverse effect on SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as applicable, business, results of operations, financial condition or prospects.

3.4 ***The SOCO Group and the Merlon Group operate and, following Completion, the Enlarged Group will operate, in jurisdictions that are subject to significant political, economic, legal, regulatory, tax and social uncertainties.***

The SOCO Group and the Merlon Group has, and, following Completion, the Enlarged Group will have, operations in Vietnam and Egypt, and may, in the future, explore the potential for licensing opportunities in other jurisdictions. As a result, the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's exploration, appraisal and development operations are exposed to significant political, economic, legal, regulatory, tax and social risks of the jurisdictions in which it operates. These risks potentially include:

(a) expropriation, which could, among other things, take the form of the cancellation, or termination of, or a unilateral change or a series of unilateral changes to, or unfavourable renegotiation of, the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's petroleum contracts, service contracts or other contracts, licences, permits, authorisations or approvals;

(b) nationalisation of property;

(c) the unilateral imposition of onerous new or unforeseen obligations on the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group;

(d) instability in political, economic or financial systems;

(e) uncertainty arising from underdeveloped and rapidly changing legal, regulatory and tax systems;

(f) bribery and corruption;

(g) civil strife, war, hostilities, armed conflict, guerrilla activities, terrorism and piracy;

(h) restrictions on production, including as a result of concerted action by members of OPEC and/or other oil-producing nations;

(i) capital controls;

(j) price controls;

(k) currency exchange restrictions or currency devaluation;

(l) economic sanctions imposed on these jurisdictions by another jurisdiction (for example the current financial sanctions imposed on Egypt by, among others, the United Kingdom);

(m) foreign ownership limitations; and

(n) restrictions or the imposition of tariffs or duties on imports of certain goods or exchange controls.

As a result, the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group may be unable to reliably establish, protect or defend legal rights or title to assets (and, in particular rights to explore for, develop and produce oil and gas) in the jurisdictions in which the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group operates and proposes to operate. Any such failure to establish, protect or defend its legal rights or title to assets could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects. Whilst the SOCO Group and the Merlon Group have investigated their title to, rights over and interests in, their petroleum contracts and other assets, this should not be construed as a guarantee of their title to such assets. The SOCO Group's and the Merlon Group's rights under its petroleum contracts and other assets, in particular those petroleum contracts in which the SOCO Group or the Merlon Group have acquired their interests from a third party rather than directly from the relevant government, may be subject to prior unregistered agreements or transfers that have not been recorded or detected through title research and title may be affected by such undetected defects. There can be no assurance that the SOCO Group's or the Merlon Group's title to some of their licence interests or other assets, including those interests which the SOCO Group or the Merlon Group have acquired from a third party rather than directly from the relevant government, will not be challenged or impugned. Any such challenge could have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects. As set above, Egypt is currently subject to financial sanctions imposed by, among others, the United Kingdom, which restrict trading with certain designated persons. The SOCO Directors do not currently expect these sanctions to have any impact on the operations of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group.

In certain of the jurisdictions in which the SOCO Group and the Merlon Group operates, in particular Egypt, there is a recent history of civil and political conflict including civil war and government change by coup d'état:

(o) in Egypt, which accounts for all of the Merlon Group's oil production and revenue, the political environment has been subject to profound upheaval and multiple changes of government in recent years, as a result of which commercial activity and economic conditions in Egypt has been negatively affected and has not yet fully recovered. In economic terms, Egypt has faced a significant loss of foreign currency revenue from the decline of external investment and foreign tourism since the onset of political unrest in early 2011, which included mass protests in 2011 and 2013 and dissolution of the government by the armed forces in 2013, as Egypt's foreign exchange reserves have significantly fallen. Because Egypt, acting via EGPC, is a net importer of oil, it depends on a sufficient inflow of US dollars from foreign investment, tourism, borrowing and other sources to fund its oil imports as well as to process US dollar payments through EGPC to counterparties, including the Merlon Group. The decline in foreign currency revenue and reserves has had a significant impact on the finances of the Egyptian government, resulting in certain government-owned entities being unable to fulfil their contractual obligations with foreign counterparties; and

(p) local or regional armed conflict could result in the partial or complete closure of pipelines or of particular ports or significant sea passages, such as the Straits of Hormuz or the Suez Canal, potentially resulting in higher costs, congestion of ports or sea passages, vessel delays or cancellations on some trade routes.

In any of the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's present or future jurisdictions of operation, it may be difficult or impossible to obtain insurance coverage to protect against civil strife, outbreaks of infectious disease, acts of war, labour unrest, armed conflict and other security incidents and as a result, the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's insurance programme may generally exclude this coverage. Consequently, such risks could have a material adverse impact on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

Any political or governmental instability could have a particularly significant impact on the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group because their principal assets are petroleum contracts granted by the governments in the jurisdictions in which it operates. The SOCO Group and the Merlon Group are and, following Completion, the Enlarged Group will be, required to negotiate the terms of its exploration and development projects with these governments and enter into petroleum contracts with the relevant authorities. However, such governments may impose conditions that could affect the viability of any given project such as providing the government with free carried interests, requiring local company participation or providing subsidies for the development of the local infrastructure or other social assistance. Additionally, if significant political changes occur, whether at the local, national or international level, there can be no assurance that the relevant governments will not seek to revise the terms of such petroleum contracts in a manner adverse to the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group.

Any of the above or other factors could result in delay to the oil and gas exploration, appraisal and development programmes of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group in the affected country or region and could restrict the ability of the SOCO Group, the Merlon Group and, following Completion, the Enlarged Group to achieve its respective strategy with regard to the nature and timing of its exploration, appraisal, development and other activities. Such risks could also result in disruption to the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's, as the case may be, production and development activities, as a result of damage to equipment and infrastructure. Any of these events could adversely impact global oil and gas prices, and consequently have a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

As at the Latest Practicable Date, the SOCO Directors are not aware that any event of the sort set out above has occurred that is expected to cause a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

3.5 ***The SOCO Group, the Merlon Group and, following Completion, the Enlarged Group will conduct business in jurisdictions with inherent risks relating to fraud, bribery and corruption.***

The SOCO Group and the Merlon Group currently conduct business in a number of jurisdictions that have been allocated low scores on Transparency International's "Corruption Perceptions Index". Doing business in developing countries brings with it inherent risks associated with enforcement of the SOCO Group's and the Merlon 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. In addition, the oil and gas industries have historically been shown to be vulnerable to corrupt or unethical practices.

While the SOCO Group maintains anti-corruption training programmes, codes of conduct and other safeguards designed to prevent the occurrence of fraud, bribery and corruption, it may not be possible for them to detect or prevent every instance of fraud, bribery or corruption in every jurisdiction in which its employees, agents, sub-contractors or joint venture partners are located. The SOCO Group and, following Completion, the Enlarged Group may therefore be subject to civil and criminal penalties and to reputational damage.

In addition, neither Merlon nor Petrosilah currently has a written comprehensive anti-corruption compliance programme in place in its business and, while the Seller has agreed pursuant to the Share Purchase Agreement that it will procure that Merlon (and will use reasonable endeavours to ensure that Petrosilah) institute and maintain the SOCO Group's anti-corruption compliance programme substantially in the terms agreed between the parties at Announcement, there is a risk that instances of corruption have already occurred within Merlon and/or Petrosilah which have yet to come to light.

Instances of fraud, bribery and corruption, and violations of laws and regulations in the jurisdictions in which the Group operate, including the UK Bribery Act 2010, could have a material adverse effect on its results of operations and financial conditions. In addition, as a result of the SOCO Group's anti-corruption training programmes, codes of conduct and other safeguards, there is a risk that it and, following Completion, the Enlarged Group could be at a commercial disadvantage and may fail to secure contracts and licences to the advantage of other companies who may not have to comply with such anti-corruption safeguards.

As at the Latest Practicable Date, the SOCO Directors are not aware of any instances of fraud, bribery or corruption causing a material adverse effect on the SOCO Group's, the Merlon Group's and, following Completion, the Enlarged Group's business, results of operations, financial condition or prospects.

3.6 ***SOCO's policy of regular distributions of excess free cash flow to its shareholders may be impacted by the fact that the SOCO Group and, following the Acquisition, the Enlarged Group will have higher levels of leverage and an increased capex investment.***

The Acquisition is being funded by SOCO in part using its RBL Facility. It is expected that approximately US$100 million will be drawn under the RBL Facility at Completion to fund part of the cash consideration for the Acquisition. In addition, as described further at paragraph 3.2 above, both the SOCO Group's and the Merlon Group's exploration, appraisal and development programmes are capital intensive and as a result of the Acquisition, the Enlarged Group will have significant capital expenditure investment commitments. As a result, the Acquisition will significantly increase the overall financial leverage and capital expenditure requirements of the Enlarged Group. Therefore, depending on the level of the Enlarged Group's borrowings, capital expenditure requirements and other macro-economic factors (including, *inter alia*, any future volatility in oil prices), this could result in reduced funds being available for the Enlarged Group's dividend payments.

PART III

FINANCIAL INFORMATION ON MERLON

Section A: Accountant's report in respect of the Historical Financial Information relating to Merlon

Deloitte.

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on behalf of SOCO International plc
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5 December 2018

Dear Sirs

SOCO International plc/Merlon Petroleum El Fayum Company ("Target" and, with its subsidiaries, the "Target Group")

We report on the financial information for the years ending 31 December 2015, 31 December 2016 and 31 December 2017 set out in Part III of the Class 1 Circular relating to the acquisition of Target Group dated 5 December 2018 of SOCO International plc (the "**Company**") (the "**Circular**"). This financial information has been prepared for inclusion in the Circular on the basis of the accounting policies set out in note 2 to the financial information. This report is required by Listing Rule 13.5.21R.

Responsibilities

The Directors of the Company are responsible for preparing the 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 financial information and to report our opinion to you.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to shareholders of the Company as a result of the inclusion of this report in the Circular, 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 or our statement, required by and given solely for the purposes of complying with Listing Rule 13.4.1R(6), consenting to its inclusion in the Circular.

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 judgments 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 jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion on financial information

In our opinion, the financial information gives, for the purposes of the Circular, a true and fair view of the state of affairs of the Target Group as at 31 December 2015, 31 December 2016 and 31 December 2017 and of its profits, cash flows and changes in equity for the years ending 31 December 2015, 31 December 2016 and 31 December 2017 in accordance with International Financial Reporting Standards as adopted by the European Union and has been prepared in a form that is consistent with the accounting policies adopted in the Company's latest annual accounts.

Yours faithfully

Deloitte LLP

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Section B: Historical Financial Information on Merlon

Basis of financial information

This Part III sets out the historical financial information of MPEFC for FY 2015, FY 2016 and FY 2017 prepared under IFRS using policies consistent with those used in preparing the latest audited consolidated financial statements of the SOCO Group.

Income Statements for the year to 31 December

	Notes	2017 US$ million	2016 US$ million	2015 US$ million
Revenue	4	58.6	59.7	59.7
Cost of sales	6	(53.1)	(60.2)	(71.0)
Gross profit/(loss)		5.5	(0.5)	(11.3)
Administrative expenses		(3.4)	(2.7)	(2.7)
Exploration expense	7	(1.9)	(5.2)	(3.3)
Operating profit/(loss)		0.2	(8.4)	(17.3)
Interest Income	4	0.1	0.2	0.3
Finance costs	8	(3.1)	(3.4)	(4.3)
Loss before tax		(2.8)	(11.6)	(21.3)
Tax	9	–	–	–
Loss for the year		**(2.8)**	**(11.6)**	**(21.3)**
Basic loss per share US$	10	(2,800)	(11,600)	(21,300)
Diluted loss per share US$	10	(2,800)	(11,600)	(21,300)

There were no items of other comprehensive income or expense in any of the periods shown.

Balance Sheets as at 31 December

	Notes	2017 US$ million	2016 US$ million	2015 US$ million
Non-current assets				
Intangible assets	11	17.4	16.0	20.8
Property, plant and equipment	12	141.4	147.6	163.8
		158.8	163.6	184.6
Current assets				
Inventories	13	12.2	13.0	14.2
Trade and other receivables	14	51.2	31.4	18.9
Cash and cash equivalents	15	8.3	14.7	13.5
		71.7	59.1	46.6
Total assets		**230.5**	**222.7**	**231.2**
Current liabilities				
Trade and other payables	16	(39.8)	(23.4)	(29.6)
Loans and borrowings	17	(30.5)	(38.0)	(47.3)
Intercompany advances	21	(10.4)	(10.1)	(10.1)
		(80.7)	(71.5)	(87.0)
Net current liabilities		(9.0)	(12.4)	(40.4)
Non-current liabilities				
Intercompany advances	18	–	–	(70.0)
		–	–	(70.0)
Total liabilities		**(80.7)**	**(71.5)**	**(157.0)**
Net assets		**149.8**	**151.2**	**74.2**
Equity				
Share capital	18	175.0	173.6	85.0
Retained deficit		(25.2)	(22.4)	(10.8)
Total equity		**149.8**	**151.2**	**74.2**

Statements of Changes in Equity for the year to 31 December

	Notes	Called up share capital US$ million	Retained deficit US$ million	Total US$ million
As at 1 January 2015		85.0	10.5	95.5
Retained loss for the year		–	(21.3)	(21.3)
As at 1 January 2016		85.0	(10.8)	74.2
Capitalisation of intercompany loan	18	70.0	–	70.0
Capital contributions	18	18.6	–	18.6
Retained loss for the year		–	(11.6)	(11.6)
As at 1 January 2017		173.6	(22.4)	151.2
Capital contributions	18	1.4	–	1.4
Retained loss for the year		–	(2.8)	(2.8)
As at 31 December 2017		**175.0**	**(25.2)**	**149.8**

Cash Flow Statements for the year to 31 December

	Notes	2017 US$ million	2016 US$ million	2015 US$ million
Net cash from operating activities	20	17.6	18.5	26.6
Investing activities				
Purchase of intangible assets		(3.0)	(1.2)	(5.2)
Purchase of property, plant and equipment		(11.9)	(22.1)	(35.3)
Net cash used in investing activities		**(14.9)**	**(23.3)**	**(40.5)**
Financing activities				
Capital contributions	18	1.4	18.6	–
Bank loans – interest and fees		(3.3)	(2.6)	(4.0)
Bank loans – capital inflows (outflows)		(7.2)	(10.0)	7.5
Net cash (used in) from financing activities		**(9.1)**	**6.0**	**3.5**
Net (decrease) increase in cash and cash equivalents		(6.4)	1.2	(10.4)
Cash and cash equivalents at beginning of year		14.7	13.5	23.9
		–	–	
Cash and cash equivalents at end of year	**15**	**8.3**	**14.7**	**13.5**

Notes to the Historical Financial Information

1. GENERAL INFORMATION

Merlon Petroleum El Fayum Company ("**MPEFC**") is a limited liability company registered in the Cayman Islands. On July 2004, MPEFC executed a concession agreement (El Fayum Production Sharing Contract – "**El Fayum PSC**") with the Egyptian General Petroleum Corporation ("**EGPC**") to conduct oil and gas exploration activities within defined geographical areas in Egypt. MPEFC has a 100% working interest in the concession.

MPEFC set up a branch in Egypt under the provisions of the Companies Law No. 159 of 1981 and its Executive Regulations for the purpose of executing concession agreements with the EGPC and the Egyptian Government.

In accordance with the concession agreement, the Petrosilah Company was formed in May of 2010. Petrosilah is an Egyptian Company, owned 50% by MPEFC and 50% by EGPC. The operating company is responsible for the management of operations within the Concession Area. All costs incurred by the operating company are fully reimbursed by MPEFC.

The following is a summary of the Concession Agreements signed by Merlon Petroleum El Fayum Company:

1.1 ***El Fayum Area Western Desert Concession***

On July 1, 2004, MPEFC, as the contractor, entered into a concession agreement (Law No. 147 for year 2004) for petroleum exploration and exploitation with the Government of the Arab Republic of Egypt and the Egyptian General Petroleum Corporation (EGPC) covering the El Fayum area in the Western Desert.

1.2 ***El Fayum Area Western Desert Concession-First Amendment***

On June 24, 2010, MPEFC, as a contractor, entered into an amendment (Law No. 132 for year 2010) of the Concession Agreement which amended the concession agreement in order to facilitate additional investment by adding two new exploration periods.

1.3 ***El Fayum Area Western Desert Concession-Second Amendment***

On August 7, 2017, MPEFC, as a contractor, entered into a second amendment (Law No. 201 for year 2017) to the Concession Agreement which amended the concession agreement in order to facilitate additional investment by extending the exploration periods.

Exploration and development costs and costs of fixed assets are fully recoverable by MPEFC from 30% of oil and gas production (cost oil). The earliest that such costs may be recovered is over a period of four years. Oil and gas operating expenditures are also recovered by MPEFC from the 30% cost oil.

The remaining oil and gas production (profit oil) is allocated according to the following production figures:

Production/Day	EGPC share	MPEFC share
Less than 5,000 BBL/Day	82%	18%
From 5,000 to 10,000 BBL/Day	83%	17%
From 10,000 to 25,000 BBL/Day	85%	15%
From 25,000 to 50,000 BBL/Day	86%	14%
From 50,000 to 100,000 BBL/Day	87%	13%
More than 1000,000 BBL/Day	88%	12%

1.4 ***Ownership***

MPEFC is a wholly owned subsidiary undertaking of Merlon International, LLC. Merlon International, LLC is a Delaware limited liability company formed on April 5, 2007 to own corporations conducting business in the oil and gas industry. Merlon International, LLC owns Merlon Texas, Inc. a Delaware corporation conducting oil and gas operations in the United States and Merlon International, Inc. a Texas corporation, which serves as the administrative entity for the group and MPEFC.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) ***Basis of preparation***

The historical financial information of MPEFC has been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union.

SOCO Directors have assessed the expected performance and financial position of MPEFC, including the impact of its acquisition by SOCO, and are satisfied that it will continue to be able to meet its financial obligations for the foreseeable future. As a result, this historic financial information has been prepared on a going concern basis.

The historical financial information has been prepared under the historical cost basis, except for the valuation of hydrocarbon inventory. The historical financial information is presented in US dollars as it is the functional currency of MPEFC and is generally accepted practice in the oil and gas sector. The principal accounting policies adopted are set out below.

(b) ***Adoption of new and revised accounting standards***

At the date of authorisation of the historical financial information, the following IFRS's and IAS's, which have not been applied in the historical financial information, were in issue but not yet effective:

IFRS 9 Financial Instruments

In July 2014, the IASB issued IFRS 9 "Financial Instruments" which is effective for annual periods beginning on or after 1 January 2018. IFRS 9 is a comprehensive standard to replace IAS 39 Financial instruments: Recognition and Measurement, and includes requirements for classification and measurement of financial assets and liabilities, impairment of financial assets and hedge accounting.

The classification and measurement of financial assets is now based on the entity's business model for managing the financial asset, and the contractual cash flow characteristics of the financial asset. The classification and measurement of financial liabilities is materially consistent with that required by IAS 39 with the exception of the treatment of modification or exchange of financial liabilities which do not result in de-recognition.

The new impairment model requirements apply to financial assets measured at amortised costs and FVOCI, lease receivables, and certain loan commitments and financial guarantee contracts. At initial recognition, an impairment allowance (or provision in the case of commitments and guarantees) is required for expected credit losses ("**ECL**") resulting from default events that are possible within the next 12 months ("**12-month ECL**"). In the event of a significant increase in credit risk, an allowance (or provision) is required for ECL resulting from all possible default events over the expected life of the financial instrument ("**lifetime ECL**"). Financial assets where 12-month ECL is recognised are in "stage 1"; financial assets that are considered to have experienced a significant increase in credit risk are in "stage 2"; and financial assets for which there is objective evidence of impairment, so are considered to be in default or otherwise credit impaired, are in "stage 3".

The hedge accounting requirements in the standard do not have an impact on MPEFC as it does not undertake any hedging activities at this time.

MPEFC has undertaken an initial assessment of the classification and measurement requirements, as well as the new impairment model, and expects that the standard will result in the recognition of an additional provision for ECL of trade receivables of approximately $1m when first applied on 1 January 2018.

- IFRS 15 Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" which MPEFC will adopt for annual periods beginning on or after 1 January 2018. IFRS 15 provides a principles-based approach for revenue recognition, and introduces the concept of recognising revenue for performance obligations as they are satisfied.

MPEFC will adopt the standard on its mandatory effective date, and it will impact the qualitative and quantitative disclosures of revenue arrangements; to depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. MPEFC has assessed the impact of IFRS 15 and expects that the standard will have no material quantitative effect, when applied, on the historical financial information of MPEFC.

- IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 "Leases" which MPEFC will adopt for annual periods beginning on or after 1 January 2019. The adoption of IFRS 16 will impact both the measurement and

disclosures of leases over a value threshold and with terms longer than one year. The lease expense recognition pattern for lessees will generally be accelerated. Additional lease liabilities and right of use assets are expected to be recorded. The cash flow statement will be affected as payments for the principal portion of the lease liability will be presented within financing, not operating, activities.

MPEFC is currently assessing the impact of IFRS 16 and is in the process of identifying all lease agreements that exist. It is not practicable to quantify the effect at the date of the publication of this historical financial information.

(c) ***Interests in joint arrangements***

A joint arrangement is an arrangement where two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. Joint arrangements where the entity has the rights to assets and obligations for liabilities of the arrangement are classified as joint operations and are accounted for by recognising the entity's share of assets, liabilities, income and expenses. Joint arrangements where the entity has the rights to the net assets of the arrangement are classified as joint ventures and are accounted for using the equity method of accounting.

Petrosilah, the joint arrangement operating company, is controlled 50% by MPEFC and 50% by EGPC and accounted for by MPEFC as a joint operation. The operating company is responsible for the management of operations within the Concession Area. All costs incurred by the operating company are fully reimbursed by MPEFC. MPEFC has rights to 100% of the asset and the obligation for 100% of liabilities and EGPC and MPEFC then separately recognise their share of revenue.

(d) ***Revenue***

Revenue represents the value of sales of oil and gas arising from upstream operations when the oil has been lifted and the title has passed. Revenue generated under Production Sharing Contracts and Risk Service Contracts is recognised once production commences and upon sale of Branch's share of the oil or gas to EGPC. Revenue recognised under the El Fayum PSC represents the sum of cost oil and its share of profit oil, as outlined in Note 1.3.

Interest income is recognised on an accrual basis in accordance with the substance of the relevant agreement.

(e) ***Intangible and Tangible non-current assets***

Oil and gas exploration, evaluation and development expenditure

MPEFC adopts the successful efforts method of accounting for exploration and evaluation costs. Pre-licence costs are expensed in the period in which they are incurred. All licence acquisition, exploration and evaluation costs and direct administration costs are initially capitalised as intangible non-current assets in cost centres by well (most typically), field or exploration area, as appropriate. Interest payable is capitalised insofar as it relates to specific development activities.

These costs are then written off as exploration costs in the income statement unless commercial reserves have been established or the determination process has not been completed and there are no indicators of impairment.

Tangible non-current assets used in acquisition, exploration and evaluation are classified with tangible non-current assets as property, plant and equipment. To the extent that such tangible assets are consumed in exploration and evaluation the amount reflecting that consumption is recorded as part of the cost of the intangible asset.

Upon successful conclusion of the appraisal program and determination that commercial reserves exits, associated costs are transferred to tangible non-current assets as property, plant and equipment. Exploration and evaluation costs carried forward are assessed for impairment.

All field development costs are capitalised as property, plant and equipment. Property, plant and equipment related to production activities is amortised in accordance with MPEFC's depletion and amortisation accounting policy.

Depreciation and depletion

Depletion is provided on oil and gas assets in production using the unit of production method, based on proven and probable reserves, applied to the sum of the total capitalised exploration, evaluation and development costs, together with estimated future development costs at current prices. Oil and gas assets which have a similar economic life are aggregated for depreciation purposes.

The effects of changes in estimates on the unit of production calculations are accounted for prospectively, from the date of adoption of the revised estimates, over the estimated remaining proven and probable reserves.

Impairment of value

Where there has been a change in economic conditions or in the expected use of a tangible non-current asset that indicates a possible impairment in an asset, management tests the recoverability of the net book value of the asset by comparison with the estimated discounted future net cash flows based on management's expectations of future oil prices and future costs. Any identified impairment is charged to the income statement.

Intangible non-current assets are considered for impairment at least annually by reference to the indicators specified in paragraphs 18 to 20 of IFRS 6. The impairment indicators in IFRS 6 for each exploration asset are:

- The period for which the entity has the right to explore in the specific area has expired during the period or will expire in the near future, and is not expected to be renewed;
- Substantive expenditure on further exploration for and evaluation of mineral resources in the specific area is neither budgeted or planned;
- Exploration for and evaluation of mineral resources in the specific area have not led to the discovery of commerciality viable quantities of mineral resources and the entity has decided to discontinue such activities in the specific area; and
- Sufficient data exist to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale.

Other tangible non-current assets

Other tangible non-current assets are stated at historical cost less accumulated depreciation. Depreciation is provided on a straight line basis at rates calculated to write off the cost of those assets, less residual value, over their expected useful lives of three to seven years.

Decommissioning

The Concession Agreement does not contain express reference to decommissioning liabilities or the funding of such liabilities. Based on the Concession Agreement and legal advice, the MPEFC position is that no decommissioning liability exists and no provision need be made at this time.

Where a decommissioning liability is required to be calculated, a provision is calculated as the net present value of the share of the expenditure which is expected to be incurred at the end of the producing life of each field in the removal and decommissioning of the production, storage and transportation facilities currently in place. The cost of recognising the decommissioning provision is included as part of the cost of the relevant property, plant and equipment and is thus charged to the income statement on a unit of production basis in accordance with the Group's policy for depletion and depreciation of tangible non-current assets. Period charges for changes in the net present value of the decommissioning provision arising from discounting are included in finance costs.

(f) ***Inventories***

Crude oil is valued at fair value less costs to sell. Any changes arising on the revaluation of inventories are recognised in the income statement.

Other inventories comprising mainly of spare parts, materials and supplies are valued at cost, determined on a weighted average cost basis, less allowance for any obsolete or slow-moving items.

Purchase cost includes the purchase price, import duties, transportation, handling and other direct costs.

(g) ***Taxation***

According to article 3.g of the Concession Agreements, MPEFC is subject to the Egyptian Income Tax Law on a concession by concession basis and should comply with the requirements of such laws with respect to the filing of returns, the assessment of tax and keeping and presenting of books and records.

The concessions are subject to corporate income tax at the standard rate of 40.55%, however responsibility for payment of corporate income taxes falls upon EGPC on behalf of MPEFC. As a result, there are no cash payments from MEF to the Egyptian tax authorities. Based on the tax returns submitted by EGPC on behalf of MPEFC, no tax was due in respect of 2015, 2016 or 2017. Due to the nature of the tax arrangements for the Concession Agreements, MPEFC does not record deferred tax in relation to the El Fayum PSC.

(h) ***Financial instruments***

Financial assets and financial liabilities are recognised on MPEFC's balance sheet when MPEFC becomes a party to the contractual provisions of the instrument. MPEFC does not currently utilise derivative financial instruments.

With the exception of Trade Receivables (see Note 14), there are no material financial assets and liabilities for which differences between carrying amounts and fair values are required to be disclosed. The classification of financial instruments as required by IFRS 7 is disclosed in Notes 14, 15, 16 and 17.

Trade receivables

Trade receivables are generally stated at their nominal value as reduced by appropriate allowances for estimated irrecoverable amounts.

Trade and bank note payables

Trade and bank note payables are generally stated at amortised costs using the effective interest rate.

(i) ***Foreign currencies***

MPEFC's functional and reporting currency is USD. Transactions denominated in currencies other than the entity's functional currency (foreign currencies) are recognised at the rate of exchange prevailing at the date of transactions.

At the end of each reporting period, balances of monetary assets and liabilities denominated in foreign currencies are retranslated to the US dollar at the exchange rates prevailing at that date, while non-monetary assets and liabilities carried at fair value that are denominated at the date when the fair value was determined.

Non-monetary assets and liabilities that are measured in terms of historical cost in a foreign currency are not retranslated.

The profit and losses resulting from the translation of foreign currencies are recognised in the income statement in the period in which they arise, except for the differences arising from the retranslation of non-monetary assets and liabilities carried at fair value which are included in the changes in fair value, whether in profit or loss in the income statement or in equity, as appropriate.

(j) ***Pension costs***

The contributions payable in the year in respect of pension costs for defined contribution schemes and other post-retirement benefits are charged to the income statement. Differences between contributions payable in the year and contributions actually paid are shown either as accruals or prepayments in the balance sheet.

3. CRITICAL JUDGEMENTS AND ACCOUNTING ESTIMATES

(a) ***Critical judgements in applying MPEFC's accounting policies***

In the process of applying MPEFC's accounting policies described in Note 2, management has made judgements that may have a significant effect on the amounts recognised in the historical financial information. These are discussed below:

Oil and gas assets

Note 2(e) describes the judgements necessary to implement MPEF's policy with respect to the carrying value of intangible exploration and evaluation assets. Management considers these assets for impairment at least annually with reference to indicators in IFRS 6. Note 11 discloses the carrying value of intangible exploration and evaluation assets. Further, Note 2(e) describes MPEFC's policy regarding reclassification of intangible assets to tangible assets. Management considers the appropriateness of asset classification at least annually.

(b) ***Key sources of estimation uncertainty***

The key assumptions concerning the future, and other key sources of estimation uncertainty at the balance sheet date, other than those mentioned above, that may have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

Oil and gas reserves and DD&A

Note 2(e) sets out MPEFC's accounting policy on DD&A. Proven and probable reserves are estimated using standard recognised evaluation techniques. Future development costs are estimated taking into account the level of development required to produce the reserves by reference to operators, where applicable, and internal engineers.

Reserves estimates are inherently uncertain, especially in the early stages of a field's life, and are routinely revised over the producing lives of oil and gas fields as new information becomes available and as economic conditions evolve. Such revisions may impact MPEFC's future financial position and results, in particular, in relation to DD&A and impairment testing of oil and gas property plant and equipment.

An independent audit of management estimates of Reserves and Contingent Resources, as of 30 June 2018, was completed by Senergy International Sdn Bhd as part of Lloyd's Register Group Limited ("**LR Senergy**").

Impairment of producing oil and gas assets

If impairment indicators are identified in relation to a producing oil and gas field, management is required to compare the net carrying value of the assets and liabilities which represent the field cash generating unit (CGU) with the estimated recoverable amount of the field. Management generally determines the recoverable amount of the field by estimating its fair value less costs of disposal, using a discounted cash flow method. Calculating the net present value of the discounted cash flows involves key assumptions which include commodity prices, 2P reserves estimates and discount rates. Other assumptions include production profiles, future operating and capital expenditures. Further information relating to the specific assumptions and uncertainties relevant to impairment tests performed in the year are discussed in Note 12.

4. TOTAL REVENUE

An analysis of MPEFC's revenue is as follows:

	2017 US$ million	2016 US$ million	2015 US$ million
Oil and gas sales	58.6	59.7	59.7
Interest income	0.1	0.2	0.3
	58.7	**59.9**	**60.0**

All MPEFC Oil and Gas revenue was from sales to EGPC in each of the years shown.

5. SEGMENT INFORMATION

MPEFC has one principal business activity being oil and gas exploration and production. MPEFC's operations are located in one country, the Arab Republic of Egypt. Accordingly, MPEFC is considered to represent a single segment and additional segmental disclosures are therefore not required.

6. COST OF SALES

	2017 US$ million	2016 US$ million	2015 US$ million
Depreciation, depletion and amortisation	24.9	32.3	27.0
Royalties	0.5	0.5	0.5
Production operating costs	27.7	27.4	43.5
	53.1	**60.2**	**71.0**

In 2017, production operating costs includes $1.5m of costs related to the unsuccessful drilling of a production well, which was subsequently redrilled.

Movements in year-end oil inventories are immaterial for disclosure in each year.

7. EXPLORATION EXPENSE

	2017 US$ million	2016 US$ million	2015 US$ million
Exploration expense	1.9	5.2	3.3
	1.9	**5.2**	**3.3**

In 2017 a review of the carrying value of costs incurred to date on future planned wells was performed. It was determined that $1.9m of costs should be impaired as substantive expenditure on such wells is no longer budgeted or planned.

In 2016 two exploration wells were deemed unsuccessful and written off as dry holes ($5.2m). In 2015 one exploration well was deemed unsuccessful and written off as a dry hole ($3.3m).

8. FINANCE COSTS

	2017 US$ million	2016 US$ million	2015 US$ million
Other interest payable and similar fees	0.1	0.1	0.3
Interest and fees – bank loan	3.0	3.3	4.0
	3.1	**3.4**	**4.3**

9. TAX

The concessions are subject to corporate income tax at the standard rate of 40.55%, however responsibility for payment of corporate income taxes falls upon EGPC on behalf of MPEFC. As a result, there are no cash payments from MPEFC to the Egyptian tax authorities. Income tax paid by EGPC is in the name of the Concession Agreement. Based on the tax returns submitted by EGPC on behalf of MPEFC, no tax was due in respect of 2015, 2016 or 2017 and, due to the nature of the tax arrangements for the Concession Agreements, MPEFC does not record deferred tax in relation to the El Fayum PSC. Accordingly, no current or deferred tax was recorded in any of the years shown.

10. LOSS PER SHARE

	2017 US$	2016 US$	2015 US$
Loss for the purposes of basic loss per share	(2,800,000)	(11,600,000)	(21,300,000)
Number of shares	1,000	1,000	1,000
Basic loss per share	(2,800	(11,600)	(21,300)
Diluted loss per share	(2,800)	(11,600)	(21,300)

11. INTANGIBLE ASSETS

	2017 US$ million	2016 US$ million	2015 US$ million
As at 1 January	16.0	20.8	18.4
Additions	3.3	0.4	5.7
Exploration expense	(1.9)	(5.2)	(3.3)
As at 31 December	17.4	16.0	20.8

During 2018, further testing on an exploration well with a year end 2017 carrying value of $6.8m demonstrated that the well was unsuccessful. It was subsequently fully impaired in 2018.

12. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas properties US$ million	Other fixed assets US$ million	Total US$ million
Cost			
As at 1 January 2015	**238.0**	**3.1**	**241.1**
Additions	20.9	1.1	22.0
As at 1 January 2016	**258.9**	**4.2**	**263.1**
Additions	15.7	0.4	16.1
As at 1 January 2017	**274.6**	**4.6**	**279.2**
Additions	18.3	0.4	18.7
As at 31 December 2017	**292.9**	**5.0**	**297.9**
Depreciation			
As at 1 January 2015	**(70.3)**	**(2.0)**	**(72.3)**
Charge for the year	(26.4)	(0.6)	(27.0)
As at 1 January 2016	**(96.7)**	**(2.6)**	**(99.3)**
Charge for the year	(31.7)	(0.6)	(32.3)
As at 1 January 2017	**(128.4)**	**(3.2)**	**(131.6)**
Charge for the year	(24.3)	(0.6)	(24.9)
As at 31 December 2017	**(152.7)**	**(3.8)**	**(156.5)**
Carrying amount			
As at 31 December 2015	162.2	1.6	163.8
As at 31 December 2016	146.2	1.4	147.6
As at 31 December 2017	140.2	1.2	141.4

At each year end, MPEFC carried out a review of the recoverable amount of its assets in accordance with IAS 36 Impairment of Assets. Recoverable amounts at each year end were based on fair value less cost of disposal. The reviews did not lead to the recognition of an impairment in MPEFC fields in Egypt at any of the year ends.

The key assumptions to which the fair value measurement is most sensitive are oil price, discount rate and 2P reserves. As at 31 December 2017, the fair value of the asset is estimated based on a post tax nominal discount rate of 12.0% (2016 and 2015: 12%) and an oil price reflecting a gradual increase over five years from US$61/bbl in 2018 (2016: US$57/bbl for 2017 and 2015: US$45/bbl for 2016) to US$71/bbl in 2022 (2016: US$69/bbl for 2021 and 2015: US$78/bbl for 2020), plus inflation of 2.0% (2016: 2.0% and 2015: 2.0%) thereafter.

Testing of sensitivity cases indicated that neither a US$5/bbl reduction in the long term oil price nor a 1% increase in discount rates, used when determining fair value less costs of disposal method, would have resulted in an

impairment of oil and gas assets for any of the years shown. Details of the uncertainties relating to the 2P reserves are provided in Note 3 (b).

Other fixed assets comprise office fixtures and fittings, computer equipment, warehouse and vehicles.

13. INVENTORIES

	2017 US$ million	2016 US$ million	2015 US$ million
Crude oil	0.3	0.2	0.3
Raw materials and spare parts	11.9	12.8	13.9
	12.2	**13.0**	**14.2**

14. TRADE AND OTHER RECEIVABLES

Amounts falling due within one year

	2017 US$ million	2016 US$ million	2015 US$ million
Trade receivables	47.6	26.1	13.5
Other receivables	2.0	3.1	0.6
Prepayments	1.6	2.2	4.8
	51.2	**31.4**	**18.9**

There are no allowances for doubtful debts in respect of trade or other receivables (2016: nil and 2015: nil).

The fair value of MPEFC's trade receivables at 31 December 2017 was approximately US$1m lower than its carrying amount (2016: US$0.5m; 2015: US$0.3m). This fair value assessment has been made using the credit default rate for the Egyptian Government (as no direct reference point for EGPC is available), which is considered to represent a Level 2 fair value under the IFRS 13 fair value hierarchy, as it is based on quoted prices for identical or similar assets in markets that are not active.

Ageing of past due but not impaired

	2017 US$ million	2016 US$ million	2015 US$ million
61-90 days	–	5.2	3.7
91-120 days	4.6	5.2	–
121-180 days	9.4	5.8	–
> 180 days	13.7	–	–
	27.7	**16.2**	**3.7**

As at 30 September 2018, all trade receivables balances outstanding at 31st December 2017 have been fully received.

15. CASH AND CASH EQUIVALENTS

As at 31 December 2017, cash and cash equivalents of US$8.3m (2016: US$14.7m and 2015: US$13.5m), which are presented as a single class of asset on the balance sheet, comprise cash, cash at bank and other short term highly liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of change in value.

16. TRADE AND OTHER PAYABLES

	2017 US$ million	2016 US$ million	2015 US$ million
Trade payables	26.9	11.5	11.6
Other payables	0.4	1.1	2.9
Accruals	12.5	10.8	15.1
	39.8	**23.4**	**29.6**

There is no material difference between the carrying value of trade payables and their fair value. The above trade and other payables are held at amortised cost and are not discounted as the impact would not be material.

Other payables relate to royalty payments due on production revenue.

Trade and other payables are financial liabilities and are therefore measured at amortised cost.

17. FINANCIAL INSTRUMENTS

Loans and Borrowings – Bank Loan

MPEFC entered into the current credit agreement originally dated October 3, 2015 and subsequently amended June 6, 2017 with foreign financial institutions, it is secured against all of MPEFC's assets. Merlon International, LLC and Merlon International, Inc. are both guarantors under the credit agreement.

The agreement provides for a revolving and reducing reserves based credit facility of up to US$55,000,000 of which US$31,646,994 is committed and US$29,930,888 is drawn as of December 31, 2017 together with US629,542 interest accrued (2016: capital US$37m and interest accrued US$1m; 2015: capital US$47m and interest accrued US$0.3m). The amount available under the facility is based on the net present value of the oil fields owned by MPEFC and is subject to redeterminations by the financial institutions at specified intervals.

The final maturity date of the facility is December 31, 2020. The interest rate is based on an Interbank rate plus a margin of 6% to 7% depending on the ageing of MPEFC's oil receivables.

The agreement contains liquidity ratio and debt to equity ratio financial covenants.

Under the terms of the Sale and Purchase Agreement with SOCO, the credit facility will be repaid in full as part of the transaction.

Financial instruments – fair value and risk management

In the normal course of its business, MPEFC uses primary financial instruments such as cash and cash equivalents, receivables and payables and as a result, is exposed to the risks indicated below.

Capital risk management

MPEFC's overriding objective when managing capital is to safeguard the business as a going concern whilst maximising returns for shareholders through the optimisation of debt and equity balances. The liquidity ratio and debt to equity ratio financial covenants are monitored on an ongoing basis to ensure compliance with the credit facility. Management maintain relationships and active dialogue with various financial institutions and may consider raising debt or equity finance at the appropriate time. Petrosilah provides daily reports on operating expenditures, and issues cash calls in advance of major expenditure.

Liquidity risk

Liquidity risk represents MPEFC's inability to settle its financial liabilities on maturity dates. MPEFC's liquidity risk management policy requires that sufficient cash is maintained to meet short term funding requirements, to avoid unacceptable loss that may affect MPEFC's reputation.

Credit risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss. The financial instruments which potentially subject MPEFC to credit risk consist of current accounts at banks and trade and other receivables. The Moody's credit ratings for the banks used by MPEFC are:

	Rating
BNP Paribas, France	Aa3
Credit Agricole CIB, France	Aa3
Standard Chartered UK	A1

All of MPEFC's sales are made to EGPC and historically EGPC has remitted payments several months in arrears, resulting in significant fluctuations in the outstanding trade receivable balance. Management maintain an active dialogue with EGPC in an effort to expedite receipts.

Foreign currency risk

Foreign currency risk is represented in foreign currency fluctuations in exchange rates affecting MPEFC's cash inflow and outflow in foreign currencies and also the exchange differences arising from translation of monetary assets and liabilities in foreign currencies. The carrying amounts of MPEFC's foreign currency denominated monetary assets and monetary liabilities at the reporting date are as follows:

	2017 US$ 000's	2016 US$ 000's	2015 US$ 000's
Liabilities			
Egyptian pound	–	–	–
Assets			
Egyptian pound	336	1,422	792

Foreign currency sensitivity analysis

MPEFC's main foreign currency exposure is to fluctuations in the Egyptian pound. The impact of a 10% movement in foreign exchange rates on the Company's foreign currency denominated net assets as at 31 December 2017 would not have been material (2016 and 2015: not material) and would not have been material with respect to the Company's profit in 2017 (2016 and 2015: not material).

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect MPEFC income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposure within acceptable parameters, while optimising the return.

Commodity price risk management

Volatility in the oil price is a pervasive element of MPEFC's business environment. As a producer, MPEFC always has a 'long' position on the product. No hedges are currently in place.

MPEFC is a seller of crude oil and natural gas, which is typically sold under short-term arrangements priced in USD at current market prices.

Interest rate risk

The risk represents the effect of changes in interest rate, which might adversely affect the results of operations and the value of the financial assets and liabilities.

If interest rates had been 1% higher/lower and all other variables were held constant, MPEFC loss for the year ended 31 December 2017 would increase/decrease by US$0.3m (2016: increase/decrease by US$0.4m; 2015: increase/decrease by $0.5m). This is attributable to MPEFC's exposure to interest rate on its variable rate borrowings.

18. SHARE CAPITAL

In 2017, the parent company made capital contributions totalling US$1.4m. In 2016 the parent company made capital contributions of US$18.6m and forgave US$70m of intercompany debt, converting it to share capital.

Ordinary shares of $1.0 each.

	2017 Shares	2016 Shares	2015 Shares	2017 US$ million	2016 US$ million	2015 US$ million
Issued and fully paid	1,000	1,000	1,000	175.0	173.6	85.0

As at 31 December 2017 authorised share capital comprised 50,000 (2016: 50,000 and 2015: 50,000) ordinary shares of US$1.0 each with a nominal value of US$50,000 (2016: US$50,000 and 2015: US$50,000). MPEFC did not issue any new ordinary shares during 2017 (2016: US$nil and 2015:US $nil).

19. CAPITAL COMMITMENTS

Capital expenditure contracted for at the end of the reporting period but not recognised as liabilities is as follows:

	2017 US$ million	2016 US$ million	2015 US$ million
First exploration extension	6.9	7.4	6.9
Second exploration extension	6.0	–	–
Tersa development	2.5	5.0	5.0
	15.4	**12.4**	**11.9**

20. CASH FLOW INFORMATION

(a) ***Reconciliation of operating profit to operating cash flows***

	2017 US$ million	2016 US$ million	2015 US$ million
Operating (loss) profit	0.2	(8.4)	(17.3)
Depletion and depreciation	24.9	32.3	27.0
Exploration expense (see Note 7)	1.9	5.2	3.3
Operating cash flows before movements in working capital	**27.0**	**29.1**	**13.0**
Decrease (increase) in inventories	0.8	1.2	6.3
Decrease (increase) in receivables	(19.9)	(12.6)	21.7
Increase (decrease) in payables	9.6	(0.6)	(14.7)
Cash generated by operations	**17.5**	**18.3**	**26.3**
Interest received	0.1	0.2	0.3
Net cash from operating activities	**17.6**	**18.5**	**26.6**

(b) ***Reconciliation of Financing Related Liabilities***

	Loans and borrowings US$ million
As at 1 January 2015	**(39.9)**
Cash flow movements	(3.5)
Interest and fee charges	(3.9)
As at 1 January 2016	**(47.3)**
Cash flow movements	12.6
Interest and fee charges	(3.3)
As at 1 January 2017	**(38.0)**
Cash flow movements	10.5
Interest and fee charges	(3.0)
As at 31 December 2017	(30.5)

21. RELATED PARTY TRANSACTIONS

Merlon International, LLC provided management, technical, accounting and administration services for MPEFC. MPEFC recorded costs of US$5.3m (2016: US$4.9m; 2015: US$5.7m) relating to those services for the year. MPEFC has short term payables due to Merlon International, LLC companies totalling US$10.4m (2016: US$10.1m; 2015: US$10.1m). There is no security or guarantees related to these payables.

The key management personnel of MPEFC are all employees of Merlon International LLC. The service fees described above accordingly include amounts incurred by MPEFC for the provision of key management personnel services. In 2017 the amount incurred covering short term employee benefits was US$1.1m (2016: US$0.8m; 2015: US$1.0m). No amounts were incurred for post-employment benefits nor shared based payments in 2017 (2016: US$nil; 2015: US$nil).

22. EVENTS AFTER THE BALANCE SHEET DATE

Sale of MPEFC

SOCO International plc has agreed to acquire MPEFC for approximately US$215 million. The consideration will be satisfied through the payment of approximately US$136 million in cash and the issue of c.66 million new SOCO shares, representing 19.75% of SOCO's current issued share capital (excluding treasury shares).

RBL repayment

As part of the transaction described above, SOCO will also arrange for the repayment of Merlon's net debt (loans and borrowings less cash and cash equivalents), which amounts to US$22.2m as at 31 December 2017.

Intangible Assets

During 2018, further testing on an exploration well with a year end 2017 carrying value of US$6.8m demonstrated that the well was unsuccessful. It was subsequently fully impaired in 2018.

PART IV

UNAUDITED PRO-FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

Section A: Accountant's report on the Unaudited Pro-Forma Financial Information of the Enlarged Group

Deloitte.

The Board of Directors
on behalf of SOCO International plc
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5 December 2018

Dear Sirs,

SOCO International plc (the "Company")

We report on the pro forma financial information (the "Pro forma Financial Information") set out in Part IV of the Class 1 circular dated 5 December 2018 (the "**Investment Circular**"), which has been prepared on the basis described in the notes to the Pro Forma Financial Information, for illustrative purposes only, to provide information about how the Acquisition and the draw down of the new RBL Facility might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the financial statements for the period ended 31 December 2017. This report is required by the Commission Regulation (EC) No 809/2004 (the "**Prospectus Directive Regulation**") as applied by Listing Rule 13.3.3R and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the directors of the Company (the "Directors") to prepare the Pro forma Financial Information in accordance with Annex II items 1 to 6 of the Prospectus Directive Regulation as applied by Listing Rule 13.3.3R.

It is our responsibility to form an opinion, as to the proper compilation of the Pro forma Financial Information and to report that opinion to you in accordance with Annex II item 7 of the Prospectus Directive Regulation as applied by Listing Rule 13.3.3R.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to shareholders of the Company as a result of the inclusion of this report in the Investment Circular, 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 or our statement, required by and given solely for the purposes of complying with Listing Rule 13.4.1R (6), consenting to its inclusion in the Investment Circular.

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 issued 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 discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

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

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.

Yours faithfully

Deloitte LLP

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Section B: Unaudited Pro-Forma Financial Information for the Enlarged Group

Basis of preparation

The unaudited pro forma financial information set out below has been prepared to illustrate the effect of the Acquisition and the draw down of the new RBL Facility on the net assets of the SOCO Group as at 31 December 2017 as if such transactions had taken place on 31 December 2017 (the "**Unaudited Pro Forma Financial Information**"). The Unaudited Pro Forma Financial Information has been prepared on the basis of, and should be read in conjunction with, the notes set out below.

The unaudited pro forma statement of net assets of the Enlarged Group as at 31 December 2017 is based on the consolidated net assets of the SOCO Group as at 31 December 2017 and the consolidated net assets of MPEFC as at 31 December 2017 and has been prepared on the basis that the Acquisition and the draw down under the new RBL Facility have taken place on 31 December 2017 and in a manner consistent with the accounting policies adopted by the SOCO Group in preparing the consolidated financial statements of the SOCO Group for the year ended 31 December 2017.

Because of its nature, the Unaudited Pro Forma Financial Information addresses a hypothetical situation and, therefore, does not represent the Enlarged Group's actual financial position. It may not, therefore give a true picture of the Enlarged Group's financial position nor is it indicative of the results that may, or may not, be expected to be achieved in the future. The Unaudited Pro Forma Financial Information has been prepared for illustrative purposes only and in accordance with Annex II of the Prospectus Directive Regulation.

Shareholders should read the whole of this Circular and not rely solely on the Unaudited Pro Forma Financial Information set out in this Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group*).

Unaudited Pro Forma Consolidated Statement of Net Assets of the Enlarged Group as at 31 December 2017

			Adjustments			
	SOCO	Merlon	Transaction costs	Transaction funding	Acquisition adjustments	Pro Forma
	Note 1 US$m	Note 2 US$m	Note 3 US$m	Note 4 US$m	Note 5 US$m	US$m
Non-current assets						
Intangible assets	3.8	**17.4**	–	–	**58.3**	**79.5**
Property, plant and equipment	505.9	**141.4**	–	–	–	**647.3**
Other receivables	36.9	–	–	–	–	**36.9**
Total non-current assets	**546.6**	**158.8**	–	–	**58.3**	**763.7**
Current assets						
Inventories	4.2	**12.2**	–	–	–	**16.4**
Trade and other receivables	20.7	**51.2**	–	–	–	**71.9**
Tax receivables	0.6	–	–	–	–	**0.6**
Liquid investments	25.3	–	–	–	–	**25.3**
Cash and cash equivalents	112.4	**8.3**	–	**69.5**	**(139.6)**	**50.6**
Total current assets	**163.2**	**71.7**	–	**69.5**	**(139.6)**	**164.8**
Total assets	**709.8**	**230.5**	–	**69.5**	**(81.3)**	**928.5**
Current liabilities						
Trade and other payables	(23.1)	**(39.8)**	**(28.7)**	–	–	**(91.6)**
Loans and borrowings	–	**(30.5)**	–	**30.5**	–	–
Intercompany balances	–	**(10.4)**	–	–	**10.4**	–
Tax payables	(6.8)	–	–	–	–	**(6.8)**
Total current liabilities	**(29.9)**	**(80.7)**	**(28.7)**	**30.5**	**10.4**	**(98.4)**

	SOCO	Merlon	Adjustments: Transaction costs	Adjustments: Transaction funding	Adjustments: Acquisition adjustments	Pro Forma
	Note 1 US$m	Note 2 US$m	Note 3 US$m	Note 4 US$m	Note 5 US$m	US$m
Non-current liabilities						
Deferred tax liabilities	(132.6)	–	–	–	–	**(132.6)**
Loans and borrowings	–	–	–	**(100.0)**	–	**(100.0)**
Long term provisions	(52.7)	–	–	–	–	**(52.7)**
Total non-current liabilities	**(185.3)**	–	–	**(100.0)**	–	**(285.3)**
Total liabilities	**(215.2)**	**(80.7)**	**(28.7)**	**(69.5)**	**10.4**	**(383.7)**
Net assets	**494.6**	**149.8**	**(28.7)**	–	**(70.9)**	**544.8**

(1) The financial information of SOCO as at 31 December 2017 has been extracted without material adjustment from the SOCO Annual Report and Accounts 2017, and incorporated by reference in this document in Part VIII (*Information Incorporated by Reference*).

(2) The financial information of MPEFC as at 31 December 2017 has been extracted without material adjustment from the Historical Financial Information as set out in Part III of this Circular.

(3) The adjustment of US$28.7m has been made to "trade and other payables" to reflect a payable for one-off transaction costs. Such costs include advisory fees of US$7.2m payable by SOCO in connection with the Acquisition.

In addition, the Share Purchase Agreement provides that, upon Completion, either Merlon will, or SOCO will on behalf of Merlon, pay any assignment fee if and to the extent due to EGPC under the concession in respect of the Acquisition, subject to a maximum aggregate amount of US$21.5 million. Further information on any such assignment fee payable is set out in paragraph 4 of Part V (Principal Terms of the Share Purchase Agreement).

(4) The Acquisition will be financed using existing cash and cash equivalents and a new debt facility as described below.

In September 2018, SOCO announced that it has signed a new US$125 million RBL Facility secured against the Group's producing assets in Vietnam. In addition to the committed US$125 million, a further US$125 million is available on an uncommitted "accordion" basis. The RBL Facility has a five-year term and matures in September 2023. A total of US$100 million will be drawn of the new RBL Facility in financing the acquisition.

At Completion of the transaction, SOCO shall repay the EBRD Facility balance in Merlon as of that date, which may differ from the amount as of 31 December 2017 of US$30.5 million

(5) The consideration for the Acquisition of US$215 million is a combination of cash of US$136.1 million and the issue to the Seller of 65,561,041 Consideration Shares. The Consideration Shares have been included in this pro forma at a value of US$78.9 million, based on the arithmetic average of the daily volume-weighted average price for a SOCO ordinary share for the 20 trading days ended 17 September 2018, (the latest practicable date prior to the date of the Announcement), equal to 92 pence per share, and the average US$ to £ sterling exchange rate for that period of US$1.31/£.

Certain leakages are permitted, including a payment of monitoring fees to the seller up to a maximum of US$3.5 million which is reflected here as cash outflow and a reduction in the book value of the net assets of Merlon, additionally, the intercompany liability of US$10.4 million will be capitalised as paid up share capital prior to the Completion Date. In combination this will increase the book value of the net assets of Merlon from US$149.8 million to US$156.7 million.

The Acquisition will be accounted for using the acquisition method of accounting. The *pro forma* statement of net assets does not reflect the fair value adjustments to the acquired assets and liabilities as the fair value measurement of these items will only be performed subsequent to completion of the Acquisition. It also does not include adjustments to the fair value of the Consideration Shares due to share price movements up to the Completion date. For the purposes of the *pro forma* statement of net assets, the excess of pro forma purchase consideration over the carrying amount of the net assets acquired has been attributed to goodwill.

The calculation of goodwill is as follows:

	US$m
Acquisition consideration	215.0
Book value net assets acquired	(156.7)
Pro-forma goodwill adjustment	**58.3**

(6) In preparing the unaudited statement of net assets of the Enlarged Group, no account has been taken of the trading activity or other transactions of SOCO since 31 December 2017 and no account has been taken of the trading activity or other transactions of Merlon since 31 December 2017.

PART V

PRINCIPAL TERMS OF THE SHARE PURCHASE AGREEMENT

1. Share Purchase Agreement

The Share Purchase Agreement was entered into on 20 September 2018 between SOCO and the Seller pursuant to which SOCO has conditionally agreed to acquire the entire issued and to be issued share capital of Merlon from the Seller. The governing law of the Share Purchase Agreement is the law of England and Wales and any dispute relating to the Share Purchase Agreement shall be settled, in London, under the Rules of Arbitration of the London Court of International Arbitration.

2. Consideration

The Consideration payable to the Seller at Completion under the terms of the Share Purchase Agreement for the entire issued and to be issued share capital of Merlon is US$215,000,000 to be settled, subject to certain adjustments and substitutions:

- through the payment to the Seller of US$136,061,251 in cash; and
- through the issue to the Seller of 65,561,041 Consideration Shares at a value of US$78,938,749 based on the arithmetic average of the daily volume-weighted average price for a SOCO ordinary share for the 20 trading days ended 17 September 2018.

Assuming that no further SOCO Shares will be issued from the Latest Practicable Date until the date of Admission (other than the Consideration Shares), the Consideration Shares will represent approximately 16.5 per cent. of SOCO's share capital (excluding treasury shares) immediately following Admission and 19.75 per cent. of SOCO's current share capital (excluding treasury shares). The Seller will transfer the Consideration Shares, subject to the terms of the Share Purchase Agreement, to its members.

The Consideration payable is subject to certain adjustments in the event of certain corporate actions undertaken by SOCO, including the payment of dividends. In the event that a takeover transaction of SOCO completes prior to Completion, each Consideration Share will be substituted with the basic offer (ignoring any alternatives to the basic offer) made for each SOCO share under the terms of such takeover transaction.

The Consideration Shares will be in registered form and capable of being held in uncertificated form.

Upon Admission, the Consideration Shares will rank *pari passu* in all respects with the existing SOCO Shares and will rank in full for all dividends and other distributions declared, made or paid on the SOCO Shares with a record date on or after the allotment.

As part of the Acquisition, SOCO will arrange for the repayment in full of Merlon's EBRD Facility at Completion. Please refer to paragraph 11.4 (*The EBRD Facility*) of Part VII (*Additional Information*) for further detail on the EBRD Facility.

3. Conduct of business prior to Completion

The Consideration under the Share Purchase Agreement has been calculated by reference to the balance sheet of Merlon as at 31 December 2017 and the Share Purchase Agreement contains anti-leakage provisions regarding the conduct of business of Merlon and Petrosilah between 31 December 2017 and Completion. Certain leakages from Merlon and/or Petrosilah will be permitted to occur without a reduction in the Consideration payable by SOCO, including (i) the payment of monitoring fees to the Seller or its associated persons in an aggregate sum not exceeding US$3,500,000 (ii) transaction costs in respect of the Acquisition not exceeding in aggregate US$250,000, and (iii) the capitalisation of an intercompany payable balance owed from Merlon to the Seller and its associated persons, for additional shares issued to the Seller, which capitalisation the Seller is required to effect prior to Completion.

In addition, the Seller has agreed to procure that Merlon, and to use reasonable endeavours to procure that Petrosilah, will (i) run the Merlon and Petrosilah business in the ordinary course up to Completion and that certain actions are not taken without the consent of SOCO and (ii) implement an anti-bribery and corruption programme similar to that of SOCO's, prior to completion.

SOCO has agreed that, subject to applicable law or regulation, it will not prior to Completion, enter into, effect or announce a transaction or enter into any agreement or option that would require the approval of the SOCO Shareholders and in respect of which SOCO proposes to consult with any of its shareholders (other than shareholders that are directors, officers or employees), without prior consultation of the Seller.

4. Conditions

Completion is conditional upon waiver or satisfaction of the following Conditions:

(a) the passing of the Resolutions at the SOCO General Meeting;

(b) the Consideration Shares having been issued and allotted to the Seller unconditionally subject to their Admission;

(c) the UK Listing Authority having acknowledged that its requirements for listing have been complied with in respect of the Consideration Shares and the London Stock Exchange having acknowledged that its requirements in respect of the Consideration Shares being admitted for trading on the London Stock Exchange's main market have been complied with, in each case, conditional upon Completion;

(d) the written waiver, or non-exercise, in accordance with the terms of the El Fayum Concession, of the pre-emptive rights of EGPC; and

(e) EGPC and/or the Minister of Petroleum in Egypt (as applicable) approving or consenting in writing to the transactions contemplated under the Share Purchase Agreement, to the extent such approval or consent (as applicable) is required under the laws of Egypt or the El Fayum Concession.

SOCO has undertaken to use all reasonable endeavours to ensure Conditions (a), (b), and (c) above are satisfied as soon as reasonably practicable, and in any event, before the Backstop Date. SOCO and the Seller have agreed to use all reasonable endeavours to procure that Conditions (d) and (e) above are satisfied as soon as reasonably practicable and in any event before the Backstop Date.

SOCO and the Seller have agreed that Merlon or SOCO shall, on Completion, pay to EGPC an amount equal to any assignment fee that may be payable by Merlon to EGPC under Article VI(2) of the El Fayum Concession (the "**Assignment Fee**") subject to a maximum aggregate amount of US$21,500,000 (the "**Assignment Fee Cap**"), and the Seller will pay all costs charges and expenses in connection with the Assignment Fee in excess of the Assignment Fee Cap. Neither party is obliged to pay the Assignment Fee prior to Completion. Save as set out above, SOCO will bear all costs and expenses associated with satisfying its obligations in connection with the Conditions and the Seller will bear all costs and expenses in connection with satisfying Conditions (d) and (e) above.

5. Warranties and Indemnities

The Share Purchase Agreement contains warranties given by the Seller, deemed to be reiterated at Completion, in relation to, among other things, title, absence of agreements, authority, execution and enforceability, powers, no breach, organisation, and wind-up and dissolution, and certain anti-bribery and corruption matters (the "**Seller Fundamental Warranties**").

The Share Purchase Agreement also contains certain warranties given by the Seller in relation to the business of Merlon and Petrosilah (the "**Business Warranties**").

The Seller's liability to SOCO for a breach of the Seller Fundamental Warranties is capped at 100 per cent. of the Consideration payable under the Share Purchase Agreement. The Seller's liability in relation to the Business Warranties is capped at 10 per cent. of the Consideration payable under the Share Purchase Agreement. The Seller will not be liable for warranty claims unless notice has been given by SOCO in respect of the claim within 18 months of Completion. The Seller will not be liable in respect of a relevant claim unless and until the aggregate amount of all such substantiated claims against the Seller exceeds two per cent. of the Consideration payable by SOCO under the Share Purchase Agreement.

The Share Purchase Agreement contains certain warranties given by SOCO, deemed to be reiterated at Completion, in relation to, among other things, authority, the Consideration Shares, execution and enforceability, no breach, organisation, powers, insolvency, wind-up and dissolution, approvals, financing, no agency, knowledge of claims, trusts and certain anti-bribery and corruption matters (the "**Buyer Fundamental Warranties**" and

together with the Seller Fundamental Warranties, the "**Fundamental Warranties**"). SOCO has also provided certain warranties in relation to litigation and its public filings.

SOCO has provided indemnities customary of exploration and production company sale and purchase agreements to the Seller, members of its group, their successors and assigns, and their respective officers and employees in relation to:

(a) from Completion, relevant claims against or otherwise involving an indemnified person relating to any liability or obligation of the Company; and

(b) relevant claims against or otherwise involving an indemnified person in connection with decommissioning liabilities or environmental liabilities of the Company related to the El Fayum Concession or Petrosilah.

As is customary, such indemnities are not subject to any limitations on liability.

6. Termination and Break-Fee

The Share Purchase Agreement will terminate:

(a) if any of the Conditions has not been fulfilled (or waived in accordance with the Share Purchase Agreement) on or before the Backstop Date;

(b) if any of the Recommendations are withdrawn, amended, qualified or adversely modified at any time;

(c) if the SOCO Shareholders do not approve the Resolutions at the SOCO General Meeting;

(d) upon notice by the non-defaulting party on a breach of a Fundamental Warranty (provided that such breach is not remedied by a date falling no later than three Business Days before Completion, or is incapable of being remedied); or

(e) if the Completion obligations of either the Seller or SOCO in the Share Purchase Agreement are not complied with, upon notice by the non-defaulting party.

SOCO has agreed to pay a break fee to the Seller of an amount equal to one per cent. of its market capitalisation at market close on the day prior to signing the Share Purchase Agreement (approximately US$3.8 million) if the Share Purchase Agreement is terminated in the circumstances described under paragraphs (b) and (c) above (the "**Break Fee**").

7. Lock-Up and Distribution of Consideration Shares

Merlon's President and CEO, Jason Stabell, will be employed by the SOCO Group after Completion and will continue to have responsibility for managing the Egyptian business within SOCO, alongside the Merlon team. Under the Share Purchase Agreement, Mr. Stabell will receive specified number of Consideration Shares that will be transferred to him by the Seller. SOCO and Mr. Stabell entered into a lock-up agreement on 20 September 2018, pursuant to which the Consideration Shares transferred to Mr. Stabell will be subject to staggered lock-ups over a 12-month period, subject to certain customary carve outs.

The remaining Consideration Shares will, subject to the terms of the Share Purchase Agreement, be distributed pro-rata amongst the remaining shareholders of the Seller and such shares will not be subject to any lock-up.

PART VI

COMPETENT PERSON'S REPORT IN RESPECT OF THE MERLON GROUP

Lloyd's Register

Working together
for a safer world

Competent Person's Report

For the El Fayum Block, Western Desert, Egypt – as of 30th June 2018

Report for:
SOCO International plc and Evercore Partners

Reference:
PRJ11085683

Reporting date:
30 June 2018

Report by:
Neville Brookes

Authors(s)	Neville Brookes, Mike Reeder, Leigh Yaxley, Matt Huntington, Vicky Yawapongsiri
Technical Audit:	Carsten Borch
Quality Audit:	Jennifer Ives-Armitage
Release to Client:	Neville Brookes
Date Released:	5th December 2018

Lloyd's Register has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. Lloyd's Register does not, however, guarantee the correctness of any such interpretations and, save for any liability or responsibility which Lloyd's Register may have to those persons to whom this report is addressed in accordance with the agreed contract terms between Lloyd's Register and SOCO, and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone else resulting from any interpretation or recommendation made by any of its officers, agents or employees.

The Directors
SOCO International plc
48 Dover Street
London, W1S 4FF
United Kingdom

Evercore Partners International LLP
15 Stanhope Gate
London, W1K 1LN
United Kingdom

5th December 2018

Dear Sirs,

In accordance with the instructions of the Directors of SOCO International plc ("SOCO", or "the Client") and Evercore Partners International LLP ("Evercore"), and as per the terms of reference in the proposal signed on 14th September 2018, Lloyd's Register ("LR") has reviewed the interests of SOCO's planned acquisition (the "Transaction") of a petroleum asset (the "Asset") located in the Western Desert of Egypt, approximately 80 km southwest of Cairo.

The Asset evaluated comprises the producing oil concession of the El Fayum Block, which includes 11 producing development leases; namely the four major leases of Silah, North Silah, North Silah Deep and Dawar (collectively "Greater Silah") and the seven smaller leases of Ain Assillen, Kahk, Saad, SE Gindi, Tersa, Ward and West Auberge (collectively the "Satellite" fields). SOCO intends to acquire Merlon International LLC's subsidiary Merlon Petroleum El Fayum Company ("Merlon") and its 100% contractor interest in the Asset and thereby take over the carry of the costs for the state entity Egyptian General Petroleum Corporation ("EGPC"), associated with its 50% interest in the Petrosilah Operating Company (the "Operator"), a joint venture between Merlon and EGPC.

LR was requested to provide a Competent Person's Report with the "Effective Date" of 30th June 2018. The report includes an audit and evaluation of the recoverable hydrocarbons expected from the Asset categorised in accordance with the 2018 Petroleum Resources Management System ("PRMS") prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the European Association of Geoscientists and Engineers (EAGE), and the Society of Petrophysicists and Well Log Analysts (SPWLA) in June 2018.

Recoverable volumes are expressed as Gross and Net Entitlement Reserves or Resources after tax. Gross Reserves or Resources are defined as the total estimated petroleum to be produced from the fields evaluated from the end of 30th June 2018. Net Entitlement Reserves or Resources are defined as that portion of the gross Reserves or Resources attributable to the 100% working interest to be acquired by SOCO subject to completion of the Transaction.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgement; hence, the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria or regulatory requirements. As far as LR is aware there are no special factors that would affect the operation of the Asset and which would require additional information for their proper appraisal.

The content of this report and LR's estimates of Reserves and Resources are based on technical and commercial data provided to LR during the virtual data room (VDR) and physical data room (PDR) due diligence period for the Transaction. All data were provided by Merlon or Merlon International LLC the "Seller" or their advisors during the Transaction. LR has not conducted an independent site visit for this CPR at the request of the Client. However, LR understands that the Client has completed a site visit during late August 2018, prior to LR's completion of this CPR.

LR confirms that to our knowledge there has been no material change of circumstances or available information since the data for this report were compiled. The majority of LR's assessments have been based upon data presented in the VDR and PDR, including digital reports, digital projects, spreadsheets, presentations and summaries.

LR acknowledges that this report may be included in its entirety, or portions of this report summarised, in documents prepared by SOCO, Evercore and their advisors in connection with commercial or financial activities and that such documents, together with this report, may be filed with any stock exchange and other regulatory body and may be published electronically on websites accessible by the public.

Yours faithfully

Neville Brookes
Principal Commercial Geoscientist, CGeol EurGeol CPG
Reserves and Asset Evaluation

For and on behalf of Lloyd's Register

EXECUTIVE SUMMARY

This report comprises an independent evaluation of the recoverable hydrocarbons for the El Fayum Block located in the Western Desert of Egypt. The Asset comprises producing and non-producing fields and undiscovered exploration potential; however, LR has assessed and reported solely the hydrocarbon volumes associated with ongoing production and planned future development.

The Asset reviewed in this CPR is presented in **Figure ES-1**, with a summary of the Asset in **Table ES-1**.

Licence	SOCO's Interest	Parties and Timing	Development Leases on Production[3]
El Fayum Block	100%[4]	Petrosilah Operating Company[1] • SOCO (50%) • EGPC (50%)[2] Development Lease Duration: • 20 years from award • plus two possible 5 year extensions	**Greater Silah** – Silah, North Silah, North Silah Deep, and Dawar **Satellite** – Ain Assillen, Kahk, Saad, Tersa (Aboud/Tersa/NE Tersa/Younis/NE Younis), SE Gindi, Ward, and West Auberge

Notes:

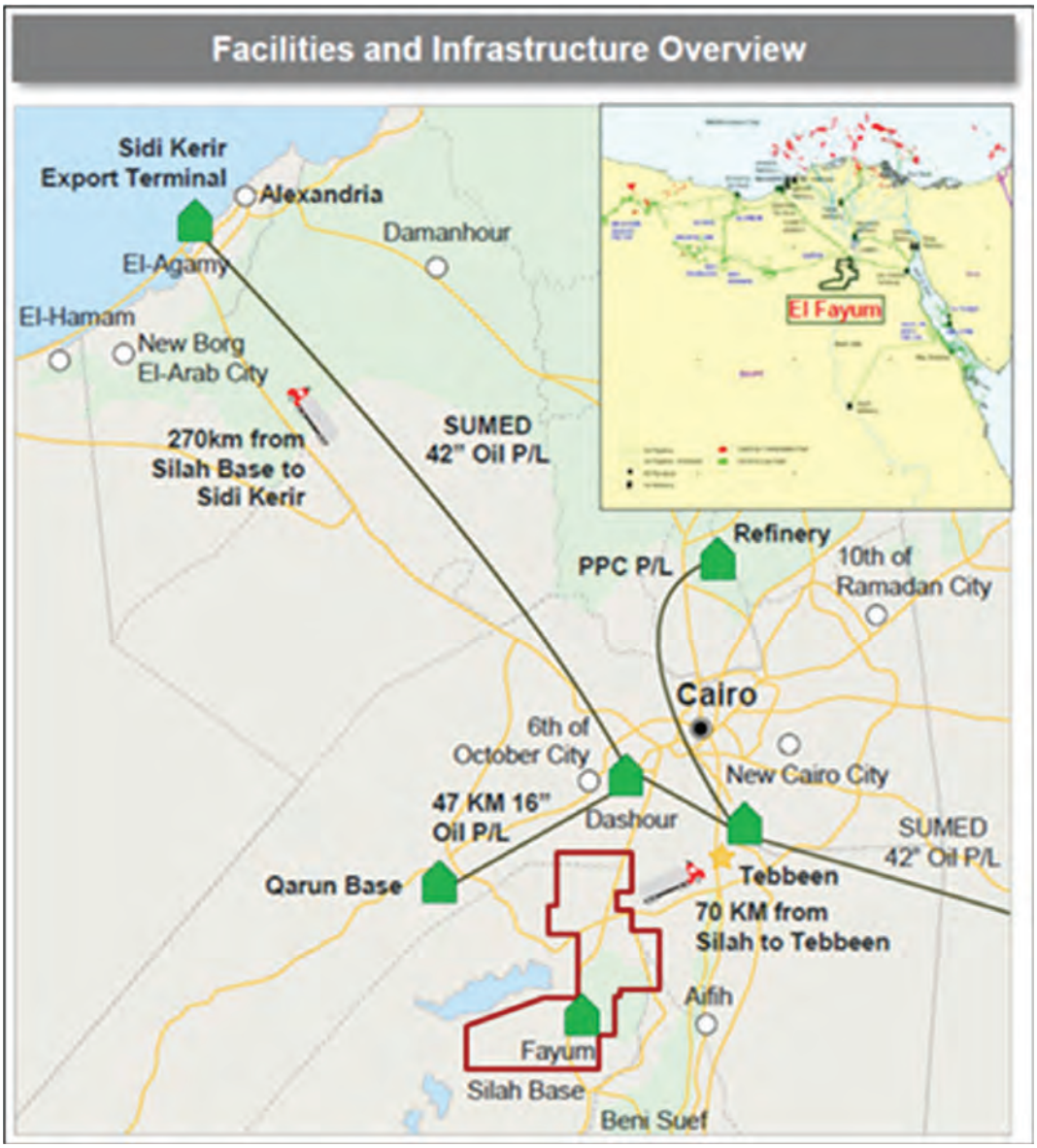
1) Denotes Operator. The El Fayum Block is operated by the Petrosilah Operating Company.

2) The Egyptian General Petroleum Corporation (EGPC) is a state-owned entity and has a 50% interest in the Petrosilah Operating Company. SOCO owns 100% contractor interest and carries EGPC for its general and administrative costs associated with its 50% interest in the Petrosilah Operating Company.

3) On production as of 30th June 2018.

4) SOCO's interest is the 100% working interest percentage intended to be acquired on successful completion of the transaction agreement with the Seller, Merlon International LLC.

Table ES-1: SOCO's Intended Licence Interest Reported in this CPR



Source: Seller

Figure ES-1: Location of the El Fayum Block, Western Desert, Egypt

EL FAYUM BLOCK

Merlon was awarded the El Fayum Block on 16th July 2004.

Under the terms of the original PSC, the exploration period comprised three, two-year terms that expired in July 2010. However, at the expiry date, the PSC was amended, and the exploration period was extended by a further six years (two, three-year periods) that included a minimum expenditure requirement of US$12 Million and drilling of three exploration wells during each of the two terms. Subsequently, the government granted a further six months to the last exploration period resulting in a revised expiration date of 15th January 2017. Finally, in August 2017, Merlon was granted a second amendment to the PSC that extended the exploration period until the 15th November 2020. That extension added the requirement of an additional commitment of US$6 Million including three exploration wells.

Development leases are issued on achieving commercial discoveries and are valid for a period of 20 years, plus two possible 5-year extensions. The El Fayum Block has 11 separate development leases. Presently, the Concession covers an area of approximately 1,830 km^2 (452,000 acres) with 14% (262.3 km^2) forming the development leases.

Merlon first discovered oil during a five-well exploration campaign in 2008, which resulted in the discovery of the Silah Field. A total of 102 exploration, appraisal, development and water supply and injection wells have been drilled since, resulting in the development of several pools throughout the Asset (**Table ES-2**).

	Development Lease Timing			
Development Lease	Awarded	Expiry	Expiry + 5 years	Area (km^2)
Silah	May 2009	May 2029	May 2034	60.0
Tersa	December 2009	December 2029	December 2034	70.5
Kahk	March 2010	March 2030	March 2035	5.8
North Silah	June 2010	June 2030	June 2035	18.0
North Silah Deep	June 2010	June 2030	June 2035	27.0
Dawar	June 2010	June 2030	June 2035	15.0
Ain Assillen	August 2010	August 2030	August 2035	21.0
SE Gindi	December 2010	December 2030	December 2035	9.0
Ward	December 2010	December 2030	December 2035	15.0
West Auberge	December 2010	December 2030	December 2035	12.0
Saad	December 2012	December 2032	December 2037	9.0

Table ES-2: Development Leases – Award, Expiry and Area

Oil produced from the various fields is trucked to a receiving station at Tabeen approximately 70 km northeast of the Silah gathering station. Production comes from three main reservoirs:

i) Abu Roash G Upper ("L AR-G") – contains a medium crude with an average crude oil gravity of ~23° API.

ii) Abu Roash G Lower ("L AR-G") – contains a light oil with an average crude oil gravity of ~ 39° API and a pour point of 33° Celsius.

iii) Upper Bahariya ("UB") – as per the Abu Roash G Lower.

As of 30th June 2018, the block has produced 19.08 Million stock tank barrels (MMstb) of oil. Near-term development plans for the field include up to 170 new wells (oil producers and water injectors) in the period mid-2018 to 2024. Production on the 30th June 2018 was 7,864 stock tank barrels per day (stb/d) of oil from 39 production and 4 injection wells.

The data available for this CPR update included wireline log interpretations, geo-cellular static and seismic interpretation projects, production and/or test data, fluid properties, sector dynamic models, third-party techno-commercial reports, development planning schedules and commercial/financial data. All data were presented via the VDR process, except for the static and seismic digital projects that were assessed by LR at the Seller's offices in Houston, USA.

LR accessed the Seller's historical production and ongoing development programmes for the Greater Silah and Satellite fields. This included a review of the historic oil and water production, water injection, forecasted production for current and new wells, and the historic and indicative future cost data.

Estimated oil Reserves attributable to the Asset are presented in **Table ES-3**.

RESERVES

Volume Oil (MMstb)	Gross (100% Licence) Oil Reserves			Net Entitlement Oil Reserves to SOCO[2)]		
	Proved (1P)	Proved plus Probable (2P)	Proved plus Probable plus Possible (3P)	Proved (1P)	Proved plus Probable (2P)	Proved plus Probable plus Possible (3P)
El Fayum[1)]	15.6	24.1	–	6.6	10.2	–

Notes:

1) Oil Reserves (after tax) for the El Fayum Production Sharing Contract relate to the ongoing production from the current 39 producing wells plus 23 planned new production wells, 16 new water injection wells, continued well work overs, fracture stimulation and recompletion operations during the period second half of 2018 to 2020. Production is truncated at CoP or licence expiry (up to and including year 2029), whichever occurs first.

2) LR has run economics sensitivities for the fields to estimate the volumes and values for the Reserves projects. The Net Entitlement Reserves for the outputs of the discounted cash flow assessment relate to the PSC volumes attributable to SOCO's intended 100% working interest participation in the Asset (subject to completion of the planned transaction with the Seller).

Table ES-3: Estimated Oil Reserves for the El Fayum Block – as of 30th June 2018

LR is informed that SOCO will have a 100% working interest participation in the Concession Agreement for the Petroleum Exploration and Exploitation between the Arab Republic of Egypt and The Egyptian General Petroleum Corporation and Merlon Petroleum El Fayum Company in El Fayum Area, Western Desert A.R.E. ("Concession Agreement"), subject to completion of the planned transaction with the Seller. The Concession Agreement sets out the production sharing terms under which costs and production are attributed to the parties. SOCO carries EGPC for its general and administrative costs associated with EGPC's 50% interest in the Petrosilah Operating Company.

Well programmes beyond 2020 are considered, by LR, contingent upon the success of the operations carried out during 2018 to 2020. Hence, Resources related to two incremental projects of further envisioned new development wells, workovers, fracture stimulations and recompletions during 1) 2021 to 2022 and 2) 2023 to 2024, respectively are classified as Contingent Resources.

Incremental Contingent Resources related to these two contingent incremental development projects are presented in **Table ES-4**.

CONTINGENT RESOURCES

Volume Oil (MMstb)	Gross (100% Licence) Oil Contingent Resources			Net Entitlement Oil Contingent Resources to SOCO[2)]		
	Low (1C)	Best (2C)	High (3C)	Low (1C)	Best (2C)	High (3C)
El Fayum 2021-22[1)]	9.1	18.1	–	3.9	6.2	–
El Fayum 2023 onwards[1)]	6.7	19.3	–	2.9	6.5	–

Notes:

1) Oil Contingent Resources (after tax) for the El Fayum Production Sharing Contract relates to two, by LR considered, contingent additional phases of incremental development projects beyond year 2020. Once the development activities during 2018 to 2020 have demonstrated sustained increased oil recovery (which includes implementation of the initial part of a planned field wide 5 spot water flood pattern drive injection programme), the Contingent Resources may be re-classified as Reserves. The "Chance of Commercialisation" of the Contingent Resources to mature them to Reserves is deemed by LR to be moderate.

2) LR has run economics sensitivities for the fields to estimate the incremental volumes and values for the Contingent Resources projects. The Net Entitlement Contingent Resources for the outputs of the discounted cash flow assessment relate to the PSC volumes attributable to SOCO's intended 100% working interest participation in the Asset (subject to completion of the planned transaction with the Seller) after tax.

Table ES-4: Oil Contingent Resources for the El Fayum Block – as of 30th June 2018

LR is informed that SOCO will have 100% working interest participation in the Concession Agreement, subject to completion of the planned transaction with the Seller. The Concession Agreement sets out the production sharing terms under which costs and production are attributed to the parties. SOCO carries EGPC for its general and administrative costs associated with EGPC's 50% interest in the Petrosilah Operating Company.

The volumes reported in the summary tables are those within the licence attributable to the full licence ("Gross Licence") and the net production share of SOCO ("Net Entitlement") after EGPC's fiscal take and without adjustment for income tax paid by EGPC on Merlon's behalf. The individual Resources descriptions provide the gross whole field volumes and the volume distribution range for the Resources for each opportunity.

LR has not assessed the near-field or virgin acreage exploration potential of the Asset.

LR, as the Competent Person, has completed the necessary reviews and due diligence during the CPR process and has revised the Seller's technical and commercial assessments where applicable.

PRMS 2018 guidelines have been used in the Reserves and Resources evaluation in this project. LR acknowledges that this is a new amendment to the PRMS guidelines and as such has not been tested or applied to many, if any, other projects or fully accepted or appreciated by the stock markets, oil companies or independent auditors. LR has used its best endeavours to assess the new guidelines and apply them to this project, but cannot be responsible for alternative interpretations of the guidelines.

Potential risks and threats to production and recoverable volumes are noted in the description of each asset. The uncertainties and specific risks associated with the future performance of the planned waterflood are summarised in Section 2.4.4.

PROFESSIONAL QUALIFICATIONS

Lloyd's Register (LR) is a global engineering, technical and business services organisation wholly owned by the Lloyd's Register Foundation, a UK charity dedicated to research and education in science and engineering. Founded in 1760 as a marine classification society, LR now operates across many industry sectors, with over 8,000 employees based in 78 countries. LR has a dedicated global Commercial Services team, which provides Reserves, Resources and Valuation expertise, and draws on staff and expertise from all of LR's Service Lines who are assigned on a project basis to provide specialist technical, asset, regional and commercial expertise. The Commercial Services team specialises in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.

Except for the provision of professional services on a fee basis, LR has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

The report entitled "Competent Person's Report – for the El Fayum Block, Western Desert, Egypt - as of 30th June 2018 – for SOCO International plc and Evercore Partners International LLP" was prepared by the following LR personnel.

Name: **Mike Reeder**
Title: Principal Geologist and Project Manager (Primary)
Name: **Neville Brookes**
Title: Principal Geologist and Project Manager
Name: **Leigh Yaxley**
Title: Principal Reservoir Engineer
Name: **Matt Huntington**
Title: Principal Development Engineer
Name: **Vicky Yawapongsiri**
Title: Principal Economist
Name: **Carsten Borch/David Tobias**
Title: Peer Reviewers

Mike Reeder was principally responsible for supervising this evaluation. Mike is a Competent Person as defined in ESMA 2013/319 para 133 subsection (a) and London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2009. Mike is LR's Director of Commercial Services in Asia Pacific. He is the current chairperson of the Singapore Chapter of the Society of Petroleum Engineers (SPE, since 2007, Chairperson since 2012) and is a Certified Petroleum Geologist (CPG) with the Division of Professional Affairs (DPA) of the American Association of Petroleum Geologists (AAPG) since 1999 and is in the South East Asia Petroleum Exploration Society (since 2003). Mike has worldwide experience including in Indonesia, SE Asia, Kazakhstan, New Zealand, India, Australia, Malaysia, China, Chad, Thailand. Mike has a Ph.D. in Geology (Sedimentology/Geology) from the University of Southampton (2000) and a B.Sc. in Geology (1st class honours) from the Royal Holloway, University of London, (1994).

Neville Brookes, provided project management support. Neville is a Competent Person as defined in ESMA 2013/319 para 133 subsection (a) and London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2009. Based in LR's London office, Neville is a Chartered Geologist (CGeol), a Fellow of the Geological Society (FGS) of London, a certified European Geologist (EurGeol), and a Certified Petroleum Geologist (CPG) with the Division of Professional Affairs (DPA) of the American Association of Petroleum Geologists (AAPG). His worldwide experience includes projects in the UK, Ireland, Norway, West, Central and North Africa, W. Kazakhstan, Siberia, Mexico, Brazil and the Middle East. Neville has a M.Sc. in Stratigraphy from Birkbeck College, University of London, 1987 – 1989 and a B.Sc. (Hon 2.1) in Geology & Chemistry from Queen Mary College, University of London, 1980 – 1983.

Leigh Yaxley is a Petroleum Engineer with over 30 years petroleum engineering experience in reservoir engineering, field development planning, reservoir management, and operational reservoir engineering together with project economics and business planning skills. He has an in-depth technical knowledge of reservoir engineering, other petroleum engineering disciplines as well as extensive experience in reserves evaluation and reporting, project economics, cost engineering and business planning. Leigh has particular experience in Malaysia, Singapore, Australia, Indonesia, Europe and Africa and Asia. Leigh has a BEng First Class Honours in Chemical Engineering from the University of Sydney (1978) and a Bachelor of Science (Applied Mathematics) from the University of Sydney (1976).

Matt Huntington has over 22 years full-time experience within the oil and gas industry working on a range of oil and gas field development and subsea construction related projects. Matt's areas of experience include project management and engineering, partner and stakeholder management, due diligence reviews, concept development/screening and assessment, subsea field design/construction/installation, topside and subsea FEED studies, flow assurance, contract management and procurement, cross discipline interfacing, cost estimating and reporting, permits and consents, risk and opportunity management. His worldwide experience has been gained through working on UK/Danish North Sea, Asia Pacific, Malaysia, Australia, Brazilian and North African projects. Matt has a BEng Hons in Mechanical Engineering from Loughborough University (1995). He is an IMechE Associate Member.

Vicky Yawapongsiri is a Commercial Advisor and Economist with over 18 years' experience. She is a very experienced commercial leader and negotiator with a broad regional Asia Pacific and worldwide experience, has robust commercial capabilities with technical, operational, strategy, M&A, financing and management experience and Vicky has strong networking and analytical skills that have been applied to many facets of the energy industry. Vicky has a BSc in Industrial Engineering from Chulalongkorn University in Bankgoko, Thailand (1995) and an MBA from Carnegie Mellon University – Tepper School of Business, Pittsburgh USA (1999). She is also a member of the Association of International Petroleum Negotiators (AIPN), the South East Asia Petroleum Exploration Society (SEAPEX) and of the Chartered Financial Analyst (CFA).

Carsten Borch is a Principal Reservoir Engineer with 35 years' experience spanning reservoir engineering, petroleum engineering, joint venture management, Reserves/Resources estimation and economic evaluation. He has worked in the following geographic areas: Onshore – East Africa (Kenya and Ethiopia), North Africa (Egypt), Europe (North West and Eastern), Papua New Guinea; Offshore – Arabian Gulf (Abu Dhabi), West Africa, North Sea, West of Shetland, Mid Norway, Barents Sea, Davis Strait (West of Disco), Newfoundland and Labrador, Black Sea, Eastern Mediterranean Sea, Gulf of Suez, Australia NW shelf. He is a member of the Society of Petroleum Evaluation Engineers (SPEE) and the Society of Petroleum Engineers (SPE). He has authored papers for SPE, SPWLA and IGU on formation evaluation as well as fluid and reservoir characterisation. He has a MSc in Petroleum Engineering, Colorado School of Mines, USA (1986) and a MSc in Civil Engineering, Technical University of Denmark, DK (1982).

David Tobias is a Geoscientist with a broad commercial and economics background obtained over 40 years in projects and project management in diverse cultural settings with LR, Texaco, Phillips Petroleum, the Lundin Group, Enterprise Oil and BHP Billiton Petroleum. Resource assessment and valuation activities span geological and geophysical interpretation, commercial and economic analysis and petroleum resource classification for fields and prospective acreage. Worldwide experience with an Africa, Europe, South America and South East Asia focus. David leads the London-based Reserves and Asset Evaluation team delivering a range of Competent Persons Reports, Due Diligence Reports and Acreage and Asset Evaluation studies. David is a Fellow of the Geological Society of London (FGS) and a P.Geol., APEGA Life Member. He is also a member of the Association of International Petroleum Negotiators; the Petroleum Exploration Society of Great Britain; and the American Association of Petroleum Geologists, Society of Petroleum Engineers. He has a BSc (Hons) in Geology from the University of Manchester (1971), a MSc. in Marine Geotechnics from the Univ. Coll. N. Wales (1972) and an MBA from the Open University (1996-1999).

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1. Introduction

This report was prepared by Lloyd's Register during August and September 2018 at the request of the Directors of SOCO and Evercore. It consists of an evaluation of the El Fayum Block, located in the Western Desert of Egypt (**Figure ES-1**).

The report details the concession interests (**Table ES-1**) and the Reserves and Contingent Resources attributable to the Assets (**Table ES-3** and **Table ES-4**).

1.1 *Evaluation Methodology*

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgement; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, including new well data, economic criteria or regulatory requirements.

The Proved (1P), Proved plus Probable (2P) Reserves volume estimates have been derived using deterministic approaches to forecast current and future well production. This has been conducted using decline curve analysis (DCA) to predict the trends of currently producing well and estimates of future wells trends based on current observations. Profiles have been cross-checked to outputs from reservoir simulation sector models provided by the Seller to estimate Low and Best future oil recoveries, as explained in **Section 2.4.4** for the Asset. Reserves have been limited to:

- Current 39 production wells and 4 water injection wells ("No-Further-Action").
- Planned operational activities during 2018 to 2020 i.e., expansion of the development well and water injection well programme and continuation of ongoing well workovers, fracture stimulation and well recompletions (1st Part of Incremental Development Project).

Reserves volumes are truncated at the earliest occurrence of either the licence expiry (assumed to be mid 2029) or the Economic Limit (whereby operating costs exceed sales revenues).

The Low (1C) and Best (2C) Contingent Resources estimates for the Asset relate to the production associated with an expansion of the ongoing and planned water injection project. LR envisages two phases of further potential development that are contingent on demonstrated expansion of the water injection programme and may be subject to significant schedule and locational changes based on that current programme:

- 2021 to 2022 (inclusive) – representing a marked increase in development drilling.
- 2023 onwards – comprising a stabilisation of drilling and management of production decline.

The PRMS standards and guidelines have been applied to this evaluation for both Reserves and Contingent Resources.

In this report, oil volumes are reported in millions of stock tank barrels (MMstb).

1.2 *Legal Framework and License Details*

Table ES-1 presents the license details intended to be acquired by SOCO as of 30th June 2018. The Asset details were supplied by SOCO and are believed to be valid at the "**Effective Date**" of 30th June 2018 for this report, as the Transaction Date of 1st January 2018 precedes the Effective Date. LR has not reviewed the legal licence documents and, hence, does not make any statement as to the ownership, contractual or legal terms of these licences.

The terms of the licences are provided in **Section 2.6** of this report.

Where appropriate, any arrangements or agreements with partner companies and any host government rights, are included in the individual asset description sections of this report.

1.3 ***Sources of Information***

The content of this report and LR's Reserves and Resource estimates are based on data provided by Merlon, as the Seller. LR has accepted, without independent verification, the accuracy and completeness of this data.

The available data comprised well and seismic data and information summarising the subsurface interpretation of structure, reservoir, petroleum initially-in place (PIIP), dynamic data, resource estimates and development costs/economics for the PSC by the Seller and third parties.

LR has had access to a set of interpreted data and has not attempted a systematic review of raw data (either well logs or seismic) but has performed a critical assessment of the existing interpretation work supplied in the databases. LR have reviewed the information provided and modified assumptions where considered appropriate.

The data provided was, in LR's opinion, complete and suitable for the evaluation. Data limitations and implications of those are noted in **Section 2**.

1.4 ***Economics***

Economic analysis was undertaken to establish the economic cut-offs for the Reserves. Economics have also been computed for the Contingent Resources to establish the net entitlement volumes attributable to SOCO's share in the Asset. Valuations have not been presented for the Contingent Resources.

1.5 ***Requirements***

LR confirms that:

- We are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and/or geoscientists;
- We have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;
- We are independent of SOCO, their directors, senior management and advisors;
- We will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of SOCO;
- We are not a sole practitioner;
- We have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being all assets, concessions, joint ventures or other arrangements owned by SOCO or proposed to be exploited or utilised by it ("Assets") and liabilities, being all liabilities, royalty payments, contractual agreements and minimum funding requirements relating to SOCO's work programme and Assets ("Liabilities").

1.6 ***Standard Applied***

In compiling this report, we have used the definitions and guidelines set out in the 2018 Petroleum Resources Management System ("PRMS") prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers ("SPE") and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE) in 2007 (abbreviated to the "PRMS"). PRMS 2018 guidelines have been used in the reserves and resources evaluation in this project. LR acknowledges that this is a new amendment to the PRMS guidelines and as such has not been tested or applied to many, if any, other projects or fully accepted or appreciated by the stock markets, oil companies or independent auditors. LR has used its best endeavours to assess the new guidelines and apply them to this project, but cannot be responsible for alternative interpretations of the guidelines.

This report has been prepared in accordance with paragraph 133, Appendix I and Appendix III of the European Securities and Markets Authority (ESMA) update of the CESR Recommendations, entitled: "The

consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive" and the standards of the SPE PRMS.

LR confirms that to its knowledge there has been no material change of circumstances or available information from the Effective Date of this report (being 30th June 2018) until the release date of this report, and we are not aware of any significant matters arising from our evaluation that are not covered within this report which might be of a material nature.

1.7 ***Site Visit***

Site visits to Merlon's onshore operations have not been conducted by LR for this CPR at the request of the Client. The Client conducted their own site visit during the Transaction due diligence period in August 2018. LR has relied upon the Operators material (production records, committee meetings, site photographs, etc.) relating to the Greater Silah and Satellite fields with respect to their ongoing operational status.

1.8 ***Liability***

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, engineering or other data. The report represents LR's best professional judgment and should not be considered a guarantee of results. The use of this material and report is at the user's own discretion and risk.

1.9 ***Consent***

We hereby consent, and have not revoked such consent to:

- the inclusion of this report, and a summary of portions of this report, subject to prior agreement of such text between the parties, in documents prepared by SOCO, Evercore and their advisors and in particular the inclusion of this report in SOCO's circular to be issued to its shareholders in connection with the transaction between the Seller and SOCO for the proposed acquisition of Merlon;
- 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 SOCO; and
- the inclusion of our name in documents prepared in connection with commercial or financial activities subject to prior approval by LR of such inclusion.

The report relates specifically and solely to the subject Asset and is conditional upon various assumptions that are described herein. The report must, therefore, be read in its entirety.

This report was provided for the sole use of SOCO and Evercore on a fee basis. Except with the express written consent of LR this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any other purpose.

2. El Fayum Block, Western Desert, Egypt

2.1 *Introduction*

SOCO intends to acquire Merlon International LLC's subsidiary Merlon Petroleum El Fayum's 100% contractor interest in the Asset and thereby take over the carry of cost for the state entity Egyptian General Petroleum Corporation ("EGPC") associated with its 50% interest in the Petrosilah Operating Company (the "Operator"); a joint venture currently between Merlon and EGPC.

2.2 *Regional Geology*

The El Fayum Block is located within the Western Desert Plateau (**Figure 2-1**), which is one of the main hydrocarbon producing regions in Egypt. The Plateau comprises a number of separate intracratonic sedimentary basins, with the majority of the El Fayum Block located in the Gindi Basin (**Figure 2-2**). The Gindi Basin is a Jurassic rift feature that was initiated in response to the left-lateral motion of Africa relative to Europe, which led to the opening of the Tethys and deposition of thick sediments. Subsidence and deposition continued throughout the Early to Middle Cretaceous until the basin was uplifted and tilted during the lattermost Cretaceous-Early Tertiary Alpine Orogeny. The regional structural KattaniyaInversion high separates the Gindi Basin from the neighbouring Abu Gharadig basin to the west and the Natrun Basin to the north.

The Gindi Basin sedimentary sequences comprises Palaeozoic sediments overlain by Mesozoic and Tertiary deposits. Both clastic and carbonate reservoirs are present in the Gindi Basin within the Jurassic and Cretaceous sections (**Figure 2-2**).

The main oil source rocks in the Gindi Basin are Upper Cretaceous marine shales and limestones of the Abu Roash F Formation and non-marine shales and coals of Lower Cretaceous and Upper Jurassic strata (**Figure 2-3**). The main productive reservoir is the Lower Abu Roash "G" (L AR-G) formation, with secondary targets of the Upper Abu Roash "G" (U AR-G) and Upper Bahariya (UB) clastic formations.

2.3 *Field Geology*

2.3.1 *Structural Elements*

The El Fayum Block is situated within an intensively folded and faulted area. Two major fault trends are interpreted:

i) the Gindi Fault which is oriented in a NW to SE and has displacement up to 3,000 feet (**Figure 2-4**). The Upper Cretaceous Lower Bahariya/Kharita Formation is deposited directly on the Basement in the up-thrown block, while the down-thrown block has an additional Early Cretaceous section between the Basement and Cretaceous rocks. Most of the hydrocarbon discoveries within the EL Fayum Block are located southwest from this fault; and

ii) the Girza, Tersa and Saad Barakat strike-slip faults trending in a northeast to southwest direction. These faults dissect the Block into a series of structurally-high terraces that host separate fields.

The Block also includes numerous antithetic faults that have a general NW-SE or WNW-SSE trend across the Asset and which may baffle the connectivity of reservoir sections for several of the fields.

2.3.2 *Sedimentological Elements*

The main oil-bearing reservoirs in the area are found in the Cretaceous section and belong to two formations (**Figure 2-5**):

i) Abu Roash "G" formation (AR-G):

The Abu Roash "G" formation consists of two main reservoirs referred to as the Upper Abu Roash "G" (U AR-G) and Lower Abu Roash "G" (L AR-G).

a) The U AR-G consists of thin sandstone beds overlain by shale. They are located approximately 50 to 100 feet below the base of the Abu Roash F shaly carbonate package and can be correlated over most of the concession.

b) The L AR-G is located approximately 200 feet above the top of the Upper Bahariya Formation and consists of sandstone. This reservoir is also well correlatable over the entire concession. The sand is significantly thicker in the northern fields in the Greater Silah area due to an additional interpreted channel section in the reservoir. The Abu Roash G Lower Reservoir has been separated into two units; a thin but pervasive transgressive sand and a thick, clean laterally discontinuous channel (incised valley) sand.

ii) Upper Bahariya formation (UB):

The UB formation consists of thin sandstones interbedded with shale and was likely formed on a broad, tidally-influenced shelf and ramp on the southern margin of the Neotethys Ocean. The fine and very fine-grained sandstones may be interpreted as thin bayhead deltas, tidal flats and distributary mouth bars. In general, the UB formation is well correlatable in the Gindi Basin. Thicker clean sand intervals have been encountered in some areas of the basin in the middle and upper parts of the UB section. These sands are isolated by shales from the other UB sands and are interpreted to be isolated bars or channels with excellent reservoir quality but limited areal extent.

2.3.3 *Field Geophysics and Structure*

The El Fayum Block contains 1,895 km^2 of 3D seismic data acquired during 2007-2008 using a dynamite source in predominantly agricultural areas (southern area of block) and a vibrator source in the desert areas (northern area of block). The overall quality of the data of the pre-stack time migration (PrSTM) volume is good and is of sufficient standard to achieve a robust interpretation of the major reservoir sequences and structural elements (**Figure 2-6**). LR reviewed the seismic in the virtual data room and as part of the Petrel™ geomodelling project in the physical data room during the asset due diligence process. No alterations were made to the interpretation and seismic ties to well stratigraphic picks in the multiple wells across the Block were noted to be good.

The Seller completed three depth conversion methods across the Block:

i) Gridded average velocities from the well data – used primarily in the Greater Silah area due to the higher density of wells;

ii) Time-to-velocity function relationship trends derived from well data – applied across the Satellite areas; and

iii) Interval velocity relationships based on vertical shotpoint (VSP) data as control – noted to be variable and unreliable, particularly due to heterogeneity in the Cretaceous stratigraphy.

The above processes are iterative and updated obtaining data from new wells. Examples presented by the Seller resulted in minimal time-depth errors, which were subsequently gridded and applied to form final depth maps.

The relationship of the producing fields to the UB formation depth structure is presented in **Figure 2-7**, showing the smaller, localised structural closures of the Satellite fields and the broader features of the Greater Silah area. Compartmentalisation of the development leases by the NW-SE and WNW-ESE trending antithetic faults on the main SW-NE trending strike-slip faults is shown in **Figure 2-8.**

The majority of well control on the structure is at the crest of the individual fields. This introduces gross rock volume (GRV) uncertainty down dip and would impact the stock tank oil initially-in-place (STOIIP) estimations (see **Section 2.3.6**). However, the Seller has produced only a best estimate structural interpretation for the reservoir depths for geocellular modelling, which does not address the commonly large range of uncertainty associated with the assessment of GRV.

2.3.4 *Well Petrophysics and Reservoir Characterisation*

The Seller undertook a review of the petrophysics in all wells during 2016 and completed the study in November 2017. This included 61 wells from the four Greater Silah area fields and 37 wells in the seven Satellite area fields. A type log from the primary reservoir sections of the North Silah Deep 1X well is presented in **Figure 2-9**.

Standard petrophysical assessments were applied consistently across all wells to estimate the total porosity (neutron-density logs), water saturation (modified Simandoux model), electrofacies, permeability (facies tied to core data), net pay (shale volume, effective porosity and effective water saturation cut-off) and fluid contacts (combining log observations, well tests and well production performance). Conventional core data were available from 9 wells and special core analyses data were available for 6 wells. The comprehensive study was reviewed by LR and is noted to form a robust assessment of the petrophysical rock characteristics of the Asset. Output logs have been used to populate the geocellular models for the fields (see **Section 2.3.5**).

The average properties for the major reservoirs are presented in **Table 2-1**:

	Effective Porosity (%)		Effective Water Saturation (%)		Permeability (mD)	
Zone	Range	Arithmetic Average	Range	Arithmetic Average	Range	Arithmetic Average
U AR-G	9.5-25.0	14.4	13-65	34	0.15-673	59
L AR-G	9.5-26.4	16.7	13-65	24	0.12-1,916	137
UB	9.5-30.0	14.4	13-65	40	0.10-2,215	36
Lower Bahariya (LB)	9.5-19.8	13.8	13.65	39	0.11-181	11

Notes:

Net-pay cut-offs applied: effective porosity ≥9.5%, shale volume ≤50% and effective water saturation ≥13% (to compensate abnormally low calculated water saturation possibly attributable to wettability variation) and ≤65%.

Table 2-1: El Fayum Block –Petrophysical Averages (Seller's Case)

A computer processed interpretation (CPI) log for the North Silah Deep-1X well is presented in **Figure 2-10** as an example of the final computed petrophysical assessment.

The Seller's assessments of the fluid contacts for the Assets highlights the large range of uncertainty in defining the oil and water levels for each of the separate reservoirs. For the most part, the ranges are defined by the Lowest Known Oil (LKO, based on well tests) and the Highest Known Water (HKW, based on wet well tests or low-resistivity in clean sands below oil tested reservoirs). The best estimate is commonly the midpoint between the LKO and HKW cases as direct contact indicators in the logs are often not present. Exceptions include, for example, the North Silah Field L AR-G sand and the Ward Field U AR-G Sand 3, where a contact is noted and used for the low, best and high estimate cases. In some cases, for example in one-well fields, there was no HKW from test or petrophysics to provide a base-case contact limit. In these cases, LKO minus two reservoir

thicknesses was used to estimate the Base (2P) Case. A High (3P) Case was estimated from structural spill point or HKW test or low resistivity plus two reservoir thicknesses. These two cases defined the uncertainty in the oil/water contacts." A summary of the contacts applied for the El Fayum fields and reservoirs is presented in **Table 2-2**.

LR has reviewed the petrophysical assessments and reports completed for the El Fayum Block and LR opines that the results are relatively robust. Issues are noted with the ranges of uncertainty assessed for the:

i) reservoir rock parameters - although ranges are noted, only the best case has been taken forward to geomodelling with no uncertainty range applied therein

ii) fluid contacts – variable parameters applied across the different fields and reservoirs to constrain the OWC. 2P and 3P cases have been calculated using different criteria for contacts, and a 1P case is presented as part of the Development Plan.

2.3.5 *Mapping and Static Modelling*

Numerous static models have been built by the Seller in Petrel™ to characterise the distribution of reservoirs, fluids and structural elements across the fields of the El Fayum Block.

Field	Formation/ Zone	Block	Observations (ftTVDSS)		Estimated OWC (ftTVDSS)		Comments
			LKO	HKW	Best	High	
Silah	U AR-G	Field	-5757	-6103	-5924	-6050	Best = midpoint for LKO test, HKW low resistivity, High = HKW+2 Res.
	L AR-G	Field	-6420	-6738	-6574	-6690	Best = midpoint for LKO test, HKW low resistivity, High = HKW+2 Res.
	UB	Main	-6802	-7221	-7006	-7200	Best = midpoint for LKO test, HKW low resistivity, High = HKW+2 Res.
		Silah 7	-6523	-6760	-6642	-6760	Best = midpoint for LKO, HKW from well tests, High = HKW+2 Res
		Silah 6	None	-6994	-6960	-6994	Best = HKW+2Res, High = HKW well test in Silah 6
		Silah 25	None	-6767	-6730	-6825	Best = 2 Res. above non-prod test, High = HKW-2 Res
Silah 17	L AR-G	Field	-6855	None	-6881	-7411	Best = LKO - 2 Res., High = fault tipout
North Silah	L AR-G	Field	-6807	-6807	-6807	-6807	N Silah 1 OWC observed in well
	UB	Field	-7376	None	-7392	-7487	N Silah 2-3 well test, no HKW test or low resistivity, contact from 2 Res below LKO
North Silah Deep	L AR-G	Field	-7406	-8034	-7466	8034	Best = contact LKO-2 Res. In NSD 2-4, High = HKW Dawar 3X
	UB	Field	-7647	-7647	-7647	-7850	LKO = test in NSD 1X, NSD 2-4 HKW from low resistivity, perched water? High = midpoint to Dawar3 HKW
North Silah Deep 4	L AR-G	Field	-8063	None	-8073	-8183	Best = LKO wet test - 1 Res., High = fault cut
Dawar	U AR-G	Field	-7374	None	-7396	-7569	LKO = Dawar 3X, Low limit from South Fault tipout
	L AR-G	Field	-7921	-8034	-7977	-8030	LKO from test in Dawar 1-1, HKW from low resistivity in Dawar 3X
	UB	Field	-8502	None	-8530	-8950	Best = Dawar 1X well test for LKO-2Res, High = fault tipout at top UB7

Field	Formation/ Zone	Block	Observations (ftTVDSS)		Estimated OWC (ftTVDSS)		Comments
			LKO	HKW	Best	High	
Ain Assillen	U AR-G	Field	-6989	-7060	-7012	-7060	LKO from test in AA 1-1, HKW Structural spill point
	L AR-G	Field	-7665	7850	-7676	-7850	LKO from test in AA 1-1, HKW Structural spill point
	UB 5	Field	-8033	-8280	-8039	-8280	LKO from test in AA 1-1, HKW Structural spill point
	UB 7	Field	-8403	-8470	-8446	-8470	LKO from test in AA 1-1, HKW Structural spill point
NE Tersa	L AR-G	Field	-8810	-9100	-8958	-9100	LKO from well test NET 1-1, HKW Structural spill point, Best = midpoint, High = spill point
West Auberge	U AR-G /Sand 1	Field	-7574	-7688	-7615	-7710	LKO from Res. log, HKW at W Tersa 1X
	U AR-G/Sand 2	Field	-7597	-7688	-7615	-7710	LKO from Res. log HKW at W Tersa 1X
	U AR-G/Sand 3	Field	-7240	-7688	-7463	-7710	LKO well test W Auberge 1X, Best = midpoint to HKW W.Tersa 1X, High = LKO from W Tersa 1X, W Tersa oil ind. marginal
Ward	U AR-G/Sand 1	Field	-7316	-7350	-7326	-7358	Best = LKO- 2 Res well test Ward 1-3, High = Sand 3 contact
	U AR-G/Sand 2	Field	-7316	-7350	-7326	-7358	Best = LKO- 2 Res well test Ward 1-3, High = Sand 3 contact
	U AR-G/Sand 3	Field	-7358	-7358	-7358	-7358	Ward 1-1 OWC observed in well
Saad	L AR-G	Field	-6196	-6358	-6277	-6338	LKO test in Saad 2X, HKW low res in Saad 1X, Best = Midpoint, High = HKW+2Res
Kahk	U AR-G	Field	-7597	-7627	-7612	-7740	Best = midpoint between LKO in Sand #2 and HKW in Sand #3, High = structural spill point
SE Gindi	UB	Field	-6273	-7212	-6743	-7212	Best = midpoint between LKO and HKW, High = Spill point
NE Younis	L AR-G	Field	-7733	-7801	-7767	-7801	Best = is midpoint between LKO and structural spill point, High = Spill point
	UB	Field	-8417	-8500	-8459	-8500	Best = is midpoint between LKO and structural spill point, High = Spill point
Tersa	L AR-G	Field	-8320	-8437	-8345	-8437	Best = is midpoint between LKO and structural spill point, High = Spill point
	UB	Field	-9046	-9124	-9085	-9120	Best = midpoint between LKO and HKW, High = structural Spill point
Younis	L AR-G	Field	-8625	-8850	-8738	-8850	Best = midpoint between LKO and structural spill point, High = Spill point

Notes:

LKO = lowest known oil (tested) and HKW = highest known water (observed)

Table 2-2: El Fayum Block –Oil Water Contact Uncertainty (Seller's Case)

LR reviewed 11 static models, associated reports and supporting material that were provided in the virtual data room and then accessed at the Seller's offices in Houston during the physical data room. Due to time constraints and the significant amount of detail in the models, LR's focus was upon the larger fields of the Greater Silah area, as these were noted to account for approximately two-thirds of the entire El Fayum estimated STOIIP (at the best estimate level).

The models combined the geophysical depth maps (based on time interpretation and depth conversion), structural components (faults), petrophysical rock parameters (petrophysics assessment), and fluid contacts (oil water contact uncertainties) in 3D geocellular models that can be used to estimate the STOIIP and be used as inputs for the dynamic modelling (see **Section 2.4.4**) and field development analyses (see **Section 2.4.3**).

The Seller had completed the assessments to create:

- STOIIP estimates - best case and selected models with high case;
- net pay and hydrocarbon pore volume (HCPV) maps for Reserves/Resources analyses and for field development planning; and
- grids and properties for dynamic sector modelling to generate production type curves.

The workflow was reviewed by LR and examples of the final depth structures for the larger fields of the Greater Silah area and the Satellite Area are presented in:

i) **Figure 2-11** for the North Silah Deep Field – Lower Abu Roash "G"

ii) **Figure 2-12** for the Silah Field – Lower Abu Roash "G"

iii) **Figure 2-13** for the Silah Field – Upper Abu Roash "G"

iv) **Figure 2-14** for the Silah Field – Upper Bahariya (sands 1-8)

v) **Figure 2-15** for the North Silah Field – Upper Bahariya (sand 1-8)

vi) **Figure 2-16** for the Aboud/West Auberge Satellite Field – Lower Abu Roash "G"

vii) **Figure 2-17** for the Ain Assillen Satellite Field – Upper Bahariya (sands 5 & 7)

LR opines that a large number of models have been built by the Seller within a limited time frame (for the purpose of the Transaction) and may not be of optimal quality. Several critical improvements are recommended:

- No uncertainty has been modelled for the structural geometry of the fields – noting that many wells are located in crestal positions and, thus, there remains unaddressed uncertainties away from well control on the flanks of the structures;
- The electrofacies interpreted during the petrophysical assessments were used to calculate permeability based on core-derived transforms inked to facies. The electro-facies were not used to control reservoir properties away from wells in the geological models;
- The Abu Roash and Upper Bahariya reservoirs have been modelled separately (due to size) in the Silah Field and are noted to cross (overlap) in the southern region;
- Certain field volumes reported in the STOIIP summations include volumes that lie outside of the Development Leases, however, they do sit within the wider Concession Area;
- Not all faults are included in the models, which although may not impact the STOIIP to a large degree, would impact the connectivity of reservoirs (compartmentalisation) if upscaled for reservoir simulation purposes;
- Upscaled geocellular models have not been used at the field scale (full field) to assess the dynamic reservoir characteristics of the field. Only sector models have been built, rather than at the full field scale based on the upscaled geocellular models.

2.3.6 *Stock Tank Oil Initially-In-Place (STOIIP)*

The STOIIP volumes were verified by LR, such that LR was able to replicate the volumes based on the Seller's inputs. They are summarised in **Table 2-3**:

Field	Reservoir	Contacts (ft TVDSS)		STOIIP (MMstb)		
		Best	High	Low	Best	High
Silah Thin-bedded	U AR-G *	-5924	-6050	8.9	22.5	32.0
	L AR-G *	-6574	-6690	25.4	33.1	41.1
	UB *	Compart.	Compart.	51.1	91.0	111.4
Silah UB7 Channel	UB	-7006	-7200	13.5	13.5	14.0
North Silah	L AR-G	-6807	-6807	8.5	8.5	9.9
	UB *	-7392	-7487	27.4	30.0	39.0
North Silah Deep	L AR-G *	-7466	8034	33.5	42.1	49.6
	UB	-7647	-7850	9.0	12.8	32.2
Dawar	U AR-G	-7396	-7569	1.5	5.2	8.7
	L AR-G	-7977	-8030	0.5	2.3	7.7
	UB	-8530	-8950	3.8	9.4	38.6
Sub-Total Greater Silah Area				183.1	270.4	384.2
Ain Assillen	U AR-G	-7012	-7060	4.0	7.6	10.6
	L AR-G	-7676	-7850	2.9	3.2	13.2
	UB *	-8446	-8470	4.5	10.6	15.2
Aboud/W. Auberge	U AR-G *	-7006	-7710	4.3	8.8	17.5
NE Tersa	L AR-G	-8958	-9100	7.1	7.4	13.6
Ward	U AR-G	-7326	-7358	1.6	2.6	3.9
Kahk	U AR-G	-7617	-7647	3.6	5.2	5.7
Saad	L AR-G	-6278	-6359	0.9	2.4	3.9
SE Gindi	UB	-6743	-7212	0.5	1.9	8.9
NE Younis	L AR-G	-7767	-7801	0.7	0.9	1.6
	UB	-8456	-7985	2.1	2.9	5.3
Tersa	L AR-G	-8345	-8437	0.6	1.1	1.4
	UB	-9085	-9120	5.2	7.3	12.5
Younis	L AR-G	-8651	-8800	0.1	0.2	1.4
Sub-Total Satellite Area				**38.1**	**62.1**	**114.7**
TOTAL EL FAYUM BLOCK				**221.2**	**332.5**	**498.9**

Notes:

Best and high estimate STOIIP volumes are derived from the Petrel™ models.

Low estimate STOIIP volumes are not modelled by the Seller. Low estimates of STOIIP came from the Development Plan HCPV maps and production blocks with proximity to production, and LKO, as limits. These are derived from mapping of the LKO and petrophysical parameters to the LKO.

Reservoirs with an asterisk are presented as figures (see **Figure 2-11 to Figure 2-17**).

Highlighted fields: the 5 major reservoirs in El Fayum based on STOIIP

Table 2-3: El Fayum Block –Field STOIIP Volumes (Seller's Case)

Table 2-3 demonstrates that 5 major reservoirs in the Greater Silah area (highlighted in yellow) hold approximately two-thirds of total El Fayum Block STOIIP at the best estimate level. An independent study by McDaniel in September 2017 presented slightly larger volumes at the best estimate case of approximately 370 MMstb.

LR opines that, although there has been a considerable amount of effort in building the geological models for the purpose of the Transaction, there are certain issues with the inputs and the assessment of uncertainty that may impact on the calculations of the resultant STOIIP volumes. Relative scales between fields are likely to be reasonable, as are approximate distribution trends of reservoir within the separate fields. These have been used by the Seller to guide development and assign estimates of productivity (type curves – see Section 2.4.6); however, LR recommends that SOCO further refines the larger volume models to ensure that all uncertainties noted above are addressed. At present, it is not possible for LR to judge whether the best estimate STOIIPs can be considered either reasonable, optimistic or pessimistic. Further, the range between the low and high estimate cases may potentially be larger if all STOIIP calculation input uncertainties are accounted for.

2.4 *Reservoir Engineering*

2.4.1 *Historical Production*

The historical production from the El Fayum Block is presented in **Figure 2-18** and summarised below:

- Production started in September 2009 from Silah, NET, Kahk and Tersa and from North Silah Deep in October 2009.
- During 2010 another seven fields were added in the order; North Silah, Dawar, Ain Assillen, South Silah, SE Gindi, Ward and West Auberge.
- Production reached an initial peak of 4,900 bopd in early 2011 and averaged around 4,000 bopd for the next two years.
- Saad Field came on-stream in January 2013 adding 400 bopd but rapidly declined.
- Further development drilling (~ 12 wells) increased production to a second peak of 7,600 bopd in September 2014 but, thereafter, it declined fairly rapidly at ~ 3.5% per month (~ 50% per annum).
- Waterflooding was initiated in the Greater Silah area fields in early 2015, starting with North Silah Deep and North Silah – **see Figure 2-19**.
- The response to waterflooding was rapid with oil production increasing to 12,750 bopd by January 2016 but water breakthrough started within 12 to 18 months and by January 2017 North Silah Deep and Silah fields were producing at 60% water cut.
- Since January 2016 production has been declining at around 34% per annum due to the water breakthrough, declining drilling activity and some operational issues related to pump failures.
- At December 2017 the El Fayum Block was producing 6,900 bopd at a water cut of 50%. There were 38 active oil producers and 5 active water injectors.
- In January 2018 oil production was negatively impacted by the unavailability of one of two workover rigs, which delayed several downhole pump repairs and planned completions. A replacement workover rig was operational by late February and since then production has been steadily recovering. Average oil production for June 2018 was 7,080 bopd with water production of 5,600 bpd (44% water cut). Water injection was 12,400 bpd.

- As of 30th June 2018, the El Fayum fields had produced a total of 19.08 MMstb oil, of which 16.76 MMstb was from the Greater Silah area fields.

2.4.2 *Fluid Properties*

The oil fluid properties in existing fields depend primarily on the producing formation.

In general, the Abu Roash 'G' Lower (LG) and Upper Bahariya (UB) have a low gas content with GOR typically less than 400 scf/stb but ranging from 200 to 600 scf/stb. The crudes are light with gravity around 38-42° API and are undersaturated at initial reservoir conditions usually by around 1,500 psi. Oil viscosities at reservoir temperature range from 0.4 to 1.1 cP, which means that oil-water mobility ratios are low and favourable for waterflooding.

Less favourable oil properties are found in the Abu Roash 'G' Upper (UG), which contains a medium crude with gravity 24-28° API and oil viscosities at reservoir temperature in the range 1.5 to 6 cp. However, only about 5% of total El Fayum production comes from the UG formation.

2.4.3 *Field Development*

The Operator's strategy for future development of the El Fayum fields is focussed on a ramping up of drilling activity to fully develop each field with waterflooding using a 5 spot 1 producer to 1 injector pattern flood. To accomplish this the Operator estimates a requirement for at least 173 new wells (producers and water injectors; of which 3 were drilled during 1H18) and numerous rig workovers & fracture stimulations plus well recompletions as detailed in **Table 2-4**.

Operational Activity	Wells		WO & Frac Stimulations	Recompletions
	Prod	Inj		
El Fayum Existing as per 30th June 2018	39	4 (active)	–	–
El Fayum 2H18-2020	23	16	87	16
El Fayum 2021-2022	29	31	86	11
El Fayum 2023-2024	34	37	103	11
El Fayum 2025-2029	–	–	4	3
Total New Activity 2H 2018 - 2029	86	84	20	41

Table 2-4: El Fayum Block - Envisioned Future Operational Activity Level

Compared to previous exploration and development history this represents a two to three-fold increase in operational activity.

The current Operator has described three different development scenarios, which are similar in design; but vary in scope and pace of development. The first is a base case and the other two are upside cases. These are summarised in **Table 2-5**.

	Base Case	Optimised Base Case	Upside Case
OOIP Basis MMstb	323	323	471
Number of new wells	173	173	209
Estimated Reserves MMstb	59	70	111

Table 2-5: El Fayum Block - Current Operator Development Scenarios, Oil-in-place and "Reserves" Cases

LR opines that these scenarios are overly optimistic (especially the upside cases) since many aspects of the FDP components are conceptual and will require operational activity from 2019 to be ramped up to previously unseen levels.

LR has based its assessment of Reserves and Resources on the Operator's base case scope of development; but has broken down the total project into a series of incremental sub-projects, each of which would need to have a distinct plan, schedule and budget and would carry a range of uncertainty on outcome.

After reviewing the current development plans LR concludes that much of the proposed programme from 2021 and beyond is going to depend on the technical success or otherwise of the early phase of waterflood expansion and, therefore, at this stage, the associated Resources volumes can only be classified as Contingent. This limits the Reserves assessment to development activities planned for the period 2018 to the end of 2020 (**Section 2.4.6** provides more details).

2.4.4 *Dynamic Model*

LR converted 9 different simulation sector models originally provided by the Seller in tNavigator™ into Eclipse. A total of 8 models could successfully be converted and run in Eclipse. The sector models had been prepared by Merlon to forecast 90 acres spacing waterflooding pattern performance of two injectors and two producers (1:1) across different areas and fields within the El Fayum Block.

Only four water injection wells are currently active (all in the better parts of the Greater Silah area). Although these injection wells have demonstrated positive pressure responses in nearby producers, the short history of water injection and the lack of five-spot waterflood pattern drive pilots do not allow calibration of the pattern fractional water-cut performance.

The sectors model production profiles, static/flowing pressures, recovery factors and EUR forecasts run by LR were in line with the Operators results as shown in the FDPs. However, LR found several issues with Merlon's sector models which potentially could lead to overestimation of the recoverable oil volumes. The details and key concerns have been communicated to SOCO to assist forward work planning. Some of the concerns are lack of full field history matched dynamic simulation model(s) and that all the sector models have been initialized at initial reservoir conditions with no-flow boundaries and four corner wells (2 producers and 2 injectors). A five-spot waterflood pattern model has one producer in the centre and ¼ of a water injector in each corner. Appropriate modelling would allow for historical fluid and pressure fluxes between neighbouring blocks/patterns.

LR opines that the output from Merlon's sector simulation models are likely overly optimistic since many aspects of the sector models are conceptual only. Although the Operator via the sector simulation models, caters for the relative reservoir variability captured in a single realisation of the full El Fayum fields static geological model, the Operator has not fully addressed reservoir uncertainties and their potential impact on forward predicted water flood performance. The impact on the predicted performance of the sector models due to these conditions is hard to judge without calibration to full field simulation runs matched to historical observed water breakthrough in pilot waterfloods patterns.

Hence, LR's low case Reserves (1P) and low case Contingent Resources (1C) have been estimated considering the reservoir and fluid properties observed in the El Fayum fields and based on a best endeavour approach for assessment of the corresponding estimated low case displacement and sweep efficiencies for five-spot waterflood patterns. However, there is a risk of downgrading the estimated waterflood based Reserves in the case that actual future field wide waterflood performance, especially away from current well control, does not perform as forecasted. A possible mitigation of related uncertainties might be early implementation of a pilot five-spot pattern waterflood in an area with less favourable reservoir quality to get a better handle on the range of pattern performance and development of a full-field history matched dynamic reservoir simulation model to calibrate waterflood performance predictions.

2.4.5 *Decline Curve Analysis*

LR has independently assessed Developed Reserves using decline curve analysis applied at the field level. Exponential decline has been used as the basis for estimating Proved Developed Reserves and hyperbolic decline (with 'd' exponent = 0.5) has been used as the basis for estimating Proved plus Probable Developed Reserves. The exponential decline is considered conservative and, therefore, a "low" case because it occurs more commonly in pure depletion type reservoirs. The hyperbolic decline is considered appropriate for a "best estimate" case, as it is frequently associated with waterflood production and hydraulically fracture stimulated wells both of which apply to the El Fayum fields.

The resulting decline curves (which are a summation of the individual field decline curves) are shown in **Figure 2-20** together with the current Operator Merlon's "PDP Reserves" production profile, which is also presumably a DCA based forecast. The LR forecasts are higher than the Merlon forecast primarily because the DCA is matched with more recent production history up to 30th June 2018. A comparison of the associated EUR estimates is shown in **Table 2-6**.

Forecast	Merlon "PDP"	LR Exponential	LR Harmonic
EUR MMstb	7.3	8.1	12.7

Note:

Truncated at 31st December 2039

Volumes from 1st July 2018 (and before any adjustment for economic cut-off)

Table 2-6: El Fayum Fields – Comparison of Decline Curve Analyses

2.4.6 *Production Forecasting*

LR has used a PRMS Project activity approach to generate forecasts for Reserves and Contingent Resources by breaking out the Operator's production trends and work programmes into a series of incremental 'sub-projects' or components:

- Component 1: Existing producing wells (as of 30th June 2018) with 'no further action' (NFA), i.e. "do nothing" case. This component is estimated from LR's decline curve analyses and is assigned to the 1P Reserves class ("Exponential Decline; Proved Developed Producing – PDP") and 2P Reserves class ("Hyperbolic Decline; Proved + Probable").
- Component 2: Work programme activities in the period 2H 2018 – 2020 which include the drilling of new wells, waterflood expansion and enhancement of existing production by work-overs (e.g., downhole pump replacements, additional perforations, recompletions, hydraulic fracturing). This component contributes to both the 1P and 2P Reserves class.
- Component 3: Same type of project activities as component 2; but carried out in the period 2021 to 2022 and, therefore, contingent on the success of infill drilling, waterflood expansion and workovers during the first three-year programme. This component contributes to the $1C^1$ and $2C^1$ Contingent Resources class.
- Component 4: Same type of project activities as component 2; but carried out from 2023 onwards and subject to lower chance of implementation due to higher risks. This component contributes to the $1C^2$ and $2C^2$ Contingent Resources class.

The "best estimate" forecasts for components 2, 3 and 4 are based on individual well production profiles and associated project activity completion dates generated by the Operator. There are two groups of profiles, one for new oil producers and the other for well workovers, which include recompletions and hydraulic fracking.

New well profiles

There are 91 separate profiles for new wells, which are based on 'type curves' derived from the sector simulation models built and run by the Operator. The type curves define a relative production trend over time while a geological prognosis of connected OOIP for each proposed well location is used to define the absolute initial well rate and ultimate recovery by well/block (refer to Section 2.4.4 for LR's review of the sector simulation models and the type curve methodology). As such, LR considers that these well-by-well profiles adequately take into account the range of reservoir *variability* seen across and within the El Fayum fields and are thereby reasonable for best case forecasting. However, without adjustment they do not account for any subsurface *uncertainty*.

Workover well profiles

There are 44 separate profiles for workover wells with incremental EUR per well ranging from 0.02 to 0.7 MMstb and average per well of around 0.24 MMstb. Technical details to explain how the production profiles were generated are lacking; but LR considers them reasonable for best case forecasting. This is based on comparison with estimates of average EUR per well for current proved and proved plus probable developed reserves. However, as for the new well profiles, some adjustment is required to account for uncertainty.

Low and Best Case Forecasts

LR accepts the Operator's unadjusted well-by-well profiles as suitable for generating best case forecasts; but has applied discount factors to generate low case forecasts. The discount factors used are shown in **Table 2-7**.

Project Activity	PRMS Category/Class	Low	Best
Workover wells	2P Reserves	0.85	1.0
New wells	2P Reserves	0.78	1.0
Workover wells	2C Contingent Resources	0.85	1.0
New wells	2C Contingent Resources	0.78	1.0

Table 2-7: El Fayum Fields: Best to Low Case Uncertainty Discount Factor

The discount factor of 0.78 for new wells is based on the range of reservoir and fluid properties seen in the El Fayum fields, together with corresponding low and best estimates of displacement and sweep efficiencies for five-spot pattern waterflooding.

The discount factor of 0.85 for workovers is based on the ratio of estimated EURs for low case and best case proved developed reserves.

Adjustments for recent drilling/workover activity

The LR forecasts also include adjustments to component 2 for workovers and new wells already completed in the period October 2017 to June 2018. Production associated with these activities is now part of the component 1 forecasts (developed producing) and the corresponding individual well forecasts previously included in component 2 as undeveloped reserves, have been subtracted.

The individual well adjustments for component 2 are based on a log of workovers and completions done up to July 2018, combined with well-by-well production data for the same period. Adjustments fell into the following categories:

- New wells or workovers completed in the period November 2017 to July 2018 and confirmed as already producing. A total of 10 wells are identified in this category, e.g. NET 1-5 and Aboud 1ST.

- New wells or workovers planned for but not completed before July 2018. The production profiles for these wells have been deferred. There are three wells in this category, NSD-5, Silah 27 and Silah NSD1-7
- New wells or workovers apparently completed before July 2018 but for which no production is yet being reported. There are two wells in this category, N Silah 3-1 and Silah 13-1.

Final Forecasts

The aggregate of LR's sub-project approach is a forecast, similar to the Operator's total production forecast; but differs in that only around 50% of LR's forecast is in the Reserves category. **Figure 2-1** upper chart, shows the overall production potential of future development projects in the El Fayum Concession. Profiles for the different Contingent Resources categories are shown separately in the lower chart for clarity. For comparison, **Figure 2-21** also shows the Operator's total production forecast, which is slightly higher than LR's aggregate forecast. The 1P and 2P forecasts are shown in **Figure 2-22** and corresponding cumulative volumes are summarised in **Table 2-8**.

Reserves Class EURs

	Raw Production Forecasts (pre-Economics)	
	Low	Best
Oil (MMstb)	17.8	28.3

Note:

Truncated at 31st December 2039

Volumes from 1st July 2018 (and before any adjustments for economic cut-off)

Contingent Resources Class EURs

	Raw Production Forecasts (pre-Economics)	
	Low	Best
Oil (MMstb)	16.4	33.8

Note:

Truncated at 31st December 2039

Table 2-8: El Fayum Concession – Summary of LR's Production Volumes

2.5 *Field Facilities Engineering*

2.5.1 *Overview of Existing Facilities*

The fields within the El Fayum Concession have a variety of facilities depending on the number of production and water injection wells in each field. A comprehensive inventory and description of the wells, facilities and pipelines was reviewed by Lloyd's Register covering the fields as shown in **Figure 2-23**.

The production and water injection wells have been drilled at multi-well pads to minimise any impact to cultivated land (8-12 wells per pad). Artificial lift in the wells is provided using Sucker Rod Pumps (SRP) or Electrical Submersible Pumps (ESP) depending on the flowrates. Electric power for the pumps is provided by on-site diesel generators or from the local electricity grid where possible.

The water injection wells have typically been converted from wells that were previously production wells. Well completions are normally performed by workover/completion rigs rather than drill rigs for efficiency and cost saving.

The field sites are equipped with modular production facilities unless a well can be connected directly to an existing facility via a pipeline. The production facilities are constructed in a way so they are easily upgraded or downgraded as production or scope changes.

Oil storage tanks are equipped with internal heaters to improve oil mobility due to the high pour point. Flowlines, process, and load lines are heat traced due to the high pour point. Production downstream of the wellhead is routed through an emulsion treater. The water phase goes to the produced water treatment facility (on location) where skim oil is pulled off via gun barrel. The clean water is then stored and treated for reinjection. The oil phase is sent to stock tanks on location. The gas phase (where volume is sufficient) supplies onsite gas electricity generators. Multi-well facilities are equipped with test separators and manifold for production confirmation and allocation. Production facilities are equipped with shipping pumps for loading trucks or transferring oil via pipeline to a trucking facility. Lloyd's Register's view is that excess capacity is in place to accommodate some growth, and facilities upgrades are possible for increased production.

2.5.2 *Water Management and Supply*

The bulk of the produced water from the production wells is re-injected into the Silah injector wells and the remaining small volume is hauled by truck to a disposal facility. Produced water treatment facilities are designed to yield a clean water phase suitable for waterflood injection by treating the water with chemicals to prevent scale and corrosion prior to pumping down an injector well. Lloyd's Register has no concerns about the water handling facilities being used albeit they will require upgrading in the future to meet increased demands for water injection in the fields.

2.5.3 *Oil Export*

All produced and processed oil is temporarily stored at the various production sites in storage tanks. The Greater Silah area has a pipeline network to transport oil to gathering stations with storage tanks. Outlying satellite fields have their own storage tanks.

The storage facilities are equipped with pumps for loading trucks. Approximately 20-30 trucks per day are used to transport the oil to the PPC Tebbeen terminal approximately 70 km to the north of the El Fayum area. The trucks travel in a convoy for security and safety reasons.

Lloyd's Register's view is that the current network of pipelines, storage tanks and trucking are appropriate for the scale of the existing operations.

2.5.4 *Future Development*

Future field development, expansion and increased water injection will require the following facilities:

- Multi well pads (up to 12 wells per pad).
- New flowlines for production and water injection streams.
- Upgrades to existing processing and oil/water storage facilities.
- New water treatment at satellite fields similar to those already in the Greater Silah area.

The Egypt Government Electrical Authority has recently constructed a new electric powerplant on the southern border of the El Fayum Concession Area and it has spare capacity. Merlon/Petrosilah intend to use electricity from the power station to reduce operational costs by reducing the volume of diesel purchased for on-site power generation. The new power line distribution infrastructure will be installed by the Government Electrical Authority as a turnkey project. The first phase of the project is scheduled to be completed by the end of 2018 and will replace 12 diesel generators using approximately 4,500 litres of diesel per day. A second phase of the project is not yet approved but would provide a similar positive result to Phase 1. Lloyd's Register has no concerns about this project as it has robust justification and long term operational benefits.

Merlon/Petrosilah have proposed two other future facilities projects; a tank farm and pipeline project to make oil trucking more efficient (USD 5,835K estimate), and pipeline projects to transport the produced oil directly to a receiving terminal (US$14-20 Million estimates) which would significantly reduce trucking requirements. Both projects could bring positive operational benefits to the concession; but in Lloyd's Register's view the capital cost estimates are too low and a greater level of detail is required to make the cost estimates more robust.

2.5.5 *Integrity Management and Maintenance*

No data was provided in the Virtual Data Room (VDR) to establish the current integrity of any facilities or wells. The Information Memorandum mentions operational issues (pump failures); but no details were provided in the VDR. Flow assurance is maintained by use of tank and pipeline heating and pour point depressant chemicals during the colder months of the year. Corrosion inhibitor, scale inhibitor and demulsifying chemicals are used on production wells and facilities. Corrosion inhibitor, scale inhibitor and oxygen scavenger chemicals are used on water treatment facilities and waterflood wells.

SOCO International personnel visited some of the El Fayum sites in late August 2018 and reported to Lloyd's Register that they had no concerns with the facilities that they visited. All sites were reported as seeming to be fit-for-purpose and there was an inventory of drilling hardware and consumables in stock for new wells and workovers.

2.5.6 *Capital and Operating Cost Schedules*

Lloyd's Register have reviewed the capital cost schedules for the proposed future development drilling and the expansion of the facilities to accommodate the incremental oil production, water production and water injection.

CAPEX costs provided for El Fayum are based upon the costs expended to date on existing wells and facilities with established supply chain contracts and newly acquired estimates. Lloyd's Register has benchmarked these against other known onshore projects in the region and deem them to be representative.

OPEX costs for the concession have also been reviewed and appear justified and benchmark well against other analogue onshore assets in Egypt.

Lloyd's Register's view is that previous facilities construction experience in the concession and costs from existing contracts has led to justified cost estimation and scheduling for future facilities. Since the El Fayum Concession development plans were not prescriptive enough to explain where each of the new wells were going to be located, the exact development costs for each well and associated facilities could not be determined. Therefore, the CAPEX and OPEX for each field development/expansion should be analysed in more detail for each development case to confirm the economic viability.

2.5.7 *Wells and Facilities Abandonment*

Lloyd's Register have not been provided with a decommissioning strategy/plan or cost estimate for the El Fayum Concession wells and facilities. LR has been advised that if the field still producing at the end of the license (in this case 2029) it will be handed over to the government.

2.6 *Economics*

An economic model for the El Fayum Block, Western Desert, Egypt was provided by the Seller in the data room. This was assessed by LR to be fit for purpose and adjusted to calculate the volumes and NPVs of both Reserves and Contingent Resources. Reserve and Contingent Resource volumes are expressed without adjustment for income tax paid by EGPC on Merlon's behalf.

2.6.1 *PSC Basic Terms*

Assets in Egypt are operated as Production Sharing Contracts (PSCs). The main terms for the El Fayum Block are summarised in **Table 2-9** and **Table 2-10** and the existing production sharing mechanism is presented in **Figure 2-24**.

Term	Block 16-1	Interest
Signed	15th July 2004	
Exploration Term	Initial exploration period 6 years 1st amendment 7 years 2nd amendment 4 years Expiry in November 2020	
Development Lease Commencement	2009 (earliest lease out of 11 leases)	
Development Lease Term	20 years, plus two possible 5-year extensions	
License Expiry	2029 with no extension 2034 with one 5-year extension 2039 with two 5-year extensions	
Operator	Petrosilah Operating Co. (50/50 SOCO/EGPC JV subsequent to Transaction)	100%
Partners	SOCO (subsequent to Transaction)	100%

Table 2-9: The El Fayum Block – Licence Details

LR has summarised the profit splits, cost recovery limits, taxes, bonus payments and fees in **Table 2-8**.

PSC	The El Fayum Block
Cost Recovery Limit	30% of gross revenues is available for the recovery of expenditures)
	Operating expenses are recoverable as incurred.
	Capital expenditures is amortised for recovery over 4 years
	Unrecovered cost can be carried forward to the next period
Share of Excess Cost	If cost recovery is less than cost recovery limit, the remaining revenues are split between Contractor and EGPC on 15:85 basis
Profit Oil Split	
Production Level (bopd)	EGPC %/SOCO (subsequent to Transaction)
Tier 1 - Up to 5,000	82.0%/18.0%
Tier 3 – 5,001 - 10,000	83.0%/17.0%
Tier 4 - 10,001 - 25,000	85.0%/15.0%
Tier 5 - 100,001 - 50,000	86.0%/14.0%
Tier 6 – 50,001 – 100,000	87.0%/13.0%
Tier 6 - Over 100,000	88.0%/12.0%
Income Tax	Egyptian income taxes are paid by EGPC on behalf of Contractor from EGPC's share of revenues
Bonus	Bonus US$
Extension	Five million (US$5,000,000)
Production bonus for production over 25,000 bbl/day	Two million (US$2,000,000)
Production bonus for production over 50,000 bbl/day	Three million (US$3,000,000)
Production bonus for production over 100,000 bbl/day	Five million (US$5,000,000)

Table 2-10: The El Fayum Block – Key Terms and Conditions

2.6.2 *Methodology*

The economic model provided by the Seller contained the agreements as detailed in **Table 2-7** and **Table 2-10**. The production profiles used as inputs were those from **Section 2.4.6** with corresponding OPEX, CAPEX and ABEX costs for each of the scenarios as per **Section 2.5.6** and **Section 2.5.7**. Further, LR applied the oil prices as presented in **Section 2.6.4**. The Cashflows are presented in **Figure 2-25**.

The unrecovered cost pool as of end of June 2018 from the primary area is provided by the Seller. Total cost pool included in the model is US$193.7 Million, comprised of cost pool balance of US$140.4 Million and unamortised CAPEX of US$53.3 Million. Unamortised CAPEX is scheduled for amortisation for recovery as below.

Amortisation Recovery		
2018	$	16.2
2019	$	20.0
2020	$	10.8
2021	$	5.8
2022	$	0.6

Table 2-11: Unamortised Capex Recovery

The model was run to calculate Reserves (1P, 2P) and rerun to include incremental "Reserves + Contingent Resources" associated with the two incremental development projects during 1) 2021 to 2020 and 2) 2023 onwards. The difference between these numbers being the incremental Contingent Resources (1C and 2C). Net present values (NPVs) with a 30th June 2018 effective date have also been extracted for the 1P and 2P Reserves.

2.6.3 *Economic Limit Test*

The economic limit test is a test of the field in terms of costs and revenue. The cessation of production date (CoP) is the point when the revenue of the field is smaller than the operating costs and the free cash flow turns negative. LR has truncated the Reserves at this point or at the expiry of the licence, whichever comes first.

For the Contingent Resources economic assessment, the license is assumed to be extended for up to two periods of 5 years with an extension bonus payment of $5 Million each time. The license will not be extended if cumulative positive future cash flow (before bonus payment) in the extension period is less than the amount of bonus.

2.6.4 *Oil Price*

The oil price used for the economic analysis was LR's "in-house" Brent benchmark price deck. This is presented in **Table 2-12**

Brent	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
US$/bbl (real)	64.0	65.0	66.0	66.0	67.0	67.0	67.0	67.0	67.0	68.0	2%
US$/bbl (nominal)	64.0	66.3	68.7	70.0	72.5	74.0	75.5	77.0	78.5	81.3	64.0

Table 2-12: LR's Oil Price Deck

The oil from the El Fayum Block is being sold with a differential discount of US$4.00/bbl which has been applied to calculate the revenue.

2.6.5 *Discount Rate*

In line with the PRMS classification, a 10% discount rate has been used in the economic analysis. LR has run sensitivities for the Reserves at NPV0, 5, 10 and 15% (**see Section 2.7.3**).

2.7 *Reserves and Contingent Resources*

A summary of the Reserves and Contingent Resources pertaining to the El Fayum Block are presented in the following sections.

2.7.1 *Reserves*

Reserves have been attributed to SOCO in the El Fayum Block relating to the ongoing production and further sanctioned near-term development during 2018 to 2020. Volumes have been truncated when the revenue of the field is smaller than the operating costs or at the end of the licence expiry in 2029, whichever comes first. Oil Reserves are presented in **Table 2-13**.

Volume Oil (MMstb)	Gross (100% Licence) Oil Reserves			Net Entitlement Oil Reserves to SOCO[2]		
	Proved (1P)	Proved plus Probable (2P)	Proved plus Probable plus Possible (3P)	Proved (1P)	Proved plus Probable (2P)	Proved plus Probable plus Possible (3P)
El Fayum[1]	15.6	24.1	–	6.6	10.2	–

Notes:

1) Oil Reserves (after tax) for the El Fayum Production Sharing Contract relate to the ongoing production from the current 39 producing wells plus 27 planned new production wells, 16 new water injection wells, continued well work overs, fracture stimulation and recompletion operations during the period 2018 to 2020 (of which 4 producers were drilled in the first half of 2018). Production is truncated at CoP or licence expiry (up to and including year 2029), whichever occurs first.

2) LR has run economics sensitivities for the fields to estimate the volumes and values for the Reserves projects. The Net Entitlement Reserves from the outputs of the discounted cash flow assessment are relative to the PSC volumes attributable to SOCO's intended 100% working interest participation in the Asset (subject to completion of the planned transaction with the Seller).

Table 2-13: El Fayum Block – Oil Reserves – as of 30th June 2018

LR is informed that SOCO will have a 100% working interest participation in the Concession Agreement, subject to completion of the planned transaction with the Seller. The Concession Agreement sets out the production sharing terms under which costs and production are attributed to the parties. SOCO carries EGPC for its general and administrative costs associated with EGPC's 50% interest in the Petrosilah Operating Company.

2.7.2 *Contingent Resources*

Contingent Resources have been attributed to SOCO in the El Fayum Block relating to oil production with volumes being truncated in 2034 for the "low case" (1C) for incremental projects 1 & 2, contingent upon the license being extended for one 5-year period and in 2039 for the "best estimate case" (2C), contingent upon the license being extended for two 5-year periods. Contingent Resources are presented in **Table 2-14**.

Volume Oil (MMstb)	Gross (100% Licence) Oil Contingent Resources			Net Entitlement Oil Contingent Resources to SOCO[2)]		
	Low (1C)	Best (2C)	High (3C)	Low (1C)	Best (2C)	High (3C)
El Fayum 2021-22[1)]	9.1	18.1	–	3.9	6.2	–
El Fayum 2023 onwards[1)]	6.7	19.3	–	2.9	6.5	–

Notes:

1) Oil Contingent Resources (after tax) for the El Fayum Production Sharing Contract relates to two, considered by LR, contingent additional phases of incremental development projects beyond year 2020. Once the development activities during 2018 to 2020, including implementation of the initial part of a planned field wide 5 spot water flood pattern drive injection programme has demonstrated sustained increased oil recovery, the Contingent Resources may be re-classified as Reserves. The "Chance of Commercialisation" of the Contingent Resources to mature them to Reserves is deemed moderate by LR.

2) LR has run economics sensitivities for the fields to estimate the incremental volumes and values for the Contingent Resources projects. The Net Entitlement Contingent Resources from the outputs of the discounted cash flow assessment relate to the PSC volumes attributable to SOCO's after tax 100% working interest participation in the Asset (subject to completion of the planned transaction with the Seller).

Table 2-14: El Fayum Block – Oil Contingent Resources – as of 30th June 2018

LR is informed that SOCO will have a 100% working interest participation in the Concession Agreement, subject to completion of the planned transaction with the Seller. The Concession Agreement sets out the production sharing terms under which costs and production are attributed to the parties. SOCO carries EGPC for its general and administrative costs associated with EGPC's 50% interest in the Petrosilah Operating Company.

2.7.3 *Valuation of Reserves*

LR has conducted a valuation of the Reserves based on adjustments to the Seller's economic models. Valuations have been conducted for the 1P and 2P Reserves in addition to sensitivities regarding the NPV discount factor for the 1P and 2P Reserves. Those valuations are presented in **Table 2-15** and **Table 2-16**, respectively.

NPV10	1P	2P	3P
Gross Project US$ MM	582	897	–
Net to SOCO US$ MM	140	251	–

Table 2-15: El Fayum Block – Valuation of the Reserves – as of 30th June 2018

Discount Factor	NPV US$ Million	1P	2P	3P
NPV0	Gross Project	791	1,319	–
	Net to SOCO	192	373	–
NPV5	Gross Project	672	1,074	–
	Net to SOCO	162	302	–
NPV10	Gross Project	582	897	–
	Net to SOCO	140	251	–
NPV15	Gross Project	512	766	–
	Net to SOCO	122	212	–

Table 2-16: El Fayum Block – Valuation Sensitivities for Discount Factor – as of 30th June 2018

LR, as the Competent Person, has completed the necessary reviews and due diligence during the CPR process and has revised SOCO's assessments where applicable.

2.8 *HSSE and CSR*

2.8.1 *Health, Safety, Security and Environment (HSSE)*

LR have not visited any of the sites to make its own assessment of the HSSE systems, processes or activities first hand.

Petrosilah have a Health, Safety and Environment (HSE) Manual designed to provide the company's standards and guidelines for basic safety policies, procedures and precautions to be incorporated in the Company's operations. Petrosilah requires its employees and contractors to have read and have a basic understanding of the rules and policies contained within the HSE Manual.

Petrosilah's goal is to eliminate injuries, control losses, and to promote good environmental, safety, and health attitudes and practices by actively seeking the full cooperation of all employees and contractors.

Petrosilah records various HSE statistics to track Key Performance Indicators (KPIs) including fatalities, lost workday cases, lost time injuries, restricted duty incidents, medical aid incidents, first aid incidents, near misses, vehicle incidents and kilometres driven. The last reported Lost Time Injury was in 2015.

To comply with the European Bank for Reconstruction and Development (EBRD) loan requirements, Merlon El Fayum implemented an Environmental and Social Action Plan (ESAP) in 2015. EBRD-financed projects are expected to be designed and operated in compliance with good international practices relating to sustainable development. To help achieve this, EBRD defined ten performance requirements covering the key areas of environmental and social issues and impacts. The performance requirements provide a base from which clients can improve the sustainability of their business operations. EBRD states that where possible, projects should avoid adverse impacts on workers, communities, and the environment. If avoidance is not possible, negative impacts should be reduced, mitigated or compensate for, as appropriate.

Regular audits are performed by independent organisations on behalf of the EBRD. The Petrosilah operations were the subject of audits in May 2015 and January 2018. All findings, recommendations and actions are documented in audit reports. According to the IM, Merlon El Fayum is in the process of implementing identified changes which includes the appointment of additional personnel to implement certified management systems and improve overall environmental and social performance.

Merlon El Fayum initiatives in 2018 include ISO 14001 and OHSAS 18001 certification although the status of these is unknown at the time of writing this CPR.

2.8.2 *Corporate Social Responsibility (CSR)*

According to the Environmental, Health, Safety and Social Monitoring Visit report written by MICA Environmental in January 2018, the ESAP includes a requirement to provide a Social Impact Assessment (SIA). The report states that Environics completed an SIA document in December 2017 and that this was sent to the EBRD together with a Biodiversity Impact Assessment and Stakeholder Engagement Plan. Lloyd's Register has not seen these documents.

Lloyd's Register found no other evidence of CSR related documentation, activities or community engagement within the data provided.

3. References

REGULATORY/STANDARDS

Financial Conduct Authority (FCA) -Prospectus Rule 5.5.3(R)(2)(f).

- https://www.handbook.fca.org.uk/handbook/PR.pdf

European Securities and Markets Authority (ESMA) - The consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive (paragraphs 131 to 133).

- https://www.esma.europa.eu/sites/default/files/library/2015/11/2013-319.pdf

Principles, Definitions and Guidelines of the Petroleum Resources Management System (PRMS) sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE) in 2007.

- https://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf
- https://www.spe.org/en/industry/Petroleum-Resources-Management-System-2018

DATA/REPORTS

Virtual Data Room (hosted by Intralinks)

- General Data (Information Memorandum, Management Presentation, concession background, independent reserves report, field development plans, field operations and infrastructure)
- Geological Data (regional, block specific, petroleum systems, reservoir summaries, geological studies)
- Geophysical Data (overview, 3D acquisition & processing, interpretation & mapping, time-to-depth conversion, seismic attributes, inversion pilot, proposed programmes)
- Petrophysical Data (overview, CPI logs, LAS logs (selected), core data review, summary tables, report)
- Petrel™ Models (model overviews, Petrel™ models)
- Well Data (list and data inventory, well data per development lease (directional surveys, final well reports, mud log, drilling fluids, completion, pressure, production, test, raw logs, workovers))
- Production Data (overview, oil & water production per well to 31st July 2018)
- Reservoir Data (SCAL, bottom-hole pressure, PVT, XPT, sector simulation models,)
- Operations & Infrastructure Data (drilling/completion/workover plans, facilities, pipelines, flowlines, HS&E)
- Resources & Opportunities Overview (Seller's assessments, base case and upside, recompletion opportunities, field development plans, growth plans)
- Legal and Financial Data (contracts, licences, economic model, human resources, corporate documents)

Physical Data Room (hosted by Seller in Houston)

- Petrel™ models and supporting geoscience data

TECHNICAL PAPERS (from SELLER)

Awad, G. M., 1984. Habitat of Oil in Abu Gharadig and Faiyum Basins, Western Desert, Egypt. AAPG Bulletin vol. 68, no. 5, p. 564-573.

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Hammad, M.M., Awad, S. A., El Nady, M.M., Mousa, D.A., 2010. The Subsurface Geology and Source Rocks Characteristics of Some Jurassic and Cretaceous Sequences in the West Qarun Area, North Western Desert, Egypt. Energy Sources, Part A: Recovery, Utilization and Environmental Effects 32, p. 1885-1898.

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Kusky, T. M., Ramadan, T.M., Hassaan, M.M., Gabr, S. 2011. Structural and Tectonic Evolution of El- Faiyum Depression, North Western Desert, Egypt Based on Analysis of Landsat ETM+, and SRTM Data. Journal of Earth Science, vol. 22, no. 1, p. 75-100.

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Mousa, D.A., Abdou, A.A., Gendy, N.H., Shehata, M.G., Kassab, M.A., Abuhagaza, A. A. 2014. Mineralogical, Geochemical and Hydrocarbon Potential of subsurface Cretaceous Shales, Northern Western Desert, Egypt. Egyptian Journal of Petroleum, p. 67-78.

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Pasley, M. A., Artigas, G., Nassef, O., Comisky, J., 2008. Depositional Facies Controls on Reservoir Characteristics in the Middle and Lower Abu Roash 'G' Sandstones, Western Desert, Egypt. AAPG International Conference and Exhibition. Search and Discovery Article #50181.

Younes, M.A., 2012. Hydrocarbon Potentials in the Northern Western Desert of Egypt. Crude Oil Exploration in the World. Chapter 2, p. 23-46.

4. Glossary of Terms

Below are common oil and gas industry terms; some of which may have been used in this report.

Term	Meaning
1C	Low Estimate Contingent Resources
2C	Best Estimate Contingent Resources
3C	High Estimate Contingent Resources
1P	Proved Reserves. Equal to P1
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
1U	Unrisked low estimate qualifying as Prospective Resources
2U	Unrisked best estimate qualifying as Prospective Resources
3U	Unrisked high estimate qualifying as Prospective Resources
AAPG	American Association of Petroleum Geologists
acre	Area in acre
AOF	Absolute Open Flow
API	American Petroleum Institute gravity
B	billion
bbl	barrels
bbl/d	barrels per day
BBTUD	Billions of British Thermal Units per Day
BOE	barrel of oil equivalent
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
B_w	water volume factor
bcpd	barrels of condensate per day
bopd	barrels of oil per day
BTU	British Thermal Unit
Bscf	billions of standard cubic feet
bwpd	barrels of water per day
°C	Temperature in Centigrade
cc	cubic centimetre

Term	Meaning
CGR	condensate gas ratio
Contractor	Party involved in extracting hydrocarbons from the Property
COP	Cessation of production
cP	Viscosity in centipoise
CPI	Computer-processed Interpretation (petrophysics)
DCQ	daily contracted quantity direct
DST	Drill Stem Test
ESMA	European Securities and Markets Authority
EGPC	Egyptian General Petroleum Corporation
Entitlement Volumes	the volumes of oil and/or gas which a Contractor receives under the terms of the licence
ELT	Economic Limit Test
EUR	Estimated Ultimate Recovery
°F	Temperature in Fahrenheit
FBHP	flowing bottom hole pressure
FFP	Full Field Development
FTHP	flowing tubing head pressure
FTHT	flowing tubing head temperature
ft	Length in feet
ft^3	Volume in cubic feet
ftSS	depth in feet below sea level
GDT	Gas Down-To
GEF	Gas Expansion Factor
GIP	Gas in Place
GIIP	Gas Initially-In-Place
gm	Weight in grams
gm/cc	Density in grams per cubic centimetre
GOR	gas/oil ratio
GR	Gamma Ray
GRV	gross rock volume
GSA	Gas Sales Agreement
GWC	gas water contact

Term	Meaning
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
HKEx	Hong Kong (Stock) Exchange
HSE	Health, Safety, Environment
KB	Kelly Bushing (elevation in metres)
km	Length in kilometres
km^2	Area in square kilometres
km^3	Volume in cubic kilometres
Ib	Weight in pounds
Ib/cuft	Density in pounds per cubic feet
LWD	Logging while drilling
m	Length in metres
MM	Million
MD	measured depth
mD	permeability in milliDarcies
MDT	Modular Formation Dynamics Tester
m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	Millions of standard cubic feet per day
MoD	Money of the Day - Cash values calculated to include the effect of inflation
MT	Thousands of Tonnes
NTG	Net-to-gross ratio
NPV	Net Present Value
OWC	Oil-water contact
P1	Proved Reserves
P2	Probable Reserves
P3	Possible Reserves
P_{10}	Probability of 10% chance the value would be larger than the reported and considered high value
P_{50}	Probability of 50% chance the value would be larger than the reported and considered best value

Term	Meaning
P_{90}	Probability of 90% chance the value would be larger than the reported and considered low value
P_b	bubble point pressure
P_c	capillary pressure
petroleum	deposits of oil and/or gas
PHI	porosity fraction
PHIE	Effective porosity fraction
PHIT	Total porosity fraction
p_i	initial reservoir pressure
PIIP	Petroleum Initially In-Place
PRMS	Petroleum Resources Management System (SPE Terminology)
PSC	Production Sharing Contract
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	Pressure Volume Temperature
QPR	Qualified Person's Report
rcf	Volume in reservoir cubic feet
Real	Cash values calculated to exclude the effects of inflation
scf	standard cubic feet measured at 14.7 pounds per square inch and 60°F
scf/d	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
SEG	Society of Exploration Geophysicists
SIMOPS	simultaneous operations
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SSE	Shanghai Stock Exchange
stb	stock tank barrels measured at 14.7 pounds per square inch and 60°F
stb/d	stock tank barrels per day
stb/MMscf	stock tank barrels per Million standard cubic feet measured at 14.7 pounds per square inch and 60°F
STOIIP	Stock Tank Oil Initially-In-Place

Term	Meaning
S_h	hydrocarbon saturation
S_w	water saturation
TPP	Trial Production Project
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
VLP	Vertical Lift Profile
V_{sh}	shale volume
WI	Working Interest
WC	water cut
WHP	Wellhead Platform
WPC	World Petroleum Council
Φ, POR	porosity

Figures

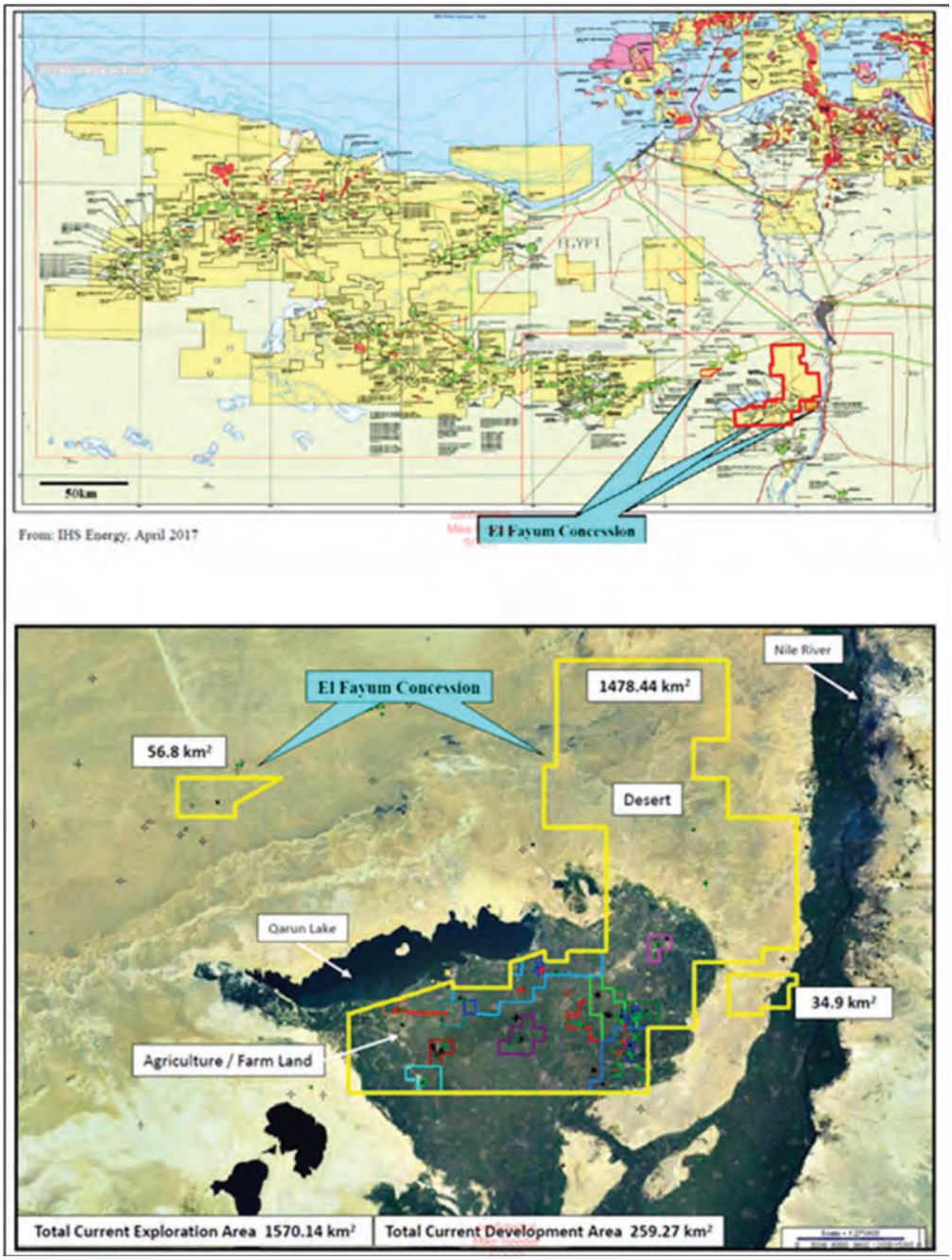


Figure 2-1: Location of the El Fayum Block, Regional Petroleum Activity and Terrain

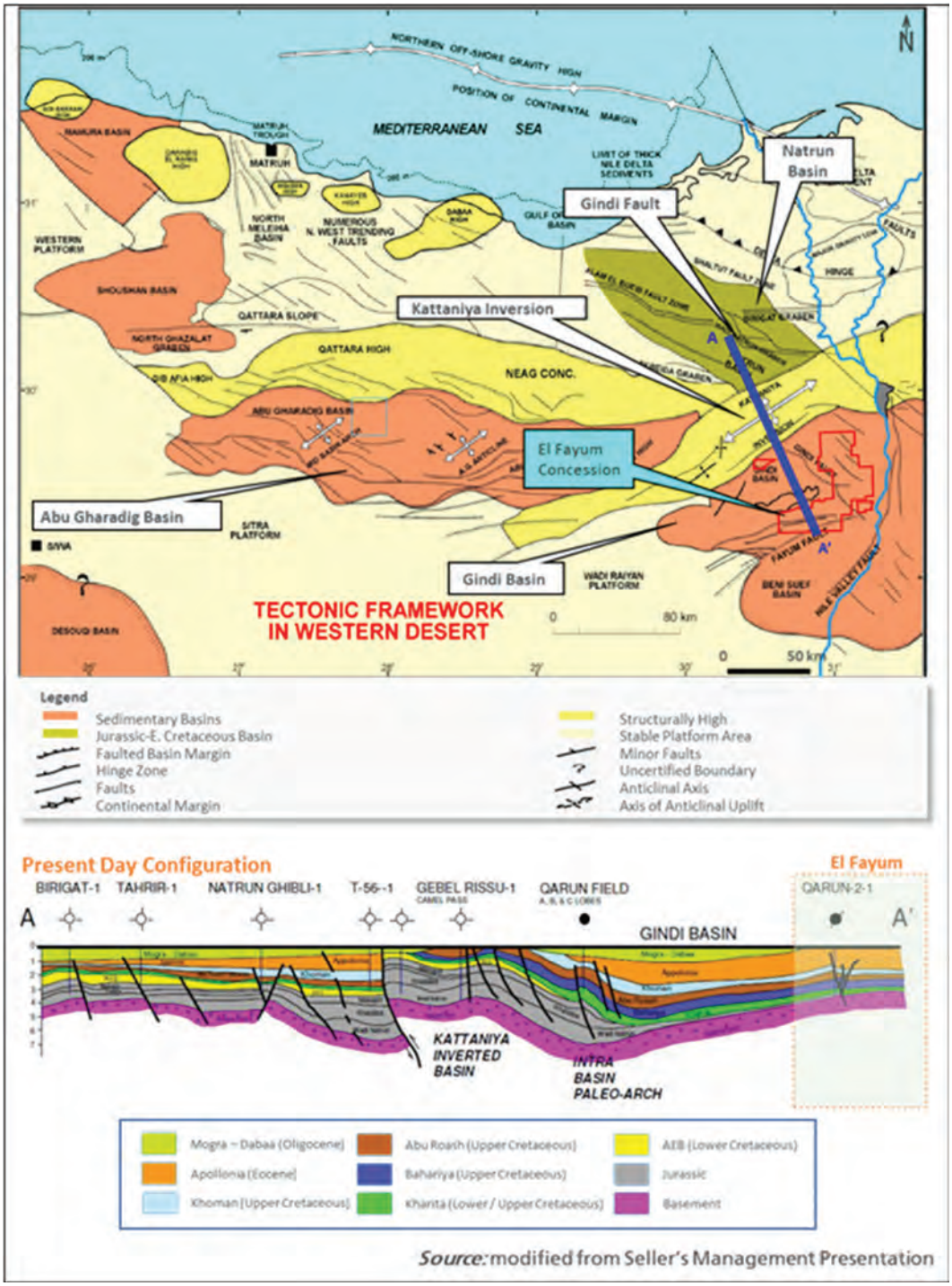


Figure 2-2: Western Desert - Tectonic Framework and Regional Cross Section

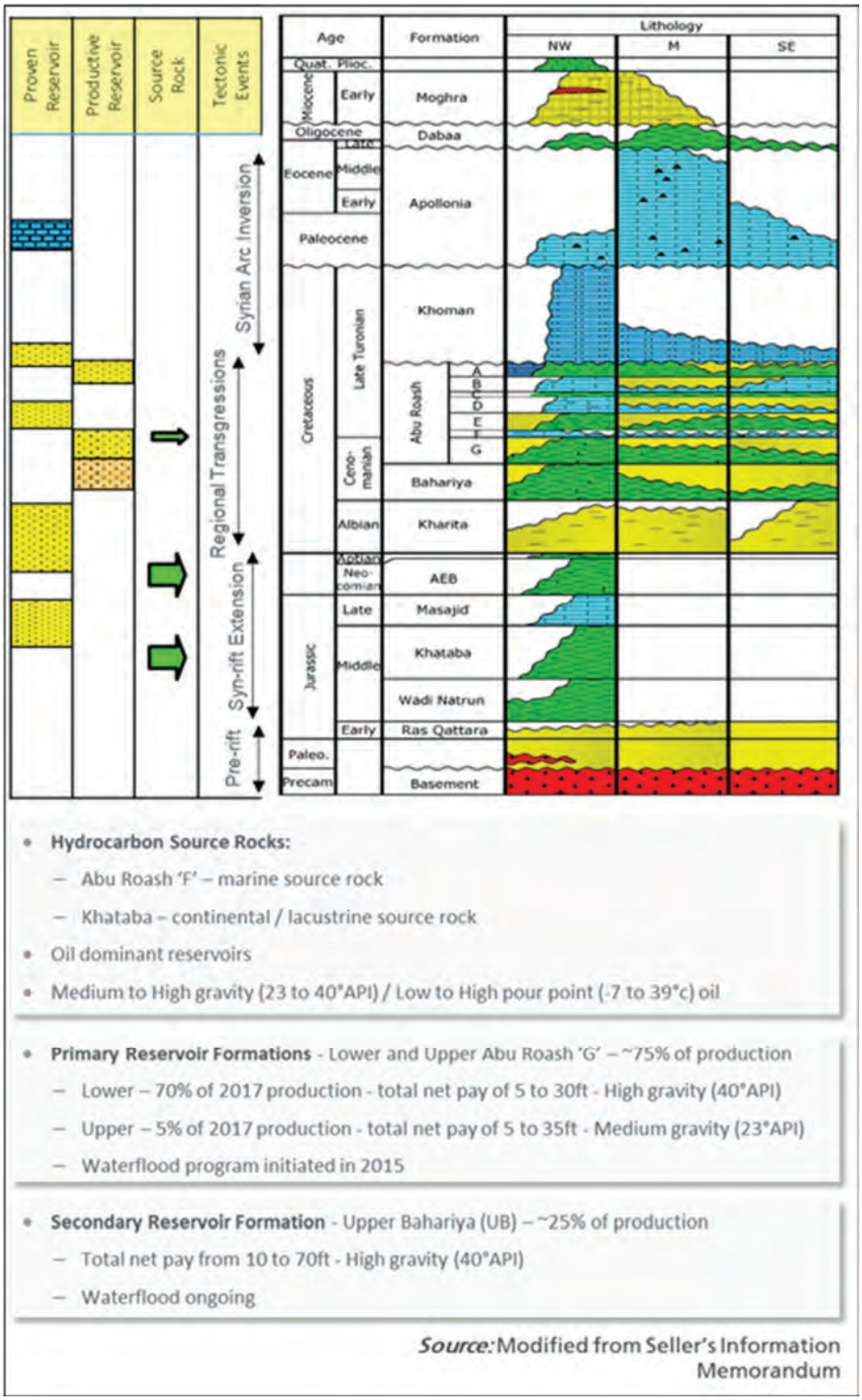


Figure 2-3: Generalised Stratigraphy and Petroleum System of the El Fayum Area

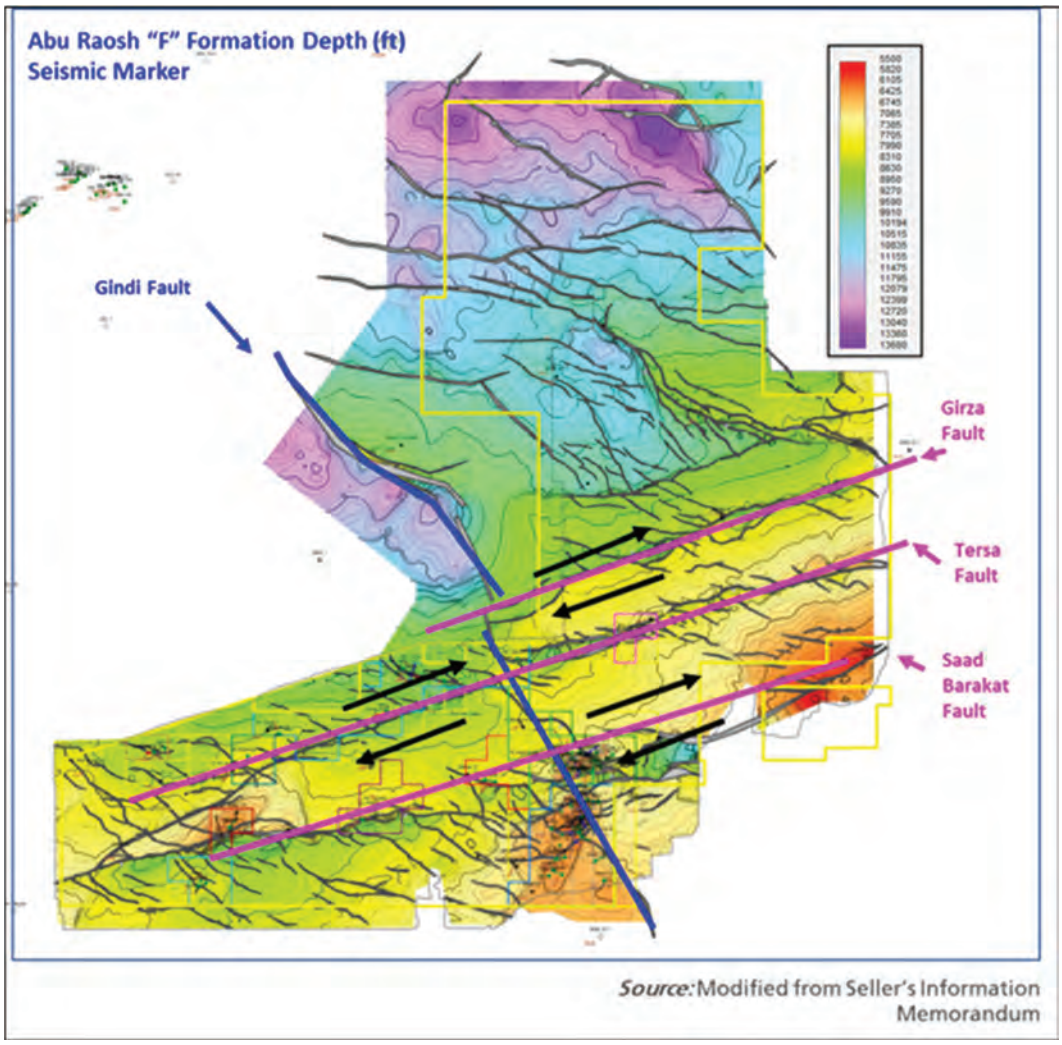


Figure 2-4: Structural Elements of the El Fayum Block – Abu Raosh "F" Formation Depth

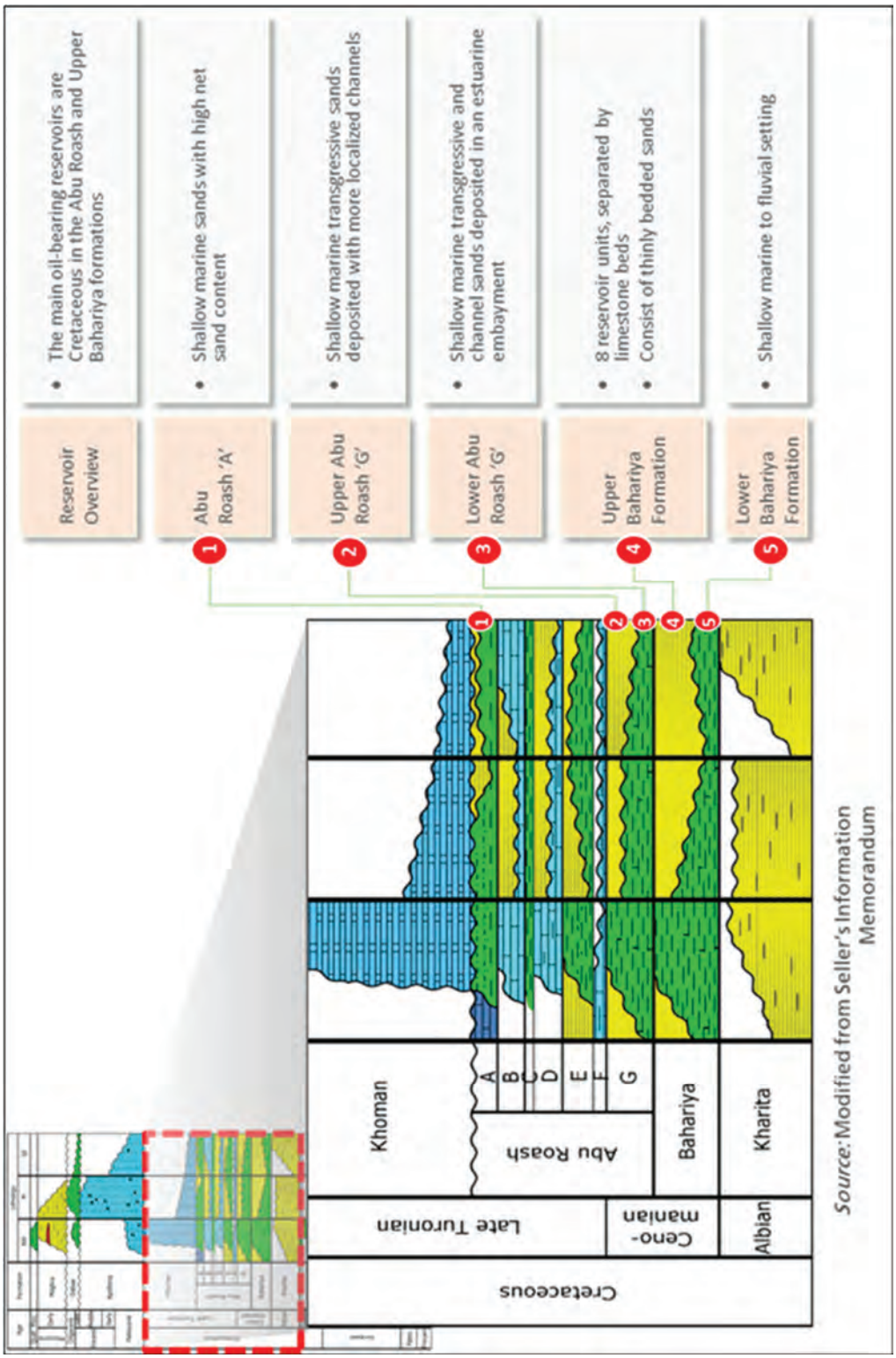


Figure 2-5: Reservoir Sections of the El Fayum Block

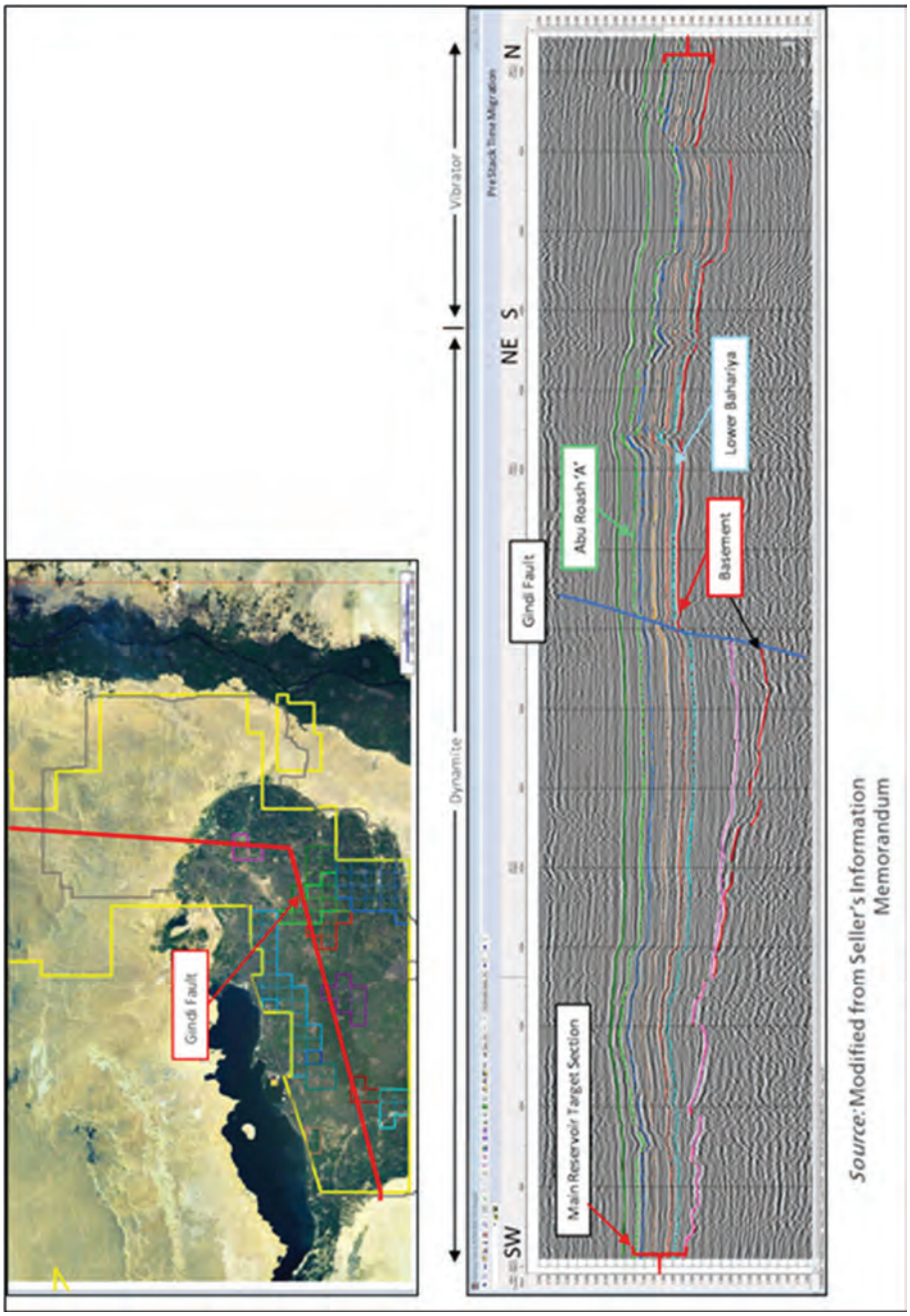


Figure 2-6: Arbitrary 3D Seismic Line Across the El Fayum Block

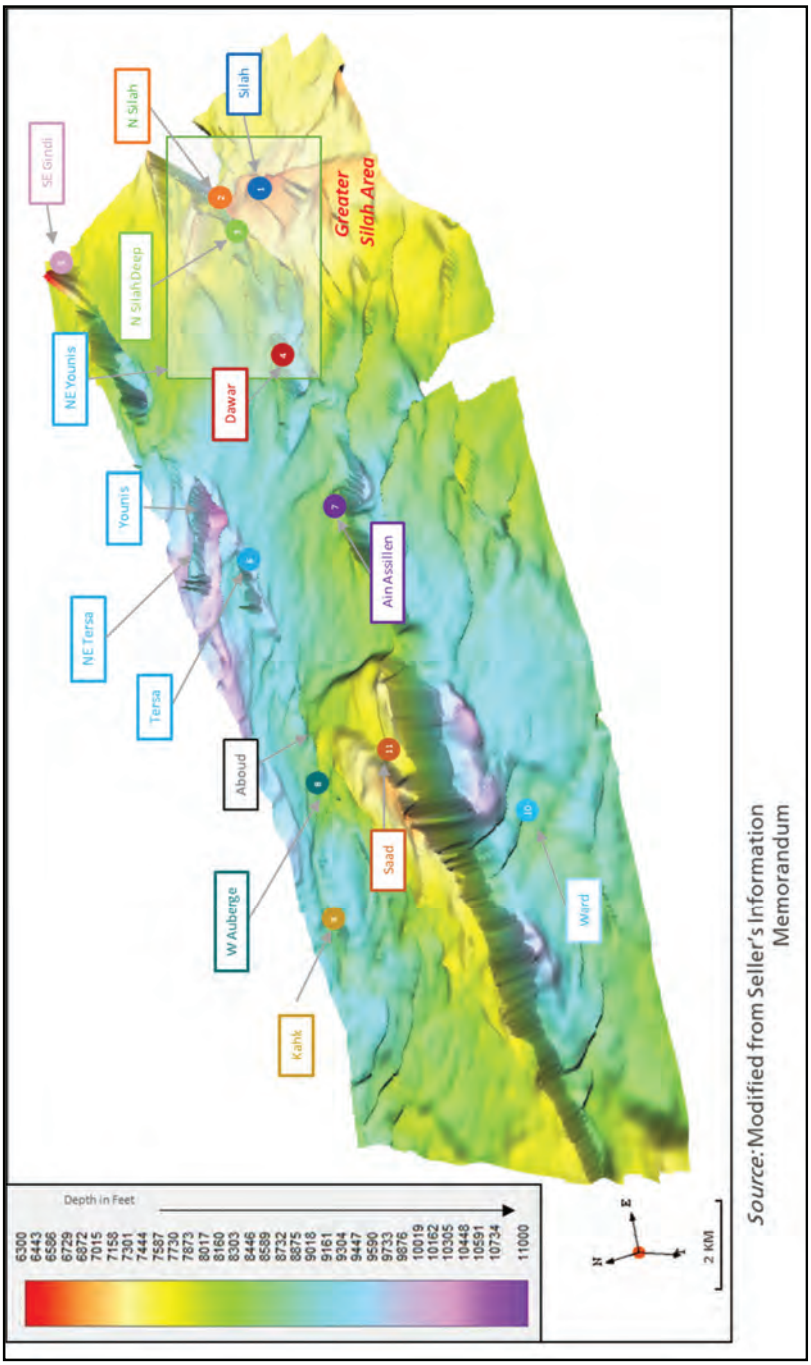


Figure 2-7: El Fayum Block Field Locations – Top Upper Bahariya Depth Structure

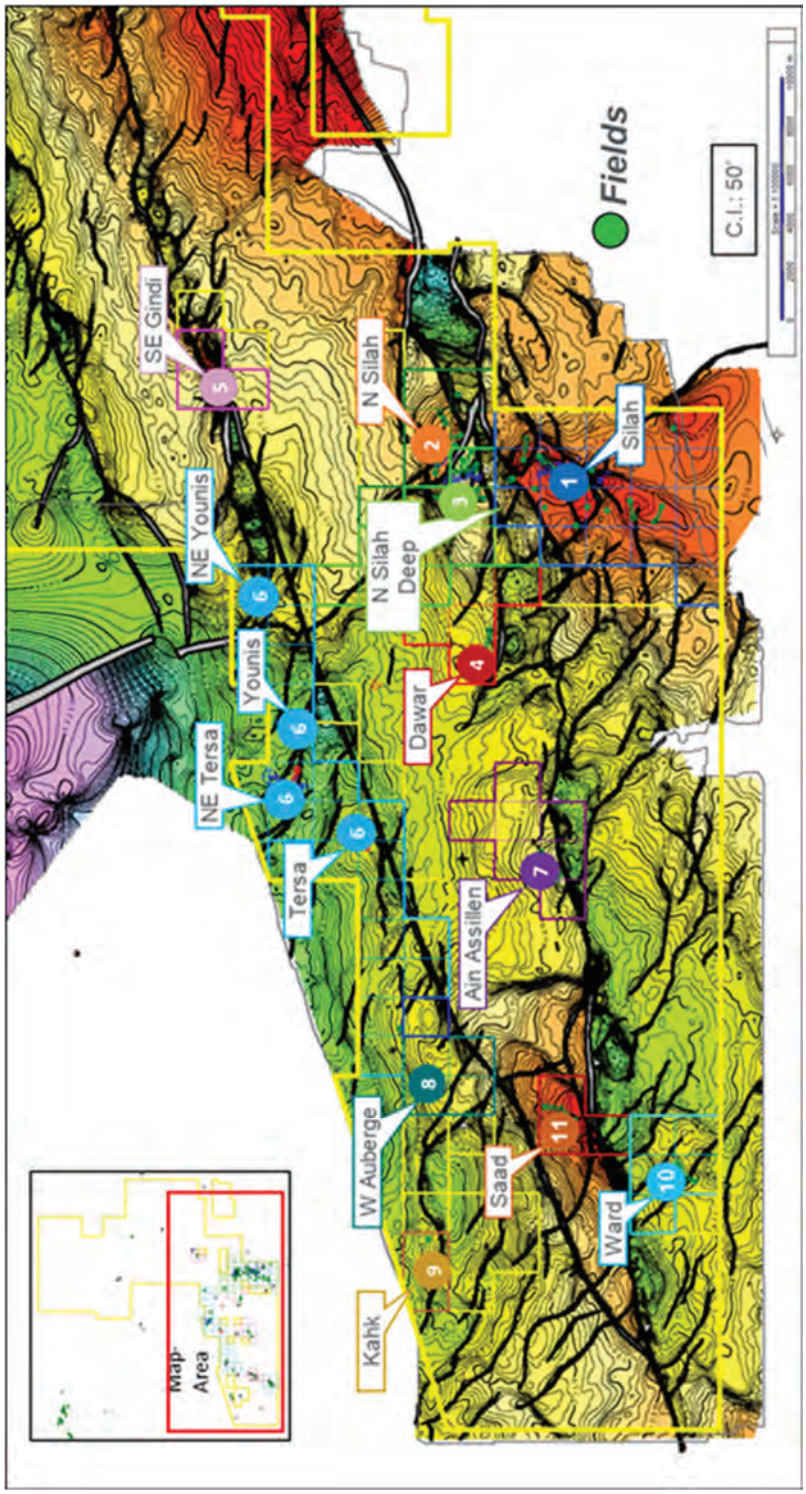


Figure 2-8: Development Lease Outlines - Upper Bahariya Depth Structure Map

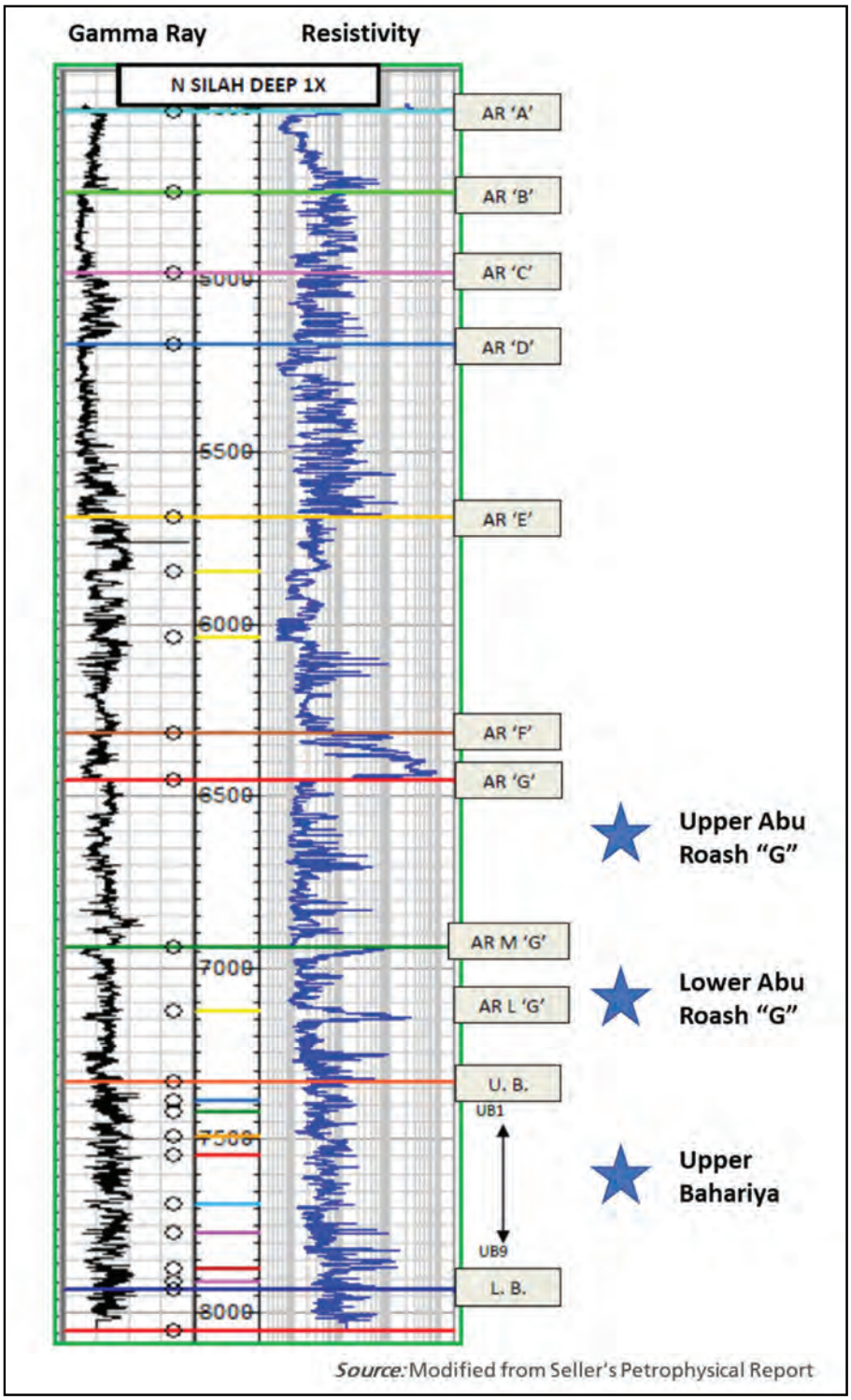
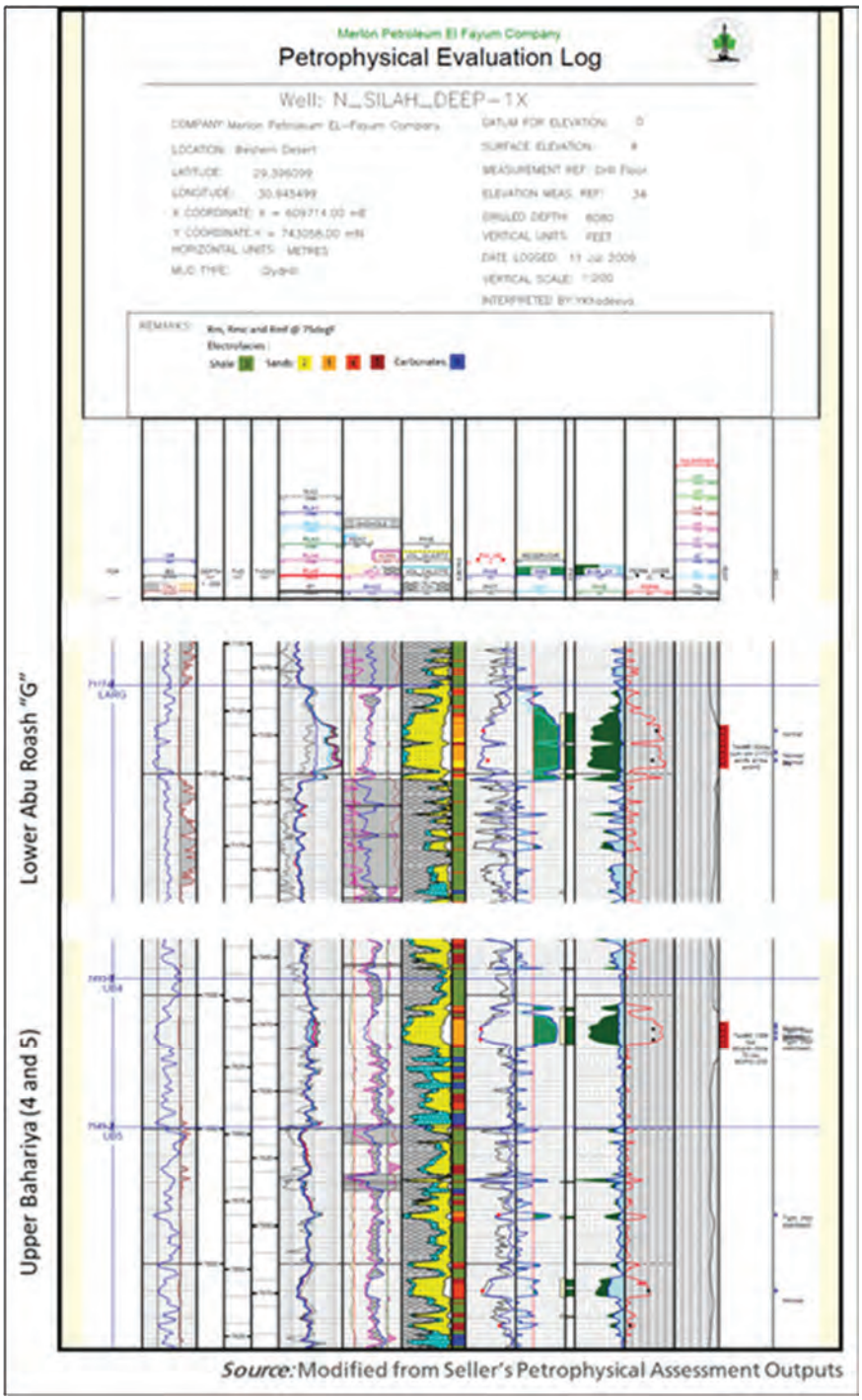


Figure 2-9: Petrophysical Type Log (North Silah Deep-1X Well)



Source: Modified from Seller's Petrophysical Assessment Outputs

Figure 2-10: Computer Processed Interpretation (CPI) Log (North Silah Deep-1X Well)

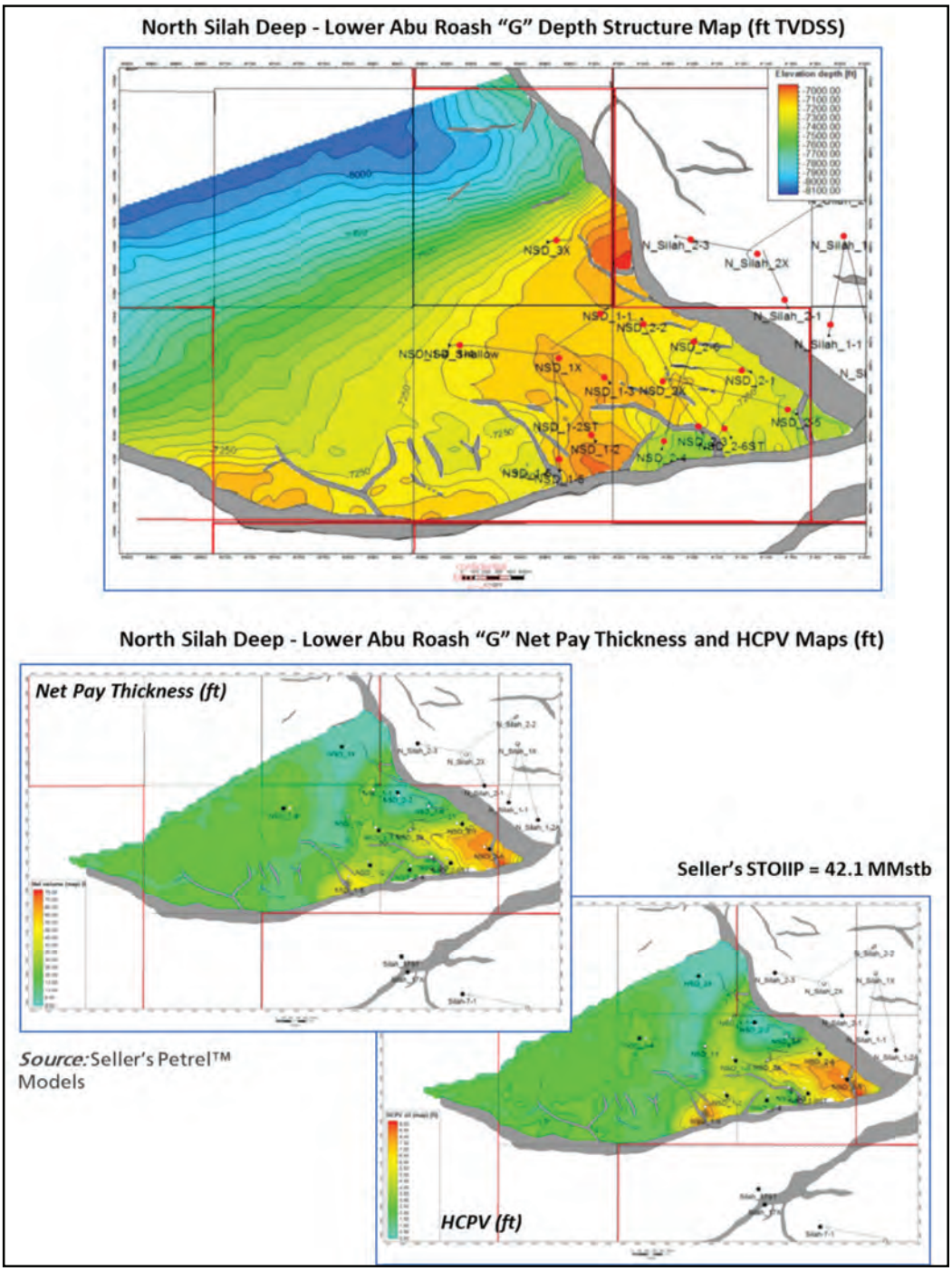


Figure 2-11: Depth Structure, Net Pay Thickness and HCPV Maps (North Silah Deep L AR-G)

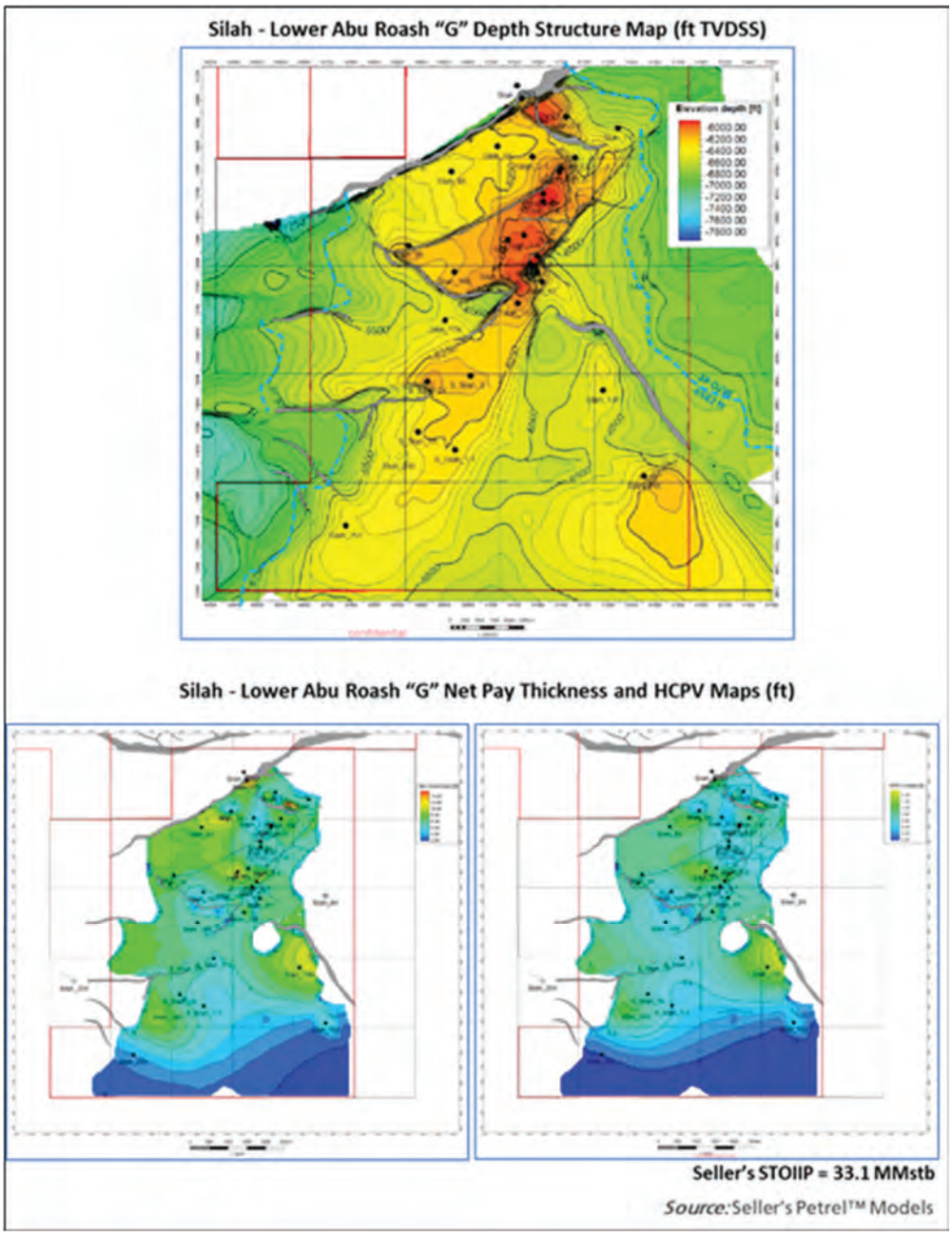


Figure 2-12: Depth Structure, Net Pay Thickness and HCPV Maps (Silah L AR-G)

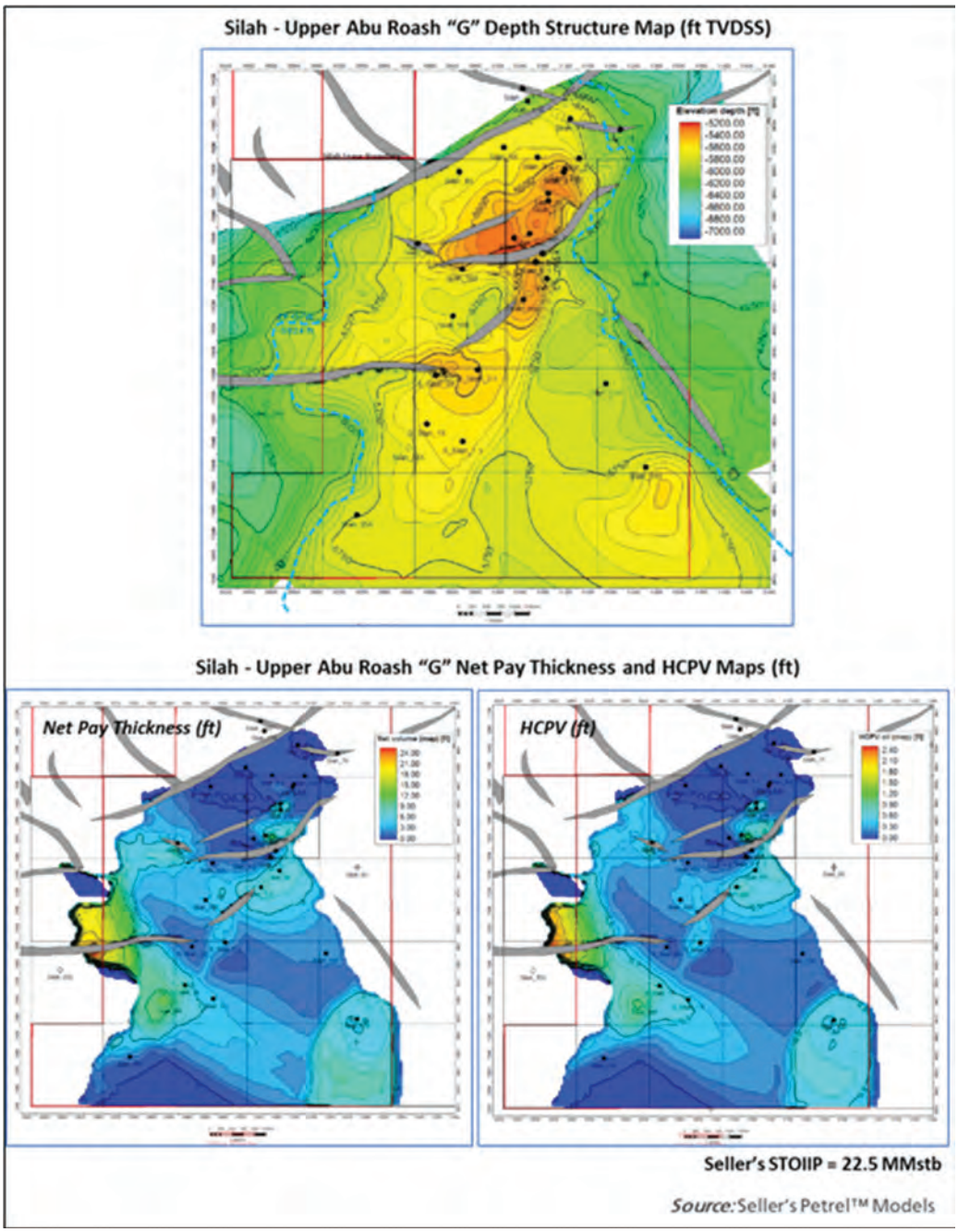


Figure 2-13: Depth Structure, Net Pay Thickness and HCPV Maps (Silah U AR-G)

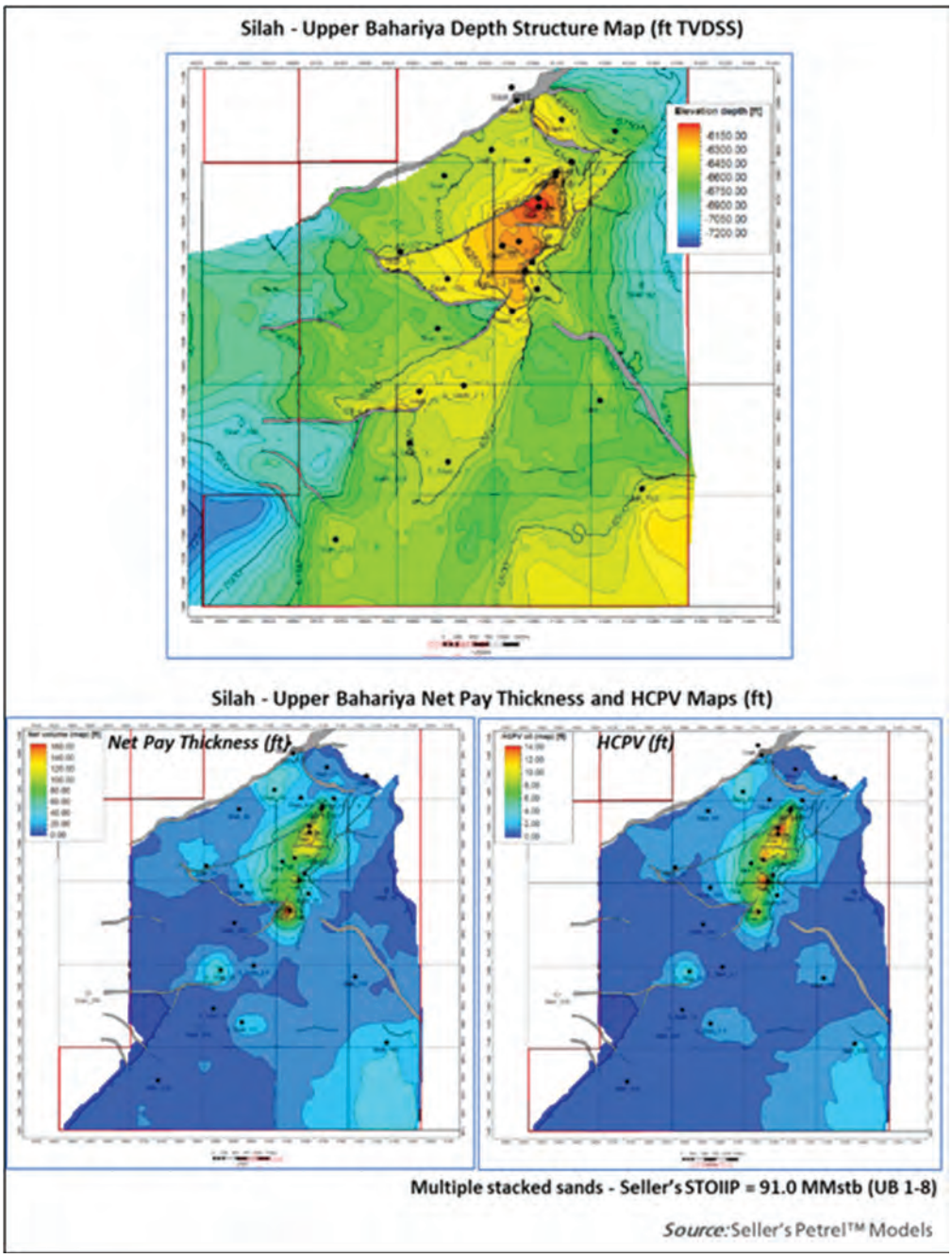


Figure 2-14: Depth Structure, Net Pay Thickness and HCPV Maps (Silah UB)

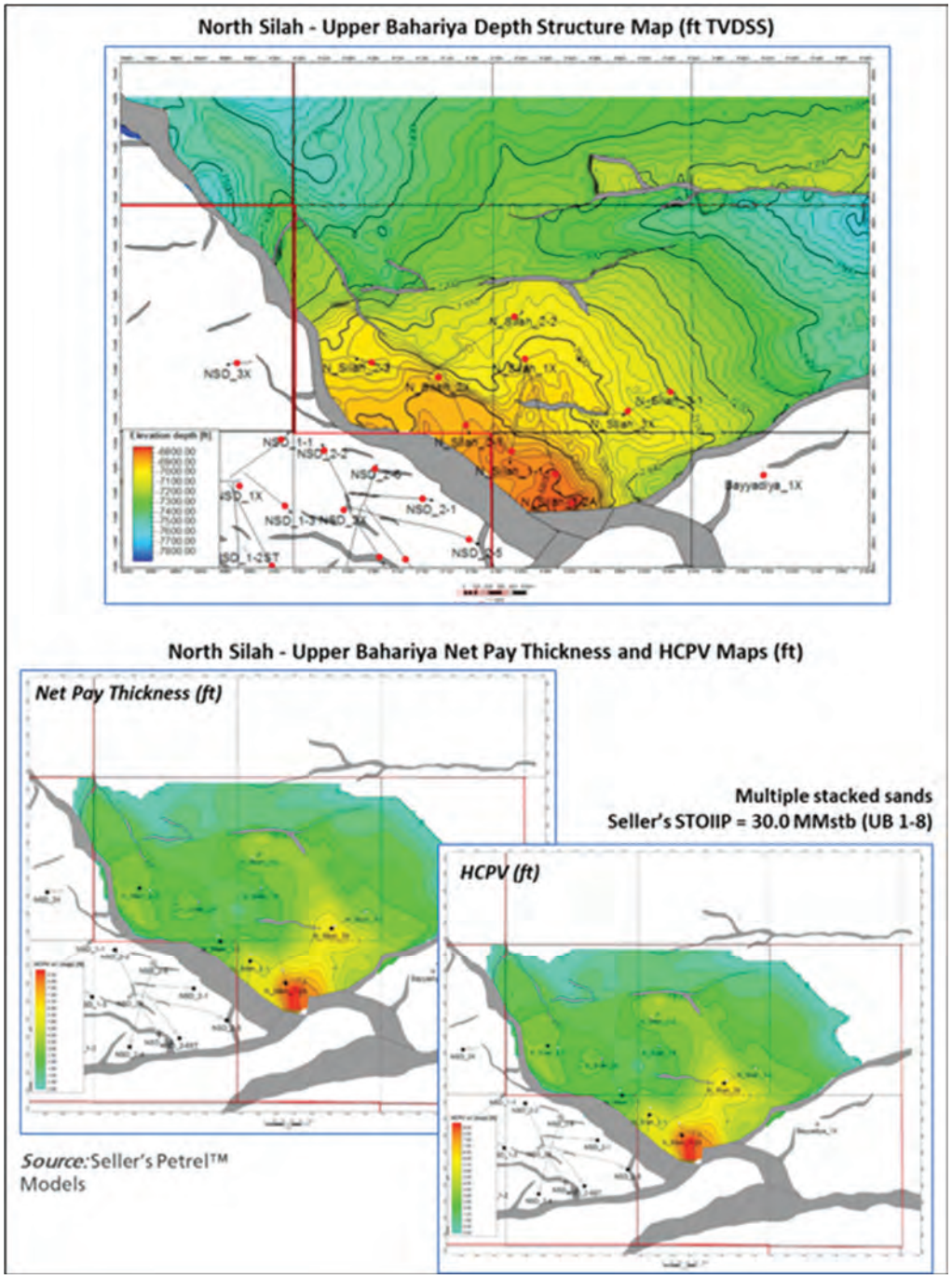


Figure 2-15: Depth Structure, Net Pay Thickness and HCPV Maps (North Silah UB)

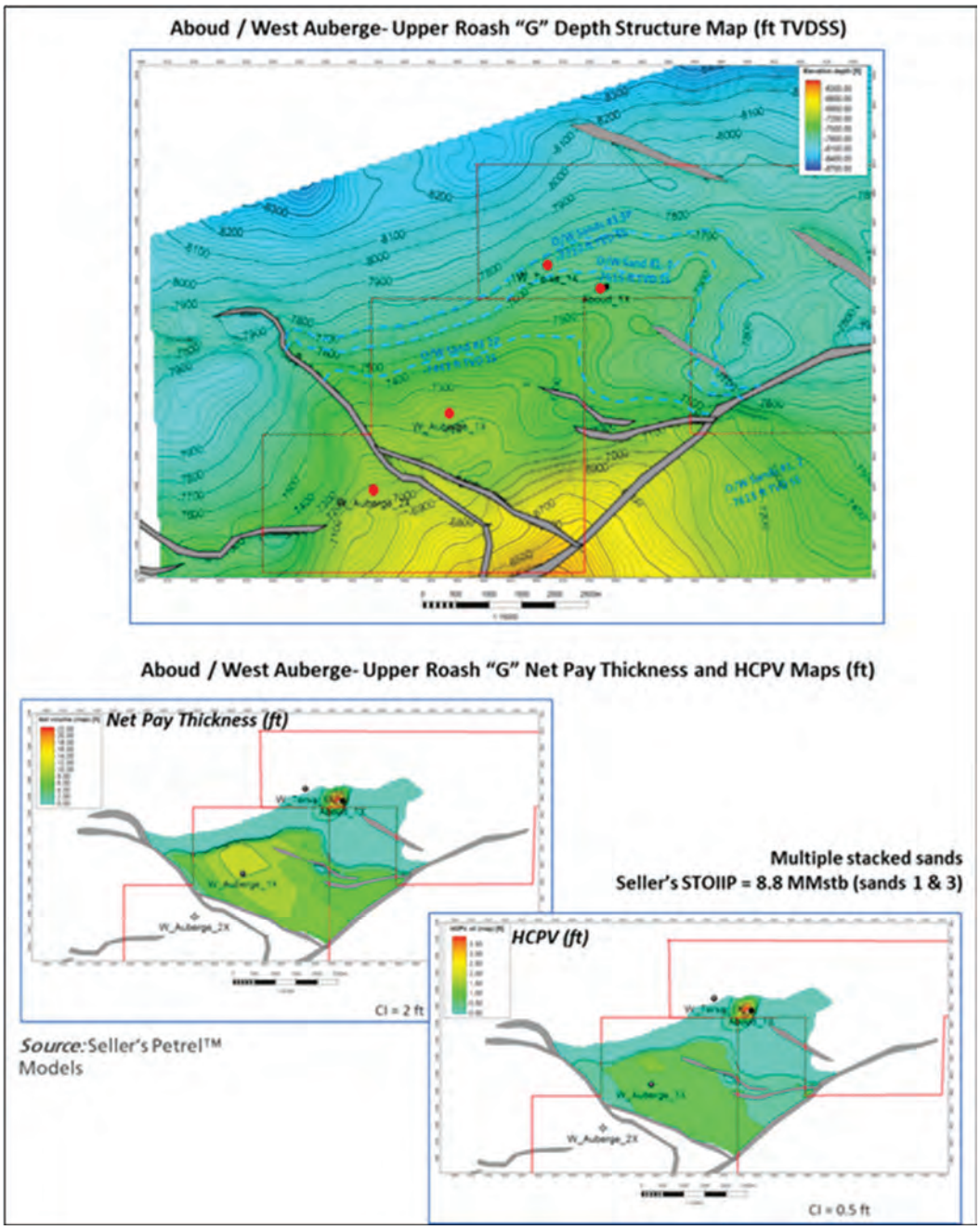


Figure 2-16: Depth Structure, Net Pay Thickness and HCPV Maps (Aboud/W Auberge U AR-G)

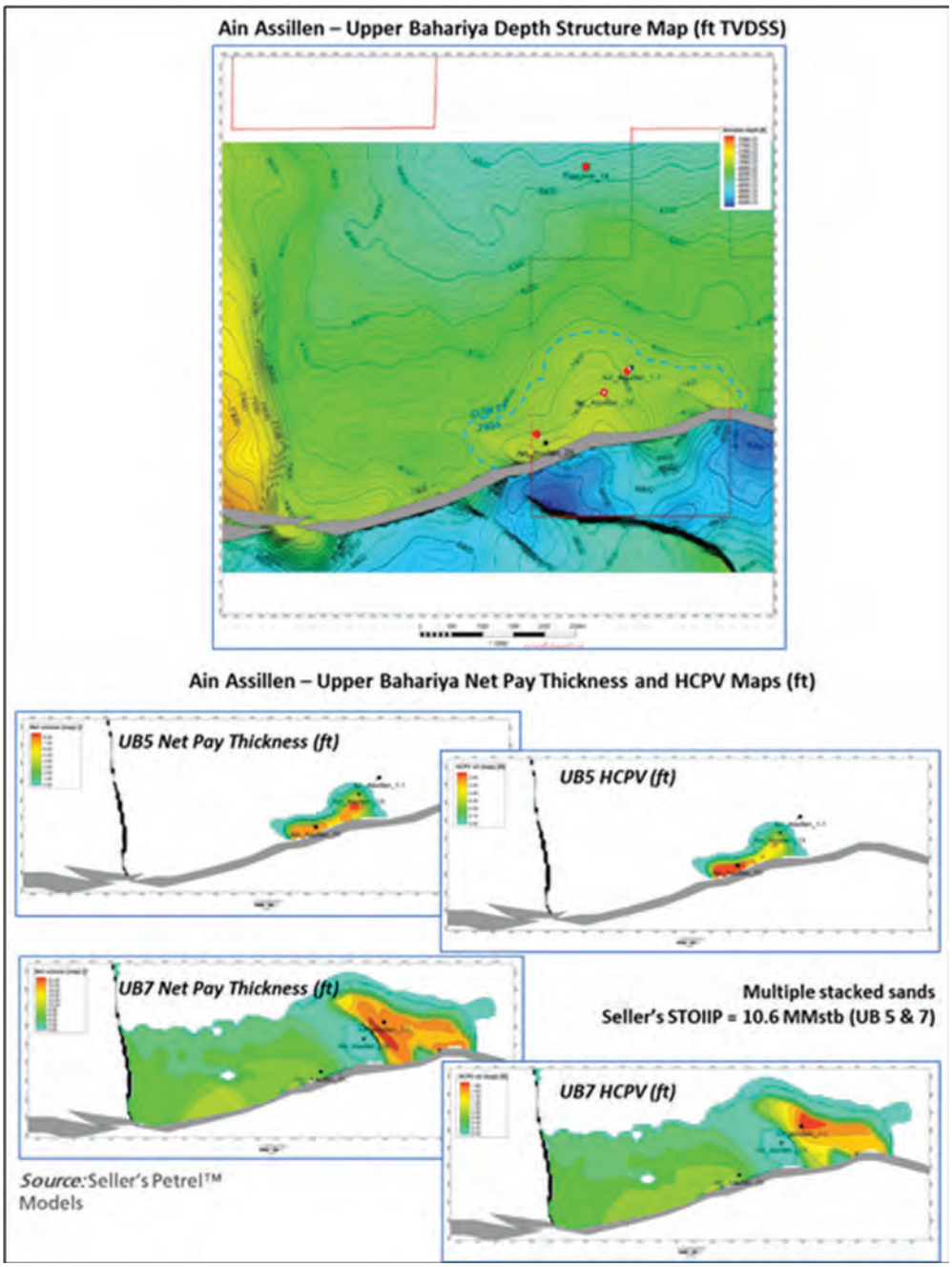


Figure 2-17: Depth Structure, Net Pay Thickness and HCPV Maps (Ain Assillen - UB)

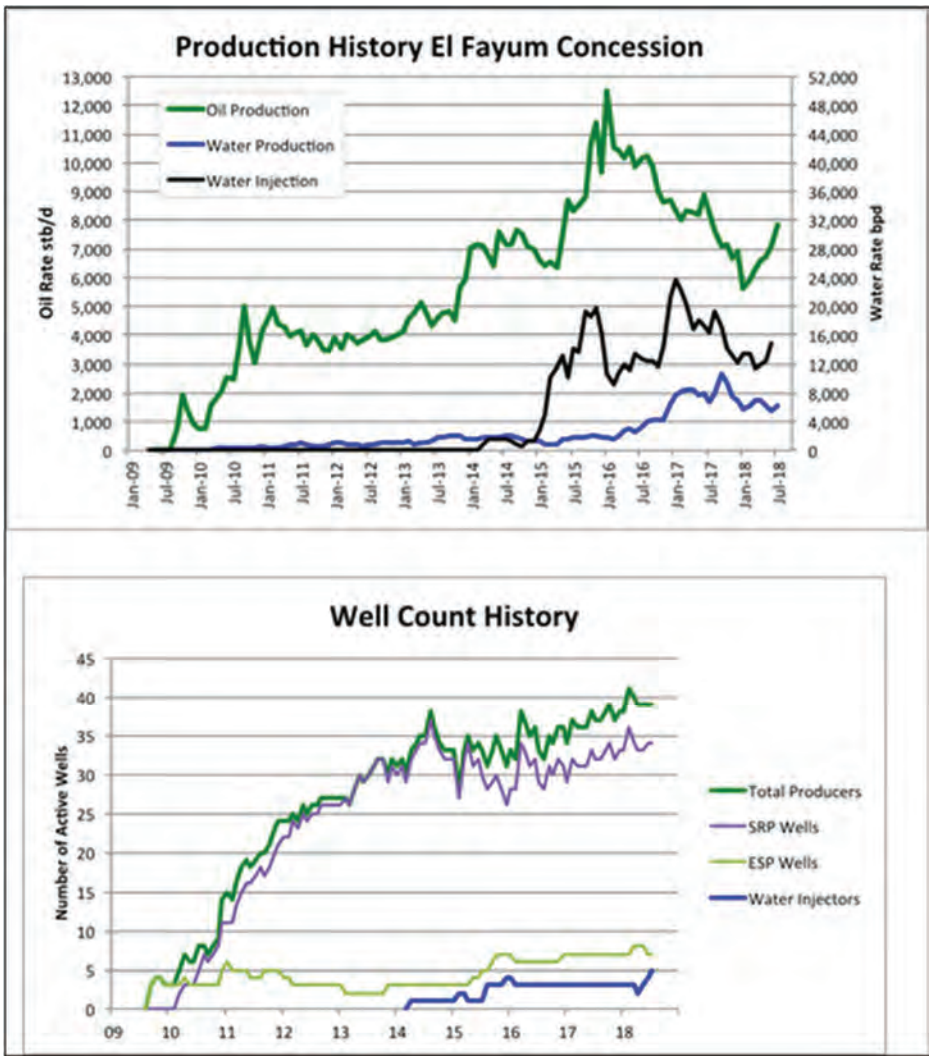


Figure 2-18: El Fayum Concession – Historical Production

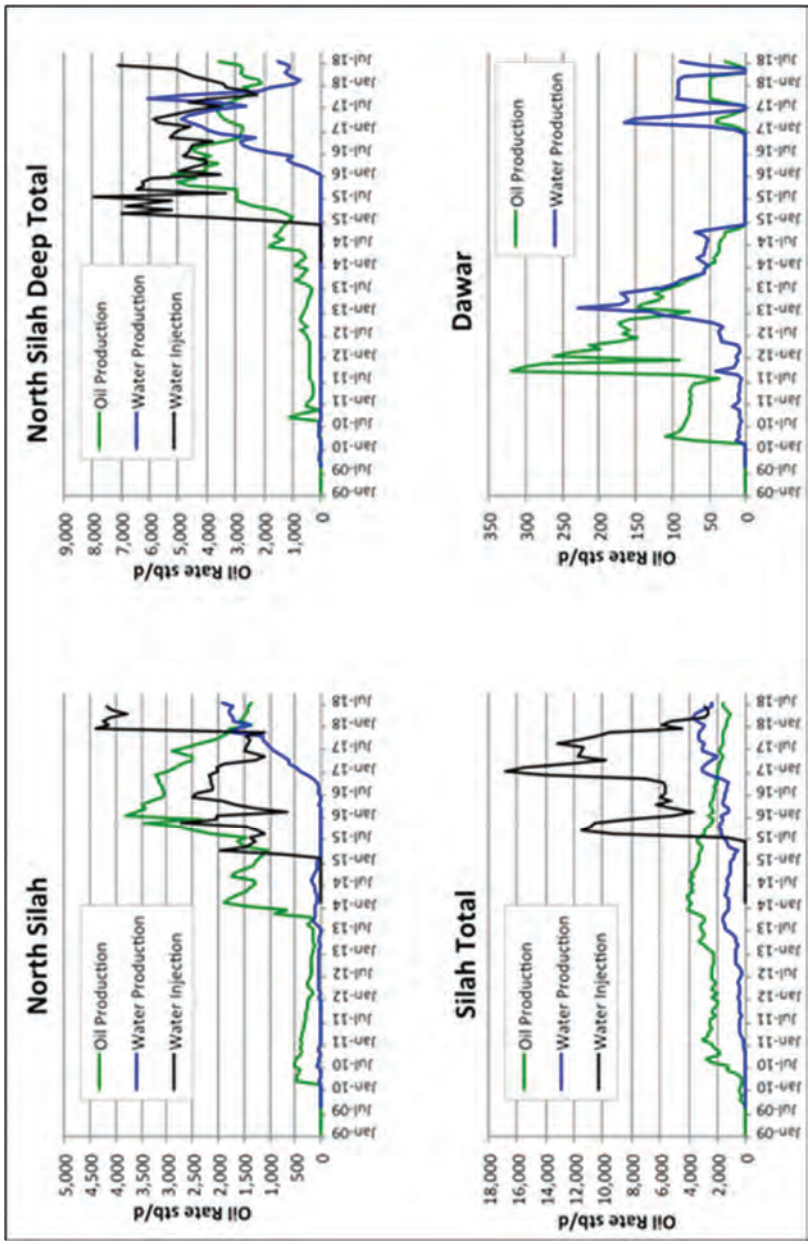


Figure 2-19: Greater Silah Area Fields– Historical Production

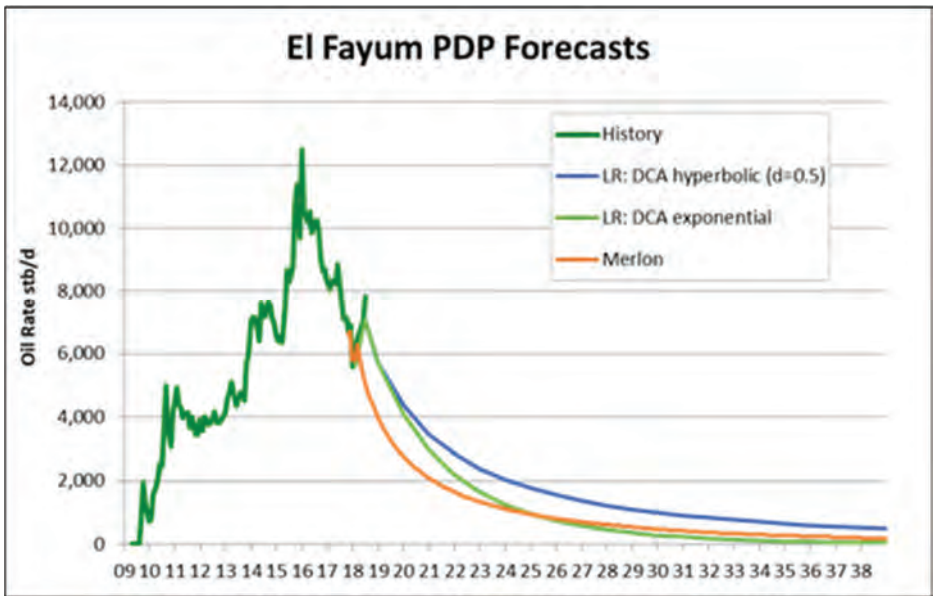


Figure 2-20: El Fayum – PDP Reserves Forecasts

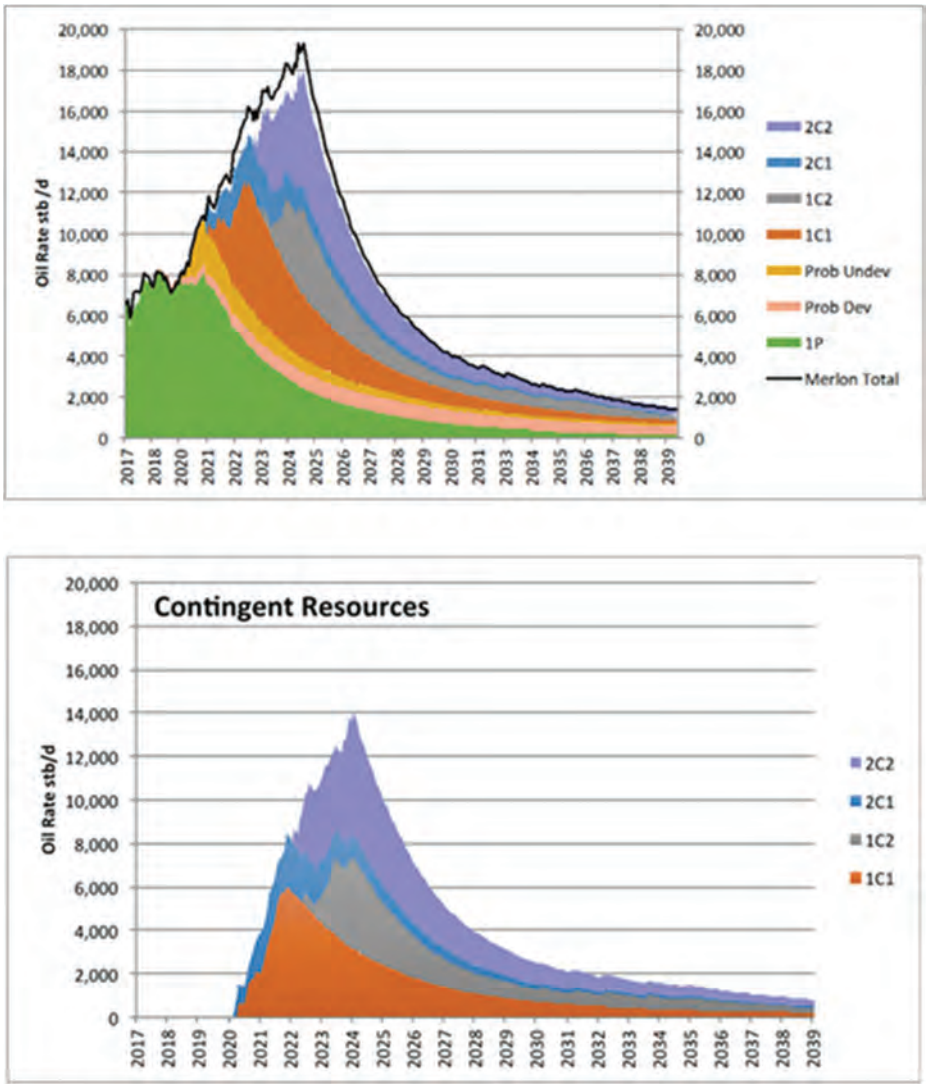


Figure 2-21: El Fayum – LR Oil Production Profiles – by incremental resource class

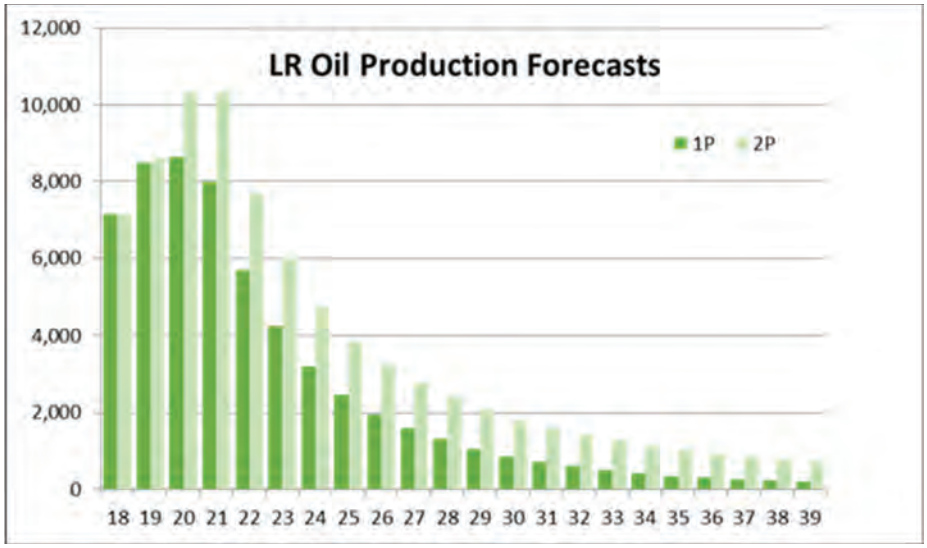


Figure 2-22: El Fayum – LR's Oil Production Forecasts (Reserves Class)

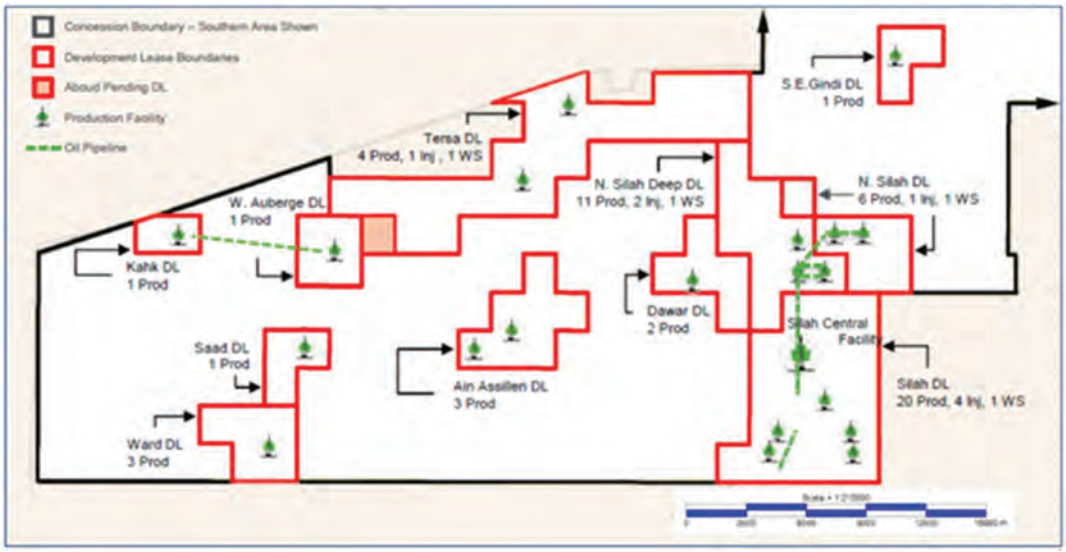


Figure 2-23: El Fayum Block – Existing Facilities

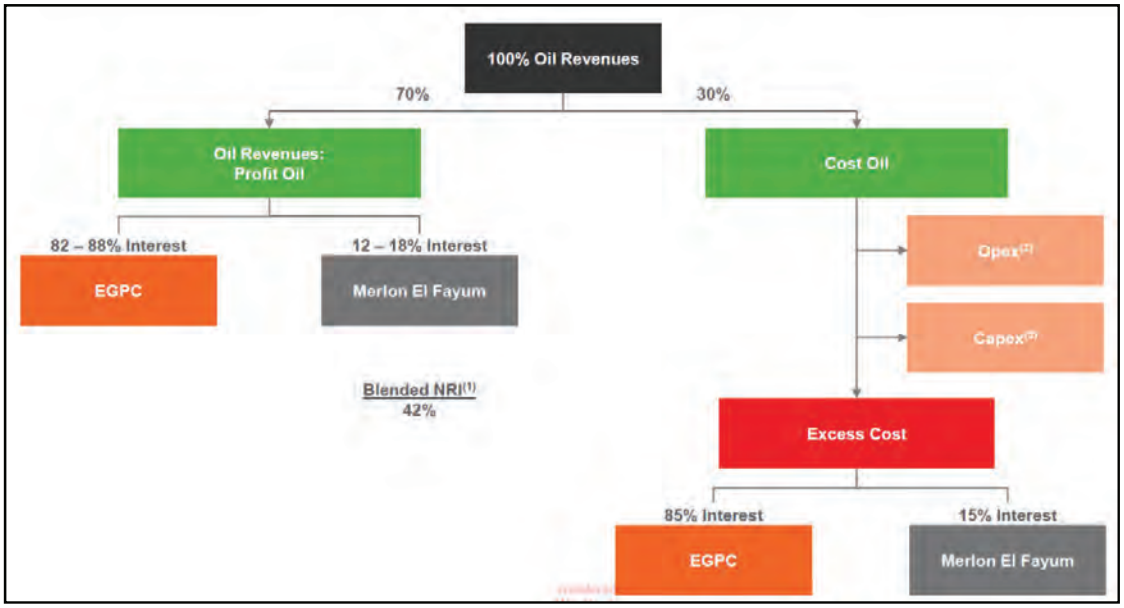


Figure 2-24: El Fayum Block – Existing Production Sharing Mechanisms

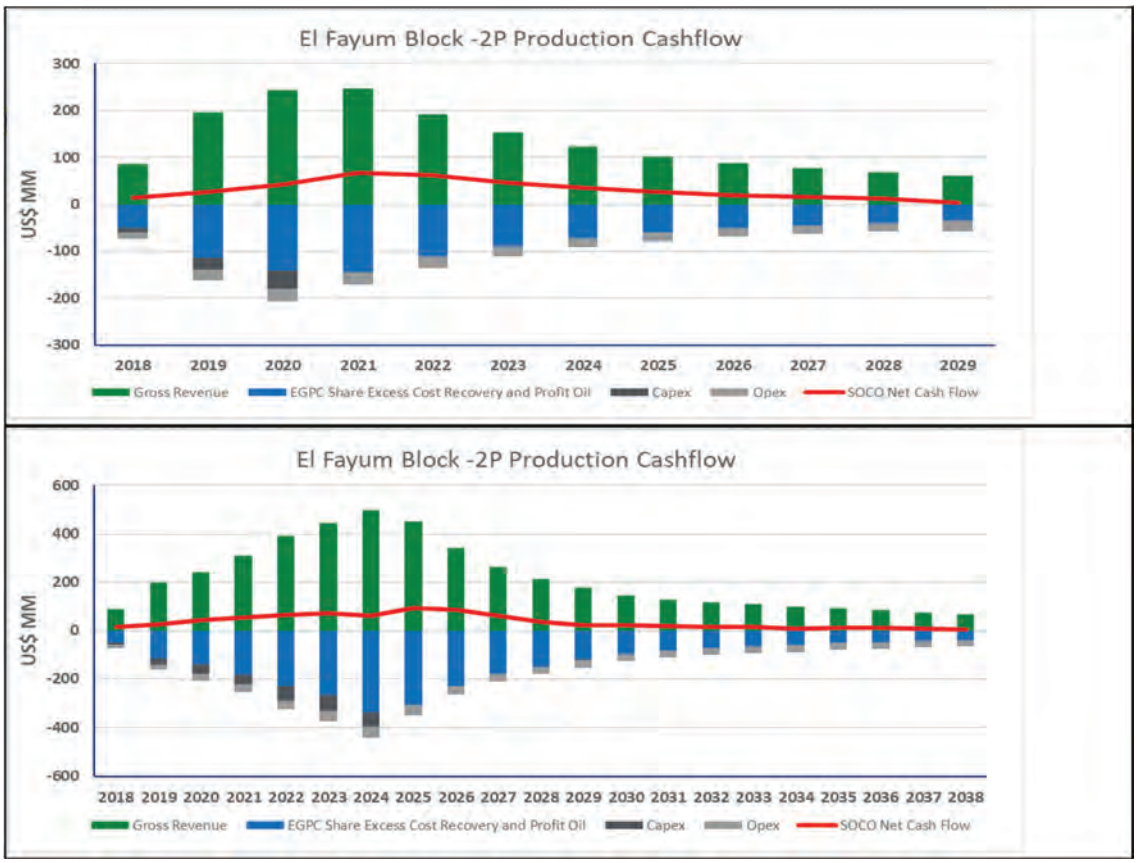


Figure 2-25: El Fayum Block – Cashflows

APPENDIX 1

PRMS RESERVES & RESOURCES DEFINITIONS

The following figures and tables have been extracted from the 2018 Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The complete document is available from:

- https://www.spe.org/en/industry/Petroleum-Resources-Management-System-2018

The following two illustrations; **Figure A1-1** and **Figure A1-2** pertain to the Classification Framework and the Project maturity sub-classes of the PRMS, which are discussed in **Table A1-1** to Table **A1-3**.

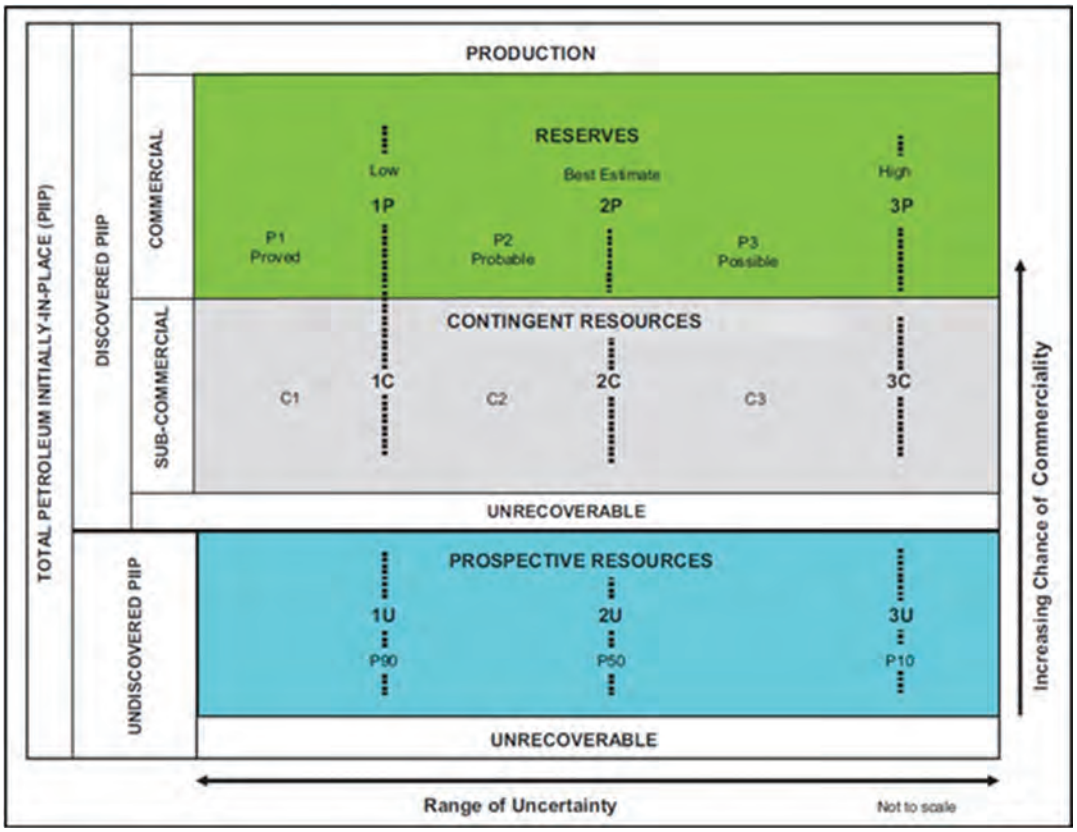


Figure A1-1. Petroleum Resources Classification Framework

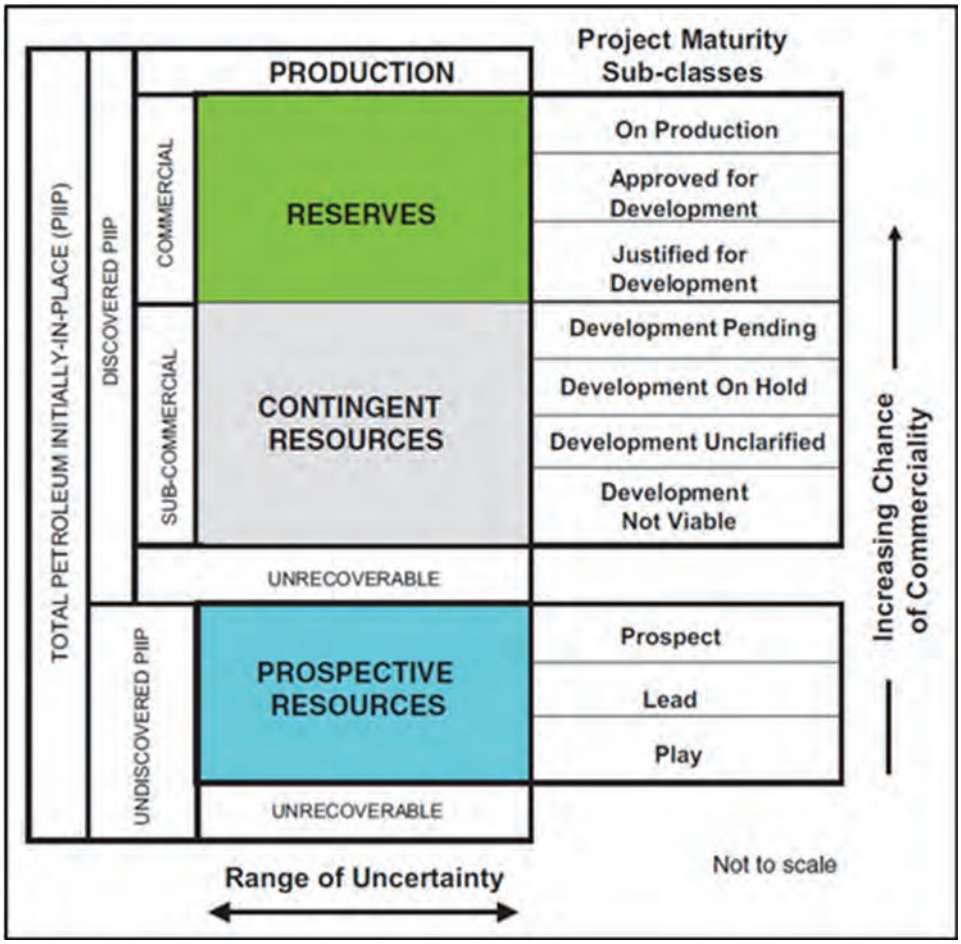


Figure A1-2. Project Maturity Sub-Classes

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 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 the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. 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 and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is 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.

Class/Sub-Class	**Definition**	**Guidelines**
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting 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 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 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 recognised 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 recognised that the development programmes 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 programme.

Class/Sub-Class	**Definition**	**Guidelines**
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 A1-1: Recoverable Resources Classes and Sub-Classes

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 or when 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 to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. 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 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 A1-2: Reserves Status 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 (P_{90}) 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 programme.
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 and commercial 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 structural 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 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.

Category	Definition	Guidelines
		In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved oil Reserves 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 A1-3: Reserves Category Definitions and Guidelines

PART VII

ADDITIONAL INFORMATION

1. Responsibility

SOCO and the SOCO Directors, whose names appear in Part I (*Letter from the Chairman of SOCO*), accept responsibility for the information contained in this document. To the best of the knowledge and belief of SOCO and the SOCO Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. Company details

SOCO was incorporated and registered in England and Wales on 10 January 1997 under the Companies Act 1985 as a public company limited by shares with registered number 03300821 and with the name Signtimed Public Limited Company.

The registered and head office of SOCO is at 48 Dover Street, London W1S 4FF. The telephone number of SOCO's registered and head office is +44 (0) 20 747 2000.

The principal legislation under which SOCO operates is the 2006 Act.

3. Treasury shares

As at the Latest Practicable Date, 9,122,268 SOCO Shares were held in treasury representing approximately 2.7 per cent. of the issued share capital (excluding treasury shares) of SOCO.

4. The Consideration Shares

The Consideration Shares to be issued pursuant to the Acquisition will be ordinary shares of five pence each in the capital of SOCO. The Consideration Shares will be issued in registered form and will be capable of being held in both certificated and uncertificated form.

Fractions of Consideration Shares will not be allotted or issued pursuant to the Acquisition.

The Consideration Shares will be issued credited as fully paid and will rank *pari passu* in all respects with the existing SOCO Shares, including the right to receive and retain in full all dividends and other distributions (if any) declared, made or paid by reference to a record date after Admission. Application will be made to the FCA for the Consideration Shares to be admitted to the premium segment of the Official List and to the London Stock Exchange for the Consideration Shares to be admitted to the London Stock Exchange's main market for listed securities. It is expected that the Consideration Shares will be issued, and that Admission is expected, subject to the satisfaction of certain conditions, to occur in the first half of 2019.

5. SOCO Directors' interests and Senior Management's interests in SOCO Shares

The following table sets out the interests in the share capital of the Company of the SOCO Directors and members of Senior Management (including beneficial interests or interests of a person connected with a Director or a member of Senior Management) (i) as at the Latest Practicable Date; and (ii) immediately following Admission, based on the assumptions that the holdings of such persons in SOCO as at the Latest Practicable Date do not change, 65,561,041 Consideration Shares are issued in connection with the Acquisition, and no other issues of SOCO Shares occur between the date of this document and Admission:

Director/Member of Senior Management	As at the Latest Practicable Date		Immediately following Admission	
	Number of SOCO Shares	Percentage of SOCO's issued share capital[4]	Number of SOCO Shares	Percentage of SOCO's issued share capital[4]
Rui de Sousa[1]	9,178,572	2.77	9,178,572	2.31
Ed Story[2]	14,073,747	4.24	14,073,747	3.54
Dr Mike Watts	478,559	0.14	478,559	0.12
Jann Brown	344,662	0.10	344,662	0.09
Rob Gray	0	0.00	0	0.00
John Martin	30,000	0.01	30,000	0.01
Ambassador António Monteiro	0	0.00	0	0.00
Ettore Contini[3]	29,000,000	8.74	29,000,000	7.30
Antony Maris	132,956	0.04	132,956	0.03

Notes:

(1) Rui de Sousa holds 9,178,572 SOCO Shares, representing 2.77 per cent. of the total voting rights of the Company, of which 469,752 Shares (0.14 per cent.) are held personally by Rui de Sousa and 8,708,820 SOCO Shares (2.62 per cent.) are held by Palamos Limited, a closely associated person to Rui de Sousa.

(2) Ed Story holds 14,073,747 SOCO Shares, representing 4.24 per cent. of the total voting rights of the Company, of which 12,398,747 (3.74 per cent.) SOCO Shares are held personally by Ed Story and 1,675,000 (0.50 per cent.) SOCO Shares are held through The Story Family Trust, a closely associated person to Ed Story.

(3) Ettore Contini holds 29,000,000 SOCO Shares, representing 8.74 per cent. of the total voting rights of the Company, of which 220,000 SOCO Shares (0.07 per cent.) are held personally by Ettore Contini and 28,780,000 SOCO Shares (8.67 per cent.) are held through Liquid Business Ltd, a closely associated person to Ettore Contini.

(4) Excluding treasury shares.

Details of awards under the Employee Share Plans held by the SOCO Directors and members of Senior Management as at the Latest Practicable Date are as set out below:

Director/Member of Senior Management	Employee Share Plan	Number of SOCO Shares under option/award[*]	Exercise price (if any)	Vesting date
Ed Story	SOCO 2011 Long-Term Incentive Plan ("**LTIP**")	919,504	–	08/01/2019
	LTIP	1,049,992	–	25/01/2020
	LTIP	1,447,020	–	23/03/2021
	SOCO 2014 Deferred Share Bonus Plan ("**DSBP**")	227,175	–	26/04/2020
Dr Mike Watts	LTIP	1,316,809	–	06/02/2020
	LTIP	997,399	–	23/03/2021
	DSBP	141,254	–	26/04/2020
Jann Brown	LTIP	1,316,809	–	06/02/2020
	LTIP	997,399	–	23/03/2021
	DSBP	141,254	–	26/04/2020
Antony Maris	LTIP	433,033	–	25/01/2020
	LTIP	775,754	–	23/03/2021
	DSBP	244,109	–	16/03/2017
	DSBP	256,872	–	14/01/2018
	DSBP	108,638	–	25/01/2019
	DSBP	99,876	–	26/04/2020
	SOCO 2009 Discretionary Share Option Plan ("**DSOP**")	174,893	–	14/09/2015
	DSOP	30,727	–	27/03/2016
	DSOP	27,622	–	14/03/2017

Notes:

(*) Outstanding awards under the Company's share schemes adjusted for dividends in accordance with Employee Share Plan Rules.

6. Major interest in SOCO Shares

As at the Latest Practicable Date, and so far as is known to SOCO by virtue of the notifications made to it pursuant to the Disclosure Guidance and Transparency Rules, the name of each person other than any SOCO Director) who, directly or indirectly, is interested in three per cent. or more of the SOCO's share capital, and the amount of such person's interest, is as follows:

Shareholder	Number of SOCO Shares	Percentage of SOCO's issued share capital (excluding treasury shares)
Blue Albacore Business Ltd	27,615,840	8.32 per cent.
Globe Deals Ltd	27,444,382	8.27 per cent.
Chemsa Ltd	24,136,925	7.27 per cent.

7. SOCO Directors' Service Agreements and Letters of Appointment

7.1 ***Executive Directors***

Ed Story

Ed Story entered into a service agreement with SOCO on 14 May 1997. His base annual salary is US$924,000. Ed also serves on the Nominations Committee.

Ed Story's service agreement can be terminated on 12 months' written notice by either party, and can be terminated with immediate effect if, amongst others, he is paid in lieu of his notice or he commits a serious breach of his obligations under his service agreement, is guilty of an act of dishonesty or serious misconduct or repeatedly or continually commits a material breach of his obligations under his service agreement. The service agreement contains provisions restricting Ed Story's use of confidential information during and after the termination of his employment with the Company and provisions which prevent him from competing with the business for three months, from soliciting employees for six months and from soliciting suppliers for 12 months after the termination of his employment.

Ed Story is eligible to receive a discretionary annual bonus capped at 150 per cent. of base salary. Under the Company's remuneration policy, payments of any annual bonus up to 100 per cent. of salary are to be made in cash and bonuses over 100 per cent. will be deferred into awards of SOCO Shares which have a minimum two year vesting period. Ed Story participates in the LTIP.

Ed Story is entitled to the following benefits: 30 days' holiday (in addition to applicable bank/public holidays), private medical insurance, permanent health insurance, life assurance cover, critical illness cover, travel benefits, expatriate benefits and car benefits. Ed Story's service agreement also provides for directors' and officers' liability insurance cover, and pension benefits are delivered though contributions to SOCO's money purchase plan up to relevant plan limits and/or a cash supplement, with the maximum benefit payable capped at 20 per cent. of base salary per annum.

Dr Mike Watts

Dr Mike Watts entered into his current service agreement with SOCO on 6 December 2017. His base annual salary is £450,000, of which £8,700 per month is applied by the Company in full towards to the purchase of SOCO Shares on the London Stock Exchange, pursuant to an agreement signed on 9 February 2017.

Dr Mike Watts' service agreement can be terminated on 12 months' written notice by either party, and can be terminated with immediate effect if, amongst others, he is paid in lieu of his notice or he is guilty of any gross misconduct or serious negligence in connection with the affairs of the Company or is convicted of an arrestable criminal offence (other than one under road traffic legislation). The service agreement contains provisions restricting Dr Mike Watts' use of confidential information during and after the termination of his employment with the Company and provisions which prevent him from competing with the business, soliciting employees, or soliciting partners, suppliers or public officials for six months after the termination of his employment (less any time spent on garden leave).

Dr Mike Watts is eligible to receive a discretionary annual bonus capped at 150 per cent. of base salary. Under the Company's remuneration policy, payments of any annual bonus up to 100 per cent. of salary are

to be made in cash and bonuses over 100 per cent. will be deferred into awards of SOCO Shares which have a minimum two-year vesting period. Dr Mike Watts participates in the LTIP.

Dr Mike Watts is entitled to the following benefits: 33 days' holiday; medical expenses; life insurance/death in service; permanent health insurance and a car allowance of £750 per month. Dr Mike Watts' service agreement also provides for pension benefits by way of a contribution of a sum equal to 15 per cent. of his monthly salary.

Jann Brown

Jann Brown entered into her current service agreement with SOCO on 6 December 2017. Her base annual salary is £450,000, of which £8,700 per month is applied by the Company in full towards to the purchase of SOCO Shares on the London Stock Exchange, pursuant to an agreement signed on 9 February 2017.

Jann Brown's service agreement can be terminated on 12 months' written notice by either party, and can be terminated with immediate effect if, amongst others, she is paid in lieu of her notice or, the Company gives notice of its intention to make a payment in lieu of notice, she is guilty of any gross misconduct or serious negligence in connection with the affairs of the Company, or is convicted of an arrestable criminal offence (other than one under road traffic legislation). The service agreement contains provisions restricting Jann Brown's use of confidential information during and after the termination of her employment with the Company and provisions which prevent her from competing with the business, soliciting employees, or soliciting partners, suppliers or public officials for six months after the termination of her employment (less any time spent on garden leave).

Jann Brown is eligible to receive a discretionary annual bonus capped at 150 per cent. of base salary. Under the Company's remuneration policy, payments of any annual bonus up to 100 per cent. of salary are to be made in cash and bonuses over 100 per cent. will be deferred into awards of SOCO Shares which have a minimum two year vesting period. Jann Brown participates in the LTIP.

Jann Brown is entitled to the following benefits: 33 days' holiday; medical expenses; life insurance/death in service; permanent health insurance and a car allowance of £750 per month. Jann Brown's service agreement also provides for pension benefits by way of a contribution of a sum equal to 15 per cent. of her monthly salary.

7.2 ***Non-Executive Directors***

Rui de Sousa

Rui de Sousa was appointed as a non-executive director of SOCO by letter of appointment dated 12 July 1999. His annual cash fee is £190,000. Rui de Sousa chairs the Nominations Committee. Rui de Sousa is entitled to expenses which are properly and reasonably incurred in performance of his duties.

John Martin

John Martin was appointed as a non-executive director of SOCO by letter of appointment dated 7 June 2018. His annual cash fee is £50,000. He serves on the Audit and Risk, Nominations and Remuneration Committees, and receives an additional fee of £5,000 per annum for his role as Chairman of the Audit and Risk Committee. John Martin is entitled to expenses properly and reasonably incurred in performance of his duties.

Ettore Contini

Ettore Contini was appointed as a non-executive director of SOCO by letter of appointment dated 11 December 2001. His annual cash fee is £50,000. Ettore Contini is entitled to expenses which are properly and reasonably incurred in performance of his duties.

Ambassador António Monteiro

Ambassador António Monteiro was appointed as a non-executive director of SOCO by letter of appointment dated 10 June 2009. His annual cash fee is £50,000. Ambassador António Monteiro serves on the Audit and Risk, Nominations and Remuneration Committees, and receives an additional fee of £5,000 per annum for his role as Chairman of the Remuneration Committee. Ambassador António Monteiro is entitled to expenses which are properly and reasonably incurred in performance of his duties.

Rob Gray

Rob Gray was appointed as a non-executive director of SOCO by letter of appointment dated 9 December 2013 and was appointed as Deputy Chairman on 7 December 2017. His fee for service as a director of SOCO is £110,000, which includes remuneration for his roles as a Senior Independent Director of SOCO and as a member of the Audit and Risk, Remuneration and Nomination Committees.

8. Profiles of key Merlon employees

Jason P. Stabell

Jason P. Stabell is the President, General Manager, Branch Manager and Managing Director of MPEFC. He establishes the vision and the strategic planning for MPEFC and oversees the implementation of that vision.

Jason has been with various entities of the Seller group with increasing responsibilities for over twenty years culminating as the Chief Executive Officer (since December 2013), President (since 2008) and Chief Financial Officer (since 2004) of Merlon International, the parent company to MPEFC. He started his tenure with Merlon International as its Corporate Development Manager in 1998. He was promoted in 2001 to Vice President. He also served as Corporate Secretary from October 2004 until early 2012.

Prior to his employment with Merlon International and related entities, Jason was a financial analyst in the Strategic Planning and Analysis Group at Salomon Smith Barney in New York from 1996 to 1998. He is a graduate of Williams College with a B.A. in Economics.

Maged Abdel Halim

Maged Abdel Halim serves as the Deputy General Manager, as a Director and as the Exploration Manager of MPEFC since November 2008. In addition to overseeing the Exploration activities of MPEFC, he acts as its main liaison with the EGPC.

Since 2002, Maged has worked with MPEFC and its predecessors as an exploration consultant. He has over 45 years' experience in the international upstream oil and gas industry. In 1991, he was named EGPC Vice Chairman for Exploration. In 2000, he was named EGPC Vice Chairman for Petroleum Agreements and International Relations. In 2001, he was appointed Chairman and Managing Director of Khalda Petroleum Company, one of the largest joint venture operators in Egypt. In the period from 1967 to 1991 he served various positions in North Africa and the Middle East.

From 1967 to 1981 Maged worked for AGIP Egypt, WEPCO (a joint venture between Philips Petroleum and EGPC) and in Algeria for the Kuwaiti Ministry of Petroleum. In 1981, he returned to Egypt as Chief Geologist for Agiba Petroleum; and from 1983 to 1991 as Exploration Manager of Phoenix Resource Company in Egypt and Khalda Petroleum Company, the joint venture formed in 1985 between Phoenix and EGPC. He holds a bachelor's degree in Geology from the Faculty of Science, Alexandria University.

Engr. Magdi El Ghor

Engr. Magdi El Ghor is the General Manager, Managing Director and Board Member of Petrosilah. He is MPEFC's highest ranking officer on the Petrosilah Board and is directly involved in all day-to-day operations of Petrosilah. He has been with the Merlon International group in Egypt for over 11 years.

Magdi joined MPEFC in 2007 as Operations Drilling Manager. When Petrosilah was formed in 2010, he was appointed to the Board of Petrosilah as Deputy Operations Manager. In 2013 he was promoted to the positions he currently holds.

Prior to joining MPEFC, Magdi held various engineering and executive positions with Qatar Petroleum, Aramco, and GPC. He has over 45 years of oil industry experience in management and engineering.

9. Related Party Transactions

9.1 Save as described in the SOCO Group's historical financial information for the three years ended 31 December 2017, 2016 and 2015 as set out in Notes 34, 35 and 32 respectively there were no related party transactions entered into by the Company or any member of the SOCO Group during the financial years ended 31 December 2017, 2016 and 2015 and during the period from 1 January 2018 up to the Latest Practicable Date.

9.2 Save as described in the Merlon Group's historical financial information for the three years ended 31 December 2017, 2016 and 2015 as set out in Note 21 there were no related party transactions entered into by Merlon or any member of the Merlon Group during the financial years ended 31 December 2017, 2016 and 2015 and during the period from 1 January 2018 up to the Latest Practicable Date.

10. Material contracts of the SOCO Group

The following are all of the contracts (not being contracts entered into in the ordinary course of business) which have been entered into by SOCO and/or members of the SOCO Group within the two years immediately preceding the date of this document and are, or may be, material to the SOCO Group or which have been entered into at any time by SOCO or any member of the SOCO Group and contain any provisions under which SOCO or any member of the SOCO Group has any obligation or entitlement which is, or may be, material to the SOCO Group at the date of this document:

10.1 ***Share Purchase Agreement***

For a description of the Share Purchase Agreement, please refer to Part V (*Principal Terms of the Share Purchase Agreement*).

10.2 ***RBL Facility Agreement***

On 15 September 2018, SOCO SEA Limited as original borrower (the "**Borrower**") and the Company, OPECO, Inc., OPECO Vietnam Limited and SOCO Vietnam Ltd. as original guarantors entered into a US$125 million senior secured borrowing base facility agreement ("**RBL Facility Agreement**") with BNP Paribas, Credit Agricole Corporate and Investment Bank and Standard Chartered Bank as original lenders, BNP Paribas as facility agent, security agent, technical bank and account bank and Standard Chartered Bank as the initial modelling bank.

The RBL Facility Agreement has an accordion mechanism that will allow the Borrower to borrow up to an additional US$125 million, subject to bringing additional petroleum assets into the borrowing base for the facility and securing funding for the increase from the existing and new lenders via the agreed mechanism. SOCO expects to move the assets acquired as part of the Acquisition into the borrowing base post completion and, following such inclusion, increase amounts available for drawdown in accordance with this accordion mechanism.

The RBL Facility is secured by way of an English law debenture and mortgage over the Borrower's assets, as well as share security documentation under Jersey, New York, Cook Islands and Cayman law and a Singaporean account charge over the relevant project accounts. The Borrower's obligations are guaranteed by the original guarantors listed above and any additional guarantors that accede to the RBL Facility Agreement.

The RBL Facility is to be applied for the following purposes: (i) payment of financing interest, fees, costs and other expenses under the Finance Documents (other than secured hedging agreements), (ii) payment of any hedging liability entered into for the purposes of implementing the agreed hedging policy, (iii) payment of expenditure items in respect of the borrowing base assets (to the extent included in the current projection under the RBL Facility Agreement), (iv) making any acquisition or investment permitted by the RBL Facility Agreement, including the Acquisition, (v) funding the debt serve reserve account, (vi) refinancing maturing loans under the RBL Facility, and (vii) for other lawful general corporate purposes relating to oil and gas activities.

The RBL Facility matures on the date falling five years after the date of the RBL Facility Agreement or earlier where the Reserve Tail Date conditions are met. The RBL Facility must be drawn in dollars and a utilisation request may be submitted, subject to satisfaction of certain conditions precedent, at any time prior to one month before the final maturity date referred to above. The RBL Facility is structured as a revolving facility with three or six month repayment periods and with the facility amortising over the five year term. The availability of US$25 million of the total US$125 million capacity under the RBL Facility is subject to the satisfaction of certain conditions which are expected to be satisfied around the time of Completion.

The RBL Facility Agreement contains customary representations, undertakings, covenants and events of default with appropriate carve-outs and materiality thresholds, where relevant. The financial covenant is a leverage test and which provides that the net borrowings of the SOCO Group shall not exceed 3.5 times the

EBITDAX of the SOCO Group in respect of each twelve month period ending on 31 December and 30 June.

The RBL Facility may be prepaid without premium or penalty but subject to breakage costs (if any) and any accrued interest. Any voluntary prepayment must be in a minimum amount of US$5 million, in integral multiples of US$1 million and only made with at least ten Business Days' notice. The RBL Facility may be automatically cancelled or subject to mandatory prepayment following the occurrence of certain events, including illegality in respect of any lender's funding, a change of control of any obligor and receipt of disposal and insurance proceeds over certain threshold amounts.

The interest rate charged on the loans made under the RBL Facility will be equal to the aggregate of the applicable margin and LIBOR (or any replacement rate, as determined in accordance with the RBL Facility Agreement). The margin from the date of the agreement to the second anniversary of the RBL Facility Agreement shall be 4 per cent. per annum, with the margin ratcheting up to 4.15 per cent. per annum for the year immediately following the second anniversary and 4.25 per cent. per annum from the third anniversary until the final maturity date.

Certain fees are payable to the finance parties in connection with the RBL Facility, including upfront fees, syndication fees, modelling and documentation bank fees and annual agency fees. The RBL Facility Agreement is governed by English law.

10.3 ***Sale and Purchase Agreement for SOCO Congo Limited and Associated Royalty Deed***

On 24 June 2018 SOCO's wholly owned subsidiary, SOCO Exploration Limited, entered into a sale and purchase agreement (the "**Congo SPA**") with Coastal Energy Congo Limited ("**Coastal Energy**"), to sell SOCO Exploration's entire 80 per cent. shareholding in SOCO Congo Limited ("**SOCO Congo**"), the company holding the SOCO Group's former interests in Congo (Brazzaville) through its Congolese subsidiary SOCO Exploration & Production Congo ("**SOCO EPC**"). These interests comprised a 40.39 per cent. operated interest in each of the Lidongo, Viodo, Lideka and Loubana exploitation permits (the "**Congo Exploitation Permits**") within the former Marine XI Block, located in shallow water offshore Congo (Brazzaville). The sale of SOCO Exploration's shareholding in SOCO Congo took effect immediately following signature of the Congo SPA on 24 June 2018.

Under the Congo SPA the cash consideration of up to US$10 million payable by Coastal Energy to SOCO Congo is structured as follows:

- US$1 million within 10 Business Days on the later to occur of:
  - agreement or expert determination of a statement of net assets or liabilities of SOCO Congo and its subsidiary SOCO Exploration and Production Congo Ltd as at 30 June 2018 (the "**30 June Statement**"); and
  - execution of the first agreement relating to the bonus payable in respect of any of the Congo Exploitation Permits;
- US$5 million within 10 Business Days of formal approval of the first development plan on any of the Congo Exploitation Permits; and
- US$4 million within 20 Business Days on the earlier to occur of:
  - first commercial production of oil or condensate from any of the Congo Exploitation Permits; and;
  - 31 December 2019.

Each element of the cash consideration is subject to potential adjustment by reference to the 30 June Statement.

The Congo SPA also contains *inter alia*:

- relatively customary commercial warranties from SOCO Exploration to Coastal Energy, with the maximum liability under such warranties linked to the amount of the cash consideration actually paid or payable under the Congo SPA;

- certain post-completion information and reporting undertakings from Coastal Energy, intended to allow SOCO Exploration to monitor progress towards, and its entitlement to, the second and third parts of the cash consideration; and

- an undertaking from Coastal Energy to change the trading and registered names of SOCO Congo and SOCO EPC to remove the "SOCO" name, and to cease using all associated SOCO trading logos, marks or designs, in each case by no later than 31 December 2018.

In addition, and pursuant to a separate royalty deed dated 25 June 2018 (the "**Congo Royalty Deed**"), SOCO EPC granted to SOCO Exploration an overriding royalty interest of on all future gross production of oil and condensate sold from any of the Congo Exploitation Permits. The royalty payable on each barrel of oil or condensate produced and sold will be determined by reference to the prevailing price of North Sea Dated Brent (the "**Benchmark Price**"), as summarised below:

- US$0.50 on each barrel where the Benchmark Price is at or under US$52.25 per barrel; or

- US$1.00 on each barrel where the Benchmark Price is over US$52.25 per barrel.

The Congo SPA and the Congo Royalty Deed are governed by English law, with the English courts having exclusive jurisdiction over the resolution of disputes or claims arising from or in connection with either contract.

The financial obligations of Coastal Energy under the Congo SPA, and the obligations of SOCO EPC under the Royalty Deed, have been guaranteed by Capital International Holdings Limited, a Seychelles-incorporated investment vehicle with certified net assets of US$155 million as at 31 May 2018.

As at the Latest Practicable Date, none of the events giving rise to an obligation on Coastal Energy to make payment of any part of the cash consideration under the Congo SPA have occurred.

10.4 ***Sale and Purchase Agreement for SOCO Cabinda Limited***

On 29 June 2018, SOCO Exploration entered into a sale and purchase agreement (the "**Angola SPA**") with Quill Trading Corporation ("**Quill**") and WMLC Resources Limited ("**WMLC**") to sell its entire 80 per cent. shareholding in SOCO Cabinda Limited ("**SOCO Cabinda**"), the company holding the SOCO Group's former 22 per cent. non-operated participating interest in the Cabinda North PSC, Angola.

Under the Angola SPA the cash consideration payable by Quill and WMLC to SOCO Exploration for its shareholding in SOCO Cabinda was US$5 million, subject to adjustment for any further funding required from the SOCO Group after 30 June 2018.

Following agreement by the parties to the Angola SPA of satisfaction or waiver of all conditions precedent, completion of the transaction occurred on 5 October 2018. At completion SOCO Exploration was paid the US$5 million cash consideration together with a further payment of US$36,181.02 reflecting costs incurred by the wider SOCO Group after 30 June 2018.

The Angola SPA also contains *inter alia*:

- relatively customary commercial warranties from SOCO Exploration to Quill and Dominio;

- an indemnity relating to any tax liabilities of SOCO Cabinda arising before the date of the Angola SPA, to the extent these are not otherwise provided for in the accounts of SOCO Cabinda;

- an allocation of all liabilities, costs and expenses of SOCO Cabinda arising in relation to the period up to and including the 30 June 2018 economic date between SOCO Exploration (80 per cent., reflecting its shareholding in SOCO Cabinda) and Quill (20 per cent.), including specific provision that environmental and decommissioning liabilities relating to SOCO Cabinda's participating interest in Cabinda North are not for the account of SOCO Exploration provided such liabilities did not become due and payable on or before 30 June 2018;

- relatively customary limitations on the liability of SOCO Exploration under the contract including an overall financial limit on the potential liability of SOCO Exploration of the amount actually paid to it by way of consideration;

- an undertaking from Quill and WMLC to change the trading and registered names of SOCO Cabinda to remove the "SOCO" name, and to cease using all associated SOCO trading logos, marks or designs, in each case by no later than 31 December 2018; and
- certain non-solicitation undertakings from SOCO Exploration in relation to the employees and customers of SOCO Cabinda, to apply for a period of 24 months after completion.

The Angola SPA is governed by English law, with disputes arising out of or relating to the contract to be referred to and finally resolved by arbitration in Lisbon under London Court of International Arbitration (LCIA) Rules.

10.5 ***Block 16-1 (Vietnam) Petroleum Contract***

The SOCO Group's operations in Block 16-1 are governed by a petroleum contract entered into on 15 November 1999 (the "**16-1 Petroleum Contract**") between PetroVietnam, PetroVietnam PSC Supervising Company (now PetroVietnam Exploration & Production Company ("**PVEP**"), a wholly owned subsidiary of PetroVietnam), SOCO Vietnam, Amerada Hess (Vietnam) Limited ("**Hess**") and OPECO Vietnam Ltd ("**OPECO**") (PVEP, SOCO Vietnam, Hess and OPECO, together with their respective successors and permitted assignees being the "**16-1 Contractor Parties**"). The 16-1 Petroleum Contract established the rights and obligations of the parties to explore for, develop and produce crude oil and/or natural gas in Block 16-1, through a joint operating company established under the 16-1 Petroleum Contract (the "**16-1 JOC**"), together with the right to export, sell or otherwise dispose of oil and gas from the Block.

Term and interests

The term of the 16-1 Petroleum Contract is 25 years which can be extended for an additional period of up to five years with the mutual consent of the parties and the approval of the Vietnamese Government.

Following various assignments and transfers, the current participating interests in the 16-1 Petroleum Contract are: PVEP, 41 per cent.; SOCO, 30.5 per cent. (28.5 per cent. through SOCO Vietnam and 2.0 per cent. through OPECO); and PTTEP Hoang-Long Company Limited ("**PTTEP-HL**"), 28.5 per cent.

Management committee

Under the terms of the 16-1 Petroleum Contract, a management committee must take certain decisions in relation to the exploration, development and production operations at the Block (the "**16-1 Management Committee**"). The 16-1 Management Committee comprises 6 members, three appointed by PVEP with the remaining three appointed by SOCO Vietnam, OPECO and PTTEP-HL (with each being entitled to appoint one representative). Each member's voting interest is equal to the participating interest of the 16-1 Contractor Party related to such member. Certain matters require the unanimous consent of all members of the 16-1 Management Committee, including, the approval of any development plan. Certain matters require the majority consent of the members of the 16-1 Management Committee, including, the approval of annual work programmes and budgets (and amendments thereto), production schedules and expenditures exceeding thresholds above the approved annual work programme. The quorum for the 16-1 Management Committee is four members, with at least three members appointed by SOCO Vietnam, OPECO and PTTEP-HL (together with their respective successors and permitted assignees, the "**16-1 Foreign Contractors**"). Once determined by the 16-1 Management Committee, certain matters relating to the Block must also be approved by PetroVietnam, including, all work programmes and budgets (and any amendments thereto), production schedules, well proposals and drilling programmes, surrender or relinquishment of all or part of the Block, expenditures exceeding certain threshold amounts above agreed work plans and budgets, and any lifting or offtake agreements. PetroVietnam retains absolute discretion to withhold its approval of matters put to it by the 16-1 Management Committee.

Joint operating company

HLJOC was established as the 16-1 JOC and operator of the Block to carry out the exploration, development and production operations as agent for and on behalf of the 16-1 Contractor Parties and in accordance with the decisions of, and work programmes and budgets approved by, the 16-1 Management Committee. The costs and liabilities of the 16-1 JOC will be borne by the 16-1 Contractor Parties.

The General Manager of the 16-1 JOC was appointed by the 16-1 Foreign Contractors and the Deputy General Manager by PVEP during the exploration period at the Block, following which the General

Manager is appointed by PVEP and the Deputy General Manager by the 16-1 Foreign Contractors. The General Manager and Deputy General Manager are primarily responsible for submitting for the approval of the 16-1 Management Committee all work programmes and budgets, appraisal and development plans, and other than in relation to matters requiring the approval of the 16-1 Management Committee, are responsible for the daily operational activities of the 16-1 JOC. Each of PVEP and the 16-1 Foreign Contractors have rights to appoint additional specified officers of the 16-1 JOC.

Minimum work and financial commitments

The 16-1 Petroleum Contract provided for certain minimum work commitments and minimum financial obligations that were required to be completed during the exploration phase of the Block. These minimum work commitments and minimum financial obligations have been satisfied.

Production sharing and recovery of costs

All costs incurred are funded by the 16-1 Contractor Parties in proportion to their participating interests.

The 16-1 Petroleum Contract provided that PVEP's 35.6 per cent. share of the costs of exploration, development and production operations funded by the 16-1 Foreign Contractors ("**16-1 Carried Costs**") were fully recoverable without interest by the 16-1 Foreign Contractors. All 16-1 Carried Costs have now been fully recovered.

All costs incurred by the 16-1 JOC on behalf of the 16-1 Contractor Parties in the course of conducting exploration, development and production operations ("**16-1 Petroleum Operations Costs**") are funded by the 16-1 Contractor Parties in proportion to their respective participating interests. All crude oil and natural gas remaining after usage in petroleum operations is referred to respectively as "**16-1 Net Crude Oil Production**" and "**16-1 Net Natural Gas Production**" (together, "**16-1 Net Petroleum Production**") under the 16-1 Petroleum Contract. The 16-1 Net Crude Oil Production and 16-1 Net Natural Gas Production is allocated as set forth below and shall be lifted or offtaken by the 16-1 Contractor Parties.

The first allocations to be made from 16-1 Net Crude Oil Production or 16-1 Net Natural Gas Production are those required to satisfy each 16-1 Contractor Party's royalty obligations to the Vietnamese Government, which are required on a monthly basis for all 16-1 Net Crude Oil Production and 16-1 Net Natural Gas Production, payable in cash (net of export tax) based on the weighted average price for crude oil or natural gas lifted or offtaken by the 16-1 Contractor Parties at the delivery point on the basis of an arm's length sales price or non-arm's length sales price, as appropriate ("**16-1 Market Price**"). Alternatively, the Vietnamese Government may, by three months written notice, elect to lift and take its royalty rate of production in kind. The rates of such royalties are set out below, determined upon reaching each of the following sustained daily production rates for a minimum of 30 consecutive days of 16-1 Net Crude Oil Production or 16-1 Net Natural Gas Production, respectively:

16-1 Net Crude Oil Production (bbls/Day)	Royalty Rate
Up to 50,000	8 per cent. of 16-1 Net Crude Oil Production
50,001 to 75,000	10 per cent. of 16-1 Net Crude Oil Production
75,001 to 100,000	15 per cent. of 16-1 Net Crude Oil Production
100,001 to 150,000	20 per cent. of 16-1 Net Crude Oil Production
Over 150,000	25 per cent. of 16-1 Net Crude Oil Production

16-1 Net Natural Gas Production (m3/Day)	Royalty Rate
Up to 5,000,000	0 per cent. of 16-1 Net Natural Gas Production
5,000,001 to 10,000,000	5 per cent. of 16-1 Net Natural Gas Production
Over 10,000,000	10 per cent. of 16-1 Net Natural Gas Production

The SOCO Group is currently paying royalties on its crude oil and natural gas from the Block at a rate of 8 per cent. and 0 per cent., respectively.

The second allocations to be made from 16-1 Net Crude Oil Production or 16-1 Net Natural Gas Production are those required to reimburse the 16-1 Contractor Parties for their cost recovery entitlements.

(a) Up to 35 per cent. of 16-1 Net Crude Oil Production is allocated to the 16-1 Contractor Parties for the recovery of all 16-1 Petroleum Operations Costs ("**16-1 Cost Recovery Crude Oil**"). 16-1 Petroleum Operations Costs are recovered from the applicable 16-1 Cost Recovery Crude Oil on a

first in, first out basis. To the extent than in any month outstanding 16-1 Petroleum Operations Costs related to the Block exceed the value of all 16-1 Cost Recovery Crude Oil from the Block for such month, the excess shall be carried forward for recovery in the next succeeding month until fully recovered.

(b) Up to 70 per cent. of 16-1 Net Natural Gas Production is allocated to the 16-1 Contractor Parties for the recovery of all 16-1 Petroleum Operations Costs ("**16-1 Cost Recovery Natural Gas**"). 16-1 Petroleum Operations Costs are recovered from the applicable 16-1 Cost Recovery Natural Gas on a first in, first out basis on the same terms as described in (a) above. To the extent than in any month outstanding 16-1 Petroleum Operations Costs related to the Block exceed the value of all 16-1 Cost Recovery Natural Gas from the Block for such month, the excess shall be carried forward for recovery in the next succeeding month until fully recovered.

After the allocations have been made for royalties, 16-1 Cost Recovery Crude Oil or 16-1 Cost Recovery Natural Gas, as applicable, the remainder of 16-1 Net Crude Oil Production or 16-1 Net Natural Gas Production, as the case may be, shall be allocated to "16-1 Profit Oil" or "16-1 Profit Gas".

Under the 16-1 Petroleum Contract, 16-1 Profit Oil and 16-1 Profit Gas for any quarter shall be shared as set forth below. The sharing of such 16-1 Profit Oil and 16-1 Profit Gas shall be accomplished through the lifting or offtaking of the respective amounts of crude oil and natural gas, as applicable, by the 16-1 Foreign Contractors and PVEP.

The respective splits for 16-1 Profit Oil:

Production Level (BOPD)	16-1 Foreign Contractors	PVEP
At any level	59 per cent.	41 per cent.

The respective splits for 16-1 Profit Gas:

Production Level (MCFPD)	16-1 Foreign Contractors	PVEP
At any level	59 per cent.	41 per cent.

Each 16-1 Contractor Party is subject to Vietnamese tax laws, and each 16-1 Contractor Party is liable for enterprise income tax payable at a rate of 50 per cent. of its net taxable profits calculated in accordance with applicable law. Each 16-1 Contractor Party shall pay to the Vietnamese Government a remittance tax at a rate of 10 per cent., subject to any tax treaty Vietnam may have for the avoidance for double taxation, on the part of the net after tax profits which are remitted and/or retained outside Vietnam, subject to normal reinvestment relief principles. In addition, each 16-1 Contractor Party shall pay export tax at a rate of four per cent. of the 16-1 Market Price of crude oil lifted and exported outside Vietnam (such payment shall qualify as 16-1 Petroleum Operations Costs). Furthermore, petroleum sold pursuant to the 16-1 Petroleum Contract is subject to VAT at the following rates:

Natural Gas sold for the export market	0 per cent. rate
Natural Gas sold for the domestic market	10 per cent. rate
Crude Oil sold for the export market	Not subject to VAT
Crude Oil sold for the domestic market	10 per cent. rate

Under the 16-1 Petroleum Contract, each of the 16-1 Contractor Parties has the right to lift, take, export and sell or otherwise dispose of its Cost Recovery Petroleum and its share of 16-1 Profit Oil and 16-1 Profit Gas outside Vietnam. However, the terms of the 16-1 Petroleum Contract provide that in the event that the Vietnamese Government declares a national demand in accordance with Vietnamese law, the Vietnamese Government may require each 16-1 Contractor Party, by written notice given 180 days in advance, to sell a portion of its crude oil to PetroVietnam, in its role as the state oil company, to meet its domestic consumption needs, provided that this right shall not apply where its exercise would cause the 16-1 Contractor Party to breach a contract of sale of such crude oil to a third party. The amount of crude oil that each 16-1 Contractor Party shall be obligated to sell to PetroVietnam in these circumstances shall be equal to that proportion of the domestic market deficit each quarter that each Contract Party's crude oil production each quarter bears to the production of crude oil of all contractors each quarter under petroleum contracts in Vietnam. The net price to be paid to each Contactor Party for such sales of crude oil shall be not less than the 16-1 Market Price, which shall be paid in dollars and within 30 days of delivery.

Bonuses

The 16-1 Petroleum Contract provides that the 16-1 Foreign Contractors shall pay to the Vietnamese Government certain bonuses (which shall not be recoverable as 16-1 Petroleum Operations Costs or deductible from tax), in proportion to their participating interest, in a number of specified circumstances which include the payment within 30 days after achieving for the first time the following sustained production levels for a period of 30 consecutive days of: (i) over 25,000 barrels per day, US$2 million; (ii) over 50,000 barrels per day, US$3 million; (iii) over 75,000 barrels per day, US$4 million; (iv) over 100,000 barrels per day, US$5 million; and (v) over 150,000 barrels per day, US$7 million. As at the Latest Practicable Date, the 50,000 barrels per day threshold has been achieved.

Ownership of assets

The 16-1 Petroleum Contract provides that physical assets purchased by the 16-1 Contractor Parties for the carrying out of petroleum operations under the 16-1 Petroleum Contract for which cost recovery is allowable, and claimed as 16-1 Petroleum Operations Costs, shall become the property of PetroVietnam on the date on which the costs of such assets has been fully recovered or upon termination of the 16-1 Petroleum Contract, whichever occurs first. The 16-1 JOC shall have the right to use such assets free of charge for the remainder of the term of the 16-1 Petroleum Contract.

The 16-1 Contractor Parties shall be liable for the abandonment and decommissioning of operations and equipment in accordance with an abandonment work programme and budget approved by the 16-1 Management Committee.

Assignment

The 16-1 Petroleum Contract provides that each 16-1 Contractor Party may freely assign its rights and obligations and participating interest under the 16-1 Petroleum Contract free of any taxes, fees, duties or charges to an affiliate with the prior written consent of PetroVietnam and the final approval of the Vietnamese Government (not to be unreasonably withheld).

Each 16-1 Contractor Party may sell or assign, all or a portion of, its rights and obligations and its participating interest free of any taxes, fees, duties or any charges to a non-affiliated third party with the prior written consent of the other 16-1 Contractor Parties and the final approval of the Vietnamese Government (such consent and approval not to be unreasonably withheld). The 16-1 Petroleum Contract further provides that, subject to certain exceptions, PetroVietnam shall have a pre-emptive right to acquire such participating interest.

Subject to the terms of the Vietnamese petroleum law, each 16-1 Contractor Party shall have a right of first refusal to purchase the participating interest (apportioned among the 16-1 Contractor Parties in accordance with their respective participating interests), of the 16-1 Contractor Party wishing to sell or assign their participating interest in whole or in part to a non-affiliate third party.

Default

Under the 16-1 Petroleum Contract, any 16-1 Contractor Party in default of any payment due thereunder (a "**16-1 Defaulting Party**") shall be promptly given notice (a "**16-1 Default Notice**") of such default by the 16-1 JOC. The amount not paid by the 16-1 Defaulting Party shall bear interest from the due date until paid in full at the monthly LIBOR interest rate plus two percent.

During the continuance of such default, the 16-1 Defaulting Party shall not have a right to its share of 16-1 Net Petroleum Production. The 16-1 non-Defaulting Parties shall be authorised to sell such entitlement at arm's length on commercially reasonable terms and, after deducting all costs incurred in connection with such sale, pay the net proceeds to the 16-1 non-Defaulting Parties in proportion to the amounts they are owed by the 16-1 Defaulting Party under the 16-1 Petroleum Contract (and apply such net proceeds toward the establishment of a reserve fund in an amount equal to the 16-1 Defaulting Party's participating interest share, for the purposes of covering its share of estimated costs in connection with the abandonment and cessation of petroleum operations in which the 16-1 Defaulting Party participated) until all such amounts are recovered and such reserve fund is established.

If a 16-1 Defaulting Party fails to remedy its default by the sixtieth day following the date of the 16-1 Default Notice, each 16-1 non-Defaulting Party shall have the option until such default is cured, to require the 16-1 Defaulting Party to withdraw from the 16-1 Petroleum Contract and transfer all of its

rights, title and beneficial interest in and under the 16-1 Petroleum Contract to the 16-1 non-Defaulting Parties. In the absence of an agreement among the 16-1 non-Defaulting Parties to the contrary, any such transfer shall be in the proportion that each of their participating interest bears to the sum of their total participating interests.

Termination

Under the 16-1 Petroleum Contract, the 16-1 Contractor Parties have various termination rights, which include: (i) where an event of force majeure (as stipulated in the 16-1 Petroleum Contract) has lasted for a continuous period of 18 months and the 16-1 Foreign Contractors are in unanimous agreement to terminate the 16-1 Petroleum Contract, they may do so by providing not less than 90 days' notice to PVEP and PetroVietnam; and (ii) in the event of insolvency or bankruptcy of one a 16-1 Contractor Party, the other 16-1 Contractor Parties shall have the option (subject to the appropriate approvals from the Vietnamese Government) to either assume the participating interest of such 16-1 Contractor Party, on a proportionate basis or any other basis agreed upon with the other 16-1 Contractor Parties, or to terminate the 16-1 Petroleum Contract.

The Ministry of Planning and Investment of Vietnam shall have the right to terminate the 16-1 Petroleum Contract in the event that it terminates the investment licence relating to the 16-1 Petroleum Contract for the 16-1 Contractor Parties' failure to comply with material provisions thereunder.

Governing law and arbitration

The 16-1 Petroleum Contract provides that differences or disputes between all of the parties to the 16-1 Petroleum Contract or the 16-1 Foreign Contractors and PetroVietnam which cannot be settled through amicable negotiations within a period of 90 days, shall be finally settled by arbitration in accordance with the Rules of Conciliation and Arbitration of the International Chamber of Commerce. The place of arbitration shall be Singapore and the 16-1 Petroleum Contract shall be construed and interpreted in accordance with the laws of Singapore, without regard to Singapore's conflict of laws rules.

A unitisation agreement was entered into between PetroVietnam, PVEP, SOCO Vietnam, PTTEP-HL, OPECO and Talisman (Vietnam 15-02/01) Ltd. on 30 October 2012 in order to provide for the creation of a new Block to develop and exploit hydrocarbon reserves which straddle the boundaries of Block 16-1 and Block 15-2/01. The current equity split granted to the 16-1 Contractor Parties, approved by the Vietnamese Government on 1 April 2016, is 98.8822 per cent. oil and condensate interest and 98.5463 per cent. gas interest.

10.6 ***Block 9-2 (Vietnam) Petroleum Contract***

The SOCO Group's operations in Block 9-2 are governed by a petroleum contract entered into on 16 December 2000 (the "**9-2 Petroleum Contract**") between PetroVietnam, SOCO Vietnam and Petroleum Investment & Development Company ("**PIDC**") (SOCO Vietnam and PIDC, together with their successors and permitted assignees being the "**9-2 Contractor Parties**"). The 9-2 Petroleum Contract established the rights and obligations of the parties to explore for, develop and produce crude oil and/or natural gas in Block 9-2, through a joint operating company established under the 9-2 Petroleum Contract (the "**9-2 JOC**"), together with the right to export, sell or otherwise dispose of oil and gas from the Block.

Term and interests

The term of the 9-2 Petroleum Contract is 25 years in the case of crude oil and 30 years in the case of natural gas which can be extended for an additional period of up to 5 years with the mutual consent of the parties and the approval of the Vietnamese Government.

Following various assignments and transfers, the current participating interests in the 9-2 Petroleum Contract are PIDC, 50 per cent.; SOCO Vietnam, 25 per cent.; and PTTEP Hoang-Long Company Limited ("**PTTEP-HL**"), 25 per cent.

Management committee

Under the terms of the 9-2 Petroleum Contract, a management committee must take certain decisions in relation to the exploration, development and production operations at the Block (the "**9-2 Management Committee**"). The 9-2 Management Committee comprises four members, two appointed by PIDC with the remaining two appointed by SOCO Vietnam (together with their successors and permitted assignees, the

"**9-2 Foreign Contractors**"). Certain matters require the unanimous consent of all members of the 9-2 Management Committee, including, the approval of any development plan. Certain matters require the majority consent of the members of the 9-2 Management Committee, including, the approval of annual work programmes and budgets (and amendments thereto), production schedules and expenditures exceeding thresholds above the approved annual work programme. The quorum for the 9-2 Management Committee is two members, with at least one member appointed by each of PIDC and the 9-2 Foreign Contractors. Once determined by the 9-2 Management Committee, certain matters relating to the Block must also be approved by PetroVietnam, including, all work programmes and budgets (and any amendments thereto), production schedules, well proposals and drilling programmes, surrender or relinquishment of all or part of the Block, expenditures exceeding certain threshold amounts above agreed work plans and budgets, and any lifting or offtake agreements. PetroVietnam retains absolute discretion to withhold its approval of matters put to it by the 9-2 Management Committee.

Joint operating company

Hoan Vu Joint Operating Company ("**HVJOC**") was established as the 9-2 JOC and operator of the Block to carry out the exploration, development and production operations as agent for and on behalf of the 9-2 Contractor Parties and in accordance with the decisions of, and work programmes and budgets approved by, the 9-2 Management Committee. The costs and liabilities of the 9-2 JOC will be borne by the 9-2 Contractor Parties.

The terms and conditions under which the 9-2 JOC acts as the agent for and on behalf of the 9-2 Contractor Parties is set out in the operating agreement dated 16 December 2000 between PIDC and SOCO Vietnam (the "**9-2 Operating Agreement**").

The General Manager of the 9-2 JOC was appointed by the 9-2 Foreign Contractors and the Deputy General Manager by PIDC during the exploration period at the Block, following which the General Manager is appointed by PIDC and the Deputy General Manager by the 9-2 Foreign Contractors. The General Manager and Deputy General Manager are primarily responsible for submitting for the approval of the 9-2 Management Committee all work programmes and budgets, appraisal and development plans, and other than in relation to matters requiring the approval of the 9-2 Management Committee, are responsible for the daily operational activities of the 9-2 JOC. Each of PIDC and the 9-2 Foreign Contractors have rights to appoint additional specified officers of the 9-2 JOC.

Minimum work and financial commitments

The 9-2 Petroleum Contract provided for certain minimum work commitments and minimum financial obligations that were required to be completed during the exploration phase of the Block. These minimum work commitments and minimum financial obligations have been satisfied.

Production sharing and recovery of costs

Under the 9-2 Petroleum Contract, the 9-2 Foreign Contractors were responsible for funding the cost of all exploration operations until determination of the first development area. All costs incurred after the determination of the first development area are funded by the 9-2 Contractor Parties in proportion to their participating interests. The 9-2 Petroleum Contract provided that PIDC's 50 per cent. share of the costs of exploration, development and production operations funded by the 9-2 Foreign Contractors ("**9-2 Carried Costs**") were fully recoverable without interest by the 9-2 Foreign Contractors. All 9-2 Carried Costs have now been fully recovered.

All costs incurred by the 9-2 JOC on behalf of the 9-2 Contractor Parties in the course of conducting exploration, development and production operations ("**9-2 Petroleum Operations Costs**") are funded by the 9-2 Contractor Parties in proportion to their respective participating interests.

All crude oil and natural gas remaining after usage in petroleum operations is referred to respectively as "**9-2 Net Crude Oil Production**" and "**9-2 Net Natural Gas Production**" (together, "**Net Petroleum Production**") under the 9-2 Petroleum Contract. The 9-2 Net Crude Oil Production and 9-2 Net Natural Gas Production is allocated as set forth below and shall be lifted or offtaken by the 9-2 Contractor Parties.

The first allocations to be made from 9-2 Net Crude Oil Production or 9-2 Net Natural Gas Production are those required to satisfy each 9-2 Contractor Party's royalty obligations to the Vietnamese Government, which are required on a monthly basis for all 9-2 Net Crude Oil Production and 9-2 Net Natural Gas

Production, payable in cash (net of export tax) based on the weighted average price for crude oil or natural gas lifted or offtaken by the 9-2 Contractor Parties at the delivery point on the basis of an arm's length sales price or non-arm's length sales price, as appropriate ("**9-2 Market Price**"). Alternatively, the Vietnamese Government may, by three months written notice, elect to lift and take its royalty rate of production in kind. The rate of such royalties are set out below, determined upon reaching each of the following sustained daily production rates for a minimum of 30 consecutive days of 9-2 Net Crude Oil Production or 9-2 Net Natural Gas Production, respectively:

9-2 Net Crude Oil Production (bbls/Day)	Royalty Rate
Up to 20,000	6 per cent. of 9-2 Net Crude Oil Production
20,001 to 50,000	8 per cent. of 9-2 Net Crude Oil Production
50,001 to 75,000	10 per cent. of 9-2 Net Crude Oil Production
75,001 to 100,000	15 per cent. of 9-2 Net Crude Oil Production
100,001 to 150,000	20 per cent. of 9-2 Net Crude Oil Production
Over 150,000	25 per cent. of 9-2 Net Crude Oil Production

9-2 Net Natural Gas Production (m3/Day)	Royalty Rate
Up to 5,000,000	0 per cent. of 9-2 Net Natural Gas Production
5,000,001 to 10,000,000	5 per cent. of 9-2 Net Natural Gas Production
Over 10,000,000	10 per cent. of 9-2 Net Natural Gas Production

The second allocations to be made from 9-2 Net Crude Oil Production or 9-2 Net Natural Gas Production are those required to reimburse the 9-2 Contractor Parties for their cost recovery entitlements.

(a) 9-2 Net Crude Oil Production is allocated to the 9-2 Contractor Parties for the recovery of all 9-2 Petroleum Operations Costs ("**9-2 Cost Recovery Crude Oil**") as follows: (i) for any month prior to and including the first month in which the aggregate amount of 9-2 Net Crude Oil Production exceeds an average daily rate for such month of 20,000 barrels per day, up to 50 per cent. of 9-2 Net Crude Oil Production and (ii) for any month thereafter, up to 35 per cent. of 9-2 Net Crude Oil Production. 9-2 Petroleum Operations Costs are recovered from the applicable 9-2 Cost Recovery Crude Oil on a first in, first out basis. To the extent than in any month outstanding 9-2 Petroleum Operations Costs related to the Block exceed the value of all 9-2 Cost Recovery Crude Oil from the Block for such month, the excess shall be carried forward for recovery in the next succeeding month until fully recovered.

(b) Up to 70 per cent. of 9-2 Net Natural Gas Production is allocated to the 9-2 Contractor Parties for the recovery of all 9-2 Petroleum Operations Costs ("**9-2 Cost Recovery Natural Gas**"). 9-2 Petroleum Operations Costs are recovered from the applicable 9-2 Cost Recovery Natural Gas on a first in, first out basis on the same terms as described in (a) above. To the extent than in any month outstanding 9-2 Petroleum Operations Costs related to the Block exceed the value of all 9-2 Cost Recovery Natural Gas from the Block for such month, the excess shall be carried forward for recovery in the next succeeding month until fully recovered.

After the allocations have been made for royalties, 9-2 Cost Recovery Crude Oil or 9-2 Cost Recovery Natural Gas, as applicable, the remainder of 9-2 Net Crude Oil Production or 9-2 Net Natural Gas Production, as the case may be, shall be allocated to "9-2 Profit Oil" or "9-2 Profit Gas".

Under the 9-2 Petroleum Contract, 9-2 Profit Oil and 9-2 Profit Gas for any quarter shall be shared as set forth below. The sharing of such 9-2 Profit Oil and 9-2 Profit Gas shall be accomplished through the lifting or offtaking of the respective amounts of crude oil and natural gas, as applicable, by the 9-2 Foreign Contractors and PIDC.

The respective splits for 9-2 Profit Oil:

Production Level (BOPD)	9-2 Foreign Contractors	PIDC
At any level	50 per cent.	50 per cent.

The respective splits for 9-2 Profit Gas:

Production Level (MCFPD)	9-2 Foreign Contractors	PIDC
At any level	50 per cent.	50 per cent.

Each 9-2 Contractor Party is subject to Vietnamese tax laws, and each 9-2 Contractor Party is liable for enterprise income tax payable at a rate of 50 per cent. of its net taxable profits calculated in accordance with applicable law. In the case of a field determined to be marginally economic or uneconomic (as determined following good faith negotiations between PetroVietnam and the 9-2 Contractor Parties and approved by the Vietnamese Government): (i) for a period of up to two years from the first production date, no enterprise income tax shall be incurred or payable, and (ii) for a further period of up to two calendar years thereafter, the enterprise income tax shall be reduced by one half to 25 per cent.

Each 9-2 Contractor Party shall pay to the Vietnamese Government a remittance tax at a rate of 7 per cent., subject to any tax treaty Vietnam may have for the avoidance for double taxation, on the part of the net after tax profits which are remitted and/or retained outside Vietnam, subject to normal reinvestment relief principles. In addition, each 9-2 Contractor Party shall pay export tax at a rate of four per cent. of the 9-2 Market Price of crude oil lifted and exported outside Vietnam net of royalty deductions (such payment shall be tax deductible). Furthermore, petroleum sold pursuant to the 9-2 Petroleum Contract is subject to VAT at the following rates:

Natural Gas sold for the export market	0 per cent. rate
Natural Gas sold for the domestic market	10 per cent. rate
Crude Oil sold for the export market	Not subject to VAT
Crude Oil sold for the domestic market	10 per cent. rate

Under the 9-2 Petroleum Contract, each of the 9-2 Contractor Parties has the right to lift, take, export and sell or otherwise dispose of its 9-2 Cost Recovery Crude Oil and 9-2 Cost Recovery Natural Gas and its share of 9-2 Profit Oil and 9-2 Profit Gas outside Vietnam. However, the terms of the 9-2 Petroleum Contract provide that in the event that the Vietnamese Government declares a national demand in accordance with Vietnamese law, the Vietnamese Government may require each 9-2 Contractor Party, by written notice given 180 days in advance, to sell a portion of its crude oil to PetroVietnam, in its role as the state oil company, to meet its domestic consumption needs, provided that this right shall not apply where its exercise would cause the 9-2 Contractor Party to breach a contract of sale of such crude oil to a third party. The amount of crude oil that each 9-2 Contractor Party shall be obligated to sell to PetroVietnam in these circumstances shall be equal to that proportion of the domestic market deficit each quarter that each Contract Party's crude oil production each quarter bears to the production of crude oil of all contractors each quarter under petroleum contracts in Vietnam. The net price to be paid to each Contactor Party for such sales of crude oil shall be not less than the 9-2 Market Price, which shall be paid in dollars and within 30 days of delivery.

Bonuses

The 9-2 Petroleum Contract provides that the 9-2 Foreign Contractors shall pay to the Vietnamese Government certain bonuses (which shall not be recoverable as 9-2 Petroleum Operations Costs or deductible from tax), in proportion to their participating interest, in a number of specified circumstances which include the payment within 30 days after achieving for the first time the following sustained production levels for a period of 30 consecutive days of: (i) over 25,000 barrels per day, US$2 million; (ii) over 50,000 barrels per day, US$3 million; (iii) over 75,000 barrels per day, US$4 million; (iv) over 100,000 barrels per day, US$5 million; and (v) over 150,000 barrels per day, US$7 million. As at the Latest Practicable Date, none of the above bonus thresholds have been achieved.

Ownership of assets

The 9-2 Petroleum Contract provides that physical assets purchased by the 9-2 Contractor Parties for the carrying out of petroleum operations under the 9-2 Petroleum Contract for which cost recovery is allowable, and claimed as 9-2 Petroleum Operations Costs, shall become the property of PetroVietnam on the date on which the costs of such assets has been fully recovered or upon termination of the 9-2 Petroleum Contract, whichever occurs first. The 9-2 JOC shall have the right to use such assets free of charge for the remainder of the term of the 9-2 Petroleum Contract.

The 9-2 Contractor Parties shall be liable for the abandonment and decommissioning of operations and equipment in accordance with an abandonment work programme and budget approved by the 9-2 Management Committee.

Assignment

The 9-2 Petroleum Contract provides that each 9-2 Contractor Party may freely assign its rights and obligations and participating interest under the 9-2 Petroleum Contract free of any taxes, fees, duties or charges (to an affiliate with the prior written consent of PetroVietnam and the final approval of the Vietnamese Government (not to be unreasonably withheld).

Each 9-2 Contractor Party may sell or assign, all or a portion of, its rights and obligations and its participating interest free of any taxes, fees, duties or any charges (except for transfer tax on profits arising from such sale or assignment) to a non-affiliated third party with the prior written consent of the other 9-2 Contractor Parties and the final approval of the Vietnamese Government (such consent and approval not to be unreasonably withheld). The 9-2 Petroleum Contract further provides that, subject to certain exceptions, PetroVietnam shall have a pre-emptive right to acquire such participating interest.

Subject to the terms of the Vietnamese petroleum law, each 9-2 Contractor Party shall have a right of first refusal to purchase the participating interest (apportioned among the 9-2 Contractor Parties in accordance with their respective participating interests), of the 9-2 Contractor Party wishing to sell or assign their participating interest in whole or in part to a non-affiliate third party.

Default

Under the 9-2 Petroleum Contract, any 9-2 Contractor Party in default of any payment due thereunder (a "**9-2 Defaulting Party**") shall be promptly given notice (a "**9-2 Default Notice**") of such default by the 9-2 JOC. The amount not paid by the 9-2 Defaulting Party shall bear interest from the due date until paid in full at the monthly LIBOR interest rate plus two percent.

During the continuance of such default, the 9-2 Defaulting Party shall not have a right to its share of 9-2 Net Petroleum Production. The 9-2 non-Defaulting Parties shall be authorised to sell such entitlement at arm's length on commercially reasonable terms and, after deducting all costs incurred in connection with such sale, pay the net proceeds to the 9-2 non-Defaulting Parties in proportion to the amounts they are owed by the 9-2 Defaulting Party under the 9-2 Petroleum Contract (and apply such net proceeds toward the establishment of a reserve fund in an amount equal to the 9-2 Defaulting Party's participating interest share, for the purposes of covering its share of estimated costs in connection with the abandonment and cessation of petroleum operations in which the 9-2 Defaulting Party participated) until all such amounts are recovered and such reserve fund is established.

If a 9-2 Defaulting Party fails to remedy its default by the sixtieth day following the date of the 9-2 Default Notice, each 9-2 non-Defaulting Party shall have the option until such default is cured, to require the 9-2 Defaulting Party to withdraw from the 9-2 Petroleum Contract and transfer all of its rights, title and beneficial interest in and under the 9-2 Petroleum Contract to the 9-2 non-Defaulting Parties. In the absence of an agreement among the 9-2 non-Defaulting Parties to the contrary, any such transfer shall be in the proportion that each of their participating interest bears to the sum of their total participating interests.

Termination

Under the 9-2 Petroleum Contract, the 9-2 Contractor Parties have various termination rights, which include: (i) where an event of force majeure (as stipulated in the 9-2 Petroleum Contract) has lasted for a continuous period of 18 months and the 9-2 Foreign Contractors are in unanimous agreement to terminate the 9-2 Petroleum Contract, they may do so by providing not less than 90 days' notice to PIDC and PetroVietnam; and (ii) in the event of insolvency or bankruptcy of one a 9-2 Contractor Party, the other 9-2 Contractor Parties shall have the option (subject to the appropriate approvals from the Vietnamese Government) to either assume the participating interest of such 9-2 Contractor Party, on a proportionate basis or any other basis agreed upon with the other 9-2 Contractor Parties, or to terminate the 9-2 Petroleum Contract.

The Ministry of Planning and Investment of Vietnam shall have the right to terminate the 9-2 Petroleum Contract in the event that it terminates the investment licence relating to the 9-2 Petroleum Contract for the 9-2 Contractor Parties' failure to comply with material provisions thereunder.

Governing law and arbitration

The 9-2 Petroleum Contract provides that differences or disputes between all of the parties to the 9-2 Petroleum Contract or the 9-2 Foreign Contractors and PetroVietnam which cannot be settled through amicable negotiations within a period of 90 days, shall be finally settled by arbitration in accordance with the Rules of Conciliation and Arbitration of the International Chamber of Commerce. The place of arbitration shall be Singapore and the 9-2 Petroleum Contract shall be construed and interpreted in accordance with the laws of Singapore, without regard to Singapore's conflict of laws rules.

10.7 ***Block 9-2 Operating Agreement***

On 16 December 2000, SOCO Vietnam, PIDC, HJVOC and PetroVietnam entered into an operating agreement (the "**9-2 OA**") to provide for supplemental terms regarding the relationship between the 9-2 Contractor Parties in the exploration, development and operation of Block 9-2 and, in particular, the duties and obligations of the 9-2 JOC, HJVOC, in conducting petroleum operations pursuant to the 9-2 Petroleum Contract as agent of the 9-2 Contractor Parties.

The 9-2 OA provides that the 9-2 Contractor Parties shall be liable for the debts of the 9-2 JOC to the extent of, and in accordance with, their respective participating interests under the 9-2 Petroleum Contract.

The 9-2 OA sets out the responsibilities of the 9-2 JOC, which include: (i) performing petroleum operations in accordance with the provisions of the 9-2 Petroleum Contract; (ii) conducting all such operations in a diligent, safe and efficient manner in accordance with good and prudent oil field practices and conservation principles consistent with the Generally Accepted International Petroleum Practices; (iii) neither making a gain nor suffering a loss as a result of conducting such operations; and (iv) preparing and submitting work programmes and budgets, appraisal plans and development plans.

The 9-2 OA provides that the 9-2 Contractor Parties shall take all reasonable steps to assist the 9-2 JOC, upon request, with the performance of its duties and obligations therein.

The governing law and arbitration clauses of the 9-2 Petroleum Contract are incorporated by reference into the 9-2 OA. An assignment of participating interest under the 9-2 Petroleum Contract shall result in the assignment of the corresponding rights and obligations of the transferring party under the 9-2 OA.

10.8 ***Blocks 125/126 (Vietnam) Petroleum Production Sharing Contract***

The SOCO Group's operations in Blocks 125/126 are governed by a petroleum production sharing contract entered into on 27 October 2017 (the "**125/126 PSC**") between PetroVietnam, SOCO Exploration (Vietnam) Limited ("**SEVL**") and SOVICO Holdings Company ("**SOVICO**") (SEVL and SOVICO together, the "**125/126 Contractor Parties**"). The participating interests of the 125/126 Contractor Parties are as follows: SEVL, 70 per cent.; and SOVICO, 30 per cent.

Term

The term of the 125/126 PSC is 30 years from 9 November 2017 (the "**125/126 Effective Date**"), which may be extended by a further five years upon mutual agreement of the parties and approval by the Prime Minister of Vietnam. The 125/126 Exploration Period (as defined below) shall be seven years from the 125/126 Effective Date (and may be extended by a further two years) and shall be divided into two phases: four years for the first phase ("**125/126 Phase One**") and three years for the second phase ("**125/126 Phase Two**") (together, the "**125/126 Exploration Period**"). The 125/126 Contractor Parties shall have the option (but not the obligation) to enter into 125/126 Phase Two.

The 125/126 PSC shall, subject to provisions providing for extensions in certain limited cases, terminate if at the end of the 125/126 Exploration Period no discovery or accumulation of hydrocarbons, which in the sole opinion of the 125/126 Contractor Parties can be exploited economically (a "**125/126 Commercial Discovery**"), has been declared in the relevant area.

Minimum work and financial commitments

The 125/126 Contractor Parties shall be required to commence operations no later than 30 days following PetroVietnam's approval of a work programme and budget. Under 125/126 Phase One, the 125/126 Contractor Parties will be required to undertake certain minimum work and financial commitments. These include undertaking the Acquisition, processing and interpretation of seismic surveys representing 7,000 km of 2D data and 500 sq. km of 3D data and the exploration or wildcat of one well. The minimum

financial commitment for 125/126 Phase One is US$23,500,000. Under 125/126 Phase Two, the 125/126 Contractor Parties will be required to undertake the Acquisition, processing and interpretation of seismic surveys representing a further 500 sq. km of 3D data and the exploration and wildcat of a further well. The minimum financial commitment for 125/126 Phase Two is US$16,500,000. Where the 125/126 Contractor Parties exceed the minimum work commitment for each phase, this excess work shall be credited towards the minimum work commitment of the following phase (if and when, the 125/126 Contractor Parties opt to enter into the subsequent phase). If the 125/126 Contractor parties satisfy their minimum work commitments at a cost less than the minimum financial commitments, they shall be deemed to have satisfied the latter.

Management committee

Under the terms of the 125/126 PSC, a management committee must take certain decisions in relation to exploration, development and production operations (the "**125/126 Management Committee**"). The 125/126 Management Committee comprises four members, two appointed by PetroVietnam and two appointed by the 125/126 Contractor Parties. The number of members comprising the 125/126 Management Committee may be increased or decreased from time to time by mutual agreement of the parties and a chairman shall be designated by the 125/126 Contractor Parties prior to the declaration of the first 125/126 Commercial Discovery, following which PetroVietnam shall designate one of its members as the chairman. Meetings shall require a quorum of at least one member from each of the 125/126 Contractor Parties and PetroVietnam.

All decisions of the 125/126 Management Committee shall be taken by the unanimous vote of its members save for those dealing with exploration and appraisal matters before the declaration of the first 125/126 Commercial Discovery which shall be taken by a majority vote or as otherwise agreed by the parties.

Matters within the remit of the 125/126 Management Committee include the adoption of annual work programmes and budgets any amendments thereto, the adoption of procedures regarding the selection of subcontractors, the adoption of the appraisal plan in relation to any discovery, the adoption of evaluation reports and annual production schedules and the adoption of any proposal on surrender.

Surrender

If the 125/126 Contractor Parties elect to enter into 125/126 Phase Two, before or by the end of 125/126 Phase One (plus any extension thereof), they shall surrender no less than 20 per cent. of the contract area (excluding any development area). Before or by the end of the 125/126 Exploration Period (plus any extension thereof), the 125/126 Contract Parties shall surrender all remaining portions of the contract area subject to limited exceptions (such as the exclusion of any development areas from such obligation).

Discovery of hydrocarbons

If the 125/126 Contractor Parties determine that a discovery has been made, they shall notify the 125/126 Management Committee as soon as practicable. Within 90 days after such notice, the 125/126 Contractor Parties shall present an appraisal plan for such discovery to the 125/126 Management Committee, following which the 125/126 Management Committee shall review and adopt the proposed appraisal plan within 30 days. Within 10 days of such adoption, the 125/126 Contractor Parties shall submit the appraisal plan to PetroVietnam for its final approval within 30 days (subject to any amendments which it wishes to make). The 125/126 Contractor Parties shall then, as soon as practicable, implement the appraisal plan approved by PetroVietnam.

Within 90 days, or such other period as agreed by PetroVietnam, the 125/126 Contractor Parties shall submit a "hydrocarbon initially in place" evaluation report of the discovery under the appraisal plan together with a declaration to the 125/126 Management Committee as to whether the discovery is a 125/126 Commercial Discovery. The 125/126 Contractor Parties shall submit their proposal for a development area in relation to such discovery in accordance with the provisions of the 125/126 PSC and the Generally Accepted International Petroleum Industry Standards. The 125/126 Management Committee shall review and adopt such report within 30 days of receipt and the 125/126 Contractor Parties shall thereafter, within 10 days of adoption, submit such report to PetroVietnam for consideration and adoption and for subsequent submission to the Prime Minister of Vietnam for final approval in accordance with the application regulations on reserves management in Vietnam.

Within 90 days, or such other period agreed by PetroVietnam, after the date of final approval of the "hydrocarbon initially in place" report in respect of any 125/126 Commercial Discovery, the 125/126 Contractor Parties shall submit to the Blocks 125/126 Management Committee for adoption a complete outline development plan which shall include a preliminary feasibility study. Subject to amendments it may wish to make, the 125/126 Management Committee shall adopt such plan within 30 days. Within 10 days of such adoption, the 125/126 Contractor Parties shall submit such outline development plan to PetroVietnam or other competent authority for its consideration, subject to any amendments it may wish to make and adoption within 60 days of submission of the plan or 60 days following submission of an amended plan (if it so requests), as the case may be.

Within 12 months, or such other period as agreed by PetroVietnam, from the date of final approval of the outline development plan, the 125/126 Contractor Parties shall submit a development plan on the basis of the selected development option under the approved outline development plan which shall be reviewed and, subject to any amendments it may wish to make, adopted by the 125/126 Management Committee within 30 days of submission of the plan or 30 days following submission of an amended plan (if it so requests), as the case may be. Within 10 days of such adoption, the 125/126 Contractor Parties shall submit such development plan to PetroVietnam for its consideration. Subject to any amendments it may wish to make, PetroVietnam and the 125/126 Contractor Parties shall endeavour to finalise within six months the development plan and then submit it to the Prime Minister of Vietnam for consideration and final approval.

The 125/126 Contractor Parties shall be under an obligation to submit a yearly work programme and budget to the 125/126 Management Committee. The 125/126 Contractor Parties shall submit 60 days prior to the first commercial production and on each subsequent year to the 125/126 Management Committee for adoption and to PetroVietnam for approval, an annual production schedule based on the forecast production envisaged in the approved development plan and updated information.

Production sharing and recovery of costs

All oil and gas remaining after usage in petroleum operations is referred to respectively as "**125/126 Net Oil Production**" and "**125/126 Net Gas Production**" (together, "**125/126 Net Petroleum Production**") under the 125/126 PSC and is allocated as set out below.

The first allocations to be made from 125/126 Net Oil Production or 125/126 Net Gas Production are those required to satisfy each 125/126 Contractor Party's royalty obligations to the Vietnamese Government, which are required for all 125/126 Net Oil Production or 125/126 Net Gas Production in each taxable period, payable in cash based on the average daily rate of 125/126 Net Oil Production or 125/126 Net Gas Production per actual production day, unless the Vietnamese Government, by three months written notice, elects to lift or offtake and take in kind its royalty rate of production which is estimated to be available for lifting or to offtake during the calendar year based on the approved production schedule of that year.

125/126 Net Oil Production (bbls/Day)	Royalty Rate
Up to 20,000	7 per cent. of 125/126 Net Oil Production
20,001 to 50,000	9 per cent. of 125/126 Net Oil Production
50,001 to 75,000	11 per cent. of 125/126 Net Oil Production
75,001 to 100,000	13 per cent. of 125/126 Net Oil Production
100,001 to 150,000	18 per cent. of 125/126 Net Oil Production
Over 150,000	23 per cent. of 125/126 Net Oil Production

125/126 Net Gas Production (m3/Day)	Royalty Rate
Up to 5,000,000	1 per cent. of 125/126 Net Gas Production
5,000,001 to 10,000,000	3 per cent. of 125/126 Net Gas Production
Over 10,000,000	6 per cent. of 125/126 Net Gas Production

The second allocations to be made from 125/126 Net Oil Production or 125/126 Net Gas Production are those required to reimburse the 125/126 Contractor Parties for their cost recovery entitlements.

(a) Up to 70 per cent. of 125/126 Net Oil Production is allocated to the 125/126 Contractor Parties for the recovery of all 125/126 Petroleum Operations Costs ("**125/126 Cost Recovery Oil**"). Costs incurred in the course of conducting exploration, development, production and abandonment operations in the Blocks ("**125/126 Petroleum Operations Costs**") are recovered from the applicable 125/126 Cost Recovery Oil on a first in, first out basis. To the extent than in any quarter

outstanding 125/126 Petroleum Operations Costs related to the Blocks exceed the value of all 125/126 Cost Recovery Oil for such quarter, the excess shall be carried forward for recovery in the next succeeding quarter until fully recovered.

(b) Up to 70 per cent. of 125/126 Net Gas Production is allocated to the 125/126 Contractor Parties for the recovery of all 125/126 Petroleum Operations Costs ("**125/126 Cost Recovery Gas**"). 125/126 Petroleum Operations Costs are recovered from the applicable 125/126 Cost Recovery Gas on a first in, first out basis on the same terms as described in (a) above. To the extent than in any quarter outstanding 125/126 Petroleum Operations Costs related to the Block exceed the value of all 125/126 Cost Recovery Gas for such quarter, the excess shall be carried forward for recovery in the next succeeding quarter until fully recovered.

After the allocations have been made for royalties, 125/126 Cost Recovery Oil or 125/126 Cost Recovery Gas, as applicable, the remainder of 125/126 Net Oil Production or 125/126 Net Gas Production, as the case may be, shall be allocated to "125/126 Profit Oil" or "125/126 Profit Gas".

Under the 125/126 PSC, 125/126 Profit Oil and 125/126 Profit Gas for any quarter shall be shared as set forth below.

The respective splits for 125/126 Profit Oil:

Production Level (bbls/Day)	125/126 Contractor Parties	PetroVietnam
Up to 20,000	80 per cent.	20 per cent.
20,001 to 50,000	78 per cent.	22 per cent.
50,001 to 75,000	74 per cent.	26 per cent.
75,001 to 100,000	65 per cent.	35 per cent.
100,001 to 150,000	53 per cent.	47 per cent.
Over 150,001	48 per cent.	52 per cent.

The respective splits for 125/126 Profit Gas:

Production Level (m3/Day)	125/126 Contractor Parties	PetroVietnam
Up to 15,000,000	85 per cent.	15 per cent.
15,000,001 to 20,000,000	70 per cent.	30 per cent.
Over 20,000,001	60 per cent.	40 per cent.

Each 125/126 Contractor Party is subject to Vietnamese tax laws, and is, in particular, liable for corporate income tax payable at a rate of 32. per cent. of its net taxable income calculated in accordance with applicable law. Each 125/126 Contractor Party shall be liable for an export tax of 10 per cent., on the net crude oil lifted and exported by it outside Vietnam, expect for crude oil used for royalty obligations. Each 125/126 Contractor Party shall pay value added tax, the tax/fee for environmental protection and windfall tax (as applicable) and in accordance with the laws of Vietnam then in force.

Bonuses

The 125/126 PSC provides that the 125/126 Contractor Parties shall pay to PetroVietnam certain bonuses (which shall not be recoverable as 125/126 Petroleum Operations Costs or deductible from corporate income tax) in a number of specified circumstances which include: (i) the payment of a signature bonus of US$500,000 within 30 days of the 125/126 Effective Date; (ii) the payment of US$500,000 within 30 days of the declaration by the 125/126 Contractor Parties of the first 125/126 Commercial Discovery; (iii) the payment of US$1,000,0000 within thirty days after the first day following the thirtieth day of petroleum produced in the area subject to the 125/126 PSC; and (iv) the payment within 30 days after the daily average production first reaches the following average levels of oil and/or gas production for a period of thirty consecutive days:

for crude oil:

Daily average of 125/126 Net Oil Production per quarter in contract area (barrels per actual production day)	Bonus amount in US$
Over 20,000	1,000,000
Over 50,000	2,000,000
Over 75,000	3,000,000
Over 100,000	4,000,000
Over 150,000	5,000,000

for gas:

Daily average of 125/126 Net Gas Production per quarter in contract area (million cubic meters per actual production day)	Bonus amount in US$
Over 5	500,000
Over 10	1,000,000
Over 15	2,000,000

Ownership of assets

The 125/126 PSC provides that physical assets purchased by the 125/126 Contractor Parties for the carrying out of petroleum operations under the 125/126 PSC and for which cost recovery is allowable, and claimed as 125/126 Petroleum Operations Costs, shall become the property of PetroVietnam on the date on which the costs of such assets has been fully recovered or upon termination of the 125/126 PSC, whichever occurs first. The 125/126 Contract Parties shall have the right to use such assets free of charge so long as they are needed for petroleum operations under the 125/126 PSC.

The 125/126 Contractor Parties shall be liable for the abandonment and decommissioning of operations and equipment in accordance with an abandonment work programme and budget approved by the 125/126 Management Committee.

Supply of Vietnamese market

The 125/126 PSC stipulates that oil produced under the 125/126 PSC must be prioritised for sale on the Vietnamese market on the basis of an approved annual production schedule (following consultation between the 125/126 Contractor Parties and PetroVietnam). The 125/126 Contractor Parties must also, if so requested by the Vietnamese Government, sell a portion of the natural gas to which they are entitled under the 125/126 PSC on the Vietnamese market.

It is further stipulated that, at the request of the Vietnamese Government, in emergency cases, PetroVietnam may require the 125/126 Contractor Parties with 30 days written notice to sell an amount of oil (to which the 125/126 Contractor Parties are entitled under the 125/126 PSC) which is greater than the amount previously agreed with PetroVietnam.

If the 125/126 Contractor parties supply oil for domestic consumption, the price paid shall be calculated on the basis of the international competitive price as calculated in accordance with the valuation provisions in the 125/126 PSC.

Assignment and change of control

The 125/126 PSC grants each 125/126 Contractor Party the right to sell, assign, convey or otherwise dispose of all or any part of its rights, interests and obligations under the 125/126 PSC to any of its affiliates upon written notice to PetroVietnam, conditional upon receipt of approval from the Prime Minister of Vietnam and subject to the pre-emption rights of PetroVietnam under Vietnamese law, and, subsequently, of the other 125/126 Contractor Parties under the joint operating agreement governing their relationship. The 125/126 PSC sets out certain requirements that the potential assignee must meet, these include adequate technical and financial capabilities and the provision of parent company or bank guarantees if required by PetroVietnam.

The 125/126 PSC provides that a chance of ownership structure of change of control of a 125/126 Contractor Party (excluding internal restructurings, a financial restructuring or a consolidation by the parent company) shall be deemed to constitute an assignment under the terms of the 125/126 PSC.

Default

Where either of the 125/126 Contractor Parties or PetroVietnam is in material breach of any of its obligations under this Contract (a "**125/126 Defaulting Party**"), the other party (the "**125/126 Non-Defaulting Party**") may give a notice to the 125/126 Defaulting Party requiring it to remedy such breach. If it fails to remedy such breach or to commence and diligently pursue the remediation of such breach within 30 days of the date on which the notice is delivered to it, the 125/126 Non-Defaulting Party may, at any time after the expiration of such 30 day period, terminate the 125/126 PSC by serving a notice of termination on the 125/126 Defaulting Party.

The 125/126 PSC provides that a material breach shall be deemed to exist when a party has:

(a) failed to make a payment in accordance with the terms of the 125/126 PSC within 30 days of the due date of such payment; or

(b) failed to implement or comply with the 125/126 PSC where:

  (i) such failure or omission has a material impact on the implementation or economic or commercial objectives of the 125/126 PSC; and

  (ii) such failure or omission continues to not be remedied within 30 days of receipt of a notice from the 125/126 non-Defaulting Party (save if it is not practicable to remedy such breach within a 30 day period and the Defaulting Party has promptly commences to remedy such breach diligently and such remedy is completed within 90 days of the aforesaid notice.

If a dispute arises between either of the parties as to whether either of them is in material breach of any of its obligations under the 125/126 PSC or whether either a party is entitled to terminate the 125/126 PSC, either party may require that the dispute be submitted for arbitration in accordance with the terms of the 125/126 PSC (as described further below).

Termination

The 125/126 PSC provides that if there are circumstances that do not warrant continuation of petroleum operations, the 125/126 Contractor Parties may, after consultation with PetroVietnam, give 90 days prior notice to PetroVietnam of their intention to relinquish their rights and be relieved of their obligations thereunder, save for any rights and outstanding obligations that may have accrued and any other rights and obligations expressed as continuing thereunder.

The 125/126 PSC stipulates a number of circumstances in which PetroVietnam may terminate the 125/126 PSC, without compensation for any losses that may arise, by giving 90 days prior written notice to the 125/126 Contractor parties. These include: (i) the 125/126 Contractor Parties failing to commence development operations pursuant to an approved development plan for a consecutive 12 months period from the date of approval of such development plan or ceasing development operations for a consecutive six month period, except in certain specified circumstances; (ii) the 125/126 Contractor Parties failing to put the field into production within 12 months from a tentative production date described in an approved schedule or ceasing production operations for a consecutive three month period, except in certain specified circumstances; (iii) a 125/126 Contractor Party becoming bankrupt, insolvent or being dissolved, provided that in such circumstances PetroVietnam's termination notice would only be effective if the remaining 125/126 Contractor Parties are unable to assume the rights and obligations of that party and so notify PetroVietnam within the aforementioned 90 days period; or (iv) all 125/126 Contractor Parties become bankrupt, insolvent or are dissolved.

Governing law and arbitration

The 125/126 PSC stipulates that it shall be interpreted and governed by the laws of Vietnam provided that, in the absence of a specific Vietnamese law or regulation governing any particular matter that may be raised, relevant provisions of the laws of England and/or Generally Accepted International Petroleum Industry Practices shall apply (to the extent that neither of these are contrary to fundamental principles of Vietnamese law).

The 125/126 PSC provides that differences or disputes between the parties thereto, which cannot be settled through amicable negotiations within a period of 90 days, shall be finally settled by arbitration in accordance with the Arbitration Rules of the Singapore International Arbitration Centre and the place of arbitration shall be Singapore.

10.9 ***Block 125/126 Joint Operating Agreement***

On 12 December 2017, SEVL and SOVICO entered into a joint operating agreement (the "**Block 125/126 JOA**") to provide for terms and conditions to govern their relations in relation to Blocks 125/126.

The current parties and their interests in the Block 125/126 JOA are: SEVL, 70 per cent.; and SOVICO, 30 per cent.

The Block 125/126 JOA established an operating committee (the "**Block 125/126 Operating Committee**") whose decisions shall be binding upon the parties thereto. Until the valid first declaration of a commercial discovery, SOVICO shall not exercise its voting rights unless directed otherwise by SEVL. After the first declaration of a commercial discovery, decisions shall be taken unanimously in relation to development plans, unitisation with an adjoining contract title area, voluntary surrender of all, or parts of Blocks 125/126 and any amendment or termination of the Block 125/126 JOA or the Block 125/126 PSC.

Each Block 125/126 Contractor Party shall be represented on the Block 125/126 Management Committee by one appointed representative.

The Block 125/126 JOA appointed SEVL as the operator of Blocks 125 and 126 (the "**Block 125/126 Operator**") and provides it, in accordance with approved programmes and budgets and subject to instructions by the Block 125/126 Operating Committee, with the exclusive right to operate, or supervise the operation of, oil-related work under the Block 125/126 PSC. It further provides that the Block 125/126 Operator's liability shall be solely limited to losses and damage arising from its gross or wilful misconduct, as set out in international standards and practices in the oil industry and in accordance with applicable Vietnamese regulations.

The Block 125/126 JOA is governed by and to be construed under English law and internationally accepted common practices. Any dispute arising from the execution or interpretation of the Block 125/126 JOA shall be finally determined in accordance with the Rules of Arbitration of the International Chamber of Commerce of London, England.

Costs and charges in respect of oil-related work, including all costs and charges born for the purchase of all materials and equipment bought in the interest of the Block 125/126 Contractor Parties, shall be borne by the Block 125/126 Contractor Parties in proportion to their respective interests. The ownership of all materials and equipment shall, subject to the terms of Block 125/126 PSC, be jointly shared by the Block 125/126 Contractor Parties in proportion to their respective interests.

The Block 125/126 JOA provides that each of the Block 125/126 Contractor Parties may assign their participating interest to the non-withdrawing party. The Block 125/126 JOA provides a pre-emption right to the Vietnam Oil and Gas Group or PetroVietnam in the event of a sale, assignment, novation, encumbrance or other disposition by one of the Block 125/126 Contractor Parties.

11. Material contracts of the Merlon Group

The following are all of the contracts (not being contracts entered into in the ordinary course of business) which have been entered into by MPEFC and/or members of the Merlon Group within the two years immediately preceding the date of this document and are, or may be, material to the Merlon Group or which have been entered into at any time by MPEFC or any member of the Merlon Group and contain any provisions under which MPEFC or any member of the Merlon Group has any obligation or entitlement which is, or may be, material to the Merlon Group at the date of this document:

11.1 ***Share Purchase Agreement***

For a description of the Share Purchase Agreement, please refer to Part V (*Principal Terms of the Share Purchase Agreement*).

11.2 ***The El Fayum Concession Agreement***

The El Fayum Area Western Desert Petroleum Exploration and Exploitation Concession Agreement between the Arab Republic of Egypt ("**ARE**"), the EGPC and MPEFC was entered into on 15 July 2004 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 147 of 2004) (the "**Original Concession Agreement**"). The Original Concession Agreement was amended by an initial amendment agreement entered into on 16 September 2010 (pursuant to Egyptian Law no. 132 of 2010) (the "**First Amendment Agreement**") and further amended by an additional amendment agreement

entered into on 22 August 2017 (pursuant to Egyptian Law no. 201 of 2017) (the "**Second Amendment Agreement**" and, the Original Concession Agreement as amended by the First Amendment Agreement and the Second Amendment Agreement, the "**Concession Agreement**").

Under the Concession Agreement (i) the ARE has granted MPEFC and EGPC exclusive rights to explore for and develop oil and gas in the Concession Area; and (ii) MPEFC agrees to bear all costs and expenses required in carrying out operations under the Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the Concession Agreement).

The governing law of the Concession Agreement is the law of Egypt with any dispute involving the ARE subject to the jurisdiction of the ARE courts, and any dispute between EGPC and MPEFC subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term

The exploration period granted to MPEFC and EGPC under the Concession Agreement for the remaining exploration area (being the original Concession Area which has not been relinquished or converted to a Development Lease) ends on 15 November 2020. The development period for each Development Lease is 20 years from the date of the Minister of Petroleum's approval of the Development Lease (*see Part 11.3 below for further details of expiry dates under the Development Leases*).

The development period for each Development Lease may be extended by two periods of five years each if MPEFC provides a written request to EGPC six months prior to the end of the relevant initial 20 year development period or the first five year extension period. Any extension is subject to the approval of the EGPC and the Minister of Petroleum.

The Concession Agreement includes termination rights in favour of the ARE, including for material breach, submission of false statements, transfer contrary to agreed restrictions, bankruptcy and non-compliance with a final decision under the dispute provisions.

Relinquishment

In the event that there is no regular production of crude oil from a Development Lease within four years of the lease approval date, MPEFC is deemed to have automatically assigned all of its rights in respect of the area covered by the Development Lease back to EGPC. The same applies to individual blocks within a development lease; if there is no commercial production of oil within four years of the commencement of commercial production in the relevant Development Lease, the relevant block is deemed to be relinquished back to EGPC.

EGPC further has a right to carry out a periodic review of the Development Blocks within each Development Lease every four years for the purposes of auditing the areas which should be subject to relinquishment.

Change of control, assignment and pre-emption

MPEFC may not assign any of its rights, duties or obligations under the Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. It is currently envisaged that the Acquisition may constitute an indirect assignment so as to trigger the assignment provisions under the Concession Agreement, in which event:

- EGPC would benefit from a pre-emption right under the Concession Agreement and may elect to acquire an assigned interest on the same terms if it notifies the assignor of such election within 90 days of written notice from the assignor of the final terms (including value) of an assignment; and
- MPEFC would be required to pay a non-recoverable assignment fee to EGPC in an amount equal to ten per cent. of the proposed transaction value upon EGPC's approval of any assignment.

The Parties are currently engaging with EGPC, for itself, and on behalf of the Egyptian Government, for the purposes of, among other things, clarifying whether or not the Acquisition is deemed an assignment for the purposes of the Concession Agreement. It is a condition to Completion under the Share Purchase Agreement that EGPC and/or the Minister of Petroleum in Egypt (as applicable) approve or consent in writing to the Acquisition, to the extent such approval or consent (as applicable) is required under the laws

of Egypt or the El Fayum Concession. The written waiver, or non-exercise, in accordance with the terms of the El Fayum Concession of the pre-emption rights of EGPC is also a condition to Completion under the Share Purchase Agreement. For further information on such conditions, please refer to paragraph 10 of Part I (*Letter from the Chairman of SOCO*). Pursuant to the Share Purchase Agreement, the Parties have agreed, upon Completion, the Company or MPEFC shall pay any Assignment Fee due and payable by MPEFC in respect of the Acquisition subject to the Assignment Fee Cap. The Seller shall pay any additional fees, costs, charges and expenses associated with any Assignment Fee in excess of the agreed cap.

Offtake provisions, local procurement and sales obligations

EGPC has a right to purchase a percentage share of MPEFC's production sharing petroleum to satisfy the requirement of the Egyptian market. This percentage share can vary and is calculated by dividing (i) the total amount of Merlon's crude oil production in the Concession Area by (ii) the total crude oil production (from all production companies) in all of the concession areas in Egypt in which EGPC has a preferential right to purchase a share of production.

Pursuant to a Crude Oil Pricing Letter issued by EGPC on 23 March 2017, EGPC has set a purchase price based on the average price of mixed oil in the Western Desert officially announced by EGPC for the shipment month minus 3.00 dollars/barrel effective 1st April 2017.

Pursuant to a letter dated 11 May 2017, EGPC has notified MPEFC that it is willing to facilitate the direct export by MPEFC of oil shipments above a production level of 7250 barrels per day.

11.3 ***Development Leases***

A summary of the current ten (10) Development Leases and their respective review and ultimate expiry dates is set out in the table below:

Development Lease	Area (km^2)	Date of Lease Issuance	Next Review Date	Expiration date (Assuming Two 5yr Extensions)
Silah	60	6-May-09	26-Jan-21	May-39
N Silah	18	2-Jun-10	22-Feb-22	Jun-40
N Silah Deep	27	2-Jun-10	31-Dec-18	Jun-40
Dawar	15	2-Jun-10	22-Feb-19	Jun-40
SE Gindi	9	15-Dec-10	30-Jun-22	Dec-40
Tersa	70.5	16-Dec-09	4-Nov-21	Dec-39
Ain Assillen	21	10-Aug-10	31-Dec-20	Aug-40
W Auberge	12	15-Dec-10	28-Apr-22	Dec-40
Ward	15	15-Dec-10	28-Jun-22	Dec-40
Saad	9	31-Dec-12	5-Nov-20	Dec-42

On October 25, 2018, the Kahk Development Lease expired due to depletion of the discovered reserves which resulted in the relinquishment to EGPC of two blocks covering a total of 5.8 km^2.

11.4 ***The EBRD Facility***

MPEFC is the borrower and the Seller and Merlon Inc., a wholly-owned subsidiary of the Seller, are guarantors under the EBRD Facility. EBRD is the sole lender. The EBRD Facility is also secured by security over the shares of MPEFC and the shares of Merlon Inc., all-asset security debentures over the assets of MPEFC and Merlon Inc. and security over accounts, intercompany loans, insurances and hedging agreements of MPEFC.

The EBRD Facility is structured as a reducing borrowing base facility where the borrower is entitled to draw on the lower of the borrowing base amount and the total commitments. The borrowing base amount is determined through periodic review of banking cases delivered by MPEFC pursuant to which additional assets are added or removed from the borrowing base. The initial borrowing base asset is the concession granted to MPEFC in Egypt under the terms of the Concession Agreement. Each loan is required to be repaid on the last day of its interest period but may be simultaneously re-borrowed. Repayments are also required where the outstanding amounts of the loans exceed the relevant approved borrowing base amount. Subject to prior cancellation by the EBRD, the EBRD Facility is available to be drawn until one month prior to the final maturity date.

The final maturity date under the EBRD Facility is the earlier of 31 December 2020 and the Reserve Tail Date. Where the Seller ceases to control or hold (directly or indirectly) 100 per cent. of the shares and voting interests in MPEFC, a prepayment and cancellation of the EBRD Facility is triggered unless the lender (in its sole discretion) approves of the new operator of the Concession Agreement and/or the borrowing base assets.

It is intended that the EBRD Facility will be repaid in full and cancelled at Completion pursuant to clause 6 of the Share Purchase Agreement. As at 30 September 2018, the outstanding principal under the EBRD Facility was US$23.3 million (based on Merlon's unaudited financial statements for the period ending 30 September 2018).

11.5 ***Stratton Overriding Royalty Interest Agreement***

Under the terms of a letter agreement dated 17 May 2005, Merlon Inc., a wholly-owned subsidiary of the Seller, and MPEFC granted Stratton Corporation an overriding royalty interest in the Concession Agreement in payment for services rendered in obtaining the Concession Area.

Such overriding interest is equal to 3 per cent. of MPEFC's share of petroleum saved and sold from the Concession Area as excess cost recovery petroleum (excess of petroleum allocated towards cost recovery compared to actual costs incurred and recoverable in the relevant period) and production sharing petroleum.

The overriding interest is valued in accordance with the pricing provisions of the Concession Agreement and required to be paid by MPEFC to Stratton Corporation within 15 days from the date that MPEFC receives such amounts under the Concession Agreement. The letter agreement came into effect on 17 May 2005 and continues in effect until the Concession Agreement is terminated.

12. Litigation

12.1 ***SOCO litigation***

There are no governmental, legal or arbitration proceedings nor, so far as the Company is aware, are any such proceedings pending or threatened, which may have, or have had during the 12 months preceding the date of this Circular, a significant effect on the Company or the SOCO Group's financial position or profitability.

12.2 ***Merlon litigation***

13. There are no governmental, legal or arbitration proceedings nor, so far as the Company is aware, are any such proceedings pending or threatened, which may have, or have had during the 12 months preceding the date of this Circular, a significant effect on Merlon or the Merlon Group's financial position or profitability.

14. No significant change in the financial or trading position

14.1 ***SOCO***

There has been no significant change in the financial or trading position of the SOCO Group since 30 June 2018, the date to which SOCO's last published interim financial statements were prepared.

14.2 ***Merlon***

There has been no significant change in the financial or trading position of the Merlon Group since 31 December 2017, the date to which Merlon's last published audited financial statements were prepared.

15. Working capital

SOCO is of the opinion that, taking into account existing available facilities and existing cash resources, 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 this document.

16. Competent Person's Report

There have been no material changes since the date of the Competent Person's Report the omission of which would make such report misleading.

17. Consents

Evercore has given and has not withdrawn its written consent to the inclusion of the reference in this document to its name in the form and context in which the name is included.

Lloyd's Register has given and has not withdrawn its written consent to the inclusion of its report set out in Part VI (*Competent Person's Report in Respect of the Merlon Group*) of this document in the form and context in which it appears and to the inclusion of the references in this document to its name in the form and context in which it is included.

Deloitte, is registered to carry on audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has acted as auditor and reporting accountant to the SOCO Group, has given and has not withdrawn its written consent to the inclusion of its accountant's report on the consolidated financial information of the Merlon Group set out in Section A of Part III (*Financial Information on Merlon*) and its accountant's report on the unaudited Pro Forma financial information set out in Section A of Part IV (*Accountant's Report on Unaudited Pro-Forma Financial Information of the Enlarged Group*) of this document in the form and context in which they appear.

18. Documents available for inspection

Copies of the following documents will be available for inspection, during usual business hours on any Business Day at the offices of Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ and at the registered office of SOCO, from the date of this document up to and including the date of the SOCO General Meeting:

(a) the articles of association of SOCO;

(b) the Share Purchase Agreement;

(c) the audited consolidated accounts of SOCO for the financial periods ended 31 December 2017, 31 December 2016 and 31 December 2015;

(d) the unaudited interim financial statements of SOCO for the six months ended 30 June 2018;

(e) the audited consolidated accounts of Merlon for the financial periods ended 31 December 2017, 31 December 2016 and 31 December 2015 as set out in Section B of Part III (*Financial Information of Merlon*);

(f) the reports from Deloitte set out in Section A of Part III (*Financial Information of Merlon*) and Section A of Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group*);

(g) the written consents referred to in paragraph 17 of this Part VII (*Additional Information*); and

(h) this document.

Dated: 5 December 2018.

PART VIII

INFORMATION INCORPORATED BY REFERENCE

Information incorporated by reference	Document reference	Page number(s) in this Circular
SOCO Annual Report 2015	Note 32 on page 85	145
SOCO Annual Report 2016	Note 35 on page 112	145
SOCO Annual Report 2017	Page 97 and Note 34 on page 118	57, 58 and 145

The parts of these documents which are not incorporated by reference are either not relevant for investors or are covered elsewhere in this Circular. To the extent that any part of any information referred to below itself contains information which is incorporated by reference, such information shall not form part of this Circular.

Copies of the above documents may be inspected during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the registered office of SOCO at 48 Dover Street, London, United Kingdom, W1S 4FF and at the offices of Clifford Chance LLP at 10 Upper Bank Street, London, E14 5JJ up to and including the date of the General Meeting. The documents are also available on SOCO's website (www.socointernational.com).

PART IX

DEFINITIONS

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

"**2006 Act**"	the Companies Act 2006 of the United Kingdom
"**Acquisition**"	the proposed acquisition by SOCO of the entire issued share capital of Merlon
"**Admission**"	the admission of the Consideration Shares by the FCA to the Official List and to trading on the London Stock Exchange's main market for listed securities
"**Announcement**"	the press announcement relating to the Acquisition made by SOCO on 20 September 2018
"**Assignment Fee**"	the assignment fee prescribed in the Concession Agreement as described in paragraph 4 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Assignment Fee Cap**"	the assignment fee cap agreed between the Company and the Seller pursuant to the Share Purchase Agreement and as described in paragraph 4 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Backstop Date**"	20 September 2019 (or such other date as the Company and the Seller may agree in writing)
"**Break Fee**"	the break fee agreed between the Company and the Seller pursuant to the Share Purchase Agreement and as described in paragraph 6 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Business Day**"	a day (other than a Saturday, Sunday, public or bank holiday) on which banks are generally open for business in London
"**Business Warranties**"	certain warranties given by the Seller in relation to the business of Merlon under the Share Purchase Agreement as described in paragraph 5 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Buyer Fundamental Warranties**"	certain warranties given by SOCO under the Share Purchase Agreement as described in paragraph 5 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Cabinda North**"	an onshore block located in an oil basin in the north of Angola
"**cents**", "**US$**", "**US dollars**" or "**$**"	the lawful currency of the United States
"**CEO**"	Chief Executive Officer
"**Completion**"	completion of the Acquisition pursuant to and in accordance with the terms of the Share Purchase Agreement
"**Concession Agreement**"	the concession agreement entered into on 15 July 2004 between Merlon, the Arab Republic of Egypt and the Egyptian General Petroleum Corporation, as amended and restated, as described in paragraph 11.2 of Part VII (*Additional Information*) of this Circular
"**Concession Area**"	means the El Fayum concession area described in Annex A and B to the Concession Agreement

"**Conditions**"	the conditions to the implementation of the Acquisition as described in paragraph 4 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Consideration**"	the consideration as described in paragraph 2 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Consideration Shares**"	the 65,561,041 new SOCO ordinary shares of five pence each to be issued credited as fully paid at Admission pursuant to and in accordance with the terms of the Share Purchase Agreement
"**CREST**"	the relevant system (as defined in the Regulations) in respect of which Euroclear is the operator (as defined in the Regulations)
"**CREST Proxy Instruction**"	a properly authenticated CREST message appointing and instructing a proxy to attend and vote in place of a SOCO Shareholder at the SOCO General Meeting and containing the information required to be contained in the CREST Manual
"**Deloitte**"	Deloitte LLP
"**Development Lease**"	means any development leases granted and existing in the Concession Area
"**Disclosure Guidance and Transparency Rules**"	the disclosure guidance and transparency rules made by the FCA under section 73A of FSMA
"**EBRD**"	European Bank for Reconstruction and Development
"**EBRD Facility**"	the up to US$31,646,994 credit facility between, among others, the EBRD as lender and Merlon as borrower dated 30 October 2015 and amended and restated on or around 1 June 2017
"**EGPC**"	the Egyptian General Petroleum Corporation
"**Egypt**"	the Arab Republic of Egypt
"**Egyptian Pounds**"	the lawful currency of Egypt
"**El Fayum Concession**"	the concession awarded under the Concession Agreement
"**Employee Share Plans**"	the SOCO 2011 Long Term Incentive Plan, the SOCO 2014 Deferred Share Bonus Plan and the SOCO 2009 Discretionary Share Option Plan
"**Enlarged Group**"	with effect from Completion, the combined group comprising the SOCO Group as enlarged following completion of the Acquisition
"**Euroclear**"	Euroclear UK & Ireland Limited
"**Evercore**"	Evercore Partners International LLP
"**FCA**"	the UK Financial Conduct Authority
"**Form of Proxy**"	the form of proxy enclosed with this document, for use by SOCO Shareholders in connection with the SOCO General Meeting
"**FSMA**"	the Financial Services and Markets Act 2000 of the United Kingdom
"**Fundamental Warranty**"	in respect of the Company, the Buyer Fundamental Warranties and, in respect of the Seller, the Seller Fundamental Warranties
"**IFRS**"	International Financial Reporting Standards as adopted by the European Union

"**Institute of Chartered Accountants in England and Wales**"	a professional membership organisation of accountants and finance professionals who have met various industry competency standards in England and Wales
"**Latest Practicable Date**"	3 December 2018, being the latest practicable date prior to the publication of this Circular for the purposes of ascertaining certain information contained in this Circular
"**LIBOR**"	London Interbank Offered Rate
"**Listing Rules**"	the listing rules made by the FCA under section 73A of FSMA
"**Lloyd's Register**"	Lloyd's Register (Senergy (GB) Limited)
"**London Stock Exchange**"	the London Stock Exchange PLC or its successor
"**LTIP**"	the SOCO 2011 Long Term Incentive Plan
"**Market Abuse Regulation**"	the Market Abuse Regulation (2014/596/EU)
"**Merlon**" or "**MPEFC**"	Merlon Petroleum El Fayum Company, an exempted company incorporated in the Cayman Islands with incorporation number 78257
"**Merlon Group**"	Merlon, its subsidiaries and subsidiary undertakings
"**Merlon Group CPR**"	the Competent Person's Report in respect of the Merlon Group set out in Part VI (*Competent Person's Report in respect of the Merlon Group*) of this Circular as of 30 June 2018
"**Merlon Inc.**"	Merlon International, Inc., a wholly-owned subsidiary of the Seller, incorporated in Texas with secretary of state number 0800403556 whose registered office is at 5151 San Felipe Street, Suite 2050, Houston, TX 77056
"**Merlon International**" or "**Seller**"	Merlon International LLC, a company incorporated in Delaware with registered number 4329892 whose registered office is at 5151 San Felipe St Suite 2050, Houston, TX 77056, USA
"**Minister of Petroleum**"	the current minister of petroleum and metallurgical wealth in Egypt and his successors
"**Official List**"	the official list of the FCA
"**pence**", "**pounds sterling**", "**sterling**", "**£**" or "**p**"	the lawful currency of the United Kingdom
"**Petrosilah**"	a joint stock company incorporated in the Arab Republic of Egypt on 1 July 2004 with MPEFC and EGPC each holding and owning one half of the capital stock
"**Prospectus Rules**"	the rules for the purposes of Part IV FSMA in relation to the offers of securities to the public and the admission of securities to trading on a regulated market
"**RBL Facility**"	the facility made available under the RBL Facility Agreement
"**RBL Facility Agreement**"	the up to US$125,000,000 senior secured borrowing base facility agreement dated 15 September 2018 between *inter alia* SOCO (as parent company), SOCO SEA Limited (as the principal borrower), OPECO, Inc, OPECO Vietnam Limited and SOCO Vietnam Limited (as guarantors) and BNP Paribas, acting through its Singapore branch, Crédit Agricole Corporate and Investment Bank and Standard Chartered Bank (as lenders)

"**Recommendation**"	the recommendation outlined in paragraph 18 (*Recommendation*) in Part I (*Letter from the Chairman of SOCO*) of this Circular
"**Regulations**"	the Uncertificated Securities Regulations 2001 of the United Kingdom
"**Reserve Tail Date**"	the date on which the aggregate remaining reserves under the borrowing base assets are projected to fall below 25 per cent. of the initially approved reserves
"**Resolutions**"	the ordinary resolutions to be proposed at the SOCO General Meeting (and set out in the notice of general meeting to be contained in this document) to, among other matters, approve the Acquisition
"**Seller Fundamental Warranties**"	certain warranties given by the Seller under the Share Purchase Agreement as described in paragraph 5 of Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**Senior Management**"	those members of the management bodies of the Company and its subsidiaries who are relevant to establishing that the Company has the appropriate expertise and experience for the management of its business for the purposes of item 14.1(d) of Annex I of the Prospectus Rules, being Anthony Maris (Chief Operating Officer)
"**Share Purchase Agreement**"	the share purchase agreement entered into on 20 September 2018 between SOCO and Merlon International in connection with the Acquisition as further described in Part V (*Principal Terms of the Share Purchase Agreement*) of this Circular
"**SOCO**", the "**Company**"	SOCO International plc, registered in England and Wales with registered number 03300821
"**SOCO Annual Report and Accounts 2015**"	SOCO's annual report and accounts for the year ended 31 December 2015
"**SOCO Annual Report and Accounts 2016**"	SOCO's annual report and accounts for the year ended 31 December 2016
"**SOCO Annual Report and Accounts 2017**"	SOCO's annual report and accounts for the year ended 31 December 2017
"**SOCO Audited Financial Statements**"	SOCO Group's consolidated financial statements for the year ended 31 December 2015 as set out in the SOCO Annual Report and Accounts 2015, SOCO Group's consolidated financial statements for the year ended 31 December 2016 as set out in the SOCO Annual Report and Accounts 2016, and SOCO Group's consolidated financial statements for the year ended 31 December 2017 as set out in the SOCO Annual Report and Accounts 2017
"**SOCO Interim Financial Statements**"	SOCO Group's unaudited condensed consolidated financial statements for the six months ended 30 June 2018 set out in the interim results release of SOCO dated 20 September 2018
"**SOCO Board**"	the board of directors of SOCO
"**SOCO Directors**"	the directors whose names are set out on page 8 of this document
"**SOCO Exploration**"	SOCO Exploration Limited
"**SOCO General Meeting**"	the general meeting of SOCO to be held at 10.00 a.m. on 21 December 2018 at Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ (and any adjournment thereof) for the purposes of considering and, if thought fit, approving the Resolutions
"**SOCO Group**"	SOCO, its subsidiaries and subsidiary undertakings

"**SOCO Shareholders**"	holders of SOCO Shares
"**SOCO Share(s)**"	the ordinary shares of five pence each in the capital of SOCO
"**UK**" or "**United Kingdom**"	the United Kingdom of Great Britain and Northern Ireland
"**UK Listing Authority**"	the UK securities regulator
"**Unaudited Pro Forma Financial Information**"	The unaudited pro forma financial information of the Enlarged Group contained in Part IV (*Unaudited Pro-Forma Financial Information of the Enlarged Group*) of this Circular
"**US**", "**USA**" or "**United States**"	the United States of America (including the states of the United States and the District of Columbia), its possessions and territories and all areas subject to its jurisdiction

For the purpose of this document, "**subsidiary**", "**subsidiary undertaking**", "**undertaking**" and "**associated undertaking**" have the meanings given by the 2006 Act.

All times referred to are London time unless otherwise stated.

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

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

PART X

GLOSSARY OF TECHNICAL TERMS

The following technical terms apply throughout this document unless the context requires otherwise:

"**1C**"	the "low estimate" scenario of contingent resources, such that there is a 90 per cent. probability that quantities of contingent resources actually recovered will equal or exceed the low estimate
"**2C**"	the "best estimate" scenario of contingent resources, such that there is a 50 per cent. probability that quantities of contingent resources actually recovered will equal or exceed the best estimate
"**3C**"	the "high estimate" scenario of contingent resources, such that there is a 90 per cent. probability that quantities of contingent resources actually recovered will equal or exceed the high estimate
"**1P**"	proved Reserves
"**2P**"	proved Reserves plus Probable Reserves
"**3P**"	proved Reserves plus Probable Reserves plus Possible Reserves
"**3D seismic**"	derived from a set of seismic lines. 3D seismic data provide detailed information about fault and subsurface structures
"**AAPG**"	American Association of Petroleum Geologists
"**bbl**"	barrels
"**bbld**"	barrels per day
"**bcd**"	barrels of condensate per day
"**bnbbl**"	billion barrels
"**boepd**"	barrels of oil equivalent per day
"**bopd**"	barrels of oil per day
"**Bscf**"	billion standard cubic feet
"**BTU**"	British Thermal Unit
"**Contingent Resources**"	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. 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
"**COP**"	Cessation of Production
"**CPI**"	Computer-processed Interpretation (petrophysics)
"**development well**"	a well drilled, within a development lease area where associated reserves are booked for an oil and/or gas reservoir, to the depth of a

	stratigraphic horizon known to be productive. A development well may be a producing well or a shut in well
"**EUR**"	Estimated Ultimate Recovery
"**Entitlement Volume**"	the volumes of oil and/or gas which a Contractor receives under the terms of the licence
"**exploration well**"	a well drilled: (i) to find and produce oil or gas from an accumulation previously considered as an undiscovered; (ii) to find a new reservoir in a known field, i.e. a field previously producing oil and gas from another reservoir (the incremental drilled is considered to be within the exploration criteria if the well targeted producing reservoirs)
"**field**"	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
"**formation**"	a body of rock that is sufficiently distinctive and continuous that it can be mapped
"**GOR**"	gas/oil ratio
"**GRV**"	gas rock volume
"**HSE**"	Health, Safety, Environment
"**hydrocarbons**"	compounds formed primarily from the elements hydrogen and carbon and existing in solid, liquid or gaseous forms
"**LTI**"	lost time incident
"**MENA**"	Middle East and North Africa
"**MM**"	million
"**MMBOE**" or "**mmboe**"	million barrels oil equivalent
"**mD**"	permeability in milliDarcies
"**mmscfd**"	million standard cubic feet per day
"**Net entitlement**"	reserves estimated to be attributable to the Group based on its contractual working interest of the costs, benefits and ownership of a particular asset, including cost recovery and profit share amounts, and reduced by royalties or share of production owing to others under applicable lease and fiscal terms, as adjusted up for any corporation tax paid on their behalf and in kind
"**OWC**"	Oil-water contact
"**PIIP**"	Petroleum Initially In-Place
"**Petroleum**"	deposits of oil and/or gas
"**Possible Reserves**"	possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves such that, when probabilistic methods are used, there is at least a 10 per cent. probability that the actual quantities recovered will equal or exceed the 3P estimate
"**Proved Reserves**"	proved reserves are those quantities of petroleum which, 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
"**PRMS**"	Petroleum Resources Management System (SPE Terminology)
"**PRMS Standards**"	the standards and guidelines prepared by the Petroleum Resources Management System for consistent and reliable definition, classification, and estimation of hydrocarbon resources
"**Probable Reserves**"	probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves such that, when probabilistic methods are used, there is at least a 50 per cent. probability that the actual quantities recovered will equal or exceed the 2P estimate
"**production**"	the quantity of petroleum produced in a given period
"**Prospective Resources**"	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources 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
"**prospects**"	a location where a well is to be drilled
"**PSC**"	production sharing contract
"**psi**"	pounds per square inch
"**psia**"	pounds per square inch absolute
"**PVT**"	Pressure Volume Temperature
"**Reserves**"	reserves are those quantities of hydrocarbons which are anticipated to be commercially recovered from known accumulations from a given date forward
"**scf**"	standard cubic feet measured at 14.7 pounds per square inch and 60°F
"**scf/stb**"	standard cubic feet per stock tank barrel
"**SEG**"	Society of Exploration Geophysicists
"**SPE**"	Society of Petroleum Engineers
"**SPEE**"	Society of Petroleum Evaluation Engineers
"**stb/d**"	stock tank barrels per day
"**STOIIP**"	Stock Tank Oil Initially-In-Place
"**sidetrack**"	a secondary wellbore drilled away from the original hole
"**TVDSS**"	true vertical depth (sub-sea)
"**VLP**"	Vertical Lift Profile
"**WPC**"	World Petroleum Council
"**Water cut**"	the percentage of water for every barrel fluid produced

"**WI**" or "**Working Interest**"	the percentage equity interest in an asset, before reduction for royalties or production share owed to the government under the applicable fiscal terms
"**workover well**"	a well intervention, which is any operation carried out on an existing well during or at the end of its productive life, which alters the state of the well and/or well geometry, provides well diagnostics, or manages the production of the well for the purpose of restoring, prolonging, or enhancing the production from that well

SOCO INTERNATIONAL PLC

(*Incorporated and registered in England and Wales with registered number 03300821*)

NOTICE OF GENERAL MEETING

NOTICE IS HEREBY GIVEN that a **GENERAL MEETING** of SOCO International plc (the "**Company**") will be held at Clifford Chance LLP, 10 Upper Bank Street, London E14 5JJ at 10.00 a.m. on 21 December 2018 for the purpose of considering and, if thought fit, passing the following resolutions:

ORDINARY RESOLUTIONS

THAT:

1. the proposed acquisition by the Company of the entire issued and to be issued share capital of Merlon Petroleum El Fayum Company (the "**Acquisition**") substantially on the terms and subject to the conditions set out in the circular to shareholders of the Company outlining the Acquisition dated 5 December 2018, of which this notice forms part (the "**Circular**") be and is hereby approved and the directors of the Company (the "**Directors**") (or any duly constituted committee thereof) be authorised:

   (a) to take all such steps as may be necessary or desirable in connection with, and to implement, the Acquisition; and

   (b) to agree such modifications, variations, revisions, waivers or amendments to the terms and conditions of the Acquisition (provided such modifications, variations, revisions, waivers or amendments are not material), and to any documents relating thereto, as they may in their absolute discretion think fit; and

2. subject to and conditional upon the resolution described in paragraph 1 above being passed by the requisite majority and without prejudice to all existing authorities conferred on the Directors, the Directors be and are hereby generally and unconditionally authorised in accordance with section 551 of the Companies Act 2006 and Article 9 of the Company's articles of association (the "**Articles**") to exercise all powers of the Company to allot SOCO Shares (as defined in the Circular), credited as fully paid, and to take all such other steps as it may deem necessary, expedient or appropriate to implement such allotment in connection with the Acquisition up to an aggregate nominal amount of £3,278,052.05, and which authority shall expire on 20 September 2019 (unless previously revoked or varied by the Company in general meeting), save that the Company may before such expiry make an offer or agreement which would or might require relevant securities to be allotted after such expiry and the Directors may allot relevant securities in pursuance of such an offer or agreement as if the authority conferred hereby had not expired.

Dated: 5 December 2018

By order of the Board

Tony Hunter
Company Secretary

Registered office:
48 Dover Street
London W1S 4FF

Notes:

1. To be entitled to attend and vote at the meeting (and for the purpose of the determination by the Company of the votes they may cast), shareholders must be registered in the register of members of the Company as at 18:30 p.m. on 19 December 2018 or, in the event that the meeting is adjourned, in the register of members at 18:30 p.m. on the date 48 hours (excluding non-working days) before the date of any adjourned meeting. Changes to entries on the register of members after the relevant deadline shall be disregarded in determining the rights of any person to attend and vote at the meeting or any adjourned meeting.

2. A holder of shares of the Company is entitled to attend and vote at the meeting is also entitled to appoint one or more proxies to exercise all or any of his rights to attend, speak and vote on their behalf at the meeting. A Form of Proxy which may be used to make such appointment and give proxy instructions is enclosed with this notice. If you think you may not be able to attend the meeting, please complete and return the Form of Proxy. Please indicate how you wish your vote to be cast by inserting an "X" in the appropriate box. In the event that you wish to appoint a person other than the Chairman as your proxy, delete the reference to the Chairman and insert the name of the person you wish to appoint in the space provided. Please initial the amendment, otherwise your proxy will be invalid. A proxy need not be a member of the Company. Instructions for use are shown on the Form of Proxy. Completion and return of a Form of Proxy, an electronic proxy or any CREST Proxy Instruction (as described in note 10 below) will not preclude a shareholder from attending the meeting and voting there in person. The Company will not exercise any rights in relation to any shares held by, or on behalf of, the Company.

3. To be effective, the Form of Proxy (together with the power of attorney or other authority (if any) under which it is signed, or a notarially certified copy of such power or authority) must be deposited at the Company's registrar, Equiniti Limited at Aspect House, Spencer Road, Lancing, BN99 6DA before 10.00 a.m. on 19 December 2018 or, if the meeting is adjourned, by not later than 48 hours (excluding non-working days) before the time of the adjourned meeting. Forms of Proxy returned by fax will not be accepted. Alternatively, you may appoint a proxy or proxies electronically through the Company's registrar's website: www. sharevote.co.uk. Full details of the procedure to be followed to appoint a proxy electronically are given on the website.

4. A holder of shares of the Company entitled to attend and vote at the meeting may appoint more than one proxy. To do so, you should photocopy the Form of Proxy. You must complete a separate Form of Proxy for each proxy. Please indicate, next to each proxy holder's name, the number of shares each proxy appointment relates to and how you wish the proxies' votes to be cast. Please also indicate, by marking the box on the proxy, if multiple appointments are being made. Please initial the amendment, otherwise your proxy will be invalid. A failure to specify the number of shares each proxy appointment relates to, or specifying a number of shares in excess of those held by the member on the date referred to in note 1 above, will result in the proxy appointments being invalid.

5. Any corporation which is a member can appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that they do not do so in relation to the same shares.

6. Any person who is not a member of the Company but has been nominated under section 146 of the Companies Act 2006 by a member of the Company (the "relevant member") to enjoy information rights, (the "nominated person") does not have a right to appoint any proxies under note 2 above. A nominated person may have a right under an agreement with the relevant member to be appointed or to have somebody else appointed as a proxy for the meeting. If a nominated person does not have such a right, or has such a right and does not wish to exercise it, he may have a right under an agreement with the relevant member to give instructions as to the exercise of voting rights.

7. The "Vote Withheld" option is provided to enable you to abstain on the specified resolution. However, it should be noted that a "Vote Withheld" is not a vote in law and will not be counted in the calculation of the proportion of votes "For" and "Against" the specified resolution.

8. As at 3 December 2018 (being the latest practicable date prior to the publication of this notice), the Company's share capital consisted of 341,076,911 ordinary shares of £0.05, carrying one vote each, including 9,122,268 shares in treasury. Therefore, the total voting rights in the Company as at 3 December 2018 (excluding voting rights attached to shares held by or on behalf of the Company) are 331,954,643.

9. In accordance with Regulation 41 of the Uncertificated Securities Regulations 2001, only those members entered on the relevant register of members of the Company at 18:30 p.m. on the date 48 hours before the meeting or, in the event that the meeting is adjourned, in the register of members of the Company at 18:30 p.m. on the date 48 hours before the adjourned meeting, shall be entitled to attend and vote at the meeting in respect of the number of shares registered in their name at that time. Changes to entries on the relevant register of members after the relevant time shall be disregarded in determining the rights of any person to attend and vote at the meeting or any adjourned meeting. Shareholders who hold their shares in the Company through CREST ("CREST members") and who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the purpose of this meeting and any adjournment(s) thereof by using the procedures described in the CREST Manual available at www.euroclear.com. CREST personal members or other CREST sponsored members, and those CREST members who have appointed a service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

10. In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear's specifications, and must contain the information required for such instruction, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or is an amendment to the instruction given to a previously appointed proxy must, in order to be valid, be transmitted so as to be received by the Company's registrar Equiniti Limited (Participant ID RA19), not later than 48 hours (excluding non-working days) before the time appointed for the meeting or any adjourned meeting. For this purpose, the time of receipt will be taken to be the time (as determined by the time stamp applied to the message by the CREST Application Host) from which the Company's registrar are able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time, any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

11. CREST members and, where applicable, their CREST sponsors, or voting service providers should note that Euroclear does not make available special procedures in CREST for any particular message. Normal system timings and limitations will, therefore, apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member, or sponsored member, or has appointed a voting service provider, to procure that his CREST

sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting system providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

12. 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.

13. 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 of members of the Company.

14. Any member attending the meeting has a right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the meeting but no such answer need be given if (a) to do so would interfere unduly with the preparation for the meeting or involve the disclosure of confidential information; (b) the answer has already been given on a website in the form of an answer to a question; or (c) it is undesirable in the interests of the company or the good order of the meeting that the question be answered.

15. A copy of this notice, and other information required by s.311A of the Companies Act 2006, can be found at www.socointernational.com.

16. No electronic address (within the meaning of section 333(4) of the Companies Act 2006) provided in this notice (or in any related documents including the Form of Proxy) may be used to communicate with the Company for any purpose other than those expressly stated.

17. If you have been nominated to receive general shareholder communications directly from the Company, it is important to remember that your main contact in terms of your investment remains as it was (the registered shareholder, or perhaps custodian or broker, who administers the investment on your behalf). Therefore, any changes or queries relating to your personal details and holding (including any administration thereof) must continue to be directed to your existing contact at your investment manager or custodian. The Company cannot guarantee dealing with matters that are directed to it in error. The only exception to this is where the Company, in exercising one of its powers under the Companies Act 2006, writes to you directly for a response.

18. The shorter notice period of a minimum of 14 clear days as approved at the Company's most recent annual general meeting has been used for the purposes of this meeting as the directors of the Company believe that the flexibility offered by the shorter notice period is merited by the Acquisition and it is in the best interests of the shareholders as a whole, taking into account the circumstances and business of the meeting.