THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt as to the action you should take, you are recommended immediately to seek your own personal financial advice from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 if you are in the United Kingdom or, if not, from another appropriately authorised independent financial adviser. If you have sold or otherwise transferred all of your shares in Cairn Energy PLC, you should pass this document, with the accompanying Form of Proxy, without delay to the stockbroker, bank or other person who arranged the sale or transfer so they can pass these documents to the person who now holds the shares except that such documents should not be sent to any jurisdiction where to do so might constitute a violation of local securities laws or regulations. If you sell or have sold part only of your holding of shares in Cairn Energy PLC, please consult the bank, stockbroker or other agent through whom the sale or transfer was effected.

Cairn

CAIRN ENERGY PLC

(Incorporated in Scotland with registered number SC226712)

Proposed acquisition of upstream interests in the Western Desert, the Arab Republic of Egypt

and

Notice of General Meeting

This Circular should be read as a whole. Your attention is drawn to the letter from the Chair of Cairn Energy PLC (the "Company", "Cairn" or "Cairn Energy") which is set out at Part I of this Circular and which recommends you to vote in favour of the Resolution to be proposed at the General Meeting referred to below. Please also see Part II of this Circular for a discussion of certain risk factors that you should consider carefully when deciding whether or not to vote in favour of the Resolution to be proposed at the General Meeting. The whole of this Circular should be read in light of these risk factors.

Notice of the General Meeting of Cairn to be held at 50 Lothian Road, Edinburgh EH3 9BY at 9.00 a.m. (BST) on 19 July 2021, is set out at the end of this Circular.

Please note that, in light of the ongoing COVID-19 pandemic and the UK and Scottish legislation and government guidance currently in force as a consequence of the pandemic, there remain in force significant restrictions on public gatherings.

Most of Scotland (including Edinburgh) is in protection level 2 (as at the Latest Practicable Date). This means that Cairn is able to facilitate the attendance of Shareholders in person at the General Meeting. However, the continuing application of social distancing and other safety requirements mean that only a very limited number of Shareholders will be able to attend at the venue for the General Meeting.

The Board therefore strongly encourages Shareholders not to attend the General Meeting in person and instead be represented by the chair of the meeting acting as their proxy.

Should any Shareholders wish to attend in person, Cairn will give preference to those who pre-register, in order of time of registration and, to the extent that there are any remaining spaces, Cairn will try to accommodate any Shareholders who have not pre-registered, on a first-come first-served basis on the day, subject to social distancing and other safety requirements. Shareholders should pre-register their intention to attend the General Meeting by emailing IR.Mailbox@Cairnenergy.com. Pre-registration for the General Meeting will close when the capacity limit has been reached or if earlier at 9.00 a.m. (BST) on 15 July 2021.

If more Shareholders seek to attend the General Meeting than the capacity of the venue allows, Cairn will have to refuse entry to any additional Shareholders once that capacity has been reached to avoid being in breach of the law. Shareholders are therefore requested not to attend the General Meeting without pre-registering and receiving confirmation of their place, as admission on the day cannot be guaranteed. Shareholders are responsible for understanding and complying with the restrictions applicable to their own journey and should bear in mind that rules may differ between different parts of the UK.

The health and wellbeing of our Shareholders and employees remains the Board's primary concern. It is essential to remain vigilant notwithstanding the ongoing UK vaccination programme, particularly given the spread of new variants in the UK and other parts of the world. For this reason, the Board strongly encourages Shareholders not to attend the General Meeting in person and instead be represented by the chair of the meeting acting as their proxy.

Cairn will continue to monitor the situation and, in particular, any changes to the applicable law or guidance in force as a consequence of the COVID-19 pandemic. In the unlikely event of a material change in circumstances that results in the further lifting or relaxation of measures or restrictions relating to travel and public gatherings before the date of the General Meeting, Cairn will consider if it is appropriate, safe and legally permissible to open up the General Meeting for attendance by more Shareholders. If this is the case, an update will be given on Cairn's website and by separate announcement through the regulatory news service of the London Stock Exchange. Further information on this is set out in Part I of this Circular.

Enclosed with this Circular is a Form of Proxy for use in respect of the General Meeting. You are requested to complete, sign and return the Form of Proxy in accordance with the instructions printed on it as soon as possible, and in any event, so as to arrive at the offices of the Company's registrars, Equiniti at Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA, not later than 9.00 a.m. (BST) on 15 July 2021. Alternatively, you may register your proxy appointment or voting directions electronically via the www.sharevote.co.uk website not later than 9.00 a.m. (BST) on 15 July 2021 (further information regarding the use of this facility is set out in the notes to the Notice of General Meeting). If you hold your Shares in CREST, you may appoint a proxy by completing and transmitting a CREST Proxy Instruction so as to be received by the Company's registrars, Equiniti, not later than 9.00 a.m. (BST) on 15 July 2021.

N. M. Rothschild & Sons Limited ("**Rothschild & Co**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting exclusively for Cairn and for no-one else in connection with the contents of this Circular and the Transaction and will not regard any other person as its client in relation to the matters in this Circular and will not be responsible to anyone other than Cairn for providing the protections afforded to clients of Rothschild & Co nor for providing advice in connection with the contents of this Circular or the Transaction or any transaction, arrangement or other matter referred to in this Circular.

Save for the responsibilities and liabilities, if any, of Rothschild & Co under the Financial Services and Markets Act 2000 or the regulatory regime established thereunder, Rothschild & Co shall not assume any responsibility whatsoever nor makes any representations or warranties, express or implied, in relation to the contents of this Circular, including its accuracy, completeness or verification or for any other statement made or purported to be made by Cairn, or on Cairn's behalf, or by Rothschild & Co or on Rothschild & Co's behalf. Nothing contained in this Circular is, or shall be, relied on as a promise or representation in this respect, whether as to the past or the future, in connection with Cairn or the Transaction. Rothschild & Co accordingly disclaims to the fullest extent permitted by law all and any responsibility and liability whether arising in tort, contract or otherwise which it might otherwise be found to have in respect of this Circular or any such statement.

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IMPORTANT INFORMATION

Regarding Forward Looking Statements

This Circular includes statements that are, or may be deemed to be, "forward looking statements". These forward looking statements can be identified by the use of forward looking terminology, including the terms "anticipates", "expects", "intends", "may", "will", "believes", "estimates", "plans", "projects" or "should" or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy, plans, objectives, goals, future events or intentions. These forward looking statements include all matters that are not historical facts. They appear in a number of places throughout this Circular and include, but are not limited to, statements regarding the Company's intentions, beliefs or current expectations concerning, among other things, the Group's results of operations, financial position, prospects, growth, strategies and the industry in which it operates. By their nature, forward looking statements involve risk and uncertainty because they relate to future events and circumstances. Forward looking statements are not guarantees of future performance and the actual results of the Group's operations and financial position, and the development of the markets and the industry in which the Group operates, may differ materially from those described in, or suggested by, the forward looking statements contained in this Circular.

In addition, even if the results of operations, financial position and the development of the markets and the industry in which the Group operates are consistent with the forward looking statements contained in this Circular, those results or developments may not be indicative of results or developments in subsequent periods. A number of factors could cause results and developments to differ materially from those expressed or implied by the forward looking statements including, without limitation, general economic and business conditions, industry trends, competition, changes in regulation, currency fluctuations, changes in its business strategy, political and economic uncertainty and other factors discussed in Part II (*Risk Factors*) of this Circular.

Forward looking statements may, and often do, differ materially from actual results. Any forward looking statements in this Circular speak only as at the date of this Circular, reflect the Company's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations and growth strategy. You should specifically consider the factors identified in this Circular which could cause actual results to differ before making any decision in relation to the Transaction. Subject to the requirements of the FCA, the London Stock Exchange, the Listing Rules and the DTRs (and/or any regulatory requirements) or applicable law, the Company explicitly disclaims any obligation or undertaking publicly to release the result of any revisions to any forward looking statements in this Circular that may occur due to any change in the Company's expectations or to reflect events or circumstances after the date of this Circular.

Currencies

References to "**Pounds Sterling**", "**£**" and "**pence**" are to the lawful currency of the United Kingdom.

References to "**US Dollars**", "**US$**", "**$**" and "**US cents**" are to the lawful currency of the United States of America.

References to "**Egyptian Pounds**" are to the lawful currency of Egypt.

Rounding

Percentages and certain amounts included in this Circular have been rounded to the nearest whole number or single decimal place for ease of presentation (except as otherwise stated). Accordingly, figures shown as totals in certain tables may not be the precise sum of the figures that precede them. In addition, certain percentages and amounts contained in this Circular reflect calculations based on the underlying information prior to rounding, and accordingly may not conform exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

Times

All times referred to in this Circular are, unless otherwise stated, references to the time in London, United Kingdom.

References to defined terms

Certain terms used in this Circular, including certain capitalised, technical and other terms are defined or described in Part VIII (*Glossary of Technical Terms*) of this Circular and Part IX (*Definitions*) of this Circular.

Reserves information and Competent Person's Report

Unless otherwise indicated, GaffneyCline has, in compiling the GaffneyCline Report concerning the hydrocarbon reserves and resources of the Assets as of 1 January 2020 contained in Part VI (*Competent Person's Report in respect of the Assets*) of this Circular, used the definitions and guidelines set out by the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("**PRMS**") (details of which are set out in Appendix III of the GaffneyCline Report).

"Contingent resources" are defined by the PRMS as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by application of development project(s), not currently considered to be commercial owing to one or more contingencies. Contingent resources have an associated chance of development. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status".

"Prospective resources" are instead defined by PRMS as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of geologic discovery and a chance of development. Prospective resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity".

"Reserves" are defined by the PRMS as "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: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied".

Reserves net to the Seller's interest are quoted in the Competent Person's Report as Net Entitlement Reserves, reflecting the terms of the applicable Production Sharing Contracts. These are lower than the working interest fraction of the gross reserves (the "working interest reserves") due to deduction of the government's share. The working interest reserves quoted herein have been derived by Cairn from the information in the Competent Person's Report.

Shareholders should not place undue reliance on the forward looking statements in this Circular or on the ability of Cairn to predict actual reserves or resources. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. It should be noted that prospective 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.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Announcement of the Acquisition	9 March 2021
Publication of this Circular (including the Notice of General Meeting) and the Form of Proxy and despatch to Shareholders	29 June 2021
Latest time and date for receipt of Forms of Proxy or electronic proxy appointments or completion and transmission of CREST Proxy Instructions	9.00 a.m. (BST) on 15 July 2021
General Meeting	9.00 a.m. (BST) on 19 July 2021
Expected date of Completion	Q3 2021
Long stop date for completion of the Acquisition	8 March 2022

Note:

The times set out in the expected timetable of principal events above and mentioned throughout this Circular may be adjusted by the Company, in which event details of the new times and dates will be notified to the London Stock Exchange, and, where appropriate, Shareholders, through the release of an announcement to a Regulatory Information Service.

Completion of the Transaction is conditional upon, among others, the satisfaction or, where applicable, waiver of the Conditions. There can be no certainty if or when all the Conditions will be satisfied or, where applicable, waived and therefore no certainty as at the date of this Circular regarding the date of Completion.

DIRECTORS, SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors	Nicoletta Giadrossi	(Non-Executive Chair)
	Keith Lough	(Non-Executive Director)
	Peter Kallos	(Non-Executive Director)
	Alison Wood	(Non-Executive Director)
	Catherine Krajicek	(Non-Executive Director)
	Erik Daugbjerg	(Non-Executive Director)
	Simon Thomson	(Chief Executive)
	James Smith	(Chief Financial Officer)
Company Secretary	Anne McSherry	
Registered and head office of the Company	50 Lothian Road Edinburgh EH3 9BY	
Sponsor	Rothschild & Co New Court St Swithin's Lane London EC4N 8AL	
Legal Adviser to the Company as to English law	Ashurst LLP London Fruit & Wool Exchange 1 Duval Square London E1 6PW	
Reporting Accountant	Ernst & Young LLP 1 More London Place London SE1 2AF	
Competent Person	Gaffney, Cline & Associates Limited Bentley Hall Blacknest Road Alton Hampshire GU34 4PU	
Registrar	Equiniti Limited Aspect House Spencer Road Lancing West Sussex BN99 6DA	

PART I

LETTER FROM THE CHAIR OF CAIRN ENERGY PLC

CAIRN ENERGY PLC

(Incorporated in Scotland with registered number SC226712)

Nicoletta Giadrossi (Non-Executive Chair)	Registered and Head Office
Keith Lough (Non-Executive Director)	50 Lothian Road
Peter Kallos (Non-Executive Director)	Edinburgh
Alison Wood (Non-Executive Director)	EH3 9BY
Catherine Krajicek (Non-Executive Director)	
Erik Daugbjerg (Non-Executive Director)	
Simon Thomson (Chief Executive)	
James Smith (Chief Financial Officer)	

29 June 2021

Dear Shareholder,

Proposed acquisition of 50 per cent. of upstream interests in the Western Desert, The Arab Republic of Egypt

1. Introduction

On 9 March 2021, Cairn, together with Cheiron Petroleum Corporation (its consortium partner) ("**Cheiron**") announced that Capricorn Egypt, a wholly owned subsidiary of Cairn, and Cheiron Oil & Gas and certain of Cheiron Energy's subsidiaries (the **"Cheiron Energy Purchasers"**), entered into a conditional agreement dated 8 March 2021 to acquire from Shell Egypt N.V. and Shell Austria Gesellschaft MBH (together, the "**Sellers**") the Assets, a portfolio of upstream oil and gas exploration, development and production interests in the Western Desert, onshore The Arab Republic of Egypt, (the "**Acquisition**" or "**Transaction**") for a purchase price of approximately US$646 million (approximately US$323 million net to Cairn), as adjusted for working capital and other customary adjustments between the economic effective date of 1 January 2020 and the completion date, with additional contingent consideration of up to US$280 million (US$140 million net to Cairn) if certain requirements are met.

Under the terms of the SPA, each of (i) Capricorn Egypt; and (ii) the Cheiron Energy Purchasers, will acquire a fifty per cent. (50 per cent.) share of the package of Sellers' interests. Further details of the terms of the Sale and Purchase Agreement and a summary of the Consortium arrangements are set out in Part III (*Principal Terms of the Sale and Purchase Agreement*) and Part VII (*Additional Information*) of this Circular.

The Transaction is of sufficient size relative to that of the Group to constitute a Class 1 transaction under the Listing Rules and is accordingly conditional upon the approval of Shareholders. Your approval of the Transaction is therefore being sought at a General Meeting to be held at 9.00 a.m. (BST) on 19 July 2021 at 50 Lothian Road, Edinburgh EH3 9BY. A notice of the General Meeting setting out the Resolution to be considered at the General Meeting can be found at the end of this Circular. A summary of the action you are requested to take in connection with the General Meeting is set out in paragraph 11 of this letter and on the Form of Proxy that accompanies this Circular.

I am writing to you to (i) explain the background to and reasons for the Acquisition; (ii) provide you with information about the Assets; (iii) provide you with information about the arrangements between the members of the Consortium; (iv) explain why the Directors unanimously consider the Acquisition to be in the best interests of the Shareholders as a whole; and (v) recommend that you vote in favour of the Resolution to be proposed at the General Meeting.

2. Interests to be acquired

As noted above, Capricorn Egypt will acquire 50 per cent. of the portfolio of interests being sold by the Sellers, comprising 13 concessions (including 5 exploration concessions), with 18 development leases and one notice of commercial discovery.

The Sellers' gross working interest production from the concessions in 2020 averaged 83,000 boepd (37 per cent. liquid and 63 per cent. gas), with 226 mmboe of gross working interest 2P reserves as at 31 December 2020 (41,500 boepd and 113 mmboe in respect of the working interest 2P reserves as at 31 December 2020 to be acquired by Cairn pursuant to the Transaction).

The producing fields are split over four distinct areas, each with different characteristics and geographies: the Obaiyed Area; Badr El Din ("**BED**"); North East Abu Gharadig ("**NEAG**"); and Alam El Shawish West ("**AESW**").

In addition to near field exploration potential within the above development areas, the portfolio also includes material potential exploration upside, with significant upcoming activity in a number of concessions, as well as three newly awarded exploration blocks (South East Horus, West El Fayium and South Abu Sennan), in the "Onshore East" oil prone area. It is intended that Capricorn Egypt shall be appointed as operator of the three newly awarded exploration concessions.

Bapetco, a joint venture company currently owned 50:50 by the Sellers and the Egyptian General Petroleum Corporation (**"EGPC"**), is operator or acting as agent of operating companies of all of the producing concessions within the portfolio. Further details in respect of Bapetco and the other operating companies are set out in paragraph 5 of this Part I[1].

Upon completion of the Transaction, the interests to be acquired by Cairn will be as follows:

Area	**Concession & Exploration Blocks**	**Cairn working interest in Concession**	**Partners in Concession**	**Operating Company**	**Cairn working interest in Operating Company**
Obaiyed Area	Obaiyed	50%	Cheiron Oil & Gas (50%)	Obaiyed Petroleum Company	25%
	North Matruh	50%	Cheiron Oil & Gas (50%)	Obaiyed Petroleum Company	25%
	North Um Baraka	50%	Cheiron Oil & Gas (50%)	North Um Baraka Petroleum Company	25%
Badr El Din (BED)	Sitra	50%	Cheiron Oil & Gas (50%)	Sitra Petroleum Company	25%
	BED	50%	Cheiron Oil & Gas (50%)	Bapetco	25%
	BED 2 & 17	50%	Cheiron Oil & Gas (50%)	Bapetco	25%
	BED-3	50%	Cheiron Oil & Gas (50%)	Bapetco	25%
	North Alam El Shawish ("**NAES**")	50%	Cheiron Oil & Gas (50%)	NAES Petroleum Company	25%
NEAG	NEAG Tiba and NEAG Extension	26%	Cheiron Oil & Gas (26%); Apache Egypt (48%)	Tiba Petroleum Company	13%

[1] As per Egyptian hydrocarbon regulation, EGPC owns a 50 per cent. share in all such operating companies. See paragraph 5 of this Part I for further detail on the regulatory regime governing such operating companies.

Area	Concession & Exploration Blocks	Cairn working interest in Concession	Partners in Concession	Operating Company	Cairn working interest in Operating Company
AESW	AESW	20%	Cheiron Oil & Gas (20%); North Petroleum International Company SA (35%); Neptune (25%)	AESW Petroleum Company	10%
Abu Sennan	South Abu Sennan	50%	Cheiron S Abu Sennan Ltd (50%)	—	—
Horus	South East Horus	50%	Cheiron S E Horus Ltd (50%)	—	—
El Fayium	West El Fayium	50%	Cheiron W El Fayium Ltd (50%)	—	—

Further information on the Assets is set out in paragraph 7 of this Part I, including details on current production levels and an independent summary of the reserves and resources attributed to each of such concessions prepared by GaffneyCline.

3. Key terms of the Transaction

The purchase price to be paid by the Consortium is approximately US$646 million, to be adjusted for working capital and other customary adjustments between the economic effective date of 1 January 2020 and the completion date. Cairn's share of such purchase price is approximately US$323 million.

The Consortium has, on 9 March 2021, paid to the Sellers a deposit of approximately US$16 million (of which Capricorn Egypt's share was approximately US$8 million). In the event that the Transaction does not proceed to Completion, such deposit shall be refundable in full by the Sellers, save where such failure to complete is due to the Consortium either being in material breach of its obligations under the Sale and Purchase Agreement or certain other documents entered into in connection with the Transaction, or due to the failure to obtain the approval of EGPC, or due to the failure to obtain the approval of Cairn's shareholders (in which case the amount of the deposit to be forfeited shall not exceed 1 per cent. of Cairn's market capitalisation).

There may also be contingent consideration payable by the Consortium of up to US$280 million (US$140 million net to Cairn) if certain requirements are met, on the following basis:

- up to US$200 million (US$100 million net to Cairn) over the years 2021 to 2024, in four instalments (of up to US$50 million gross per annum), subject to average annual dated Brent price being equal to or above US$55/bbl in each of 2021, 2022, 2023 and 2024, with full pay-out in each year achieved at US$75/bbl or above, based on a linear scale; and
- up to US$80 million (US$40 million net to Cairn) based on the amount of commercially recoverable liquid hydrocarbons discovered in the first nine exploration wells drilled following signing of the Sale and Purchase Agreement. The amount to be paid is determined by a calculation of US$0.4 per barrel of independently audited 2P reserves following the award of a development lease in respect of such discovery or discoveries, subject to the above cap.

The Transaction is conditional, inter alia, on the approval of the Minister and EGPC. In addition, the Transaction is of sufficient size relative to that of the Group to constitute a Class 1 transaction under the Listing Rules, and is therefore subject to the approval of Cairn's shareholders, by a simple majority of votes cast.

While Capricorn Egypt and the Cheiron Energy Purchasers are jointly and severally liable to the Sellers in respect of the obligations of the Consortium under the SPA, the parties have agreed in the Joint Management Agreement (see paragraph 5 of this Part I) to indemnify each other in respect of any liability to the Sellers borne by a party in excess of their 50 per cent. interest. In addition, the obligations of Capricorn Egypt and the Cheiron Energy Purchasers to the Sellers under the SPA are guaranteed by Capricorn Oil Limited and Cheiron Holdings, on a similar joint and several basis, but also subject to counter indemnification under the JMA (for further details see paragraph 5 of this Part I, together with a detailed summary of the terms of the JMA at Part VII (*Additional Information*) of this Circular.

The principal terms of the Sale and Purchase Agreement, including further detail on the conditions to completion, the interim period adjustment, the contingent consideration and the details of payment of the deposit are set out in Part III (*Principal Terms of the Sale and Purchase Agreement*) of this Circular.

4. **Background to and reasons for the Transaction**

Cairn's strategy is to hold assets within the oil and gas life cycle in order to create, add and deliver value for stakeholders. The cash flow from production assets funds exploration, appraisal and development activity to deliver further value growth. Active portfolio management is central to this strategy, and following the disposal of its interests in Senegal, Cairn again demonstrated its commitment to returning significant capital to shareholders with a special dividend of approximately US$250 million paid to Shareholders on 25 January 2021.

In recent years, the Company has evaluated acquisition opportunities as it seeks to diversify and extend its production base. Cairn Energy has remained disciplined and has focused on opportunities with low full-cycle break even economics which would create meaningful value for shareholders.

The acquisition of the Sellers' upstream interests in the Western Desert is consistent with the core strategic objectives of the Company: targeting assets with a sustainable production base across multiple fields that can be competitive and relevant against the backdrop of global energy transition. The Assets materially enhance and diversify Cairn's production base, provide immediate operating cashflow contribution, add a significant gas volume to the portfolio and provide attractive opportunities for near term growth. The key highlights are outlined below.

Material portfolio with strong and stable production levels

- The Sellers' gross working interest 2P reserves of 226 mmboe (113 mmboe in relation to the working interest to be acquired by Cairn) as at 31 December 2020 delivers significant additional scale to Cairn's reserve base.
- The portfolio consists of 18 development leases across 13 concessions and one notice of commercial discovery with 83,000 boepd working interest production as at 31 December 2020 (41,500 boepd in respect of the working interest to be acquired by Cairn).
- Assets with a long production history and strong track record of reserves replacement, with the Sellers' gross working interest production averaging 92,000 boepd over the past 10 years.

Attractive new country entry into Egypt for the Company, in one of the most prolific basins in North Africa

- Significantly diversifies and prolongs Cairn's production base.
- One of the most competitive hydrocarbon regimes across the MENA region – favourable cost recovery and profit split across the Assets.
- Low cost of production: opex/bbl of less than US$6/boe (year ended 31 December 2020).

Enhances the contribution of gas to the Cairn portfolio

- Two thirds of production from the Assets is gas.
- Gas is sold domestically to EGPC, largely at a fixed price.

Opportunity to reduce operational emissions and enhance ESG

- Well managed assets by Bapetco, with shareholders EGPC and Shell Egypt and Shell Austria, members of a global major group, which has ensured a high standard of asset, facility and well integrity with regular maintenance programmes completed and a good uptime track record.
- It is the Consortium's intention to conduct a greenhouse gas baseline survey to identify any uncertainties and help develop a greenhouse gas reduction plan, which is likely to include a target reduction in flaring, change in stationary combustion and potential elimination of venting, wherever possible.

- Investment in electrification is proposed to take place across some of the Assets which should result in significant reduction in flaring and replacement of some of the diesel generated power by fuel gas.
- Identified opportunities regarding waste and water management, welfare and national content.

Delivers immediate operating cashflow

- The average Cashflow from Operations[2] for previous three reported years (2018 – 2020) was approximately US$124 million net to Cairn (if Cairn had owned the assets over the period).
- Fixed price gas sales reduce sensitivity to volatile global oil markets; oil and condensate export entitlement reduces risk of material receivables build-up.
- The Transaction will enable Cairn to continue to pursue transformational exploration across its global portfolio.

Near term growth options enhanced

- The Sellers' gross 2C working interest contingent resources of 99 mmboe (49 mmboe in relation to the working interest to be acquired by Cairn).
- Opportunities identified to extend field life and increase recovery rates via infill drilling and facilities optimisation.
- Control and flexibility over timings of any future developments. Future investment decisions will be benchmarked against opportunities in Cairn's wider portfolio and adhere to its strict capital allocation policies.

Significant exploration potential remaining, with active near-term drilling programme

- The Western Desert remains a highly prospective oil and gas region.
- The Sellers portfolio consists of 15,000 km^2 of exploration acreage with more than 400 prospects[3] identified; growth prospects seen across conventional, deep oil & gas, carbonate and unconventional themes.
- 810 mmboe of gross unrisked exploration resource potential, with nine firm commitment wells and two seismic acquisition programmes.
- Infrastructure control and proximity enables short-cycle, low cost exploration tieback opportunities.

5. Information on the Operating Companies and the Consortium

Operating Companies

Under the terms of the Concessions, following a commercial discovery, the operations in the area subject to the development lease are carried out by a newly formed Egyptian company based on the model articles attached to the Concession, which shall be 50 per cent. owned by the relevant governmental agency (EGPC in respect of each of the Assets) and 50 per cent. owned by the relevant Contractor(s). Prior to a commercial discovery, a Contractor is the operator of the Concession. Details of the various Operating Companies in respect of each of the Assets subject to the Transaction are set out in the Table at paragraph 2 of this Part I.

While each concession has a separate Operating Company, established in accordance with the relevant concession, all producing fields forming part of the Assets are in fact operated by Bapetco (which was originally incorporated to operate the BED Concession Agreement).

Each Operating Company has an eight member Board of Directors, four of whom are appointed by EGPC and four of whom are appointed by the Contractor(s). The Chairman of the Operating Company is appointed by EGPC, while its general manager is appointed by the Contractor. The Operating Company is responsible for managing all operations, preparing a work program and budget for future explorations and development of the discovery.

[2] Cashflow from operations is a non-IFRS measure and excludes working capital movements. Cashflow from operations is presented in order for readers to understand the cash profitability.

[3] Resources estimates and number of prospects to drill are based on Shell estimates.

Where there is more than one Contractor (as is currently the case in the AESW and NEAG Concessions, and will be the case on all Concessions following Completion) it is typical for a joint operating agreement to be put in place, pursuant to which operating committees will decide on matters to be raised by or voted on by the Contractors.

All matters at Operating Company level are decided unanimously by both EGPC and the Contractor(s), with authority delegated to the relevant body (shareholders, board of directors, general managers, etc.) depending on financial thresholds for the matter to be decided (with each Operating Company having a manual of authority governing its decision making process).

All the payment obligations of the Operating Companies lie with the Contractor(s) under the Concession agreement, including the payment of salaries and benefits to the employees, which are mainly appointed by EGPC.

The Consortium

On 17 January 2020, Cairn and Cheiron formed a consortium for the purposes of the Acquisition. Cheiron is a well-established and experienced operator in Egypt, and the Company believes that it is a good strategic partner for the Company in relation to the Transaction and Cairn's new country entry into Egypt.

Cheiron focuses on onshore and shallow water opportunities, and specialises in revitalising and optimising production from mature fields with upside potential. Cheiron also has an in depth knowledge of the Egyptian hydrocarbon basins and infrastructure. Its operations range from near field exploration and appraisal activity to new field developments. Cheiron has an established track record of using its technical and operational expertise, coupled with prudent cost management practices, to add value to its asset base.

The Consortium intend that certain of Cheiron Energy Purchasers shall be appointed as operator under the relevant JOAs for each of the Concessions in the four producing areas (namely Obaiyed, BED, NEAG and AESW). It is intended that Capricorn Egypt shall be appointed as operator of the three exploration concessions: South East Horus, West El Fayium and South Abu Sennan.

On 8 March 2021 Cairn and Cheiron entered into a Joint Management Agreement (the "**JMA**"), setting out the legal basis governing their relationship as consortium partners. The JMA covers a number of areas, including:

- **Governance**: including (i) appointees by each party to the board of directors of the various Operating Companies, and to the Bapetco management team positions; and (ii) the manner in which the Consortium will exercise its voting rights and decision making powers vis-à-vis the Bapetco Board of Directors and Committees.
- **Operational matters**: including the processes by which the parties will take financial, operational and HSE decisions in respect of each of the Concessions, together with the format of various JOAs to be entered into following completion, in respect of each of the Obaiyed Concession, the BED area Concessions and the new exploration Concessions (as well as entering into deeds of novation in respect of existing JOAs for the AESW and NEAG Concessions).
- **Cross indemnification**: the JMA provides for each party to cross indemnify the other party's group in respect of any costs or liabilities incurred by the indemnified party in excess of its 50 per cent. interest. This addresses any disproportionate liability suffered by either party in respect of, for example, the parties being jointly and severally liable under the Acquisition RBL Facility or to the Sellers in respect of the Consortium's obligations under the SPA.

For more information on the agreements between the Consortium and how their relationship will be governed (including the rights and obligations of the Group) please refer to paragraph 8.1 of Part VII (*Additional Information*).

6. Financing of the Acquisition

Cairn will finance a significant proportion of its share of the consideration from the Acquisition RBL Facility, a new debt finance facility entered into jointly with Cheiron Energy.

Cairn will fund its share of the remaining cash balance from its share of the Junior Debt Facility as well as existing cash resources. Cairn's cash reserves totalled approximately US$570 million as at 31 December 2020.

Cairn understands that Cheiron Energy will fund its share of the cash balance from a combination of the Acquisition RBL Facility, the Junior Debt Facility and its existing cash resources.

Acquisition RBL Facility

On 24 June 2021 the Consortium and the Acquisition RBL Lenders entered into a reserves based lending facility (the "**Acquisition RBL Facility**") pursuant to which the Acquisition RBL Lenders will make up to US$162.5 million available to Capricorn Egypt and up to US$162.5 million available to Cheiron Oil & Gas. As noted above the JMA provides for a balancing mechanism and cross indemnification between the Consortium in respect of the Acquisition RBL Facility. The key terms of the Acquisition RBL Facility are summarised in paragraph 8.1(g) of Part VII (*Additional Information*) of this Circular.

Junior Debt Facility

On 24 June 2021 the Consortium entered into a US$80 million subordinated term loan facility agreement (the **"Junior Debt Facility"**) with, among others, Deutsche Bank AG, Amsterdam Branch and Trafigura Ventures V B.V as lenders (the **"Junior Debt Lenders"**) and Deutsche Bank Luxembourg S.A. as junior agent pursuant to which the Junior Debt Lenders will make up to US$40 million available to Capricorn Egypt and up to US$40 million available to Cheiron Oil & Gas. The key terms of the Junior Debt Facility are summarised in paragraph 8.1(h) of Part VII (*Additional Information*) of this Circular.

7. Information on the Assets

The Assets are situated in the Western Desert. 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. Further, the Western Desert is renowned as a low-cost exploration region.

The Assets comprise 13 concessions (including five for exploration (two of which have had development leases granted)). The portfolio includes 18 development leases and one notice of commercial discovery and full details of each of the Concessions can be found in paragraph 8.2 of Part VII (*Additional Information*) of this Circular.

The Asset portfolio can be split into five distinct areas with different characteristics and geographies as follows:

Obaiyed Area

The Obaiyed Area is the largest onshore gas field in Egypt and includes the Obaiyed Concession and three other producing concessions which also have outstanding exploration commitments, namely North East Obaiyed, North Um Baraka and North Matruh.

Upon Completion, Capricorn Egypt will acquire a 50 per cent. working interest in 3 of the concession agreements in the Obaiyed Area (together with a 25 per cent. interest in the relevant Operating Companies: Obaiyed Petroleum Company and North Um Baraka Petroleum Company). The North East Obaiyed Concession is not being acquired as part of the Transaction.

The working interest production attributable to the interest to be acquired by Capricorn Egypt in the Obaiyed Area was 22 kboe/d, 18 kboe/d and 14 kboe/d for the years ended 31 December 2018, 2019 and 2020.

In respect of the fiscal terms of the Obaiyed concessions, there is a range of cost recovery limits between 25 and 30 per cent. (varying between individual concessions), with the Contractor's share of profit oil/gas/LPG ranging from 12.5 and 23 per cent. The Contractor is also entitled to recover a share of excess cost oil, pursuant to the NUB and Obaiyed concessions.

Badr El Din (BED)

The BED area comprises the five producing concessions: BED, BED-3, BED 2 & 17, Sitra and North Alam El Shawish).

Upon Completion, Capricorn Egypt will acquire a 50 per cent. working interest in the 5 concession agreements in the BED area (together with a 25 per cent. interest in the relevant Operating Companies: Bapetco, Sitra Petroleum Company and NAES Petroleum Company).

The working interest production attributable to the interest to be acquired by Capricorn Egypt in the BED Area was 17 kboe/d, 17 kboe/d and 18 kboe/d for the years ended 31 December 2018, 2019 and 2020.

In respect of the fiscal terms of the BED concessions, there is a range of cost recovery limits between 30 and 40 per cent. (varying between individual concessions), with the Contractor's share of profit oil/gas/LPG ranging from 17 to 20 per cent.. The Contractor is also entitled to recover a share of excess cost oil, ranging from 17 to 20 per cent., pursuant to all of the BED concessions other than the NAES concession.

North East Abu Gharadig (NEAG)

The NEAG area comprises the concession which covers the NEAG Tiba area and the NEAG Extension area. The working interest in the NEAG concession is currently held by three contractor partners: the Sellers (together holding 52 per cent.) and Apache Egypt (48 per cent.). Shell Egypt is currently designated as the operator among these parties, pursuant to the terms of the NEAG JOA.

Upon Completion, Capricorn Egypt will acquire a 26 per cent. working interest in the NEAG concession agreement (together with a 13 per cent. interest in the Tiba Petroleum Company).

The working interest production attributable to the interest to be acquired by Capricorn Egypt in the NEAG concession was 5 kboe/d, 4 kboe/d and 3 kboe/d for the years ended 31 December 2018, 2019 and 2020.

In respect of the fiscal terms of the NEAG concessions, there is a cost recovery limit of 40 per cent., with the Contractor's share of profit oil ranging from 14 to 23 per cent., with a fixed rate of 25 per cent. in respect of Contractor profit gas/LPG.

Alam El Shawish West (AESW)

The AESW concession is currently held by three contractor partners: Shell Egypt (40 per cent.), ZhenHua (35 per cent.) and Neptune (25 per cent.). Shell Egypt is currently designated as the operator among these parties pursuant to the terms of the AESW JOA.

Upon Completion, Capricorn Egypt will acquire a 20 per cent. working interest in the AESW concession agreement (together with a 10 per cent. interest in the Alam El Shawish Petroleum Company).

The working interest production attributable to the interest to be acquired by Capricorn Egypt in the AESW concession was 6 kboe/d, 6 kboe/d and 6 kboe/d for the years ended 31 December 2018, 2019 and 2020.

In respect of the fiscal terms of the AESW concessions, there is a cost recovery limit of 30 per cent., with the Contractor's share of profit oil/gas/LPG ranging from 15 to 17 per cent..

New Exploration Blocks

The Assets also include three new exploration blocks awarded in January 2020 at South Abu Sennan, South East Horus and West El Fayium. Shell Egypt currently holds a 100 per cent. working interest in such concessions, and is currently the operator.

Upon Completion, Capricorn Egypt will acquire a 50 per cent. working interest in these three exploration concessions. It is intended that Capricorn Egypt shall be appointed as operator of the three exploration concessions.

The exploration commitments for the initial exploration phases under these concessions include an initial financial commitment, of which Capricorn Egypt's net share will be of US$19.75 million and the drilling of nine wells.

The fiscal terms in respect of these new concessions provide a cost recovery limit of 27 per cent., with the Contractor's share of profit oil ranging from 14 to 23 per cent. (19 to 23 per cent. in respect of profit gas/LPG). The Contractor is also entitled to recover a 5 per cent. share of excess cost oil, pursuant to the South East Horus and West El Fayium concessions.

Infrastructure

The Assets also comprise interests in the following:

- the Obaiyed processing plant, which has a gas capacity of 450 MMSCFD;
- the BED-3 oil and gas facility; and
- the crude oil processing and treatment equipment that comprises the third processing train of the Qaran processing facility which is owned jointly by EGPC, the Sellers, Apache, Sahara North Bahariya Company and Sipetrol International S.A and which is operated on their behalf by Qarun Petroleum Company; and
- over 800km of main Western Desert pipelines.

Interests in the relevant infrastructure agreements and processing, handling and transportation agreements will be transferred as part of the Transaction.

Estimated Reserves and Resources

Set out below are the Sellers' gross working interest reserves attributable to the Assets as at 31 December 2019 and 31 December 2020 respectively and Cairn's 50% share thereof. The figures have been derived from the GaffneyCline Report, where reserves were estimated in accordance with PRMS. The base case assumptions used by GaffneyCline in their assessment of the reserves, as well as various sensitivities, are set out in the Competent Persons' Report, which is set out in full in Part VI (*Competent Persons' Report in respect of the Assets*).

2P Reserves	Gross WI (31 December 2019)	Cairn WI (31 December 2019)	Gross WI (31 December 2020)	Cairn WI (31 December 2020)
Oil (mmboe)	89	44	76	38
Gas (bcf)	936	468	822	411
Total (mmboe)	256	128	226	113

GaffneyCline has estimated the post-tax NPV at 10% discount rate of Cairn's share of the estimated cash flow from the Assets (being 50 per cent. of the net Shell entitlement) on a Proved plus Probable basis at US$572 million as at 31 December 2019, and US$415.7 million as at 31 December 2020.

8. Financial effects of the Transaction

On a pro-forma basis and assuming completion of the Acquisition on 31 December 2020, the Group would have had net assets of approximately US$1,178.4 million (based on the net assets of the Group as at 31 December 2020 and the Assets as at 31 December 2020) as more fully described in Part V (*Unaudited Pro Forma Financial Information on the Group*).

On a pro-forma basis and assuming completion of the Acquisition on 31 December 2020, the Group would have had loans and borrowings of US$177.0 million and cash and cash equivalents of US$133.3 million (based on the loans and borrowings, cash and cash equivalents of the Group as at 31 December 2020 and the Assets as at 31 December 2020) as more fully described in Part V (*Unaudited Pro Forma Financial Information on the Group*).

As at 31 December 2020, the value of the gross assets attributable to the Assets totalled US$1,055.1 million.

9. Current trading, trends and prospects

Cairn current trading, trends and prospects

On 9 March 2021, the Company published its full year results for the financial year ended 31 December 2020, containing, *inter alia*, the following statements:

Reserves

- "The Group 2P reserves decreased during the year by 116.8 mmboe from 149.7 mmboe to 32.9 mmboe. This was principally as a result of disposals (106.5 mmboe relating to Sangomar and Nova) but also accounts for production in the period (7.8 mmboe) and revisions (2.5 mmboe), the latter primarily related to a change in oil price assumptions for the Group."

Catcher

- "Average 2020 gross production from the Catcher Area (Cairn 20% WI) was 50,200 bopd, with production levels impacted in H2 by planned maintenance, shutdown activity and a produced water plant issue, resolved by the Operator. Drilling of the Varadero infill well (VP1) was completed with the well supporting plateau oil rates. In 2020 Phase 1 of a gas injection trial took place, with Phase 2 taking place in Q1/Q2 of this year."

Kraken

- "Average 2020 gross production from Kraken (Cairn 29.5% WI) was 37,500 bopd. The FPSO delivered high production efficiency rates over the period, averaging 87% oil production efficiency and 91% water injection. In 2020, the Kraken JV successfully brought on-line the Worcester producer-injector well pair. Overall subsurface and well performance has been good, with the rate of water cut evolution remaining stable."

Mexico

- "Cairn has interests in four blocks in the Gulf of Mexico, two as Operator (Blocks 9 and 15) and two as non-Operator (Blocks 7 and 10). In Block 10 in the Sureste basin, an oil discovery was confirmed on the ENI-operated Saasken-1 exploration well (15% non-operated WI) during Q1 2020, with Operator preliminary estimates of 200 to 300 million barrels of oil in place. Following regulatory approval of the Operator's updated exploration plan, the JV is preparing a second exploration well on the licence in H1 2021. The appraisal plan for the Saasken discovery, with the option to drill an appraisal well, is being assessed by CNH. On Block 9 (50% WI), Cairn completed its second operated well in Mexico in Q1 2020. The exploration objectives were dry and the well was permanently plugged and abandoned. Cairn continues to update its assessment of the prospectivity of Block 9 (50% WI). On Block 7 (30% WI), the Ehecatl-1 well, operated by ENI, completed operations during Q2 2020 and was permanently plugged and abandoned. The Operator ENI and Cairn are working to identify prospects for drilling a second exploration well, currently planned for 2022."

UK

- "Following the exchange of 50% WI between Cairn operated P2379 and Shell operated licence P2380 in 2020, Shell expects to spud the Jaws prospect on P2380 during Q2 2021. Cairn aims to drill the Diadem prospect (P2379 50% WI operated) in Q2 2022, with a site survey underway. With both licences close to Shell's Nelson platform, exploration success can be fast-tracked to production via subsea tieback. A drill stem test is planned in a success case for both wells. There is analogous follow-on potential in the event of success on licences P2379 and P2381(100% WI). On licence P2468 (50% WI, operated) in the East Orkney Basin, reprocessing of legacy 2D seismic is completed and shallow boreholes and geophysical data will be acquired in 2021 to inform a decision on acquisition of 3D seismic over this acreage. Cairn exited the Agar- Plantain (P1763) and Chimera (P2312) licences as it proactively managed its portfolio."

Suriname

- "Cairn (100% WI) operates Block 61, the largest offshore PSC in Suriname at 13,080 km². The block is situated within the world-class Guyana-Suriname basin where significant discoveries continued to be made in 2020 and 2021. On Block 61, acquisition of 3D seismic is being considered to develop potential drilling opportunities in both shallow and deep-water areas of the block. The licence has been extended for an additional 12 months until June 2022."

Israel

- "Cairn has a 33.34% WI as Operator in eight licences offshore Israel. During 2020, as part of the minimum work commitment, Cairn awarded a contract for seismic processing, which is ongoing. The project aims to improve the imaging of existing seismic in order to mature prospectivity."

Côte d'Ivoire

- "Cairn has assumed Operatorship (90% WI) in blocks CI-301 and CI-302 from Tullow which has exited both licences. Cairn remains in the Tullow-operated CI-520 (30% WI). The JV has exited blocks

CI-518, CI-519, CI-521 and CI-522 effective end Q4 2020. The proposed 2021 work programme for blocks CI301 and CI-302 is focused on completing the planned 2D seismic acquisition, when safe to do so."

Disposal of Senegal interests and return of cash to shareholders

- "The sale of Cairn's interests in Senegal to Woodside completed in Q4 2020, providing flexibility for future investment, enabling shareholder returns and avoiding significant long- term development capital expenditure. Cash received at completion was US$525m, comprising the US$300m acquisition consideration and a US$225m reimbursement of expenditure incurred on the sale assets since 1 January 2020. A further US$100m is payable to Cairn subject to certain conditions being met relating to the date of first production from the Sangomar development and the prevailing oil price at that time. As a result of this transaction, in January 2021 Cairn returned approximately US$250m to shareholders via a special dividend of 32 pence per eligible ordinary share."

Disposal of interests in Catcher and Kraken

- "Cairn also announces the proposed sale of its entire interests in the UK Catcher and Kraken fields to Waldorf Production UK Limited for a firm consideration of US$460m with a further uncapped contingent consideration dependent on oil price and production performance. The divestment realises value for these assets as they fall into natural decline, enabling Cairn to further pursue its strategic goals at an opportune time in the industry cycle. Subject to regulatory and shareholder approval, the disposal is expected to complete in H2 2021."

Current trading, trends and prospects relating to the Assets

Production, drilling, well services and operations have continued largely unaffected by COVID-19 and low oil prices.

In the period since 31 December 2020, there has been no significant change in the financial position or the financial performance of the Assets.

The Sellers' gross working interest production from the Assets averaged 83,000 boepd in 2020 (31,000 bopd and 294 MMSCFD), which is consistent with the average in 2019 of 89,000 boepd (31,000 bopd and 321 MMSCFD).

During 2020, 29 new development wells have been drilled on the Assets, 24 of which are currently in production, 3 of which was a dry hole and 2 which are currently suspended.

Total sales from the Assets were US$391.3 million gross in 2020 (excluding under/overlift), driven by realised oil prices (average of US$40 per barrel during 2020 versus US$63 per barrel during 2019). The December 2020 realised sales price, of US$48 per barrel, represents a 27 per cent. decrease over the equivalent figure as at 31 December 2019. These figures are based on Shell Egypt unaudited management accounts for the period ending 31 December 2020.

Sales receivables from EGPC were US$84.7 million (net) as at 31 December 2020, of which US$75.1 million is overdue (with US$11.1 million overdue by 1 to 30 days, US$29.6 million overdue by 31 to 180 days and US$34.5 million overdue by more than 180 days). The equivalent figure as at 31 December 2019 was -US$44.4 million (net) (that is, such amount was owing from EGPC to Shell) and represented no amounts overdue. These figures are based on Shell Egypt unaudited management accounts for the period ended 31 December 2020.

Operating costs per boe for the period ended 31 December 2020 were higher than for the period ended 31 December 2019 (which the Directors believe is due to lower production levels) but remain below US$6 per boe.

10. **General Meeting**

Completion of the Transaction is conditional upon Shareholders' approval being obtained at the General Meeting. You will find set out at the end of this Circular a notice convening the General Meeting, to be held at 50 Lothian Road, Edinburgh EH3 9BY at 9.00 a.m. (BST) on 19 July 2021 and at which the Resolution will be proposed.

The Resolution will be proposed as an ordinary resolution, meaning that, in order to be passed, it will require a simple majority of the votes cast in favour of the Resolution.

Impact of Public Gathering Restrictions

In light of the ongoing COVID-19 pandemic and the UK and Scottish legislation and government guidance currently in force as a consequence of the pandemic, there remain in force significant restrictions on public gatherings.

Most of Scotland (including Edinburgh) is in protection level 2 (as at the Latest Practicable Date). This means that Cairn is able to facilitate the attendance of Shareholders in person at the General Meeting. However, the continuing application of social distancing and other safety requirements mean that only a very limited number of Shareholders will be able to attend at the venue for the General Meeting.

The Board therefore strongly encourages Shareholders not to attend the General Meeting in person and instead be represented by the chair of the meeting acting as their proxy.

Should any Shareholders wish to attend in person, Cairn will give preference to those who pre-register, in order of time of registration and, to the extent that there are any remaining spaces, Cairn will try to accommodate any Shareholders who have not pre-registered, on a first-come first-served basis on the day, subject to social distancing and other safety requirements. Shareholders should pre-register their intention to attend the General Meeting by emailing IR.Mailbox@Cairnenergy.com. Pre-registration for the General Meeting will close when the capacity limit has been reached or if earlier at 9.00 a.m. (BST) on 15 July 2021.

If more Shareholders seek to attend the General Meeting than the capacity of the venue allows, Cairn will have to refuse entry to any additional Shareholders once that capacity has been reached to avoid being in breach of the law. Shareholders are therefore requested not to attend the General Meeting without pre-registering and receiving confirmation of their place, as admission on the day cannot be guaranteed. Shareholders are responsible for understanding and complying with the restrictions applicable to their own journey and should bear in mind that rules may differ between different parts of the UK.

The health and wellbeing of our Shareholders and employees remains the Board's primary concern. It is essential to remain vigilant notwithstanding the ongoing UK vaccination programme, particularly given the spread of new variants in the UK and other parts of the world. For this reason, the Board strongly encourages Shareholders not to attend the General Meeting in person and instead be represented by the chair of the meeting acting as their proxy.

Cairn will continue to monitor the situation and, in particular, any changes to the applicable law or guidance in force as a consequence of the COVID-19 pandemic. In the unlikely event of a material change in circumstances that results in the further lifting or relaxation of measures or restrictions relating to travel and public gatherings before the date of the General Meeting, Cairn will consider if it is appropriate, safe and legally permissible to open up the General Meeting for attendance by more Shareholders. If this is the case, an update will be given on Cairn's website and by separate announcement through the regulatory news service of the London Stock Exchange.

Given the expectation that only a very limited number of Shareholders will be able to attend the meeting in person, Shareholders are strongly encouraged to ensure that their votes are counted at the General Meeting by appointing the chair of the General Meeting as their proxy and submitting their completed Form of Proxy as soon as possible and, in any event, so as to arrive at the offices of the Company's registrars, Equiniti, Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA, not later than 9.00 a.m. (BST) on 15 July 2021.

You may register your proxy appointment or voting directions electronically via the www.sharevote.co.uk website not later than 9.00 a.m. (BST) on 15 July 2021 (further information regarding the use of this facility is set out in paragraph 11 of this Part I below). If you hold your Ordinary Shares in CREST, you may appoint a proxy by completing and transmitting a CREST Proxy Instruction so as to be received by the Company's registrars, Equiniti, not later than 9.00 a.m. (BST) on 15 July 2021. We encourage Shareholders to submit their vote electronically where possible. Further instructions on voting by proxy are set out in paragraph 11 of this Part I below.

The Board remains committed to allowing Shareholders the opportunity to engage with the Board. If Shareholders have any questions for the Board in advance of the General Meeting, these can be sent by e-mail to IR.Mailbox@caimenergy.com. The Board will endeavour to answer key themes of these questions on the Company's website as soon as practical.

11. **Action to be taken**

As stated in paragraph 10 of this Part I above, only a very limited number of Shareholders will be able to attend at the venue for the General Meeting.

Shareholders who wish to attend the General Meeting should pre-register their intention to attend the General Meeting by emailing IR.Mailbox@Cairnenergy.com. Pre-registration for the General Meeting will close when the capacity limit has been reached or if earlier at 9.00 a.m. (BST) on 15 July 2021. Cairn will give preference to those who pre-register, in order of time of registration and, to the extent that there are any remaining spaces, Cairn will try to accommodate any Shareholders who have not pre-registered, on a first-come first-served basis on the day, subject to social distancing and other safety requirements.

The health and wellbeing of our Shareholders and employees remains the Board's primary concern. It is essential to remain vigilant notwithstanding the ongoing UK vaccination programme, particularly given the spread of new variants in the UK and other parts of the world. **For this reason, the Board strongly encourages Shareholders not to attend the General Meeting in person and instead be represented by the chair of the meeting acting as their proxy.**

Enclosed with this Circular is a Form of Proxy for use in respect of the General Meeting. You are requested to complete, sign and return the Form of Proxy as soon as possible, and in any event, so as to arrive at the offices of the Company's registrars, Equiniti, at Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA, not later than 9.00 a.m. (BST) on 15 July 2021 being 48 hours before the time appointed for the meeting. Alternatively, you may register your proxy appointment or voting directions electronically via the www.sharevote.co.uk website not later than 9.00 a.m. (BST) on 15 July 2021. Further information regarding the use of this facility is set out in the notes to the Notice of General Meeting. If you hold your Shares in CREST, you may appoint a proxy by completing and transmitting a CREST Proxy Instruction so as to be received by Equiniti no later than 9.00 a.m. (BST) on 15 July 2021.

If you have any queries in relation to the Form of Proxy you may call the Shareholder helpline on 0371 384 2660 (for calls from within the United Kingdom) and +44 121 415 7047 (for calls from outside the United Kingdom) between 8.30 a.m. and 5.30 p.m. (BST) on any Business Day. Please note that calls to these numbers may be monitored or recorded. Calls to +44 121 415 7047 from outside the United Kingdom are charged at applicable international rates.

Please note that the Shareholder helpline will not provide advice on the merits of the resolutions to be proposed at the General Meeting, or give any personal, legal, financial or tax advice.

As only a very limited number of Shareholders are expected to attend the General Meeting, the Board will also offer an opportunity for Shareholders to engage in advance of the meeting through a facility to submit questions by email. If Shareholders have any questions for the Board in relation to the Transaction before the General Meeting, these can be sent by email to IR.Mailbox@Cairnenergy.com. The Board will endeavour to answer the key themes of these questions on the Company's website as soon as practical.

12. **Further information**

Your attention is drawn to the further information contained in Parts II to VII of this Circular and, in particular, to Part II (*Risk Factors*) of this Circular.

13. **Recommendation**

The Board has received financial advice from Rothschild & Co in relation to the Acquisition. In providing financial advice to the Board, Rothschild & Co has relied on the Board's commercial assessment of the Acquisition.

The Board considers that the Acquisition is in the best interests of the Shareholders as a whole and, accordingly, the Board unanimously recommends Shareholders to vote in favour of the Resolution, as the Directors intend to do so in respect of their own beneficial holdings of 1,630,769 Shares, representing approximately 0.327 per cent. of the Company's existing issued ordinary share capital as at the Latest Practicable Date.

Yours faithfully

Nicoletta Giadrossi
Chair

PART II

RISK FACTORS

Prior to making any decision to vote in favour of the Resolution, Shareholders should carefully consider all the information contained in this Circular, including, in particular, the specific risks and uncertainties described below. The risks and uncertainties set out below are those which the Directors believe are the material risks relating to the Transaction, material new risks to the Group as a result of the Transaction or existing material risks to the Group which will be impacted by the Transaction. If any, or a combination of, these risks actually materialise, the business operations, financial condition and prospects of the Group, as appropriate, could be materially and adversely affected. The risks and uncertainties described below are not intended to be exhaustive and are not the only ones that face the Group. The information given is as at the date of this Circular and, except as required by the FCA, the London Stock Exchange, the Listing Rules, MAR and/or any regulatory requirements or applicable law, will not be updated. Additional risks and uncertainties not currently known to the Directors or that they currently deem immaterial, may also have an adverse effect on the business, financial condition, results of operations and prospects of the Group. If this occurs, the price of the Shares may decline and Shareholders could lose all or part of their investment.

1. Material risks relating 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 certain conditions, including the following:

- the Minister and EGPC approving the transfer of the Assets;
- approval from EGPC of the forms of deed of assignment in respect of each Concession and the release or return of certain existing guarantees and, if required, the replacement of those existing guarantees; and
- approval of the Resolution by Shareholders at the 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 Group or the Consortium. 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 and subject to certain conditions set out in the Sale and Purchase Agreement, the Consortium may not recover the approximately US$16 million deposit paid to the Sellers on signing of the Sale and Purchase Agreement.

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

While Cairn believes that the business growth opportunities and cost savings 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 the Assets into the 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 Assets (and their integration within the existing Group); and addressing possible differences between the Group's business culture, processes, controls, procedures and systems and those of the Assets. The Acquisition will result in the Group obtaining its first 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 Group's management team and require additional skills and resources within the Group. Under any of these circumstances, the business growth opportunities and cost savings anticipated by Cairn to result from the Acquisition may not be achieved as expected, or at all, or may be delayed materially. To the extent that the Group incurs higher integration costs than expected, its results of operations, financial condition and/or prospects may be adversely affected.

1.3 *Cairn is funding its share of the consideration for the Acquisition from the Acquisition RBL Facility and the Junior Debt Facility (and existing cash resources) which will reduce the Group's financial flexibility*

Cairn is funding its share of the consideration for the Acquisition from the Acquisition RBL Facility and the Junior Debt Facility (and Cairn's existing cash resources). As at 31 December 2020, the Group had US$575 million undrawn in its reserves-based lending facility.

The Acquisition will reduce the Group's cash balances and increase the overall indebtedness and financial leverage of the Group, which will result in increased repayment commitments and borrowing costs. This could limit the Group's commercial and financial flexibility in the longer term, causing Cairn 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 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 Group's results of operations, financial condition and prospects in the longer term.

1.4 *The Sale and Purchase Agreement may not provide Cairn with full recourse in respect of all potential liabilities associated with the Assets*

The warranties and other purchaser protections given by the Sellers in the Sale and Purchase Agreement are limited and may not cover all potential liabilities associated with the Assets, whether identified or unidentified. The liability of the Sellers is also limited in time and amount, in accordance with market practice. Accordingly, the Consortium may not have recourse against, or otherwise be able to recover from, the Sellers in respect of material losses which it may suffer in respect of a breach of those warranties or otherwise in respect of liabilities of the Assets or Bapetco.

In addition, the ability of the Consortium to terminate the Sale and Purchase Agreement in the period between signing and Completion is limited. If such material liabilities arose and it was not possible to make a claim under the warranties in respect thereof, or if the Consortium could not terminate the Sale and Purchase Agreement, this could adversely affect the Group's business, results of operations, financial conditions and prospects.

In addition, Cairn is jointly and severally liable for certain of the Cheiron Energy Purchasers' obligations under the Sale and Purchase Agreement and the Sellers could seek redress from Cairn in the event of a default by the Cheiron Energy Purchasers. Cairn is therefore assuming credit risk in relation to Cheiron and its subsidiaries, subject to the terms of the counter indemnity from Cheiron and its subsidiaries pursuant to the Joint Management Agreement. In the event that the Cheiron Energy Purchasers default on their obligations, the Group's business, results of operations, financial conditions and prospects could be materially adversely affected.

2. Material risks relating to the Group which result from the Acquisition

2.1 *Following Completion, the Group will be, dependent on the Egyptian General Petroleum Corporation for a significant portion of its revenues, profits and free cash flows, and receivables due from the Assets operations in Egypt under the Concessions are paid irregularly and may be subject to significant delay*

The majority of the revenues generated from the Assets is from sales of oil and gas in Egypt to EGPC under the terms of the Concessions. As a result, the Assets are, and following Completion, the Group will be, exposed disproportionately to counterparty risk in respect of EGPC.

Under the terms of the Concessions, 100 per cent. of the gas produced from the Assets is sold to EGPC, at prices that vary per Concession and can range from fixed prices to prices linked to Brent.

Under the terms of the Concessions, EGPC has a preferential right to purchase part of the Contractors' share of crude oil and condensate production from the Concession Areas, to satisfy domestic market requirements. EGPC can exercise this priority right by written notice to the Contractor 45 days prior to the beginning of a calendar semester. The price for any crude oil purchased by EGPC from the Contractor is calculated in accordance with a formula set out in the concession agreement and is payable by EGPC in US Dollars or any other freely convertible currency to the Contractor. Shell's entitlement to crude oil and condensate that is not purchased by EGPC is exported for sale internationally, via the Sidi Krir terminal (in respect of oil production from NEAG Extension) and the Hamra terminal (in respect of liquids production from BED and Obaiyed). In respect of the 8 separate crude oil liftings by Shell in respect of the Assets for 2020, 3 were purchased by EGPC, with the remaining 5 exported for sale.

Historically, EGPC has remitted payments due to Shell several months in arrears, resulting in significant fluctuations in the outstanding receivables due from EGPC to Shell in the past. As at 31 December 2020, the total amount of receivables due to Shell from EGPC was US$84.7 million (net). While the potential to export some or all of Cairn's entitlement interest crude oil and condensate production provides some mitigation to this exposure, EGPC's payments to the Consortium may continue to be received on an irregular and unpredictable basis that is outside the Consortium's ability to predict or control. Any remittance to the Consortium 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 Consortium in Egypt.

Furthermore, receipt of 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. There can be no assurance that EGPC will, following Completion, meet its existing or future payment obligations to the Group or the Consortium; that the political or economic situation in Egypt will not deteriorate; or that the Egyptian government will be successful in continuing with the improvement of financial stability. The 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 Group's business, results of operations, financial condition or prospects.

2.2 *Following Completion, the Company will have operations in Egypt as a new country entry*

As at the date of this Circular, the Group has no assets in Egypt. In addition, the Group has not previously carried out business in Egypt, meaning that the risks to the Group's operations in Egypt may be greater than those it faces in the existing markets in which the Group is more familiar. These risks potentially include instability in political, economic or financial systems, bribery and corruption and civil unrest and security issues around infrastructure sites.

Any of these factors could result in delay to the oil and gas exploration, appraisal and development programmes of the Group in Egypt and could restrict the ability of the Consortium 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 Group's production and development activities, as a result of damage to equipment and infrastructure.

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

Following Completion, it is expected that over half of the Group's revenue from production of oil and gas will be derived from the Assets. In addition, the Directors believe that the Group's operations in Egypt may become increasingly important to the Group.

Following Completion, the Group will be exposed 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, failure of third party infrastructure, equipment failure, political or social unrest, significant adverse governmental regulation, natural disasters, adverse weather or tidal conditions, wars or terrorist attacks. In addition, certain of the gas sales agreements are negotiated on an annual basis and there can be no guarantee that these agreements will be renewed on terms commercially acceptable to the Consortium or at all. Furthermore, certain arrangement relating to the transportation of petroleum from the Assets are undocumented. The concentrated nature of the Assets and, following Completion, the Group's producing asset portfolio results in such conditions having a relatively greater impact on the Assets, and following Completion, the Group's as applicable, business, results of operations, financial condition and prospects than they might have if the Assets were more diversified.

2.4 *The Consortium may not be successful in securing extensions to certain concession agreements and development leases*

Certain of the development leases relating to the Assets state that the development lease for a gas discovery shall have an initial term of 20 years with an optional extension on the part of the Contractors of five years subject to approval by the Minister. The development agreements further state that the term of the agreement shall not exceed 35 years from the date of the relevant commercial discovery. On 16 April 2019, the Egyptian Constitution was amended such that, pursuant to Article 31 of the Egyptian Constitution, the maximum possible term for a concession is 30 years. There can be no guarantee that the Minister will agree to extend the concessions to the original 35-year term, or to any five-year extension. Any such refusal by the Minister to extend a development lease for any of the Assets may adversely affect production from the Assets which could have a material adverse effect on the Group's business, results of operations, financial condition or prospects.

In addition, certain of the development leases under the Obaiyed Concession, the Sitra Concession, the BED-3 Concession and the NEAG Concession will expire in periods between five and 10 years. If the Consortium is unsuccessful in seeking an extension to these leases or is unsuccessful in obtaining new development leases at any of the Assets, production from the Assets could be adversely affected which could have a material adverse effect on the Group's business, results of operations, financial condition or prospects.

2.5 ***The Company will not be the operator of the Assets, other than certain exploration concessions***

As a non-operator, the Company will have limitations on the control and powers it has to determine the operations and costs relating to the Assets and the Group will be dependent on Cheiron and EGPC to make certain decisions.

Pursuant to the terms of the relevant JOAs, following Completion the Consortium has agreed that Cheiron will be designated as the Contractor's operator in respect of each of the producing Assets. Under the terms of the Concessions (and as is standard in the Egyptian Concession model), operating companies are established to carry out the development and production activities relating to each Concession. Such operating companies are owned 50 per cent. by EGPC and 50 per cent. by the relevant Contractor(s). Following Completion, the Company will acquire a 25 per cent. interest in each operating company which is currently owned 50:50 between Shell and EGPC (including Bapetco), and in respect of the operating companies for the AESW and NEAG Concessions the Company will acquire a 10 per cent. and 13 per cent. in each of the relevant operating companies.

Bapetco is the joint venture company originally established by Shell and EGPC in respect of the BED Concession Agreement. Bapetco is appointed to act as designated operator/sub-contractor of each of the operating companies in which Shell has an interest to carry out all development and exploration operations in respect of all the Assets.

Bapetco is currently owned 50:50 by Shell and EGPC and the shareholders have joint control over the exploration and development operations of the company in respect of the Assets. Under Bapetco's bylaws, the board of directors consists of eight members, four of whom are appointed by EGPC and four of whom are appointed by the Contractor. Following completion of the Transaction, Cairn and Cheiron have agreed to appoint four directors between themselves to the Bapetco board. Decisions of the board of Bapetco require a vote in favour of at least six directors. The manner in which the Consortium exercises its voting rights and decision making powers in relation to its director on the Bapetco board is set out in the terms of the JMA and the relevant JOAs where the parties have agreed all 4 Contractor appointed directors shall vote in the same way on any Bapetco board decision as agreed in accordance with decisions approved pursuant to the terms of the relevant JOA.

The Group will therefore be dependent on both Cheiron and EGPC to make any decisions in relation to the Assets. The JOAs and Bapetco's bylaws both provide for resolution procedures in case of a deadlock. The relevant JOAs are and will be based on industry model documents which contain standard decision making and dispute resolution provisions. Under the Bapetco bylaws and the Concession Agreements, whether at a shareholders' or directors' meetings, once a deadlock arises and is unresolved for a period of 30 consecutive days, the parties have a period of 60 days to meet and 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

Through the governance structure described above, the Company will have negative control over any decision made in respect of the Assets and therefore cannot be forced into any decision. However, as a non-operator, the Group will have limited powers to determine and influence the operations and costs relating to the Assets. In addition, it is possible that the interests of the Group, on the one hand, and Cheiron and/or EGPC, on the other will not always be aligned which could result in possible project delays, additional costs or disagreements. As a result of the Group not being the operator of the Assets or being able to exercise voting rights in respect of a particular Asset to direct or exert influence over decisions relating to such asset could materially and adversely affect the business, financial condition and results of operations of the Group in Egypt.

The terms of any relevant operating agreement will generally impose standards and requirements in relation to an operator's activities. While the Directors believe Cheiron to be a reputable operator, there can be no assurance that Cheiron will observe such standards or requirements.

Failure by Cheiron to comply with its obligations under relevant licences including, for example, health and safety and environmental requirements, or the relevant operating agreement may result in delays or increased costs, lead to fines, penalties and restrictions and/or the withdrawal of licences or termination of the agreements under which it operates.

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

3. Existing material risks to the Group which will be impacted by the Acquisition

3.1 *The Group may be unable to implement its growth strategy*

Cairn's strategy is to deliver value for Shareholders from the discovery, development or acquisition of hydrocarbons within a sustainable, self-funding business model.

There can be no assurance that the Group will continue to implement this strategy successfully or that future oil and gas prices will support this business model in future. Any failure to do so could materially adversely affect the reputation, financial condition and/or operating results of the Group.

3.2 *Without the addition of reserves through exploration, acquisition or development activities, the Group's reserves and production will decline over time as reserves are exploited*

The Group's future oil and gas reserves, production and cash flows to be derived therefrom are highly dependent on its success in exploiting its current reserve and resource base. Without the addition of reserves through exploration, acquisition or development activities, the Group's reserves and production will decline over time as reserves are exploited. A future increase in the Group's reserves will depend not only on its ability to develop present properties, but also on its ability to select and acquire suitable producing properties or prospects. If such efforts are unsuccessful, the Group's total reserves may not increase or may decline, which could have a material adverse effect on its business, financial condition, prospects and results of operations.

PART III

PRINCIPAL TERMS OF THE SALE AND PURCHASE AGREEMENT

The following is a summary of the principal terms of the Sale and Purchase Agreement. The Sale and Purchase Agreement is available for inspection up to and including the date of the General Meeting, as described in paragraph 13 of Part VII (*Additional Information*) of this Circular.

The Sale and Purchase Agreement

1. **Introduction**

1.1 The Sale and Purchase Agreement was entered into on 8 March 2021 between Capricorn Egypt, Capricorn Oil Limited, Cheiron Holdings, Cheiron Oil & Gas and the other Cheiron Energy Purchasers and the Sellers to acquire the SENV Transferred Interests and the SAG Transferred Interests from the Sellers.

1.2 On Completion, each of (i) Capricorn Egypt; and (ii) the Cheiron Energy Purchasers will acquire 50 per cent. of the SENV Transferred Interests and the SAG Transferred Interests, which includes the Sellers' interest (if any) in the Concessions and related agreements, operating companies and assets. The effective date of the sale and purchase of the SENV Transferred Interests and the SAG Transferred Interests is 1 January 2020.

1.3 Capricorn Egypt appointed Cheiron Energy to be its representative and agent in respect of the Sale and Purchase Agreement, including to take any action on Capricorn Egypt's behalf in connection with the documents relating to the Transactions.

2. **Conditions precedent**

2.1 Completion is conditional upon fulfilment or waiver of the following conditions, among others:

(a) EGPC approval, which includes EGPC approval of the forms of deeds of assignment in respect of each Concession, agreement of EGPC to release/return the Sellers' existing guarantees (none in relation to the AESW Concession and NEAG Concession) and, if required by EGPC, the replacement at the relevant completion by the Buyers of the relevant existing guarantees with replacement guarantees; and

(b) the passing of the Resolution at the General Meeting.

2.2 The Sellers have undertaken to use reasonable endeavours to procure that the conditions set out at paragraphs 2.1(a) and (b) above are fulfilled as soon as practicable and in any event before the Long Stop Date. The Buyers have undertaken to use reasonable endeavours to procure that the conditions set out at paragraph 2.1(a) and (b) are fulfilled as soon as practicable and, in any event, on or before the Long Stop Date.

3. **Pre-Emption**

3.1 If a pre-emption right under the AESW JOA or NEAG JOA is exercised by a joint venture partner shall become excluded from the overall transfer of the SENV Transferred Interests and SAG Transferred Interests provided that EGPC has approved the transfer of such concession interest to the relevant joint venture partner within 30 calendar days from the date that the Sellers have notified EGPC of exercise of the pre-emption right by such joint venture partner and subject to Completion of the BED Concession.

3.2 Any pre-emption/priority rights exercised by EGPC under the relevant concession where EGPC has such rights follows the same principles.

3.3 The period for the exercise of pre-emption rights by EGPC and joint venture partners has expired and no notice has been received from such parties that they wish to exercise their pre-emption/priority rights.

4. **Consideration**

4.1 The total consideration consists of firm and contingent success based consideration.

4.2 The firm consideration payable is the sum of approximately US$646 million (approximately US$323 million net to Cairn) to be adjusted for working capital and other customary adjustments between the economic effective date of 1 January 2020 and the date of Completion.

4.3 A deposit of approximately US$16 million was paid to the Sellers on 9 March 2021. Credit is given for the value of the deposit on Completion. In the event that the Acquisition does not proceed to Completion, then such deposit shall be refundable in full by the Sellers, save where such failure to complete the Transaction is due to the Consortium either being in material breach of its obligations under the Sale and Purchase Agreement or certain other documents entered into in connection with the Transaction, or due to the failure to obtain the approval of EGPC, or due to the failure to obtain the approval of Cairn's shareholders (in which case the amount of the deposit to be forfeited shall not exceed 1 per cent. of Cairn Energy's market capitalisation).

4.4 There may be contingent consideration payable by the Buyers of up to US$280 million (US$140 million net to Cairn) if certain requirements are met, on the following basis:

(a) the first contingent success amount is capped at US$200 million (US$100 million net to Cairn) and is payable in four instalments (of up to US$50 million gross per annum) in respect of the periods 1 January to 31 December in each of 2021, 2022, 2023 and 2024, subject to the average annual dated Brent price being equal to or above US$55/bbl in each of those four periods, with full pay-out in each year achieved at US$75/bbl or above, based on a linear scale.

(b) the second contingent success amount is payable if:

(i) following the date of the Sale and Purchase Agreement, any of the first nine exploration wells drilled in the areas covered by the exploration concessions results in a relevant commercial discovery in respect of an exploration well (the "**Relevant Commercial Discovery**"), provided that any appraisal well (being any wells drilled in follow-up to an exploration well discovery and which are needed to determine commercially recoverable resource volumes) shall not count towards the limit of nine exploration wells; and

(ii) some or all of a portion of the area covered by a Relevant Commercial Discovery is converted into a development lease prior to 30 June 2024.

If a second contingent success amount becomes payable, then, within thirty days of the date on which such development lease is awarded, the Buyers shall pay to Shell Egypt an amount which shall be determined by a calculation of US$0.04 per barrel of independently audited 2P reserves following the award of a development lease in respect of a Relevant Commercial Discovery, provided that the aggregate of all second contingent success amounts shall not exceed US$80 million (US$40 million net to Cairn).

5. **Interim Period**

5.1 The Sellers have agreed to carry on affairs in relation to the Assets in the ordinary course of business, in accordance with good oil and gas field practice in Egypt and in compliance with the terms of the relevant documents relating to the Concessions in all material respects. The Sellers have further agreed not to take certain actions without the consent of the Buyers.

5.2 Other than in respect of any action required to be taken by the Buyers' lenders, the Buyers have agreed not to, and to procure that no member of their respective groups shall, take any action which shall alter the ownership structure of a Buyer (directly or indirectly) without the prior written consent of the Sellers (not to be unreasonably withheld) (the "**Purchaser Undertaking**").

6. **Completion**

6.1 In accordance with Egyptian law, legal title shall pass immediately on signature of a deed of assignment by a duly authorised representative of the Egyptian government. The Sellers and the Buyers have agreed to use all reasonable endeavours to procure that completion in respect of all interests shall occur on or about the same date.

6.2 The consideration is paid to an escrow agent prior to Completion and completion deliverables are to be exchange by the Sellers and the Buyers pre-completion so that Completion may automatically occur on the signing of the deed of assignment by a duly authorised representative of the Egyptian government. Pre-Completion Date is the first business day falling 15 Business Days on which the last condition precedent has been fulfilled or waived.

6.3 Both the Sellers and the Buyers have undertaken to use reasonable endeavours to procure that Completion occurs as soon as practicable after the Pre-Completion Date in respect of any non- pre-empted interests and in any event before the Cut-Off Date.

7. **Warranties and Indemnities**

7.1 The Sale and Purchase Agreement contains warranties given by the Sellers in relation to, amongst other things, title, capacity, authority, insolvency and anti-bribery and corruption (the "**Fundamental Warranties**"). The Sale and Purchase Agreement also contains certain business and other warranties relating to the Assets, including in respect of litigation and investigations, environment, taxation, insurance and commercial and operational warranties (the "**General Warranties**"). The Fundamental Warranties and the General Warranties are given on signing and the Fundamental Warranties are repeated at the Pre-Completion Date.

7.2 The Sale and Purchase Agreement contains certain warranties, including in relation to capacity, authority, its funding of the consideration, solvency, litigation and anti-bribery and corruption which are given by the Buyers, their respective guarantors (being Capricorn Oil Limited and Cheiron Holdings) and any other member of their respective groups which is a party to a Transaction document both on signing and immediately prior to the Pre-Completion Date.

7.3 The Sellers and the Buyers have each provided indemnities relating to the allocation of pre- and post-economic date benefits and liabilities. The Sellers are liable for all pre-economic date liabilities and entitled to all pre-economic date benefits and the Buyers are liable for all post-economic date liabilities and entitled to all post-economic date benefits. In addition, the Buyers are liable for and indemnify the Sellers in respect of all decommissioning and environmental liabilities relating to the Assets.

8. **Limitations on liability for warranty claims**

8.1 The Seller's liability relating to:

(a) the Fundamental Warranties is limited to the firm consideration paid by the Buyers; and

(b) the General Warranties is limited to 30 per cent. of the firm consideration paid by the Buyers.

The Seller's aggregate liability in respect of both Fundamental Warranty and General Warranty claims is limited to the firm consideration paid by the Buyers.

8.2 The Sellers will not be liable for a warranty claim (other than a tax warranty claim) unless notice has been given by the Buyers in respect of the claim within twelve months of the Pre- Completion Date. The Buyers have seven years to give notice of a tax warranty claim. The Sellers will not be liable in respect of a warranty claim unless the aggregate amount of all substantiated claims against the Sellers exceed 1.5 per cent. of the firm consideration paid by the Buyers. Other general limitations on the Sellers' liability apply (including if matters are disclosed, otherwise compensated for or due to acts of the Buyers).

9. **Termination**

9.1 The Sale and Purchase Agreement may be terminated prior to the Pre-Completion Date:

(a) by either the Buyers or the Sellers, if a party becomes sanctioned, or breaches sanctions or is held liable for a violation of any anti-bribery law;

(b) by the Sellers, if a Buyer breaches the Purchaser Undertaking;

(c) by the Buyers if there is an agreed or determined material adverse change (being, subject to certain exemptions, the loss, destruction or damage to facilities);

(d) if the conditions precedent have not been fulfilled or waived by the Long Stop Date; and

(e) if a party has failed to perform its completion obligations on the Pre-Completion Date and is in material default of the Sale and Purchase Agreement which default remains unremedied for twenty Business Days.

9.2 The Sale and Purchase Agreement may be terminated after the Pre-Completion Date if completion has not occurred in respect of the BED Concession on or prior to the Cut-Off Date.

10. **Tax**

10.1 *Transfer taxes and turnover taxes*

All transfer taxes resulting from the transactions under the Sale and Purchase Agreement shall be borne by the Buyers, other than where due to a Seller's tax registration in Austria or the Netherlands. All sums payable under the Sale and Purchase Agreement are exclusive of turnover taxes.

10.2 *Filing fees and Assignment bonus*

The Buyers assume liability for any filing fees imposed by, or payable to, EGPC or any governmental authority in respect of their review of the Transaction.

The Sellers assume any liability to pay any assignment bonus to be paid by a Seller to EGPC or any other government authority in connection with the assignment of any of the SENV Transferred Interests and the SAG Transferred Interests.

11. **Guarantee**

Capricorn Oil Limited has agreed to guarantee Capricorn Egypt's and its affiliates respective obligations under the Sale and Purchase Agreement and any other document entered into by the parties in connection with the Sale and Purchase Agreement and the transaction. Cheiron Holdings has agreed to guarantee Cheiron Energy and its affiliates respective obligations.

The guarantors are jointly and severally liable for any joint and several obligations of the Buyers, and are liable on a several basis in respect of several obligations of the Buyers.

12. **Governing law and dispute resolution**

The governing law of the Sale Purchase Agreement is the law of England and Wales and any dispute relating to the Sale Purchase Agreement shall be settled, in London, under the Rules of Arbitration of the London Court of International Arbitration.

PART IV

FINANCIAL INFORMATION RELATING TO THE ASSETS

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

The Directors
Cairn Energy PLC
50 Lothian Road
Edinburgh
EH3 9BY

29 June 2021

Dear Ladies and Gentlemen

Package of Egypt onshore assets to be acquired from Shell ("Shell Egypt Interests")

We report on the financial information set out in Section B of Part IV of the circular dated 29 June 2021 of Cairn Energy PLC (the "**Circular**"), for the years ended 31 December 2018, 2019 and 2020 (the "**Financial Information**").

This report is required by Listing Rule 13.5.21 and is given for the purpose of complying with that item and for no other purpose.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to ordinary shareholders 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.

Opinion on the Financial Information

In our opinion, the Financial Information gives, for the purposes of the Circular dated 29 June 2021, a true and fair view of the state of affairs of the Shell Egypt Interests as at 31 December 2018, 2019 and 2020 and of its profits, cash flows and changes in equity for the periods then ended in accordance with the basis of preparation set out in note 2.

Responsibilities

The Directors of Cairn Energy PLC are responsible for preparing the Financial Information on the basis of preparation set out in note 2 to the Financial Information.

It is our responsibility to form an opinion on the Financial Information and to report our opinion to you.

Basis of Preparation

The Financial Information has been prepared for inclusion in the Circular on the basis of the accounting policies set out in note 3 to the Financial Information.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Financial Reporting Council ("**FRC**") in the United Kingdom. We are independent in accordance with the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the 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 other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Conclusions Relating to Going Concern

In performing our work on the Financial Information, prepared on the basis that the acquisition of the Shell Egypt Interests by Cairn Energy PLC completes, we have concluded that the Directors' use of the going concern basis of accounting in the preparation of the Financial Information is appropriate.

Based on the work we have performed, we have not identified any material uncertainties related to events or conditions that, individually or collectively, may cast significant doubt on Shell Egypt Interests' ability to continue as a going concern for a period of at least twelve months from the date of the Circular.

Yours faithfully

Ernst & Young LLP

Section B: Historical financial information relating to the Assets

Combined Statement of Income for the years ended 31 December

	Note	2020 $m	2019 $m	2018 $m
Revenue	5	391.3	649.2	680.6
Cost of sales		(179.9)	(231.8)	(244.0)
Depletion and amortisation	9	(249.7)	(185.9)	(197.3)
Gross profit/(loss)		**(38.3)**	**231.5**	**239.3**
Unsuccessful exploration costs	8	(19.3)	(28.1)	(13.7)
Administrative expenses		(47.9)	(83.3)	(48.2)
Impairment of producing assets	9	—	(5.4)	—
Profit/(loss) before taxation		**(105.5)**	**114.7**	**177.4**
Taxation credit / (charge)	7	8.3	(111.0)	(107.0)
Comprehensive profit/(loss) for the period		**(97.2)**	**3.7**	**70.4**

The results relate entirely to continuing operations.

There were no items of other comprehensive income during the period and therefore no separate combined statement of comprehensive income is required.

All comprehensive income is attributable to the equity holders of the Target Group.

Combined Statement of Financial Position as at 31 December

	Note	2020 $m	2019 $m	2018 $m
Assets				
Non-current assets				
Intangible exploration/appraisal assets	8	331.4	326.9	253.4
Plant, property and equipment	9	289.2	419.2	400.5
Deferred tax asset	7	144.3	106.3	92.9
		764.9	852.4	746.8
Current assets				
Inventories	11	25.4	30.5	30.2
Trade and other receivables	10	212.5	161.8	238.2
Cash and cash equivalents	12	52.3	5.8	98.1
		290.2	198.1	366.5
Total assets		**1,055.1**	**1,050.5**	**1,113.3**
Liabilities				
Non-current liabilities				
Trade and other payables	13	(3.0)	(1.5)	(1.9)
Lease liabilities	13	(7.0)	(8.9)	—
Deferred tax liability	7	(35.6)	(37.3)	(23.3)
Provisions	14	(1.8)	(1.7)	(1.7)
		(47.4)	(49.4)	(26.9)
Current liabilities				
Trade and other payables	13	(112.3)	(212.6)	(255.2)
Lease liabilities	13	(1.9)	(2.1)	—
Provisions	14	(0.1)	(0.1)	—
		(114.3)	(214.8)	(255.2)
Total liabilities		**(161.7)**	**(264.2)**	**(282.1)**
Equity				
Invested capital		(893.4)	(786.3)	(831.2)
Total equity attributable to equity holders of the Target Group		**(893.4)**	**(786.3)**	**(831.2)**
Total liabilities and equity attributable to the equity holders of the Target Group		**(1,055.1)**	**(1,050.5)**	**(1,133.3)**

Combined Statement of Changes in Equity for the years ended 31 December

	Invested capital $m
At January 1, 2018	**899.3**
Profit for the period	70.4
Capital distribution	(138.5)
At December 31, 2018	**831.2**
Profit for the period	3.7
Capital distribution	(48.6)
At December 31, 2019	**786.3**
Loss for the period	(97.2)
Capital investment	204.3
At December 31, 2020	**893.4**

On November 2020, the parent company provided, by way of share premium, an additional equity injection of USD 200,000,000, the remaining USD 4,300,000 is in relation to pension liabilities which are borne by Shell Egypt. The injection was required to meet Shell Egypt's liquidity requirements and satisfy all financial obligations to government till completion date.

Combined Statement of Cash flow for the years ended 31 December

	Note	2020 $m	2019 $m	2018 $m
Profit/(loss) before taxation for the period		(105.5)	114.7	177.4
Adjustments for non-cash income and expense:				
Unsuccessful exploration costs	8	19.3	28.1	13.7
Depreciation, depletion and amortisation	9	249.7	185.9	197.3
Impairment of producing assets	9	—	5.4	—
Other asset write-offs		0.7	2.5	0.9
Other non-cash items		6.7	1.7	0.5
Finance expense		0.7	0.7	—
Adjustments for cash flow movements in assets and liabilities:				
Income tax paid		(31.5)	(110.4)	(113.4)
Inventory movement		5.1	(0.2)	(9.0)
Trade and other receivables movement		(44.6)	75.4	(66.3)
Trade and other payables movement		(103.5)	(46.2)	74.5
Other provisions movement		(0.3)	—	0.2
Cash flow from operating activities		**(3.2)**	**257.6**	**275.8**
Expenditure on intangible exploration/appraisal assets	8	(23.8)	(117.8)	(51.9)
Expenditure on property, plant & equipment	9	(124.9)	(179.8)	(138.3)
Interest received		—	0.1	—
Cash flow from investing activities		**(148.7)**	**(297.5)**	**(190.2)**
Capital distributions		—	(50.0)	(138.5)
Capital contribution		200.0	—	—
Repayment of lease liabilities		(2.7)	(2.8)	—
Cash flow from financing activities		**197.3**	**(52.8)**	**(138.5)**
Effect of exchange rates on cash and cash equivalents		1.1	0.4	0.5
Increase/(decrease) in cash and cash equivalents		46.5	(92.3)	(52.4)
Cash and cash equivalents at beginning of year		5.8	98.1	150.5
Cash and cash equivalents at end of year	12	**52.3**	**5.8**	**98.1**

Notes to the Historical Financial Statements

For the years ended 31 December

1. **General information**

The principal activity of the Target Group is the exploration and appraisal of, and production from, oil and gas interests in Egypt.

2. **Basis of preparation**

The Target Group financial information reflects the Target Group's interest in the following hydrocarbon producing concessions and exploration concessions (together the "**Concessions**").

Hydrocarbon producing concessions:

- Obaiyed area concessions – Obaiyed and North Um Baraka (Target Group's interest 100%).
- Badr El Din ("**BED**") area concessions – BED, BED 2 & 17, BED-3, Sitra and North Alam El Shawish (Target Group's interest 100%).
- North East Abu Gharadig area concessions – North East Abu Gharadig ("**NEAG**") Tiba and NEAG Extension (Target Group's interest 52%). The Target Group jointly controls these concessions and these are determined to be joint operations and therefore the Target Group's proportionate share of income and costs and assets and liabilities have been proportionately combined into these financial statements.
- Alam El Shawish West concession (Target Group's interest 40%). The Target Group jointly controls the concession and these are determined to be joint operations and therefore the Target Group's proportionate share of income and costs and assets and liabilities have been proportionately combined into these financial statements.

Exploration concessions – North Matruh, South Abu Sennan, South East Horus and West El Fayium (Target Group's interest 100%).

The Target Group also includes a 50% equity interest in the following operating companies (the "**Operating Companies**"):

- OBAIYED Petroleum Company;
- SITRA Petroleum Company;
- TIBA Petroleum Company;
- BADR EL DIN Petroleum Company ("**Bapetco**");
- Alam El Shawish Petroleum Company;
- North Alam El Shawish Petroleum Company; and
- North Um Baraka Petroleum Company.

The partner in each case is the Egyptian General Petroleum Company. The Target Group jointly controls the operating companies and has rights to the assets and obligations for the liabilities. These are determined to be joint operations and therefore, the Target Group has combined its share of the income, cost, assets and liabilities of the operating companies.

The Target Group also includes the Target Group's share of assets, liabilities and expenses incurred by Shell Egypt N.V. and Shell Austria GmbH (as applicable) in respect of these concessions.

Whilst the Concessions and Operating Companies are under common control, the Target Group has not previously constituted a single legal group, which has prepared combined financial results. Accordingly, the combined historical financial information has been prepared specifically for the purposes of this Circular and reflects the Target Group's share of the income, expenses, assets and liabilities that are specifically attributable to the each Concession and Operating Company, and the allocations of direct and indirect costs and expenses related to the operations. Such allocations have been made on a reasonable basis based on all available information and the agreed methodology with the national oil company but are not necessarily indicative that these costs were those that would have been incurred if the Target Group had operated independently. This combined historical financial information does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006.

The combined historical financial information has been prepared in accordance with the Listing Rules and Prospectus Directive Regulation, together with International Financial Reporting Standards ("**IFRS**") as adopted by the EU for the three years ended 31 December 2020, except as noted below.

IFRS does not explicitly provide guidance for the preparation of combined historical financial information, therefore certain accounting conventions permitted for the preparation of historical financial information for inclusion in investment circulars, as described in the Standards for Investment Reporting Annexure (the "**Annexure**") to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements on historical financial information) issued by the UK Auditing Practices, have been applied where IFRS does not provide specific accounting treatments.

The combined historical financial information is not prepared on a combined basis and therefore does not comply with the requirements of IFRS 10 'Combined Financial Statements'. However, the combined historical financial information has been prepared on a combined basis applying the aggregation principles underlying the consolidation procedures of IFRS 10. In all other respects, IFRS has been applied.

The Target Group was not a separate legal entity during the three years ended 31 December 2020 and therefore has no share capital. Therefore, Invested Capital represents a combination of the funding balances with the equity holders. Capital distributions represent the remittance of cash or dividends outside of the Target Group.

The principal accounting policies applied in the preparation of the historical financial information are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated and are consistent with the accounting policies used to prepare the latest audited financial statements of Cairn Energy PLC.

Going concern

This financial information relating to the Target Group has been prepared on a going concern basis.

The going concern assessment has been performed on the basis that the acquisition of the Target Group by Cairn and Cheiron ('the parties') completes. Following completion Cairn will own a fifty per cent. share in the Target Group (together with the existing Cairn Group, the 'Enlarged Group'). The acquisition will in part be funded by a $325m senior debt facility and a $80m junior debt facility, for which the parties are jointly and severally liable in respect of the obligations to the Lenders. These facilities have been taken into account for the purposes of the going concern assessment.

The going concern assessment has been performed for the period to 30 June 2022. Forecasts for the standalone Target Group show that these will be dependent upon working capital support from the parties during the going concern period. Accordingly, the going concern assessment by the directors of Cairn (the 'Directors') has also considered the Enlarged Group to assess the availability from Cairn of this working capital support. Cairn has sufficient resources to provide funding to the Target Group as required.

The Directors have considered forecasts of the Target Group and the Enlarged Group reflecting a number of plausible scenarios and stress tests. The assessment is based on detailed trading and cash flow forecasts, including forecast liquidity and covenant compliance in respect of the facilities described above. In making this assessment the Directors have considered the potential impacts of Covid-19 on the Enlarged Group's operations, noting that there have been no significant impacts as a result of the pandemic to date. The plausible scenarios and stress tests consider both a significant reduction in oil prices and non-completion of Cairn's expected disposal of its interests in the Kraken and Catcher assets. The Directors have also considered mitigations at their disposal to enhance liquidity if required.

In all scenarios modelled, including the severe-but-plausible scenario, the Enlarged Group continues to have satisfactory liquidity and covenant headroom throughout the going concern period.

Based on this assessment, the Directors have a reasonable expectation that, taking into account available loan facilities, the Target Group has adequate resources to continue in operational existence for the period to 30 June 2022. Accordingly, the Directors conclude it to be appropriate that the Historical Financial Information of the Target Group be prepared on a going concern basis.

3. Accounting policies

3.1 Adoption of new and revised standards

The following new and revised Standards and Interpretations have been adopted, none of which had a material impact on the Target Group's results except IFRS 16:

- IFRS 16 Leases (effective for annual periods commencing on or after 1 January 2019);
- Annual Improvement Cycle 2015-2017 (effective for annual periods commencing on or after 1 January 2019);
- IFRIC 23 Uncertainty over income tax treatments (effective for annual periods commencing on or after 1 January 2019);
- IFRS 9 'Financial Instruments' (effective for annual periods commencing on or after 1 January 2018); and
- IFRS 15 'Revenue from Contracts with Customers' (effective for annual periods commencing on or after 1 January 2018).

At the date of authorisation of these historical financial statements, the following Standards and Interpretations which have not been applied in these historical financial statements were in issue but not yet effective (and in some cases had not yet been adopted):

- Amendments to References to the Conceptual Framework in IFRS Standards (effective 1 January 2020);
- Amendments to IFRS 3 (effective 1 January 2020);
- Amendments to IAS 1 and IAS 8 (effective 1 January 2020);
- Amendments to IFRS 9, IAS 39 and IFRS 7 (effective 1 January 2020);
- Amendment to IFRS 16 (effective 1 January 2020);
- Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 (effective 1 January 2021);
- Annual Improvements to IFRS Standards 2018-2020 (effective 1 January 2022);
- Amendments to IFRS 3 (effective 1 January 2022);
- Amendments to IAS 37 (effective 1 January 2022);
- IFRS 17 (effective 1 January 2022);
- Amendments to IFRS 17 (effective 1 January 2023);
- Amendments to IAS 1 (effective 1 January 2023); and
- Amendments to IFRS 10 and IAS 28 (effective 1 January 2023).

None of these amendments or standards are expected to have a material effect on the historical financial statements.

Please see note 4 for the impact to the Combined Financial Statements upon the adoption of IFRS 16.

3.2 Significant accounting policies

Foreign currency transactions and balances

This historical financial information is presented in US Dollars and all values are rounded to the nearest million US Dollars ($ million) except where otherwise indicated. Monetary assets and liabilities denominated in foreign currencies are retranslated at the currency rate of exchange ruling at the balance sheet date. All exchange movements are included in the Group's income statement for the period. Non- monetary items that are measured at historical cost in a currency other than the US Dollars are translated using the exchange rate prevailing at the dates of the initial transaction.

Revenue recognition

The Target Group generates revenue through the sale of oil and natural gas. Revenue from sales of oil and natural gas is recognised at the transaction price to which the Target Group expects to be entitled, after deducting sales taxes, excise duties and similar levies.

Revenue is recognised when control of the products has been transferred to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism and ownership transferred. Revenue resulting from hydrocarbon production from assets in which the Target Group has an interest with partners in joint arrangements is recognised on the basis of Target Group's volumes lifted and sold. Revenue resulting from the production of oil and natural gas under production-sharing contracts ("**PSCs**") is recognised for those amounts relating to the Target Group's cost recoveries and the Target Group's share of the remaining production.

The Egyptian General Petroleum Corporation (**"EGPC"**) assumed, paid and discharged, in the name and on behalf of the Target Group, the Egyptian corporate income tax of the Target Group out of EGPC's share of Petroleum. All taxes paid by EGPC in the name and on behalf of the Target Group are considered as income for the Target Group.

Cost of sales

Production costs include the Target Group's share of costs incurred by the joint operation in extracting oil and gas. Also included are marketing and transportation costs and loss-of-production insurance costs payable over the year.

Adjustments for overlift (where liftings taken by the Target Group exceed the Group's entitlement share), underlift (where liftings taken by the Target Group are less than the Group's entitlement share) and movements in inventory are included in cost of sales. Oil inventory is measured at market value in accordance with established industry practice.

Intangible Exploration/Appraisal Assets

The Target Group follows a successful efforts-based accounting policy for oil and gas assets.

Expenditure incurred on the acquisition of a licence interest is initially capitalised on a licence-by-licence basis. Costs are held, undepleted, within intangible exploration/appraisal assets until such time as the exploration / appraisal phase on the licence area is complete or commercial reserves have been discovered and a field development plan approved.

Exploration expenditure incurred in the process of determining oil and gas exploration targets is capitalised initially within intangible exploration/appraisal assets and subsequently allocated to drilling activities. Costs are recognised following a cost accumulation model where any contingent future costs on recognition of an asset are recognised only when incurred.

Exploration/appraisal drilling costs are capitalised on a well-by-well basis until the success or otherwise of the well has been established. The success or failure of each exploration/appraisal effort is judged on a well-by-well basis. Drilling costs are written off on completion of a well unless the results indicate that hydrocarbon reserves exist and there is a reasonable prospect that these reserves are commercial and work to confirm the commercial viability of such hydrocarbons is intended to be carried out in the foreseeable future. Where results of exploration drilling indicate the presence of hydrocarbons which are ultimately not considered commercially viable, all related costs are written off to the Income Statement.

Following appraisal of successful exploration wells, if commercial reserves are established and technical feasibility for extraction demonstrated and approved in a field development plan, then the related capitalised intangible exploration/appraisal costs are transferred into a single field cost centre within property, plant & equipment – development/producing assets, after testing for impairment (see below).

Impairment

Intangible exploration/appraisal assets are reviewed regularly for indicators of impairment and tested for impairment where such indicators exist. An indicator that one of the Group's assets may be impaired is most likely to be one of the following:

- There are no further plans to conduct exploration activities in the area;
- Exploration drilling in the area has failed to discover commercial reserve volumes;

- Changes in the oil price or other market conditions indicate that discoveries may no longer be commercial; or
- Development proposals for appraisal assets in the pre-development stage indicate that it is unlikely that the carrying value of the exploration/appraisal asset will be recovered in full.

In such circumstances the intangible exploration/appraisal asset is allocated to any property, plant & equipment – development/producing assets within the same cash generating unit (CGU) and tested for impairment. Any impairment arising is recognised in the Income Statement for the year. Where there are no development assets within the CGU, the excess of the carrying amount of the exploration/appraisal asset over its recoverable amount is charged immediately to the Income Statement.

Property, plant and equipment

Costs

All costs incurred after the technical feasibility and commercial viability of producing hydrocarbons has been demonstrated and a development plan approved are capitalised within development/producing assets on a field-by-field basis. Subsequent expenditure is capitalised only where it either enhances the economic benefits of the development/producing asset or replaces part of the existing development/producing asset. Any remaining costs associated with the part replaced are expensed.

Net proceeds from any disposal, part disposal or farm-down of development/producing assets are credited against the appropriate portion of previously capitalised cost. A gain or loss on disposal of a development/producing asset is recognised in the Income Statement to the extent that the net proceeds, measured at fair value, exceed or are less than the appropriate portion of the net capitalised costs.

Depletion and amortisation

Depletion is charged on a unit-of-production basis, based on proved reserves on a field-by-field basis. Fields within a single development area may be combined for depletion purposes. Where production commences prior to completion of the development, costs to be depleted include the costs-to-complete of the facility required to extract the volume of reserves recorded.

Rights and concessions in respect of proved assets are depleted on the unit-of-production basis over the total proved reserves of the relevant area. Where individually insignificant, unproved properties may be grouped and depreciated based on factors such as the average concession term and past experience of recognising proved reserves.

Property, plant and equipment held under lease contracts are depreciated or amortised over the term of the respective contract.

Impairment

The carrying amount of assets other than unproved assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs to sell (see 'Fair value measurements') and value in use.

Value in use is determined as the amount of estimated risk-adjusted discounted future cash flows. For this purpose, assets are grouped into cash-generating units based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, market supply and demand and potential associated costs. In addition, management takes into consideration the expected useful lives, and exploration and production assets, and expected production volumes. The latter takes into account assessments of field and reservoir performance and includes expectations about both proved reserves, under the SEC-mandated classification system, and certain volumes that are expected to constitute proved reserves in the future (unproved volumes), which are risk-weighted utilising geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on the Target Group's marginal cost of debt.

Impairments are reversed as applicable to the extent that the events or circumstances that triggered the original impairment have changed.

Leases (from 1 January 2019)

A contract or parts of contracts that conveys the right to control the use of an identified asset for a period of time in exchange for payments to be made to the owners (lessors) are accounted for as leases. Contracts are assessed to determine whether a contract is, or contains, a lease at the inception of a contract or when the terms and conditions of a contract are significantly changed. The lease term is the non-cancellable period of a lease, together with contractual options to extend or to terminate the lease early, where it is reasonably certain that an extension option will be exercised or a termination option will not be exercised.

At the commencement of a lease contract, a right-of-use asset and a corresponding lease liability are recognised, unless the lease term is 12 months or less in which case the lease expenses are recognised directly in cost of sales or administrative expenses depending on their nature. The commencement date of a lease is the date the underlying asset is made available for use. The lease liability is measured at an amount equal to the present value of the lease payments during the lease term that are not paid at that date. The lease liability includes contingent rentals and variable lease payments that depend on an index, rate, or where they are fixed payments in substance. The lease liability is re-measured when the contractual cash flows of variable lease payments change due to a change in an index or rate when the lease term changes following a reassessment.

Lease payments are discounted using the interest rate implicit in the lease. If that rate is not readily available, the incremental borrowing rate is applied. The incremental borrowing rate reflects the rate of interest that the lessee would have to pay to borrow over a similar term, with a similar security, the funds necessary to obtain an asset of a similar nature and value to the right-of-use asset in a similar economic environment.

In general, a corresponding right-of-use asset is recognised for an amount equal to each lease liability, adjusted by the amount of any pre-paid lease payment relating to the specific lease contract. The depreciation on right-of-use assets is recognised in income unless capitalised as exploration drilling cost or capitalised when the right-of-use asset is used to construct another asset.

Where the Target Group, usually in its capacity as operator, has entered into a lease contract on behalf of a joint arrangement, a lease liability is recognised to the extent that the Target Group has primary responsibility for the lease liability. A finance sub-lease is subsequently recognised if the related right- of-use asset is subleased to the joint arrangement. This is usually the case when the joint arrangement has the right to direct the use of the asset. Right-of-use assets are subject to existing impairment requirements as set out in '*Property, plant and equipment*'.

Leases (prior to January 1, 2019)

Agreements under which payments are made to owners in return for the right to use an asset for a period are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognised at the commencement of the lease term as finance leases within property, plant and equipment and debt at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments. Finance lease payments are apportioned between interest expense and repayments of debt. All other leases are classified as operating leases and the cost is recognised in income on a straight-line basis, except where capitalised as exploration drilling costs (see '*Exploration costs*').

Joint arrangements

A joint arrangement is an arrangement of which 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.

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities relating to the arrangement. In the financial statements the Target Group's share of the asset/liabilities and revenues/expenses of the joint operations is recognised upon rights and obligations to the arrangements. After the initial recognition, the assets/liabilities and revenues/expenses of the joint operations are measured in accordance with the measurement criteria applicable to each case.

Inventories

Inventories are stated at cost or net realisable value, whichever is lower. Cost comprises direct purchase costs (including transportation), and associated costs incurred in bringing inventories to their present condition and location, and is determined using the weighted average cost method.

Taxation

Taxation represents the corporate income tax payable on income in the Arab Republic of Egypt. The tax charge is computed separately for each production-sharing contract ("**ring-fence**") in accordance with the Egyptian Income Tax Law and Regulations and applicable terms and conditions as per PSC.

The charge for current tax is calculated based on the taxable income reported by the Target Group, as adjusted for items that are non-taxable or disallowed and using rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is determined, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Combined Balance Sheet and on unused tax losses and credits carried forward.

Deferred tax assets and liabilities are calculated using the enacted or substantively enacted rates that are expected to apply when an asset is realised or a liability is settled. They are not recognised where they arise on the initial recognition of goodwill or of an asset or liability in a transaction that, at the time of the transaction, affects neither accounting nor taxable profit, or in respect of taxable temporary differences where the reversal of the respective temporary difference can be controlled by the Target Group and it is probable that it will not reverse in the foreseeable future.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences, unused tax losses and credits carried forward can be utilised.

The Egyptian General Petroleum Corporation ("EGPC") assumed, paid and discharged, in the name and on behalf of the Target Group, the Egyptian corporate income tax of the Target Group out of EGPC's share of Petroleum. All taxes paid by EGPC in the name and on behalf of the Target Group are considered as income for the Target Group.

Income tax receivables and payables as well as deferred tax assets and liabilities take provisions for uncertain income tax positions/treatments into consideration. Income tax assets and liabilities are presented separately in the Combined Balance Sheet except where there is a right of offset within a particular PSC.

Provisions

Provisions are recognised at the balance sheet date at management's best estimate of the expenditure required to settle the present obligation. Non-current amounts are discounted at a rate intended to reflect the time value of money. The carrying amounts of provisions are regularly reviewed and adjusted for new facts.

Decommissioning and restoration

Provisions for decommissioning and restoration costs, which arise principally in connection with hydrocarbon production facilities, are measured on the basis of current concession requirements, technology and price levels; the present value is calculated using amounts discounted over the useful economic life of the assets. The liability is recognised (together with a corresponding amount as part of the related property, plant and equipment) once an obligation crystallises in the period when a reasonable estimate can be made. The effects of changes resulting from revisions to the timing or the amount of the original estimate of the provision are reflected on a prospective basis, generally by adjustment to the carrying amount of the related property, plant and equipment. However, where there is no related asset, or the change reduces the carrying amount to nil, the effect, or the amount in excess of the reduction in the related asset to nil, is recognised in income.

Financial instruments

Financial assets and liabilities are presented separately in the Combined Balance Sheet except where there is a legally enforceable right of offset and the Target Group has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial assets

Financial assets are classified at initial recognition and subsequently measured at amortised cost, fair value through other comprehensive income or fair value through profit or loss. The classification of financial assets is determined by the contractual cash flows and where applicable the business model for managing the financial assets.

A financial asset is measured at amortised cost, if the objective of the business model is to hold the financial asset in order to collect contractual cash flows and the contractual terms give rise to cash flows that are solely payments of principal and interest. It is initially recognised at fair value plus or minus transaction costs that are directly attributable to the acquisition or issue of the financial asset. Subsequently the financial asset is measured using the effective interest method less any impairment. Gains and losses are recognised in the Combined Statement of Income when the asset is derecognised, modified or impaired. A receivable is recognised if an amount of consideration that is unconditional is due from the customer.

Underlifted or overlifted positions of hydrocarbons are valued at market prices prevailing at the balance sheet date or the prevailing contract price. An underlift of production is included in the current receivables while an overlift of production is included in the current liabilities.

Impairment of financial assets

The expected credit loss model is applied for recognition and measurement of impairments in financial assets measured at amortised cost. The loss allowance for the financial asset is measured at an amount equal to the 12-month expected credit losses. If the credit risk on the financial asset has increased significantly since initial recognition, the loss allowance for the financial asset is measured at an amount equal to the lifetime expected credit losses. Changes in loss allowances are recognised in profit and loss. For trade receivables, a simplified impairment approach is applied recognising expected lifetime losses from initial recognition.

Financial liabilities

Financial liabilities are measured at amortised cost, unless they are required to be measured at fair value through profit or loss. Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost. Interest expense on debt is accounted for using the effective interest method, and other than interest capitalised, is recognised in income.

Financial assets

Cash and cash equivalents comprise cash at bank and in hand.

Trade receivables are recognised initially at fair value based on amounts exchanged and subsequently at amortised cost less any impairment.

Underlifted or overlifted positions of hydrocarbons are valued at market prices prevailing at the balance sheet date or the prevailing contract price. An underlift of production is included in the current receivables while an overlift of production is included in the current liabilities. The adjustments are recognised cost of sales in the Combined Statement of Income.

Interest income is recognised in income using the effective interest method.

Financial liabilities

Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost. Interest expense is accounted for using the effective interest method and, other than interest capitalised.

Fair value measurements

Fair value measurements are estimates of the amounts for which assets or liabilities could be transferred at the measurement date, based on the assumption that such transfers take place between participants in principal markets and, where applicable, taking highest and best use into account.

3.3 **Critical accounting judgements and key sources of estimation uncertainty**

In the application of the Target Group's accounting policies, the directors are required to make judgements (other than those involving estimations) that have a significant impact on the amounts recognised and to make estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Proved oil and gas reserves – key source of estimation uncertainty

Unit-of-production depreciation, depletion and amortisation charges are principally measured based on management's estimates of proved developed oil and gas reserves. Also, exploration drilling costs are capitalised pending the results of further exploration or appraisal activity, which may take several years to complete and before any related proved reserves can be booked.

Proved reserves are estimated by a central group of reserves experts. The estimated proved reserves are made by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Yearly average oil and gas prices are applied in the determination of proved reserves. Estimates of proved reserves are inherently imprecise, require the application of judgement and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms, legislation or development plans.

Changes to estimates of proved developed reserves affect prospectively the amounts of depreciation, depletion and amortisation charged and, consequently, the carrying amounts of exploration and production assets. The outcome of, or assessment of plans for, exploration or appraisal activity may result in the related capitalised exploration drilling costs being recognised in income in that period.

Judgement is involved in determining when to use an alternative reserves base in order to appropriately reflect the expected utilisation of the assets concerned. The Target Group's proved and probable and contingent reserve estimates are based on P50 probabilities. P10 and P90 estimates are also produced but would not provide a reasonable estimate to be used in calculating the fair value of the Group's assets.

Impairment of Property, plant and equipment – key source of estimation uncertainty

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value-in-use measures are future oil and gas prices, potential costs associated and expected production volumes. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can affect the rate used to discount future cash flow estimates or the risk-adjustment in the future cash flows.

The determination of cash-generating units requires judgement. Changes in this determination could impact the calculation of value in use and therefore the conclusion on the recoverability of assets' carrying amounts when performing an impairment test. Refer to estimates made in determining impairment of property plant and equipment and note 9 for sensitivity analysis.

Commodity prices

Future commodity price assumptions, presented in note 8, tend to be stable because management does not consider short-term increases or decreases in prices as being indicative of long-term levels, but they are nonetheless subject to change.

Expected production volumes

Expected production volumes, which comprise proved reserves and unproved volumes, are used for impairment testing because management believes this to be the most appropriate indicator of expected future cash flows. As discussed in 'Proved oil and gas reserves' above, reserves estimates are inherently imprecise. Furthermore, projections about unproved volumes are based on information that is necessarily less robust than that available for mature reservoirs. Due to the nature and geographical spread of the business activity in which those assets are used, it is typically not practicable to estimate the likelihood or extent of impairments under different sets of assumptions for the Target Group overall.

Discount rate assumptions

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate. Fair value less costs of disposal calculations use the post-tax discount rate. The discount rates applied in impairment tests are reassessed each year and in 2020 the pre-tax discount rate was 6% (2019 6%; 2018 6%).

Changes in assumptions could affect the carrying amounts of assets, and any impairment losses and reversals will affect income. Refer to note 9 for further disclosure on key assumptions and sensitivity analysis.

Deferred tax – key judgements

Deferred tax assets

Recognition of deferred tax assets which are dependent on future taxable profits and not arising from the reversal of existing deferred tax liabilities, involves an assessment of when those assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognised in respect of deferred tax assets as well as in the amounts recognised in income in the period in which the change occurs.

The Target Group's deferred tax assets are recognised to the extent that taxable profits are expected to arise in future against which tax losses and allowances in the Target Group may be utilised. In accordance with paragraph 37 IAS 12 the Target Group has reassessed its deferred tax assets on the basis of current business modelling and underlying oil and gas price assumptions.

Taxation information, including charges and deferred tax assets and liabilities, is presented in note 7.

4. **Adoption of IFRS 16 leases**

IFRS 16 was adopted as from January 1, 2019. All operating lease contracts, with limited exceptions, were recognised on the balance sheet by recognising right-of-use assets and corresponding lease liabilities at the transition date. The Target Group applied the modified retrospective transition method, and consequently comparative information is not restated. As a practical expedient, no reassessment was performed of contracts that were previously identified as leases and contracts that were not previously identified as containing a lease applying IAS 17 Leases ("**IAS 17**") and IFRIC 4 Determining whether an Arrangement contains a Lease. At the adoption date, additional lease liabilities were recognised for leases previously classified as operating leases applying IAS 17. These lease liabilities were measured at the present value of the remaining lease payments and discounted using entity-specific incremental borrowing rates at January 1, 2019. In general, a corresponding right-of-use asset was recognised for an amount equal to each lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to the specific lease contract, as recognised on the balance sheet at December 31, 2018. Provisions for onerous lease contracts at December 31, 2018 were adjusted to the respective right-of-use assets recognised at January 1, 2019. As a practical expedient the recognition exemption for leases with a remaining term of less than 12 months from the adoption date was applied upon adoption.

At the transition date, the remaining lease payments were discounted, as required under the transition approach chosen, using the incremental borrowing rate as per the transition date of January 1, 2019. To determine the incremental borrowing rate for each lease contract, a risk-free rate at transition date was applied, adjusted for other factors such as the credit rating of the entity that entered into the lease contract, a country risk premium, the impact of currency, an asset specific element and the term the lease contract. The weighted average incremental borrowing rate applied upon transition was 7%.

Compared with the previous accounting for operating leases under IAS 17, the application of the new standard has a significant impact on the classification of expenditures and cash flows. It also impacts the timing of expenses recognised in the statement of income. With effect from 2019, expenses related to leases previously classified as operating leases are presented under 'Depreciation, depletion and amortisation' and 'Interest expense'. Before 2019, these were mainly included in 'Selling, distribution and administrative expenses'. Payments related to leases previously classified as operating leases are presented under 'Cash flow from financing activities' (before 2019 these were included in 'Cash flow from operating activities' and 'Cash flow from investing activities').

The adoption of the new standard had no accumulated impact on equity at January 1, 2019 following the recognition of lease liabilities of $0.9 million and additional right-of-use assets of $0.9 million and reclassifications mainly related to pre-paid leases and onerous contracts previously recognised.

The reconciliation of differences between the operating lease commitments under the prior standard and the additional lease liabilities recognised on the balance sheet at January 1, 2019 upon adoption of IFRS 16 is as follows:

	$m
Lease liabilities reconciliation	
Undiscounted future minimum lease payments under operating leases at December 31, 2018 (see note 13)	**1.0**
Impact of discounting	(0.1)
Total lease liability at January 1, 2019	**0.9**

The detailed impact on the Combined Balance sheet at January 1, 2019, is as follows:

Combined Statement of Financial Position

	31 December 2018 $m	IFRS 16 impact $m	1 January 2019 $m
Assets			
Non-current assets			
Intangible exploration/appraisal assets	253.4	—	253.4
Plant, property and equipment	400.5	1.0	401.5
Deferred tax asset	92.9	—	92.9
Current assets			
Inventories	30.2	—	30.2
Trade and other receivables	238.2	—	238.2
Cash and cash equivalents	98.1	—	98.1
Total assets	**1,113.3**	**1.0**	**1,114.3**
Liabilities			
Non-current liabilities			
Trade and other payables	(1.9)	—	(1.9)
Lease liabilities	—	(0.5)	(0.5)
Deferred tax liability	(23.3)	—	(23.3)
Provisions	(1.7)	—	(1.7)
Current liabilities			
Trade and other payables	(255.2)	—	(255.2)
Lease liabilities	—	(0.5)	(0.5)
Provisions	—	—	—
Total liabilities	**(282.1)**	**(1.0)**	**(283.1)**
Equity			
Invested capital	(831.2)		(831.2)
Total liabilities and equity	**(1,113.3)**	**(1.0)**	**(1,114.4)**

Leases entered into in 2019 and 2020 are recognised as a right-of-use asset with a corresponding lease liability. Depreciation, depletion and amortisation on the right-of-use asset (see note 9), and the interest expense on the lease liability is recognised in the income statement. The lease liabilities were measured at the present value of the remaining lease payments and discounted using entity-specific incremental borrowing rates (see note 13). There were no low value and short-term lease arrangements during the three years ended 31 December 2020

5. Revenue

Revenue is derived from the production and sale of liquid and gaseous hydrocarbons. The entire revenue is derived in Egypt.

	2020 $m	2019 $m	2018 $m
Liquid hydrocarbons			
Revenue from third parties	138.1	161.6	222.0
Revenue from related companies	98.1	310.8	307.2
Gaseous hydrocarbons			
Revenue from third parties	155.1	176.8	151.4
Revenue from related companies	—	—	—
Total	391.3	649.2	680.6

Related companies relates to Shell International Trading and Shipping Company ("**STASCO**") who are subject to common control with the Target Group during the reported periods.

6. Combined profit before taxation

Combined profit before taxation was presented after (charging)/crediting:

	2020 $m	2019 $m	2018 $m
Salaries and wages	(45.1)	(57.1)	(47.5)
Staff related expenses	(46.1)	(23.4)	(25.2)
Depreciation – production	(248.6)	(185.5)	(196.7)
Depreciation - capitalised research and development costs	(1.1)	(0.4)	(0.6)
Impairment losses and reversals	—	(5.4)	—
Net (loss)/gain on foreign exchange	0.8	(4.6)	3.4
Employee benefit expense	(4.6)	(1.4)	(0.2)

All permanent employees in Egypt are eligible to participate in a defined employee benefit plan of Shell Egypt. The pension liabilities are borne by Shell Egypt. An increase in pension liability is allocated to the Target Group on annual basis and recognised as an expense to the income statement.

7. Taxation

	2020 $m	2019 $m	2018 $m
Current tax:			
Charge in respect of current period	(31.5)	(110.3)	(113.3)
Total	**(31.5)**	**(110.3)**	**(113.3)**
Deferred tax:			
Relating to the origination and reversal of temporary differences, tax losses and credits	39.8	(0.7)	6.3
Total	**39.8**	**(0.7)**	**6.3**
Total taxation credit / (charge)	**8.3**	**(111.0)**	**(107.0)**

Reconciliation of applicable tax charge at statutory tax rates to taxation charge

	2020 $m	2019 $m	2018 $m
Combined (loss)/income before tax	(105.5)	114.7	177.4
Tax calculated at domestic rate [A]	42.8	(46.5)	(71.9)
Calculated tax on HFI net income before tax	42.8	(46.5)	(71.9)
Adjustments in respect of prior periods	—	(1.0)	(0.1)
Tax effects on expenses not deductible for tax [B]	(40.8)	(60.6)	(43.6)
Tax effects on income not subject to tax [C]	—	—	8.6
Re-/Derecognition of deferred tax asset previously recognised in BED 2/17 [D]	6.3	(2.9)	—
	8.3	**(111.0)**	**(107.0)**

[A] The applicable statutory tax rate in Egypt for the period was of 40.55% in 2020 (2019: 40.55%; 2018: 40.55%)

[B] Non tax deductible costs and expenditures such as bonus, services and non-recoverable cost

[C] Reversal of non tax deductible provision in 2018

[D] The deferred tax asset previously unrecognised in 2019, was recognized on signature of BED-2/17 Concession Agreement with regards to 10 years extension on January 19, 2020.

2020 – Deferred tax

	Property, plant and equipment $m	Tax losses carried forward $m	Total $m
Deferred tax asset			
At January 1, 2020	**101.9**	**7.0**	**108.9**
Credit to income	28.7	7.3	36.0
At December 31, 2020	**130.6**	**14.3**	**144.9**
Deferred tax liability			
At January 1, 2020	(39.9)	—	(39.9)
Credit to income	3.7	—	3.7
At December 31, 2020	**(36.2)**	**—**	**(36.2)**
Deferred tax asset	**130.6**	**14.3**	**144.9**
Deferred tax liability	**(36.2)**	**—**	**(36.2)**
Deferred tax asset as presented in the combined balance sheet at December 31, 2020	**130.6**	**13.7**	**144.3**
Deferred tax liability as presented in the combined balance sheet at December 31, 2020	**(36.2)**	**0.6**	**(35.6)**

2019 – Deferred tax

	Property, plant and equipment $m	Tax losses and credits carried forward $m	Total $m
Deferred tax asset			
At January 1, 2019	88.8	15.9	104.7
Impact of IFRS 16	—	—	—
At January 1, 2019 (as revised)	88.8	15.9	104.7
(Charge)/credit to income	13.1	(8.9)	4.2
At December 31, 2019	101.9	7.0	108.9
Deferred tax liability			
At January 1, 2019	(35.1)	—	(35.1)
Impact of IFRS 16	—	—	—
At January 1, 2019 (as revised)	(35.1)	—	(35.1)
(Charge)/credit to income	(4.8)	—	(4.8)
At December 31, 2019	(39.9)	—	(39.9)
Deferred tax asset	101.9	7.0	108.9
Deferred tax liability	(39.9)	—	(39.9)
Deferred tax asset as presented in the combined balance sheet at December 31, 2019	**101.9**	**4.4**	**106.3**
Deferred tax liability as presented in the combined balance sheet at December 31, 2019	(39.9)	2.6	(37.3)

2018 – Deferred tax

	Property, plant and equipment $m	Tax losses and credits carried forward $m	Total $m
Deferred tax asset			
At January 1, 2018	67.3	14.6	81.9
(Charge)/credit to income	21.5	1.3	22.8
At December 31, 2018	88.8	15.9	104.7
Deferred tax liability			
At January 1, 2018	(18.6)	—	(18.6)
(Charge)/credit to income	(16.5)	—	(16.5)
At December 31, 2018	(35.1)	—	(35.1)
Deferred tax asset	88.8	15.9	104.7
Deferred tax liability	(35.1)	—	(35.1)
Deferred tax asset as presented in the combined balance sheet at December 31, 2018	88.8	4.1	92.9
Deferred tax liability as presented in the combined balance sheet at December 31, 2018	(35.1)	11.8	(23.3)

The presentation in the Combined Balance Sheet takes the separate computation for each PSC into consideration. The overall deferred tax position for a respective PSC determines if a deferred tax balance for that PSC is presented within deferred tax assets or deferred tax liabilities.

The amount of deferred tax assets dependent on future taxable profits not arising from the reversal of existing deferred tax liabilities, where the Target Group has suffered a loss in the current or preceding year, was $13.7 million at December 31, 2020 for Sitra, BED-3, BED-19 and NAES (2019: $4.4 million – BED-19 and NAES; 2018: $4.1 million – BED-19; $nil NAES). It is considered probable based on annually revised business forecasts that taxable profits for the ring-fenced PSC will be available, within the 5-year tax loss carry forward period as per the Egyptian Income Tax Law.

Unrecognised deductible temporary differences of tax losses incurred, where the utilization under the respective annual business forecast was not considered probable future taxable income within the 5-year loss carry forward period, consist of $10.6 million relating to NAES $9.4 million and for BED-19 $1.2 million (2019: $3.8 million relating to NAES only; 2018 $0 million). Furthermore, whilst a temporary difference on PP&E associated with BED 2 & 17 was not considered in absence of an extension at December 31, 2019, the temporary difference was re-recognised with the signature of the extension of BED 2 & 17 under the new ring-fenced PSC occurred on 19 January 2020 and resulted in a re-recognition of $6.3 million DTA in Q1 2020.

8. **Intangible Exploration / Appraisal Assets**

	Total $m
Cost	
At January 1, 2020	326.9
Additions	23.8
Unsuccessful exploration costs	19.3
At December 31, 2020	**331.4**
At January 1, 2019	**253.4**
Additions	117.8
Transfers to development / producing assets	(16.2)
Unsuccessful exploration costs	(28.1)
At December 31, 2019	**326.9**
At January 1, 2018	**234.8**
Additions	50.5
Transfers to development / producing assets	(18.2)
Unsuccessful exploration costs	(13.7)
At December 31, 2018	**253.4**

Exploration and evaluation assets principally comprise rights and concessions in respect of unproved properties and capitalised exploration drilling costs.

All additions to exploration/appraisal assets have been funded through cash and working capital.

The carrying amount of exploration / appraisal assets at December 31, 2020, included rights and concessions in respect of unproved properties of $73.8 million (2019: $73.2 million; 2018: $22.0 million).

Exploration and appraisal assets principally comprise rights and concessions in respect of unproved properties and capitalised exploration drilling costs.

Capitalised exploration drilling costs

	2020 $m	2019 $m	2018 $m
At January 1	78.8	61.8	49.6
Additions pending determination of proved reserves	20.4	61.2	44.2
Amounts charged to expense	(19.3)	(28.1)	(13.8)
Reclassifications to productive wells on determination of proved reserves	—	(16.1)	(18.2)
At December 31	**79.9**	**78.8**	**61.8**

9. **Property, plant and equipment**

2020

	Development / Producing Assets $m
Cost	
At January 1, 2020	3,810.4
Additions	119.7
At December 31, 2020	3,930.1
Depreciation, depletion and amortisation, including impairments	
At January 1, 2020	3,391.2
Charge for the year	249.7
At December 31, 2020	**3,640.9**
Carrying amount at December 31, 2020	**289.2**

2019

	Development / Producing Assets $m
Cost	
At January 1, 2019	3,600.4
Impact of IFRS 16 [note 4]	1.0
At January 1, 2019 (revised)	**3,601.4**
Additions	192.8
Transfers from exploration/appraisal assets	16.2
At December 31, 2019	3,810.4
Depreciation, depletion and amortisation, including impairments	
At January 1, 2019	3,199.9
Charge for the year	185.9
Impairment charge	5.4
At December 31, 2019	3,391.2
Carrying amount at December 31, 2019	**419.1**

2018

	Development / Producing Assets $m
Cost	
At January 1, 2018	3,442.2
Additions	140.0
Transfers from exploration/appraisal assets	18.2
At December 31, 2018	3,600.4
Depreciation, depletion and amortisation, including impairments	
At January 1, 2018	3,002.6
Charge for the year	197.3
At December 31, 2018	3,199.9
Carrying amount at December 31, 2018	**400.5**

Under the terms of the production sharing agreements, assets can only be disposed of with the agreement of the state enterprise, Egyptian General Petroleum Corporation.

The carrying amount of property, plant and equipment at December 31, 2020, included $48.6 million (2019: $77.8 million; 2018: $68.0 million) of assets under construction. This amount excludes exploration and evaluation assets.

The carrying amount of Development / production assets at December 31, 2020, included rights and concessions in respect of proved properties of $58.6 million (2019: $81.6 million; 2018: $89.4 million).

Contractual commitments for the purchase and lease of property, plant and equipment at December 31, 2020, amounted to $25.8 million (2019: $43.6 million; 2018: $29.8 million).

Within property, plant and equipment the following amounts relate to leases:

Right-of-use assets

	Production $m	Total $m
Cost		
At January 1, 2019	—	—
Impact of IFRS 16 (see note 4)	1.0	1.0
At January 1, 2019 (revised)	1.0	1.0
Additions	1.0	1.0
At December 31, 2019	13.0	13.0
Depreciation, depletion and amortisation, including impairments		
At January 1, 2019	—	—
Charge for the year	2.5	2.5
At December 31, 2019	2.5	2.5
Carrying amount at December 31, 2019	**10.5**	**10.5**

	Production $m	Total $m
Cost		
At January 1, 2020	13.0	13.0
At December 31, 2020	13.0	13.0
Depreciation, depletion and amortisation, including impairments		
At January 1, 2020	2.5	2.5
Charge for the year	2.3	2.3
At December 31, 2020	4.8	4.8
Carrying amount at December 31, 2020	**8.2**	**8.2**

Impairments

In 2019, impairment reviews performed showed a US$5.4 million impairment in NEASW concession CGU, triggered by lower than expected production, which reduced the carrying value to its ViU of $21.5 million. There were no material impairment triggers for other concessions.

For impairment testing purposes, the respective carrying amounts of property, plant and equipment were compared with their value in use. Cash flow projections used in the determination of value in use were made using management's forecasts of commodity prices, market supply and demand, associated potential costs and expected production volumes over the life of the concession – to 2040 for NEASW. These cash flows were adjusted for the risks specific to the assets, and therefore these risks were not included in the determination of the discount rate applied. The nominal pre-tax rate applied in 2020 was 6% (2019: 6%; 2018: 6%).

In 2020 and in 2018, there were no impairments to property, plant and equipment based on the impairment reviews performed.

Oil and gas price assumptions applied for impairment testing are reviewed and, where necessary, adjusted on a periodic basis. Reviews include comparison with available market data and forecasts that reflect developments in demand such as global economic growth, technology efficiency, policy measures and, in supply, consideration of investment and resource potential, cost of development of new supply, and behaviour of major resource holders. The near-term commodity price assumptions applied in impairment testing were as follows:

Commodity price assumptions [A] – 2020

	2021 $m	2022 $m	2023 $m
Brent crude oil ($/b)	40	50	60
Henry Hub natural gas ($/MMBtu)	2.50	2.50	2.75

[A] Real prices.

For periods after 2023, the real terms long-term price assumptions applied were $60 per barrel (/b) for Brent crude oil and $2.75 per million British thermal units (/MMBtu) for Henry Hub natural gas.

Commodity price assumptions [A] – 2019

	2020 $m	2021 $m	2022 $m
Brent crude oil ($/b)	60	60	60
Henry Hub natural gas ($/MMBtu)	2.75	2.75	3.00

[A] Real prices.

For periods after 2022, the real terms long-term price assumptions applied were $60 per barrel (/b) for Brent crude oil and $3.00 per million British thermal units (/MMBtu) for Henry Hub natural gas.

Commodity price assumptions [A] – 2018

	2019 $m	2020 $m	2021 $m
Brent crude oil ($/b)	65	65	70
Henry Hub natural gas ($/MMBtu)	3.25	3.50	3.50

[A] Real prices.

For periods after 2021, the real terms long-term price assumptions applied were $70 per barrel (/b) for Brent crude oil and $3.50 per million British thermal units (/MMBtu) for Henry Hub natural gas.

Sensitivities:

In the 2019 period, a reduction or increase in the two-year forward curve of $65/bbl, based on the approximate volatility of the oil price over the previous two years, and a reduction in the medium and long-term price assumptions of $45/bbl, based on the range seen in external oil price market forecasts, are considered to be reasonably possible changes for the purposes of sensitivity analysis.

Decreases to oil prices specified above would increase the impairment charge by $4.9 million in 2019. A 1 per cent. increase in the pre-tax discount rate would increase the impairment by $7.8 million in 2019. A 1 per cent. decrease in the pre-tax discount rate would cause no impairment in 2019.

There is no impact on the impairment charge in 2018 and 2020 as a result of changes in oil prices.

10. Trade and other receivables

	2020 $m	2019 $m	2018 $m
Trade receivables	143.5	96.5	100.2
Other receivables	30.2	38.6	119.4
Prepayments and deferred charges	38.8	26.8	18.6
Total	**212.5**	**161.8**	**238.2**

The fair value of all financial assets included within the above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other receivables includes JV cash call receivables, receivables from Bapetco, and Bapetco receivables from sister companies.

In 2018, 2019 and 2020 the group applies the IFRS 9 simplified approach to measuring expected credit losses by using a lifetime expected loss allowance for all trade receivables and any impairments under this model are not considered to be material.

The Target Group enters into offsetting with EGPC. Where there is a legally enforceable right of offset under this agreement, and the Target Group has the intention to settle on a net basis or realise the asset and settle liability simultaneously, the net EGPC receivable or payable is recognised in the Combined Balance Sheet. These amounts, as presented net and gross within trade receivables or trade payables (note 13), in the combined Balance Sheet at December 31, were as follows:

	2020 $m	2019 $m	2018 $m
EGPC Gross receivable	143.4	138.6	135.5
Excess cost offset	(10.2)	(87.5)	(80.5)
Overlift offset	(26.5)	(24.1)	5.0
Provision	(22.0)	(58.5)	(118.7)
EGPC Net receivable/(payable)	**84.7**	**(31.5)**	**(58.7)**

The 2020 the low oil price reduced the monthly excess liability to almost zero, whereas gas invoices continued to build up at the same levels as the prices are contractually fixed. Moreover, more crude oil was sold domestically in comparison to 2019 due to change in lifting schedule to STASCO, bringing the overlift position down. In addition, due to low cash collection the gross EGPC receivables increased.

11. Inventories

	2020 $m	2019 $m	2018 $m
Raw material and consumables	25.4	30.5	30.2
Total	**25.4**	**30.5**	**30.2**

There is no material difference between the carrying value of inventories and their net realisable value. Inventories at December 31, 2020, include write-downs to net realisable value of $25.4 million (2019: $0.2 million; 2018: $0.5 million).

12. Cash and cash equivalents

	2020 $m	2019 $m	2018 $m
Cash and cash equivalents	52.3	5.8	98.1

The carrying amount of these assets is approximately equal to their fair value. The cash balances are at the free disposal of the Target Group.

Cash and cash equivalents in 2018 include $85.6 million cash pooling, from Shell Treasury Centre Limited (STCL). In 2020 $48.0 million (2019: $2.6 million) is included within trade payables with respect to amounts owed by the Target Group to Shell Treasury Centre Limited (STCL).

13. Trade and other payables

	2020		2019		2018	
	Current $m	Non-current $m	Current $m	Non-current $m	Current $m	Non-Current $m
Trade payables	(31.6)	—	(68.1)	—	(113.7)	—
Amounts due to related companies	(2.0)	—	(34.9)	—	(16.8)	—
Other payables	(0.6)	(3.0)	(2.4)	(1.5)	(12.2)	(1.9)
Accruals	(71.2)	—	(106.6)	—	(110.8)	—
Government duties payable	(6.9)	—	(0.6)		(1.7)	
Total	**(112.3)**	**(3.0)**	**(212.6)**	**(1.5)**	**(255.2)**	**(1.9)**

The fair value of financial liabilities included within the above approximates the carrying amount and was determined from predominantly unobservable inputs.

Trade payables include EGPC net payable as disclosed in note 10.

Accruals comprise of goods and services received by Bapetco from 3rd party vendors, related to normal business operations, but not yet invoiced.

Leases are recognised as a right-of-use asset (see note 4) and a corresponding liability at the date which the lease asset is available for the use by the Target Group. Lease liabilities are secured on the leased assets. The future lease payments under lease contracts and the present value of future lease payments at December 31, by payment date are as follows:

2019	Contractual lease payments [A] $m	Interest $m	Lease liabilities [B] $m
Less than 1 year	2.7	0.6	2.1
Between 2 to 5 years	10.1	1.2	8.9
Total	**12.8**	**1.8**	**11.0**

2020	Contractual lease payments [A] $m	Interest $m	Lease liabilities [B] $m
Less than 1 year	2.4	0.5	1.9
Between 2 to 5 years	7.7	0.7	7.0
Total	**10.1**	**1.2**	**8.9**

[A] See note 4.

[B] Future cash outflows in respect of leases may differ from lease liabilities recognised due to future decisions that may be taken by Target Group in respect of the use of leased assets. These decisions may result in variable lease payments to be made. In addition, the Target Group may reconsider whether it will exercise extension options or termination options, where future reconsideration is not reflected in the lease liabilities. There is no exposure to these potential additional payments in excess of the recognised lease liabilities until these decisions have been taken by the Target Group.

14. **Provisions**

2020	Decommissioning and restoration $m	Total $m
At January 1, 2020	(1.8)	(1.8)
Unwinding	0.3	0.3
Additions	(0.4)	(0.4)
At December 31, 2020	**(1.9)**	**(1.9)**
Current	(0.1)	(0.1)
Non-current	**(1.8)**	**(1.8)**

2019	Decommissioning and restoration $m	Total $m
At January 1, 2019	(1.7)	(1.7)
Unwinding	(0.1)	(0.1)
Additions	—	—
At December 31, 2019	**(1.8)**	**(1.8)**
Current	(0.1)	(0.1)
Non-current	(1.7)	(1.7)

2018	Decommissioning and restoration $m	Total $m
At January 1, 2018	—	—
Additions	(1.7)	(1.7)
At December 31, 2018	**(1.7)**	**(1.7)**
Current	—	—
Non-current	(1.7)	(1.7)

15. **Financial instruments**

The Target Group does not use derivative financial instruments. The Target Group manages the following market risks:

Foreign exchange risk

The Target Group's currency risk mainly relates to positions and future transactions in currencies other than the US Dollar. During the period, the Target Group followed the Treasury policies of Royal Dutch Shell plc to mitigate the currency risks. Assuming other factors remained constant and that no further foreign exchange risk management action were taken, a 10% appreciation against the dollar at December 31 of the main currencies to which the Target Group is exposed would have the following effects::

	Increase/(decrease) in income before taxation		
	2020	2019	2018
10% appreciation against the dollar of:			
Egyptian Pound	16.0	21.0	6.2
Euro	0.9	0.2	0.8

The above sensitivity information was calculated by reference to carrying amounts of assets and liabilities at December 31 only. The effect on the Combined Statement of Income before taxation arises in connection with monetary balances denominated in currencies other than an entity's functional currency.

Interest rate risk

The Target Group does not have any interest bearing debt. The Target Group's exposure to interest rate risk on interest-bearing assets mainly cash at banks is minimal.

Commodity price risk

The Target Group may be exposed to commodity price fluctuations through the sale of petroleum products. Commodity price risk was managed by the Royal Dutch Shell plc and was not pushed down to the Target Group. As such, the Target Group reflects commodity price fluctuations over the track record period. At reporting dates included within the historical financial information, the Target Group entities had no open commodity price swap or option contracts and therefore the Target Group is not exposed to movements in commodity prices except to commodity price fluctuations through the sale of petroleum products.

Credit risk

The Target Group does not have any significant concentrations of credit risk other than the manageable receivables balance from Government of Egypt and joint venture partners.

Liquidity risk

The Target Group has minimal liquidity risk. The Target Group has been funded by Shell Treasury Centre Limited (STCL) for its imminent funding requirements which are disclosed under the Amounts Payable to Group Companies. The following table analyses the contractual maturities of the Target Group's financial liabilities into relevant maturity groupings based on the remaining period at the reporting date to the contractual maturity date.

2020

	Within 1 year $m	2-5 years $m	Total $m
Trade payables	(31.6)	—	(31.6)
Amount due to Group companies	(2.0)	—	(2.0)
Other payables	(0.6)	(3.0)	(3.6)
Accruals	(71.2)	—	(71.2)
Government duties payable	(6.9)	—	(6.9)

2019

	Within 1 year $m	1-2 years $m	Total $m
Trade payables	(68.1)	—	(68.1)
Amount due to Group companies	(34.9)	—	(34.9)
Other payables	(2.4)	(1.5)	(3.9)
Accruals	(106.6)	—	(106.6)
Government duties payable	(0.6)		(0.6)

2018

	Within 1 year $m	1-2 years $m	Total $m
Trade payables	(113.7)	—	(113.7)
Amount due to Group companies	(16.8)	—	(16.8)
Other payables	(12.2)	(1.9)	(14.1)
Accruals	(110.8)	—	(110.8)
Government duties payable	(1.7)	—	(1.7)

Capital management

The Target Group funding requirements were managed by Royal Dutch Shell plc. The Target Group does not have any external financing. Cash and cash equivalents is disclosed in note 12 and equity attributable to equity holders is disclosed in the Combined Statement of Changes in Equity.

Gearing ratio

Given all funding is derived from related party sources, the gearing ratio is not considered a materially important key performance indicator for the Target Group.

16. **Material joint operations**

The following joint operations are considered individually material to the Target Group as at 31 December 2020.

Name	% interest held
Alam El Shawish Petroleum Company (Cairo, Egypt)	20%
Badr Petroleum Company (Cairo, Egypt)	50%
Obaiyed Petroleum Company (Cairo, Egypt)	50%
Tiba Petroleum Company (Cairo, Egypt)	26%
North Alam El-Shawish Petroleum Company (Cairo, Egypt)	50%
Sitra Petroleum Company (Cairo, Egypt)	50%
North Umbaraka Petroleum Company (Cairo, Egypt)	50%

17. **Commitments**

Capital commitments

For the three concessions, West El Fayium, South East Hours and South Abu Sennan, the Target Group has a financial commitment to spend $18 million, $16 million and $5.4 million respectively by 2024, 2024 and 2023 respectively, measured as each reporting date included within the historical financial information. For the concession BED 3 (2-17) the Company has a financial commitment granted in 2020 to spend $60 million by 2029 for exploration and development activities.

EGPC has performed audits in the normal course of business and within the scope of the concession agreements and several audit exceptions are raised. The Company recognised a provision for remediation costs based upon management's expectation regarding the outcome of negotiations. The Company is jointly and severally liable for the performance of the obligations under the concession agreements of all participants.

Total capital expenditure contracted for at the reporting date but for which no amounts have been provided for in the historical financial statements.

	2020 $m	2019 $m	2018 $m
Due within one year	—	—	—
Due later than one year but within five years	39.4	39.4	—
Due in five years or more	60.0	—	—
Total	**99.4**	**39.4**	**—**

18. **Post-balance sheet events**

There were no material events post the balance sheet date ending 31 December 2020 which impacts the historical financial information of the Target Group.

19. **Related parties**

All legal entities that can be controlled, jointly controlled or significantly influenced are considered to be a related party. Also entities which can control the Target Group are considered to be a related party. In addition, key management personnel, other key management of the Target Group or Royal Dutch Shell plc and close relatives are regarded as related parties.

Outstanding balances owed to and from related parties have been disclosed in note 9 and 12.

All subsidiaries and associates listed in Appendix 1 of the Royal Dutch Shell plc Annual Report and Exhibit 8.1 of Form 20-F of Royal Dutch Shell plc as deposited with the Trade Register in The Hague are considered related parties for the purpose of the Target Group.

An amount of $0.6 million (2019: $0.4 million; 2018: $0.8 million) was incurred by the Target Group in respect of salaries, pensions and other similar payments for key management personnel.

PART V

UNAUDITED PRO FORMA FINANCIAL INFORMATION ON THE GROUP

Section 1. Basis of financial information

The following unaudited pro forma statement of net assets of the Group has been prepared under the Group's accounting policies as set out in its consolidated unaudited financial statements for the year ended 31 December 2020 and on the basis of the notes set out below to illustrate how the Transaction might have affected the net assets of the Group as if it had occurred on 31 December 2020.

The pro forma financial information has been prepared for illustrative purposes only and because of its nature only addresses a hypothetical situation and, therefore, does not represent the actual financial position of the Group.

The pro forma statement of net assets has been prepared in accordance with paragraph 13.3.3R of the Listing Rules. Shareholders should read the whole of this document and not rely solely on the summarised financial information contained in this this Part V.

Ernst & Young LLP's report on the unaudited pro forma statement of net assets is set out in Section 2 of this Part V.

Unaudited Pro Forma Statement of Net Assets

			Adjustments				
	Group as at FY 2020	**Target as at FY 2020**	**Equity share adjustment**	**Significant Gross Change transactions**	**Additional Borrowing**	**Acquisition Accounting**	**Pro Forma**
	Note 1 US$m	**Note 2 US$m**	**Note 3 US$m**	**Note 4 US$m**	**Note 5 US$m**	**Notes 6, 7 US$m**	**US$m**
Non-current assets							
Intangible exploration/appraisal assets	112.1	331.4	(165.7)		—	—	277.8
Property, plant & equipment – development/producing assets	849.8	289.2	(144.6)	—	—	68.6	1,063.0
Other property, plant & equipment and intangible assets	11.5	—	—		—	—	11.5
Deferred tax asset	—	144.3	(72.2)		—	—	72.2
	973.4	**764.9**	**(382.5)**	**—**	**—**	**68.6**	**1,424.5**
Current assets							
Inventory	12.3	25.4	(12.7)		—	—	25.0
Financial asset at fair value through profit or loss	5.2	—	—		—	—	5.2
Cash and cash equivalents	569.6	52.3	(26.2)	(256.9)	177.0	(382.6)	133.3
Trade and other receivables	74.6	212.5	(106.3)	—	—	—	180.9
Derivatives	0.2	—	—		—	—	0.2
	661.9	290.2	(145.1)	(256.9)	177.0	(382.6)	344.5
Total assets	**1,635.3**	**1,055.1**	**(527.6)**	**(256.9)**	**177.0**	**(314.0)**	**1,769.0**
Current liabilities							
Lease liabilities	(43.2)	(1.9)	1.0		—	—	(44.2)
Derivatives	(3.2)	—	—		—	—	(3.2)
Trade and other payables	(91.6)	(112.3)	56.2	—	—	—	(147.8)
Deferred revenue	(4.8)	—	—		—	—	(4.8)
Provisions	—	(0.1)	0.1		—	—	(0.1)
	(142.8)	(114.3)	57.2	—	—	—	(200.0)
Non-current liabilities							
Loans and borrowings	—	—	—		(177.0)	—	(177.0)
Provisions – decommissioning	(153.2)	(1.8)	0.9		—	—	(154.1)
Trade and other payables	—	(3.0)	1.5		—	—	(1.5)
Lease liabilities	(196.8)	(7.0)	3.5		—	—	(200.3)
Deferred revenue	(16.9)	—	—		—	—	(16.9)
Provisions – pensions	—	—	—		—	—	—
Deferred tax liabilities	—	(35.6)	17.8	—	—	—	(17.8)
	(366.9)	(47.4)	23.7	—	—	—	(390.6)
Total liabilities	**(509.7)**	(161.7)	**80.9**	**—**	**—**	**—**	**(590.6)**
NET ASSETS	**1,125.6**	893.4	**(446.7)**	**(256.9)**	**177.0**	**(314.0)**	**1,178.4**

Notes:

1. The financial information in respect of the Group has been extracted without material adjustment from the audited financial statements for the Group for the year ended 31 December 2020 prepared in accordance with IFRS in conformity with the requirements of the Companies Act 2006 and pursuant to Regulation (EC) No 1606/2002 as it applies to the European Union.
2. The financial information for the Assets has been extracted from Part IV (*Financial information relating to the Assets)* of this Circular after adjusting for Cairn's proposed 50 per cent. interest in the Assets.
3. The financial information for the Assets extracted from Part IV (*Financial information relating to the Assets)* of this Circular has been adjusted to reflect Cairn's proposed 50 per cent. interest in the Assets.
4. Significant gross change transactions reflect the return of cash to shareholders of Cairn in January 2021.
5. The adjustment to borrowings relates to the Acquisition RBL Facility of up to US$162.5 million and the Junior Debt Facility of up to US$40 million. At completion the proceeds drawn from the facilities are expected to be US$181.4 million, presented net of estimated debt financing expenses of US$4.4 million.
6. The unaudited pro-forma financial information has been prepared on the basis that the Acquisition will be treated as a business combination in accordance with IFRS 3 Business Combinations. The unaudited pro forma financial information does not reflect the fair value adjustments that are expected to be made post-completion. Cairn expects to undertake a full fair value exercise following completion and the fair value adjustments, when finalised following completion, may be material. For the purposes of the unaudited pro forma financial information, the excess of the unadjusted carrying amount of net assets acquired over the purchase consideration has been assumed to have been taken to the Income Statement. The calculation of the acquisition adjustments included in the pro-forma is set out below:

	US$m
Acquisition cost	378.1
Net assets of target	446.7
Negative Goodwill Adjustment in Income Statement	68.6

7. Cash and cash equivalents reductions relating to the acquisition include transaction costs of US$4.5 million.
8. No adjustment has been made to reflect the financial results of either the Group or the Assets since 31 December 2020.

Section 2. Report on the Unaudited Pro Forma Statement of Net Assets of the Group

The Directors
Cairn Energy PLC
50 Lothian Road
Edinburgh
EH3 9BY

29 June 2021

Dear Ladies and Gentlemen

Cairn Energy PLC (the "Company")

We report on the pro forma financial information (the "**Pro Forma Financial Information**") set out in Part V of the circular dated 29 June 2021 (the "**Circular**").

This report is required by Listing Rule 13.3.3R and is given for the purpose of complying with that rule and for no other purpose.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to ordinary shareholders 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.

Opinion

In our opinion:

- the Pro Forma Financial Information has been properly compiled on the basis stated; and
- such basis is consistent with the accounting policies of the Company.

Responsibilities

It is the responsibility of the directors of the Company to prepare the Pro Forma Financial Information in accordance with Listing Rule 13.3.3R.

It is our responsibility to form an opinion, as required by Listing Rule 13.3.3R as to the proper compilation of the Pro Forma Financial Information and to report that opinion to you.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information of the Company 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. No reports or opinions have been made by us on any financial information of Cairn Energy PLC used in the compilation of the Pro forma Financial Information. In providing this opinion we are not providing any assurance on any source financial information on which the Pro Forma Financial Information is based beyond the above opinion.

Basis of preparation

The pro forma financial information has been prepared on the basis described in Section 1 of Part V of the Circular, for illustrative purposes only, to provide information about how the transaction 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 2020.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent in accordance with the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the directors of the Company.

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 other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Yours faithfully

Ernst & Young LLP

PART VI

COMPETENT PERSON'S REPORT IN RESPECT OF THE ASSETS

Project Madero, Competent Person's Report

Prepared for

Cairn Energy Plc

29 June 2021

Gaffney Cline

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29 June 2021

Chris Burnside
Chief Petroleum Engineer
CAIRN ENERGY PLC
50 Lothian Road
Edinburgh
EH3 9BY

Project Madero, Competent Person's Report

Introduction

At the request of Cairn Energy Plc (Cairn), Gaffney, Cline & Associates Limited (GaffneyCline) has prepared this Competent Person's Report (CPR) on various onshore assets in the Western Desert (Egypt) in which the Shell group of companies (Shell or the Vendor) holds an interest (the Shell Western Desert Assets or the Assets). Shell has offered its interests in these assets for sale, and GaffneyCline understands that Cairn and its Consortium partner Cheiron Petroleum Company (Cheiron) have signed a Sales and Purchase Agreement (SPA) to acquire the assets subject to certain requirements being met. Cairn and Cheiron will each hold a 50% working interest in the Consortium, with Cheiron as the Operator. The CPR has been prepared for inclusion in a Circular to be issued by Cairn to its shareholders ahead of a vote to approve the deal.

In preparing this report, GaffneyCline had access to a data set of technical and commercial information made available by the Vendor in a Virtual Data Room (VDR) and in a "virtual Physical Data Room" (vPDR). This data set included details of concession interests and agreements, geological and geophysical data, interpretations and technical reports, historical production and engineering data, cost and commercial data, and approved development plans as at the Effective Date of 31st December 2019. The vPDR also included reservoir models. In addition, results of some wells drilled in the first half of 2020 were taken into account in preparing the estimates of Reserves as at 31st December 2019.

GaffneyCline was also supplied with the Consortium's Business Plan (BP), developed during the due diligence process conducted by the Consortium in January-June 2020. This BP has been used as the basis for the classification of hydrocarbon resources as Reserves and Contingent Resources. The report is prepared assuming that the Consortium executes the activities described in the BP according to the schedule set out therein.

The purpose of the CPR is to provide an independent evaluation of the Reserves and Contingent Resources of the Assets at 31st December 2019, which is the effective date of the SPA. The review process and preparation of the CPR was carried out during the months of January to July 2020. Considering the volatility in the global oil markets in 2020, GaffneyCline ran a sensitivity assuming an oil price US$10/Bbl lower than the year-end 2019 oil price scenario used as the reference case in this CPR. The results of this sensitivity are presented in Section 4.4.

In addition, given the time that has elapsed since the Effective Date of the estimates of Reserves and net present values (NPVs), to meet the requirements of the FCA, GaffneyCline has included tables showing the Reserves that would remain as at 31st December 2020 and the corresponding NPVs at that date. For this purpose, GaffneyCline has taken out the forecast 2020 production and costs, but has not made any other adjustment to the forecasts made as at 31st December 2019. This is considered a reasonable assumption given that actual production from January to December 2020 has been comparable, in the aggregate, with GaffneyCline's estimates made as at 31st December 2019. An updated (31st December 2020) Brent crude oil price scenario has been used. The resulting tables are presented below and in Appendix IV.

Since 31st December 2020, GaffneyCline has reviewed information regarding the performance of the Assets in 2020, and compared forecasts (including production and costs) against those set out in the CPR. GaffneyCline notes the deferral in the implementation of the drilling schedule planned by the Consortium, which may defer some production that was forecast to be produced in 2021. The deferral could impact the NPVs but is unlikely to have a material impact on the Reserves. However, any reduction in the NPVs will be offset by the recovery in oil prices since the beginning of 2021, which makes the price scenario used by GaffneyCline appear conservative in the short term. GaffneyCline therefore believes that the Reserves and NPVs as at 31st December 2020 reported herein remain valid in the aggregate (see Appendix IV).

GaffneyCline believes that, other than the deferral described above, all information in the CPR remains valid.

This report relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

A glossary of terms and abbreviations is included as Appendix I.

Summary

Licence Summary

Table 1 lists the licences in Egypt in which Shell holds a working interest (WI) as at 31st December 2019, which are included in the sales process. Reserves and Contingent Resources have been attributed to the majority of these licences; Prospective Resources (i.e. exploration prospects and leads) are not considered in this report, either in the exploration licences or within the production and development licences.

GaffneyCline understands that Cairn has a 50% share in the Consortium. Therefore, Cairn's WI in the Assets will be half of the Shell WIs shown in Table 1.

Table 1: Shell's Onshore Western Desert Portfolio

Area	Concession & Exploration Blocks	Shell WI (%)	Status	Final License Expiry
Obaiyed Area	Obaiyed	100%	Production	22 August 2029
	North Matruh (NM)	100%	Development	25 years from 1st gas
	North Um Baraka (NUMB)	100%	Development	26 April 2043
Badr El Din (BED)	Sitra	100%	Production	01 December 2025
	Badr El Din 19 & 20 (BED)	100%	Production	BED 19: 15 October 2036 BED-20: 31 May 2044
	Badr El Dine 2, 16 & 17 (BED 2, 15 & 17)	100%	Production	10 April 2034
	Badr El Dine 3, 15 & 18 (BED 3, 15 & 18)	100%	Production	27 April 2026
	North Alam El Shawish (NAES)	100%	Production/ Development	17 April 2042
Alam El Shawish	Alam El Shawish West (AESW)	40%	Production	Assil, Al Karam & Al Magd: 1 April 2033 Al Barq & Bahga: 28 May 2032
North East Abu Gharadig (NEAG)	NEAG Tiba	52%	Production	JG: 20 February 2027 JD: 19 May 2029 JD Apollonia Gas: 19 May 2034 Sheiba: 11 May 2029
	NEAG Extension (NEAG Ext)	52%	Production	NEAG 1: 18 November 2032 NEAG 2&3: 15 March 2034 NEAG 4: 18 February 2036 NEAG 5: 03 November 2036
Abu Sennan	South Abu Sennan	100%	Exploration	18 January 2023 (First Exploration Period)
Horus	South East Horus	100%	Exploration	18 January 2024 (First Exploration Period)
El Fayum	West El Fayum	100%	Exploration	18 January 2024 (First Exploration Period)

Overview

The portfolio is composed of a variety of oil and gas onshore assets in multiple stages of development, most of which hold additional opportunities to be explored and exploited. The assets benefit from being in a low cost environment, with existing facilities, and with infrastructure available within the surrounding area.

In the Matruh Basin, further development of the Obaiyed field, its satellites, and the undeveloped Teen field are planned. Gas-bearing sandstones are proven but relatively tight, and realisation of the full potential will rely on successful exploitation of marginal, possibly discontinuous reservoirs, partly via application of multi-stage fracking of horizontal wells.

In the Abu Gharadig Basin, there are several well-established oil and gas fields in the BED, Sitra, AESW and NEAG areas with multiple stacked reservoirs. Infill with additional production and injection wells is expected to add to the ultimate recovery. In the gas-bearing reservoirs, this partly relies on exploiting low grade reservoir between the main sandstone bodies, which is only locally proven. In the oil-bearing reservoirs, recent successful wells have demonstrated the sandstone reservoir fairways to be more extensive than previous thought.

Also in the Abu Gharadig Basin, in the NAES area, the recent appraisal of the BTE discovery shows the existence of a significant undeveloped gas field. However, further work is needed to optimize the development of the deep, relatively high temperature, and tight reservoirs found, not all of which are proven by production testing to date.

On review of the overall facilities and infrastructure assets, there is considered to be adequate ullage provided in all the processing facilities, with no foreseeable bottlenecks for production moving forward. This assurance is provided through the planned capital expenditure program to expand facility capacities and capability. There are challenges for the facilities and infrastructure, especially as they are ageing across the field, with work planned at Obaiyed, BED 3 and NEAG in the short term to ensure reliability of equipment and facilities for continued uninterrupted production. As long as the asset integrity work program is delivered, it should provide adequate assurance in terms of reliability and production efficiency. The overall drilling expenditure across the field is predicated on matching the current Consortium's cost performance, and this will require delivery of the reduction in rig rates and lower overall costs from renegotiated contracts to ensure there is no negative impact on the current plans.

For the operating costs, the planned electrification program provides improved reliability, environmental performance and significant cost improvement through reduced diesel consumption. The operating costs reflect the change to a new Consortium's operating practices and organisational design, which will need to be carefully implemented to ensure knowledge retention and transition is smooth from the Vendor's handover. The operating costs in addition incorporate the assumption of continued 3rd party use of processing and transportation infrastructure owned by the Consortium, this usage level will need to be maintained as per the current plan to ensure no negative impact on operating costs is felt in the near term.

From an economic perspective, using the hydrocarbon pricing assumption detailed in the economics section, most assets continue production for at least 5 years and generate materially positive NPVs; several have the potential to continue economic production beyond the current license end. Approximately a third of the value from hydrocarbon sales is generated by gas subject to fixed prices under existing Gas Sales Agreements, reducing the exposure to fluctuations in hydrocarbon market prices. However, some assets with a larger proportion of liquids production could become uneconomic earlier if hydrocarbon liquids prices remain lower than those assumed here.

Reserves Summary

On the basis of technical and other information made available, GaffneyCline hereby provides the following statement of oil, condensate and gas Reserves in the Assets as at 31st December 2019 (Table 2).

For the reasons mentioned in the Introduction, the Reserves that would remain as at 31st December 2020, calculated simply by taking out the forecast 2020 production and costs and re-running the economic limit tests with a revised oil price scenario, are shown in Table 3.

Table 2: Summary of Reserves as at 31st December 2019

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	17.1	22.2	26.8	100.0	6.3	7.6	8.6	50.0	3.2	3.8	4.3
NUMB	0.2	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.1	0.1	0.1
NM	5.0	10.0	19.8	100.0	2.0	3.4	5.0	50.0	1.0	1.7	2.5
BED 2	2.9	6.0	8.3	100.0	1.2	2.4	3.1	50.0	0.6	1.2	1.6
BED 3	10.7	15.3	20.5	100.0	4.9	6.6	7.6	50.0	2.5	3.3	3.8
Sitra	6.3	11.9	17.3	100.0	2.9	5.5	6.6	50.0	1.4	2.7	3.3
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	6.0	8.9	12.7	52.0	1.5	1.8	2.3	26.0	0.7	0.9	1.2
NEAG Ext.	8.8	12.8	18.7	52.0	2.3	3.1	4.2	26.0	1.2	1.6	2.1
AESW	16.9	30.2	45.1	40.0	2.8	4.7	5.7	20.0	1.4	2.3	2.8
Total	**74.0**	**117.5**	**169.4**		**24.0**	**35.3**	**43.4**		**12.0**	**17.6**	**21.7**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	367.1	425.7	483.0	100.0	137.3	147.4	157.2	50.0	68.6	73.7	78.6
NUMB	14.5	15.0	15.5	100.0	6.7	6.9	7.1	50.0	3.4	3.5	3.6
NM	46.4	76.8	128.0	100.0	18.5	25.9	32.5	50.0	9.3	12.9	16.3
BED 2	9.3	42.4	76.4	100.0	3.7	18.2	29.8	50.0	1.8	9.1	14.9
BED 3	47.1	60.8	75.0	100.0	21.7	26.9	28.2	50.0	10.9	13.5	14.1
Sitra	21.4	32.1	42.3	100.0	9.9	14.8	16.9	50.0	4.9	7.4	8.4
NAES	1.1	24.6	36.7	100.0	0.5	10.8	16.1	50.0	0.2	5.4	8.1
NEAG Tiba	16.7	23.1	32.2	52.0	4.1	5.0	6.3	26.0	2.1	2.5	3.1
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	473.3	616.2	785.8	40.0	77.6	94.2	99.5	20.0	38.8	47.1	49.8
Total	**997.0**	**1,316.8**	**1,674.9**		**279.9**	**350.2**	**393.6**		**140.0**	**175.1**	**196.8**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 3: Summary of Reserves[3] as at 31st December 2020

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	15.1	20.2	24.8	100.0	5.8	7.1	8.1	50.0	2.9	3.5	4.0
NUMB	0.1	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.0	0.0	0.0
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.7
BED 2	1.0	3.8	6.0	100.0	0.4	1.7	2.4	50.0	0.2	0.8	1.2
BED 3	7.8	12.0	16.9	100.0	3.6	5.5	6.8	50.0	1.8	2.7	3.4
Sitra	0.0	9.9	15.2	100.0	0.0	4.6	6.5	50.0	0.0	2.3	3.2
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	5.1	7.9	11.7	52.0	1.4	1.8	2.3	26.0	0.7	0.9	1.1
NEAG Ext.	6.0	9.9	15.1	52.0	1.7	2.6	3.6	26.0	0.8	1.3	1.8
AESW	15.1	27.4	42.6	40.0	2.5	4.5	5.7	20.0	1.3	2.3	2.8
Total	**55.2**	**101.3**	**152.2**		**17.4**	**31.3**	**40.7**		**8.7**	**15.7**	**20.4**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	320.1	378.2	435.0	100.0	130.0	140.4	150.2	50.0	65.0	70.2	75.1
NUMB	9.1	9.6	9.9	100.0	4.2	4.4	4.6	50.0	2.1	2.2	2.3
NM	46.4	76.8	128.0	100.0	18.5	27.4	34.7	50.0	9.3	13.7	17.3
BED 2	4.1	33.4	67.0	100.0	1.8	15.1	27.6	50.0	0.9	7.5	13.8
BED 3	36.7	49.6	63.3	100.0	16.9	22.8	25.7	50.0	8.5	11.4	12.9
Sitra	0.0	22.1	31.4	100.0	0.0	10.2	13.5	50.0	0.0	5.1	6.7
NAES	0.0	23.2	35.3	100.0	0.0	10.2	15.5	50.0	0.0	5.1	7.8
NEAG Tiba	12.1	18.3	27.2	52.0	3.3	4.2	5.5	26.0	1.7	2.1	2.8
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	418.3	547.6	729.5	40.0	68.5	89.4	97.4	20.0	34.3	44.7	48.7
Total	**846.8**	**1,158.8**	**1,526.6**		**243.3**	**324.1**	**374.6**		**121.6**	**162.0**	**187.3**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Reserves are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

NPV Summary

Reference Net Present Values (NPVs) at 10% discount rate (NPV10) have been attributed to the Proved, the Proved plus Probable, and the Proved plus Probable plus Possible Reserves as at 31st December 2019. These are summarized in Table 4.

GaffneyCline's own 1Q 2020 Brent crude oil price scenario, adjusted for quality and location, has been used in preparing these NPVs. In light of the recent volatility in global crude prices, a sensitivity to a lower oil price scenario has been evaluated, the results of which are summarized in Section 4.

For the reasons mentioned in the Introduction, the NPVs as at 31st December 2020 of the Reserves that would remain as at 31st December 2020 are shown in Table 5. GaffneyCline's own 1Q 2021 Brent crude oil price scenario, adjusted for quality and location, has been used in preparing these NPVs.

All NPVs quoted are those exclusively attributable to Shell's Net Entitlement Reserves in the properties under review.

Table 4: Summary of Post-Tax NPV10 of Future Cash Flow from Reserves, as at 31st December 2019

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	287.6	351.2	411.4	143.8	175.6	205.7
NUMB	18.7	19.4	20.0	9.3	9.7	10.0
NM	7.9	72.3	138.5	3.9	36.2	69.2
BED 2	30.4	58.7	81.4	15.2	29.4	40.7
BED 3	101.5	192.0	239.4	50.8	96.0	119.7
Sitra	33.1	139.7	195.8	16.5	69.9	97.9
NAES	0.7	4.5	11.7	0.3	2.2	5.8
NEAG Tiba	23.9	40.7	62.1	11.9	20.4	31.1
NEAG Ext	41.2	61.7	89.2	20.6	30.9	44.6
AESW	118.8	204.0	243.3	59.4	102.0	121.7
Total	**663.6**	**1,144.4**	**1,492.9**	**331.8**	**572.2**	**746.4**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Table 5: Summary of Post-Tax NPV10[2] of Future Cash Flow from Reserves, as at 31st December 2020

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	216.5	276.0	332.8	108.2	138.0	166.4
NUMB	11.5	12.2	12.7	5.7	6.1	6.4
NM	-6.3	64.5	131.1	-3.2	32.2	65.6
BED 2	4.7	27.3	50.6	2.3	13.6	25.3
BED 3	26.3	119.8	178.3	13.2	59.9	89.1
Sitra	0.0	76.7	161.9	0.0	38.4	81.0
NAES	0.0	3.7	11.4	0.0	1.8	5.7
NEAG Tiba	12.9	29.2	47.7	6.5	14.6	23.9
NEAG Ext	14.0	33.4	57.0	7.0	16.7	28.5
AESW	89.4	188.8	228.1	44.7	94.4	114.1
Total	**368.9**	**831.4**	**1,211.7**	**184.5**	**415.7**	**605.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. NPVs are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
3. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Contingent Resource Summary

On the basis of technical and other information made available, GaffneyCline hereby provides the following statement of oil, condensate and gas Contingent Resources as at 31st December 2019 (Table 6).

Contingent Resources are shown both as gross volumes and net to Shell's interest on a Working Interest (WI) basis, i.e. Shell's Working Interest fraction of the gross volumes. The WI basis volumes do not represent Shell's actual Net Entitlement under the terms of the Contracts that govern the assets, which would be lower. The WI basis volumes are quoted here since the development projects are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the Net Entitlement.

Table 6: Summary of Contingent Resources as at 31st December 2019

(a) Oil and Condensate

Assets	Gross Contingent Resources (MMBbl)			WI (%)	Shell Net (WI Basis) Contingent Resources (MMBbl)			50% WI (%)	50% of Shell Net (WI Basis) Contingent Resources (MMBbl)		
	1C	2C	3C		1C	2C	3C		1C	2C	3C
Obaiyed	4.2	7.0	9.7	100	4.2	7.0	9.7	50.0	2.1	3.5	4.9
NUMB	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NM	0.9	1.9	4.1	100	0.9	1.9	4.1	50.0	0.5	1.0	2.1
BED 2	1.3	2.3	3.7	100	1.3	2.3	3.7	50.0	0.7	1.2	1.9
BED 3	0.2	0.6	1.1	100	0.2	0.6	1.1	50.0	0.1	0.3	0.6
BED 19/20	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
Sitra	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NAES	0.1	0.2	0.5	100	0.1	0.2	0.5	50.0	0.1	0.1	0.3
NEAG Tiba	0.9	1.0	1.5	52	0.5	0.5	0.8	26.0	0.3	0.3	0.4
NEAG Ext	0.0	0.0	0.0	52	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	2.1	4.9	7.8	40	0.8	2.0	3.1	20.0	0.4	1.0	1.6
Total	**9.7**	**17.9**	**28.4**		**8.0**	**14.5**	**23.0**		**4.0**	**7.3**	**11.5**

(b) Natural Gas

Assets	Gross Contingent Resources (Bscf)			WI (%)	Shell Net (WI Basis) Contingent Resources (Bscf)			50% WI (%)	50% of Shell Net (WI Basis) Contingent Resources (Bscf)		
	1C	2C	3C		1C	2C	3C		1C	2C	3C
Obaiyed	72.5	106.1	150.6	100	72.5	106.1	150.6	50.0	36.3	53.1	75.3
NUMB	7.4	14	23.4	100	7.4	14.0	23.4	50.0	3.7	7.0	11.7
NM	6.2	10.9	20.3	100	6.2	10.9	20.3	50.0	3.1	5.5	10.2
BED 2	26.3	58.6	107.8	100	26.3	58.6	107.8	50.0	13.2	29.3	53.9
BED 3	13.4	28.1	46.3	100	13.4	28.1	46.3	50.0	6.7	14.1	23.2
BED 19/20	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
Sitra	0.0	0.0	0.0	100	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NAES	118.6	219.1	347.9	100	118.6	219.1	347.9	50.0	59.3	109.6	174.0
NEAG Tiba	1.2	1.8	3.1	52	0.6	0.9	1.6	26.0	0.3	0.5	0.8
NEAG Ext	0.0	0.0	0.0	52	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	76.7	92.8	117.4	40	30.7	37.1	47.0	20.0	15.4	18.6	23.5
Total	**322.3**	**531.4**	**816.8**		**275.7**	**474.8**	**744.9**		**137.9**	**237.4**	**372.5**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. Net (WI Basis) Contingent Resources in this table are Shell's Working Interest fraction of the Gross Resources; they do not represent Shell's actual Net Entitlement under the terms of the Contracts that govern the asset, which would be lower.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

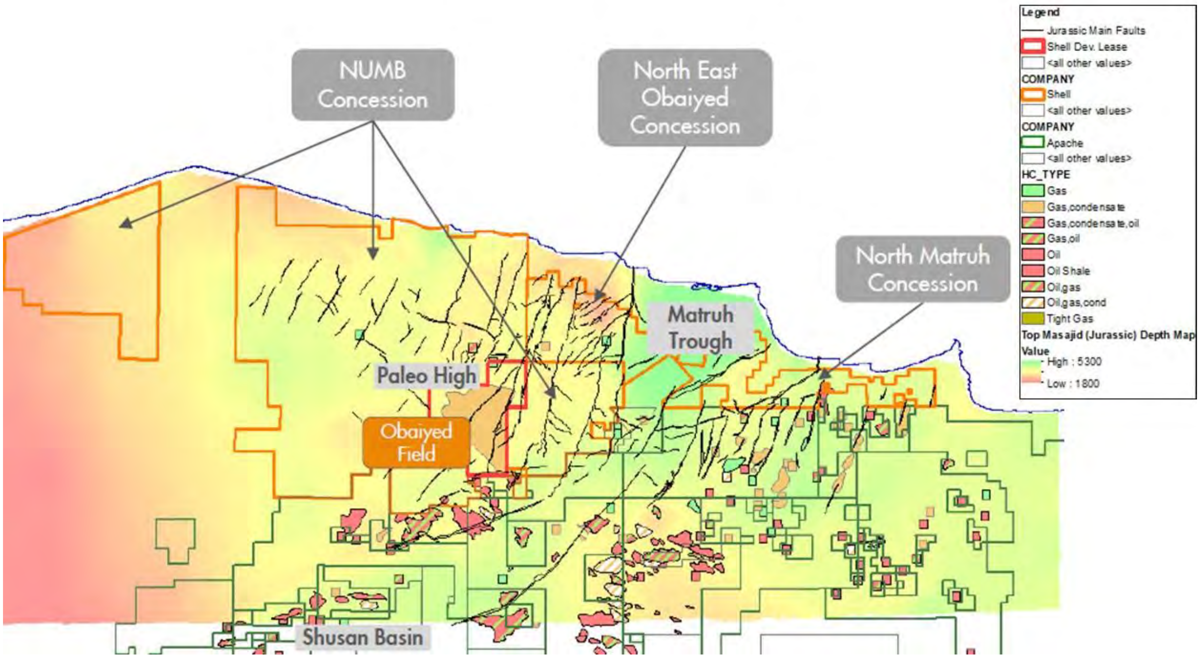
Discussion

1 Matruh Basin

1.1 Regional Geology

The Matruh Basin assets include the contract areas adjacent to the Mediterranean coast (Figure 1). The main Matruh Trough is an approximately NE-SW trending rift basin running through the centre of the area, normal to the continental margin, with subordinate faulting varying from the same NE-SW orientation to E-W. Rifting was active in the Triassic to Early Cretaceous, succeeded by a post-rift phase in the Late Cretaceous. Propagation of stresses along the continental margin during the latest Cretaceous and Early Cenozoic, as a result of Tethyan ocean closure, led to inversion and the local overprint by a ENE-WSW fault trend. Post Eocene, the area is one of passive subsidence on the Mediterranean margin.

Figure 1: Structural Elements of Matruh Basin

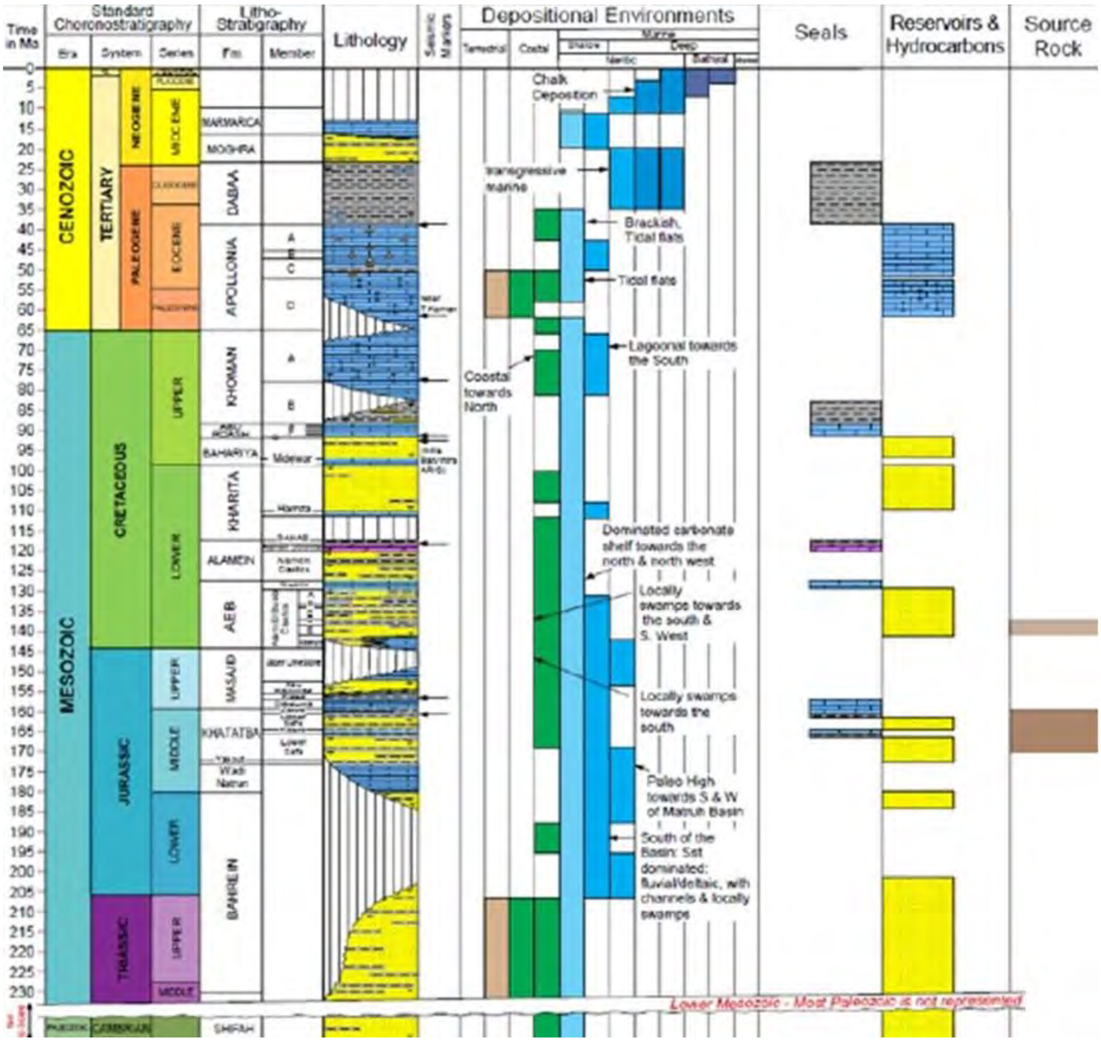


Source: Vendor VDR

The overall stratigraphy is shown in Figure 2. An eroded basement of Palaeozoic clastics is locally seen in the wells which represents the pre-rift phase. An initial phase of Triassic sandstones represents the earliest rift phase. This was followed by a mix of clastic and carbonate sedimentation in the Jurassic and Lower Cretaceous, as a result of the complex interplay of local rifting and overall sea level. Regional carbonate sedimentation dominates the later Cretaceous and Cenozoic stages of the basin's history.

Reservoirs relevant to the plays in the area are in the Safa Formation sandstones (Middle Jurassic), predominantly for gas, with some minor prospectivity attached to underlying Palaeozoic sandstones. There is also some oil potential in the Lower Cretaceous Alam el Bueib sandstones.

Figure 2: Matruh Basin Stratigraphy



Source: Vendor VDR

Source rocks are in the Khatatba Formation, which is equivalent to and interleaves with the Safa Formation, providing close juxtaposition of source and reservoir. This generates gas over most of the area, but modelling and hydrocarbon distribution show an oil fairway in the northwestern part of the area, in the NUMB contract area. Oil is also generated locally from source rocks in the Alam el Bueib Formation.

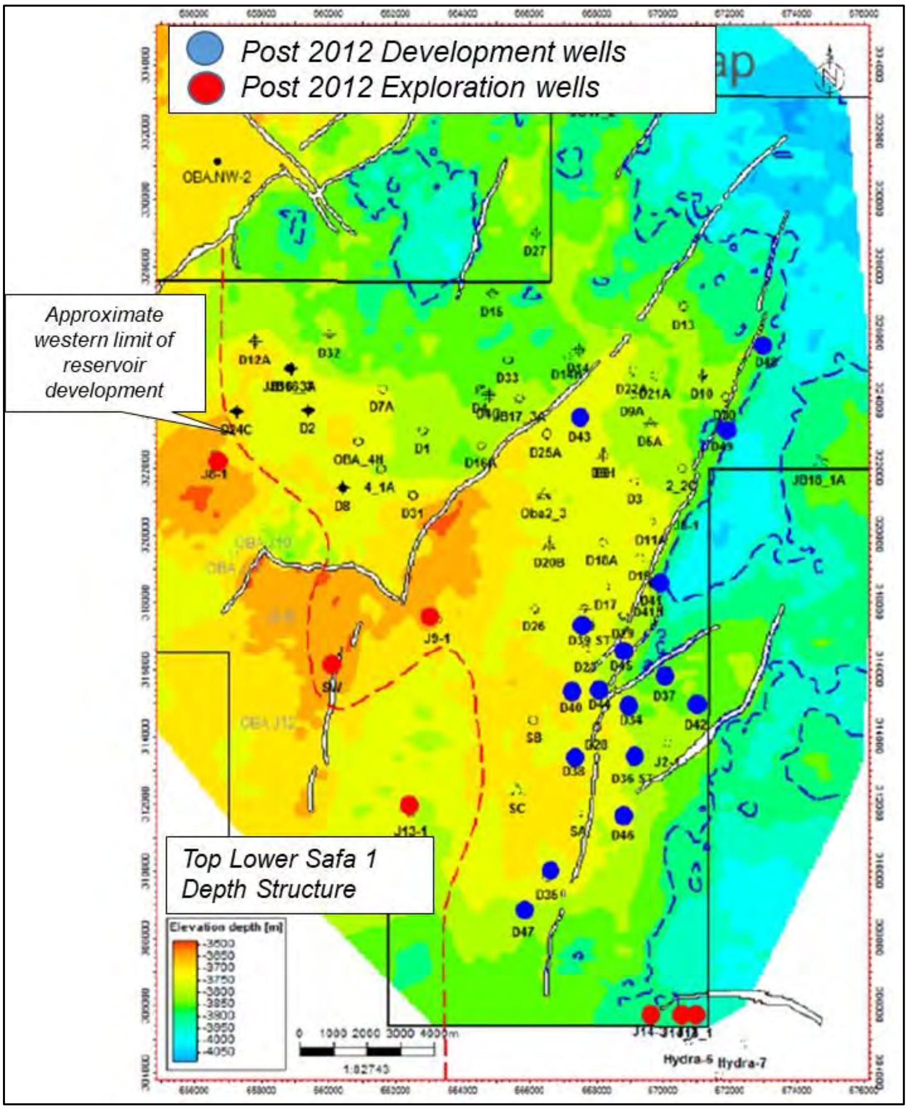
1.2 Obaiyed

1.2.1 Asset Description

1.2.1.1 Structure and Trap

Obaiyed is the principal gas and condensate field of the area, consisting of the main Obaiyed Field and the smaller J14 satellite to the south. It overlies a set of NW-SE trending fault blocks, which originally formed a palaeohigh, onto which reservoirs (Upper and Lower Safa Formation) pinched out from NE to SW. Trapping is thus partly structural, but with an element of stratigraphic closure to the southwest. Top Lower Safa Formation depth structure is depicted in Figure 3. GWC is for the most part interpreted as field-wide at -3,875 m subsea, but there is evidence for some fault compartmentalization, and hence variation in GWC on the northeastern flank, notably at D-48 where the GDT is at -3,910 m subsea (Figure 3).

Figure 3: Obaiyed Field. Top Lower Safa Formation Depth Structure (m)



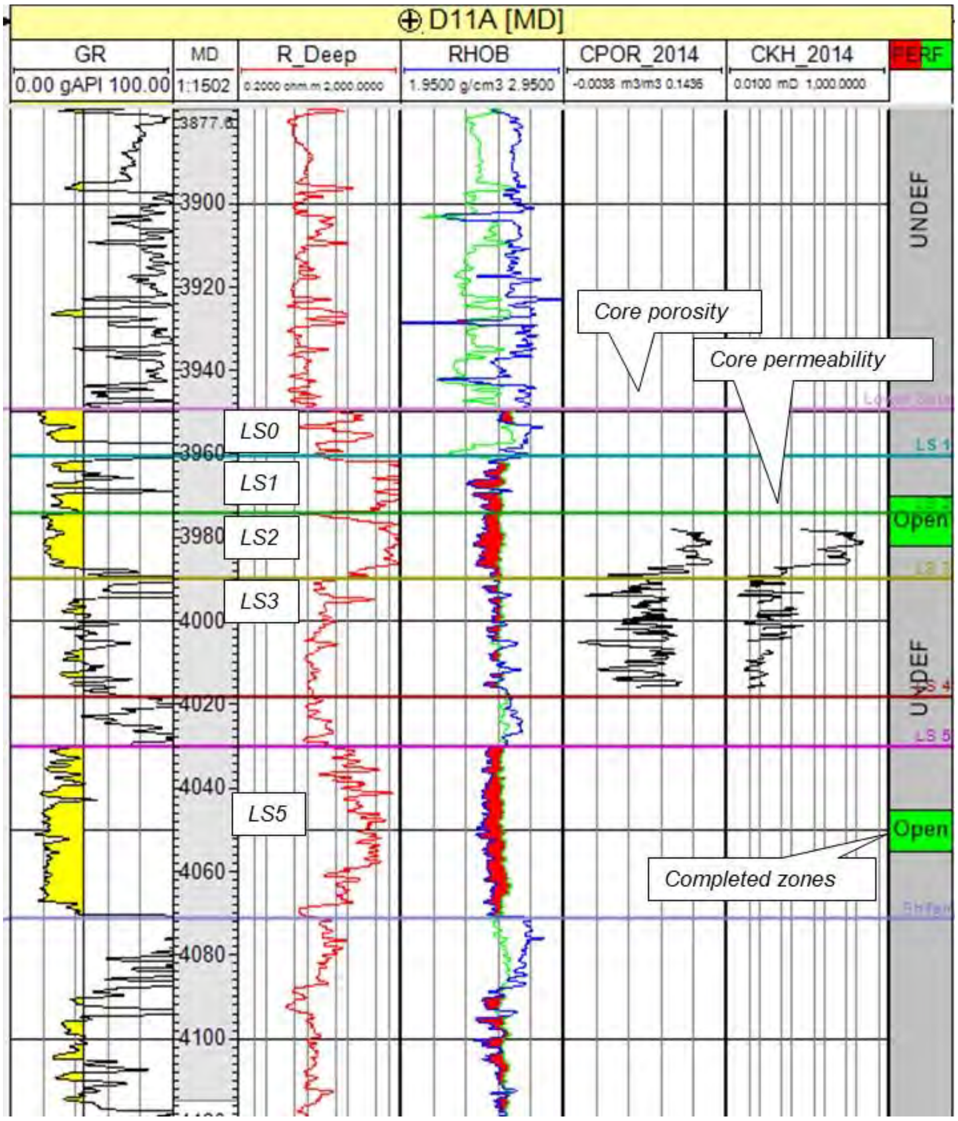
Source: Vendor VDR

1.2.1.2 Reservoir

Reservoirs in both Upper and Lower Safa Formations are divided into subunits (US 1 to 4.2) and (LS 1-5). For practical purposes, however, the Lower Safa can be simply divided into an upper unit (LS1-3) and lower unit (LS5), in which the bulk of the gas resource resides.

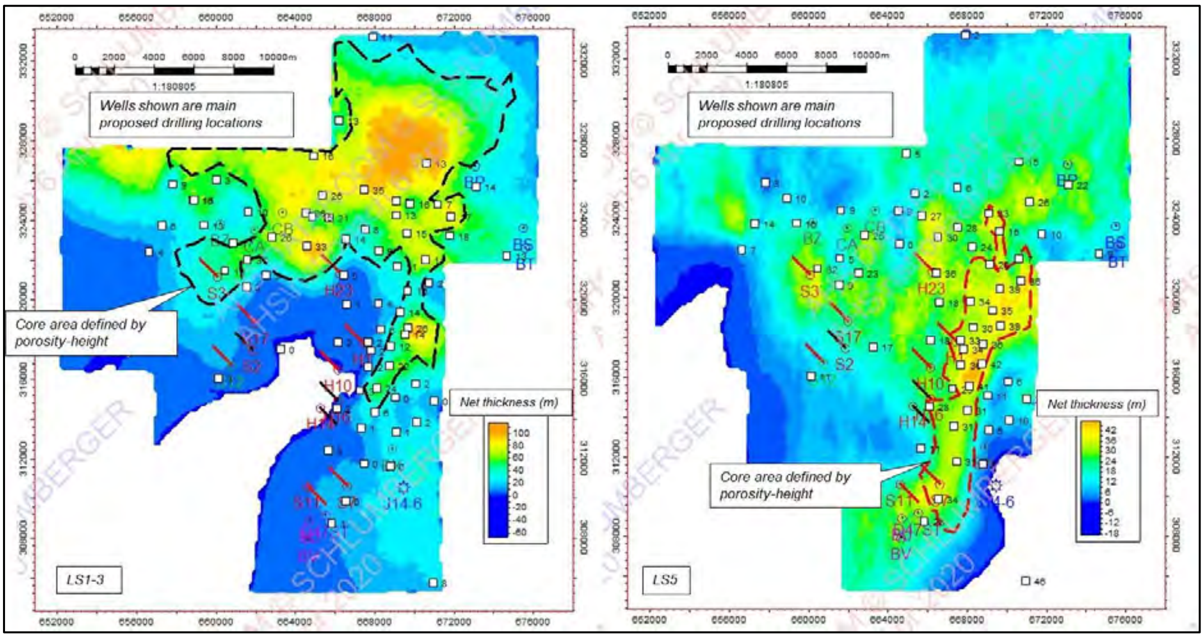
A representative reservoir section is shown in Figure 4. Reservoirs are tight, with porosities typically 7-8%, but rarely up to 13%. Core data suggest a conventional cut-off of approximately 6%. Lower Safa sandstones are extensive across the field, but pass laterally into tighter and/or more argillaceous reservoirs on the southwest flank. This has the effect of creating tighter reservoir facies, but also introduces areas of so-called "lean" facies, at the base of each of the productive units. These are understood to relate to lithological waste zones, or in places transition zones near the GWC, where possible pay exists, with high Sw and low measured resistivity (LRP), but with the additional risk of mobile water. Very broadly, the Lower Safa reservoirs can be considered to compose a "Core Area" with optimum reservoir development, both in terms of thickness and porosity, and a "Flank Area", with more marginal facies. The orientation of these differs between the LS1-3 and LS5 packages, and is inferred to result from a change from confined estuarine sand bodies in the lower unit to a less constrained deltaic complex in the upper. GaffneyCline has confirmed these interpretations based on porosity-height mapping (Figure 5).

Figure 4: Lower Safa Formation, Representative Reservoir Section



Source: GaffneyCline from vPDR database

Figure 5: Obaiyed Field. Lower Safa Formation Core Reservoir Area



Source: GaffneyCline from vPDR database

Unlike the Lower Safa, the Upper Safa is composed of thin discrete sandstone layers, which are laterally separate, and are interpreted to have been deposited in NE-SW trending tidal sand bars, subparallel to the axis of the Matruh Trough.

1.2.1.3 Reservoir and Fluid Properties

The pressure data provided mostly consist of MDT measurements that indicate the reservoirs have normal pressure and temperature gradients (Table 7). Obaiyed is a wet gas field and the condensate-gas ratio (CGR) for Obaiyed is generally approximately 30-50 scf/Bbl, but CGR can be higher, and range from an average of 38 Bbl/MMscf in the SE part of the field to 100 Bbl/MMscf (LS 5) or 144 Bbl/MMscf (LS1-3) in the NW. The dividing line between these two domains is taken as the principal NE-SW normal fault that bisects the field. Methane is 78.8 Mole % while CO_2 is seen to be 8.4 Mole % from PVT data.

No PVT data are available for the Upper Safa formation. Here, CGR is assumed high throughout from test and production data, and a value of 120 Bbl/MMscf is used in evaluation.

Table 7: Obaiyed: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Obaiyed	Lower Safa	3,994	149.5	5,900	5,361	0.0042	30-50	0.01	0.73

1.2.1.4 Production Facilities

The Obaiyed area fluids are transported via pipelines for treatment in the Obaiyed processing plant. The facility takes its feedstock from the Obaiyed, North Um Baraka (NUMB) and Khalda Qasr (3rd party gas) producing fields. The processing plant has two main processing trains and has the potential to process 420 MMscfd of gas and 16 Mbpd of condensate. The facility separates and then compresses the lower pressure feedstocks from Obaiyed and NUMB fields, which are co-mingled with Khalda Qasr gas before entering the main process trains.

Each processing train at the Obaiyed processing plant is designed to separate the liquid (condensate and water), treat the gas to remove CO_2, dehydrate and extract NGLs to ensure the export gas is of sales quality. Produced water is treated and then reinjected into a well. The treated gas from Obaiyed is exported via a booster compression station before export into the EPC gas distribution network. Condensate is stabilised and exported to Meleiha before being forwarded to the Hamra Terminal for offtake by tanker.

After December 2020, the Khalda Qasr gas supply to Obaiyed processing plant will cease. When developed, it is planned that the North Matruh (NM), NUMB and North East Obaiyed (NEO - which is not part of the acquisition) fluids will feed into the Obaiyed facility to fill any ullage.

1.2.2 HIIP

GaffneyCline has reviewed GIIP estimates presented by the Vendor and the static model database for the Lower Safa Formation provide as part of the vPDR. Some independent estimates and cross-checks have also been made.

GaffneyCline checked the petrophysical interpretations made by the vendor by making an independent analysis of data available for three wells D-10, D-34 and D-45. This generally validated the vendor analyses and gave confidence in the petrophysical inputs to the static model and the targets identified for recompletions.

Estimates of the GIIP are shown in Table 8. The salient points are:

- For the Lower Safa Formation, GaffneyCline has conducted sufficient volume checks to be satisfied that the volumes represented by the vendor static model are valid as a Best Case;
- Volumes derived from dynamic modelling do not include all of the mapped volume, but are included to illustrate the range of uncertainty present;
- The static model volumes do not include any “lean” facies; and
- Upper Safa volumes estimated approximately by GaffneyCline are only those in the pools believed to be accessible by planned activities, not all of the gas contained in other, unconnected pools.

Table 8: GIIP, Obaiyed Field

<table>
<tr><th rowspan="2">Reservoir</th><th rowspan="2">Source</th><th></th><th colspan="3">GIIP (Bscf)</th><th></th></tr>
<tr><th></th><th>Low</th><th>Best</th><th>High</th><th>Notes</th></tr>
<tr><td rowspan="4">Lower Safa</td><td>FDP 2016</td><td>Total</td><td>2,690</td><td>3,140</td><td>3,650</td><td>Based on dynamic model</td></tr>
<tr><td rowspan="3">PETREL calculation in VDR</td><td>LS 1-3</td><td>-</td><td>2,457</td><td>-</td><td>Includes some volume in LS 0 unit</td></tr>
<tr><td>LS 5</td><td>-</td><td>1,191</td><td>-</td><td></td></tr>
<tr><td>Total</td><td>-</td><td>3,648</td><td>-</td><td>Volumes do not include any gas in high Sw “lean” facies</td></tr>
<tr><td rowspan="2">Upper Safa</td><td>Vendor FDP 2013</td><td>Total</td><td>146</td><td>180</td><td>210</td><td>Understood to be total volume</td></tr>
<tr><td>GaffneyCline Estimate</td><td>Total</td><td>-</td><td>86</td><td>-</td><td>GaffneyCline approximate estimate of GIIP in pools associated with planned completion etc. activities</td></tr>
</table>

Source: Vendor VDR, vPDR and GaffneyCline estimates

In addition, GaffneyCline has used the static model volumes to estimate the Best Case GIIP in the core, and western and eastern flanks of the field, to be targeted by the future development programme (Table 9).

Table 9: Obaiyed Field GIIP in Lower Safa Formation in “Flank” Areas of Field

Area	GIIP (Bscf) Best
Core	**2,826**
Western Flank	697
NW Flank LS1-3	*328*
NW Flank LS 5	*164*
SW Flank LS 5	*205*
Eastern Flank	125
(Total flank)	***(822)***
Total Field	**3,648**

1.2.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline’s evaluation are listed in Table 10.

Table 10: Obaiyed: Resources Described in Databooks

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NFA	Existing wells NFA		**Reserves**
Lower Safa Infill	Lower Safa Core infill	Defined well locations in core of field	**Reserves:** 12 vertical and horizontal well locations defined.
	Lower Safa flanks	Defined well locations in flanks, with more marginal reservoir quality	
	Lower Safa Upsides	Notional well locations in vendor plan, principally in flanks of field	**Contingent Resources,** 22 notional locations are considered CR based on the drilling schedule and the lack of a defined plan to exploit marginal reservoir facies.
Upper Safa Infill	Upper Safa Infill	Recompletion and fracking programme in existing wells	**Reserves:** 8 activities defined, and a further 12, contributing to **Contingent Resources** are included, to be selected from other available targets.
General infill	LLP	Benefit to vendor of introduction of Low Line Pressure	**Reserves**
N/A (WOs added by Consortium)	Reactivation of shut-in wells	Also treated as additional infill project contributing to Reserves	**Reserves**

1.2.4 Historical Field Performance

Obaiyed production commenced in August 1999 and it currently comprises production of gas and condensate, with very small amounts of water.

Gas production reached a peak of some 336 MMscfd in 2003, declining to 117 MMscfd by 2019, as the pressure has substantially declined. The Obaiyed J14 area started production in 2015 and production peaked to 88 MMscfd in 2017.

The CGR is approximately 30-50 Bbl/MMscf, with current CGR at 44 Bbl/MMscf for Obaiyed main and 50 Bbl/MMscf for Obaiyed J14 area.

The current water rate is around 984 bwpd in Obaiyed main and 330 bwpd in J14 area.

Historical field performance for Obaiyed main and the J14 area are shown in Figure 6 and Figure 7 respectively. The cumulative produced volumes, rates and water cuts are summarised in Table 11.

Figure 6: Historical Production, Obaiyed Main

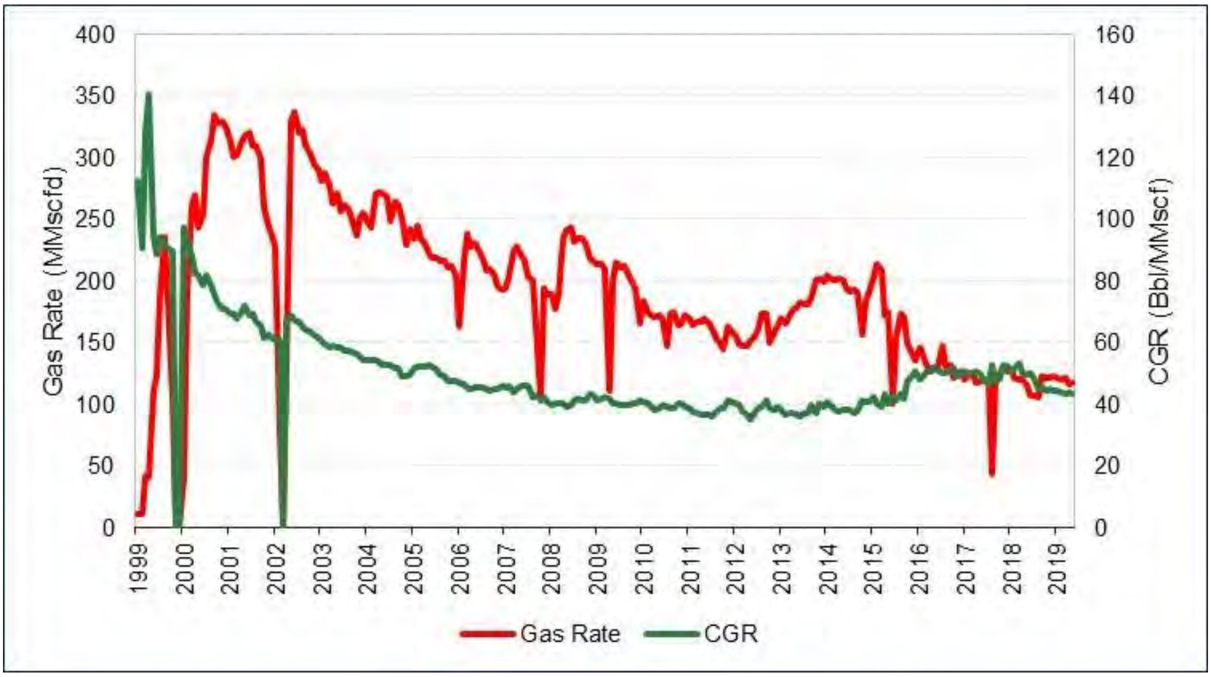


Figure 7: Historical Production, Obaiyed J14 Area

Table 11: Obaiyed Field Production Performance as at 31st December 2019

Field	Active Well Count in December 2019	Cumulative Gas Production to End 2019	Average Gas Rate in 4Q 2019	Average Condensate Rate in 4Q 2019	Average Water Rate in 4Q 2019
	Number	Bscf	MMscfd	bcpd	bwpd
Obaiyed	36	1,423.1	118.6	5,164.5	984.5
J14	7	89.2	42.3	807.3	329.5
Total	**43**	**1,512.3**	**160.9**	**5,971.7**	**1,314.0**

1.2.5 Field Development Plan

The consortium's five year future development plan for the fields includes the following activities:

- Infill opportunities in the Lower Safa core area: continued drilling primarily in the Lower Safa in order to produce from currently un-drained areas that have been identified by the Vendor, and audited by GaffneyCline. These include five Core well locations.
- Lower Safa Flank Development: Developing poorly drained areas by long horizontal multi-fracced wells. These include seven flank wells and one workover for well H22, which has well integrity issues.
- Re-completions and fracs targeting eight upper Safa sands across the Core development area. These comprise eight recompletions and fracs in existing lower Safa wells.
- Low Line Pressure project: lowering the pre-compression inlet pressure to 6 bar.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The new production wells and well workovers are summarised in Table 12 and Table 13 respectively.

Table 12: Obaiyed Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Lower Safa	0	2	3	3	4	**12**
Upper Safa	0	0	0	0	0	**0**
Total	**0**	**2**	**3**	**3**	**4**	**12**

Table 13: Obaiyed Workover Schedule

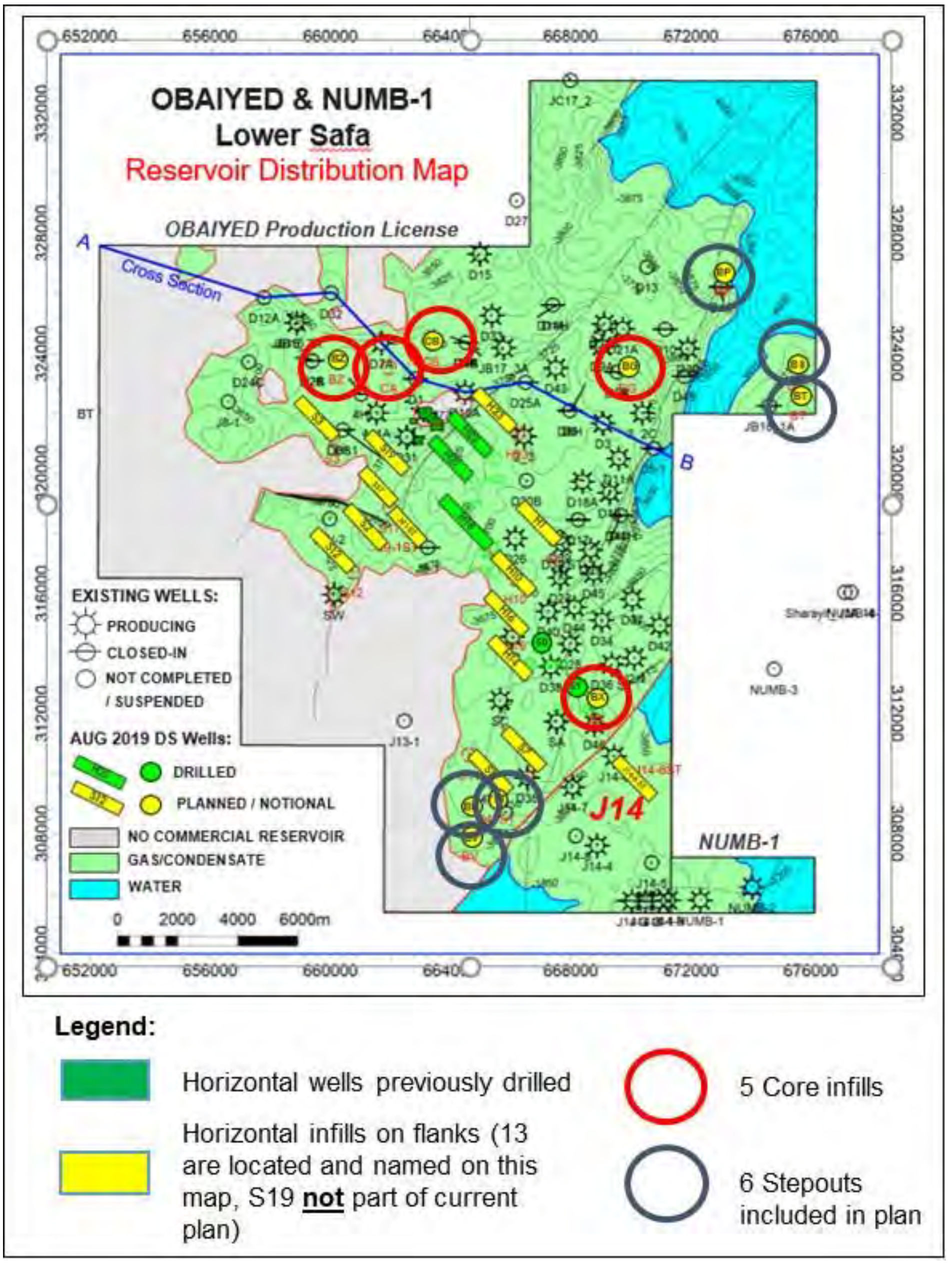
Year	2020	2021	2022	2023	2024	Total
Lower Safa	0	1	0	0	0	**1**
Upper Safa	0	7	1	2	2	**12**
Total	**0**	**8**	**1**	**2**	**2**	**13**

Further details of the new locations contributing to the work programme are discussed below.

Lower Safa Formation

Discussions with the vendor during the vPDR confirmed that their overall plan consists of a programme of 24 defined locations, including horizontal wells in the more marginal western flank area, vertical wells within the field core, and “stepouts” to further assess the eastern and northern flanks of the field, both in terms of reservoir development, and in terms of assessing the position of the GWC. Locations are shown in Figure 8. In addition, there is provision for a further ten wells, whose locations are not yet defined in detail, making a total of 34 future wells.

Figure 8: Lower Safa Formation, Future Development Locations



Source: Vendor VDR

GaffneyCline has reviewed these locations and graded their attractiveness in terms of the principal geological risks anticipated. These are:

- Definition of location within dataset;
- Horizontal/vertical well;
- Proximity to core area, based on porosity and net reservoir thickness;
- Proximity to GWC in NE of field; and
- Likelihood of encountering "Lean" facies at base of each reservoir – high water saturation in transition zone or associated with clay-bound water.

Results of the ranking of locations are described in Table 14.

Table 14: Obaiyed Field. Assessment of Planned Lower Safa Infill Locations

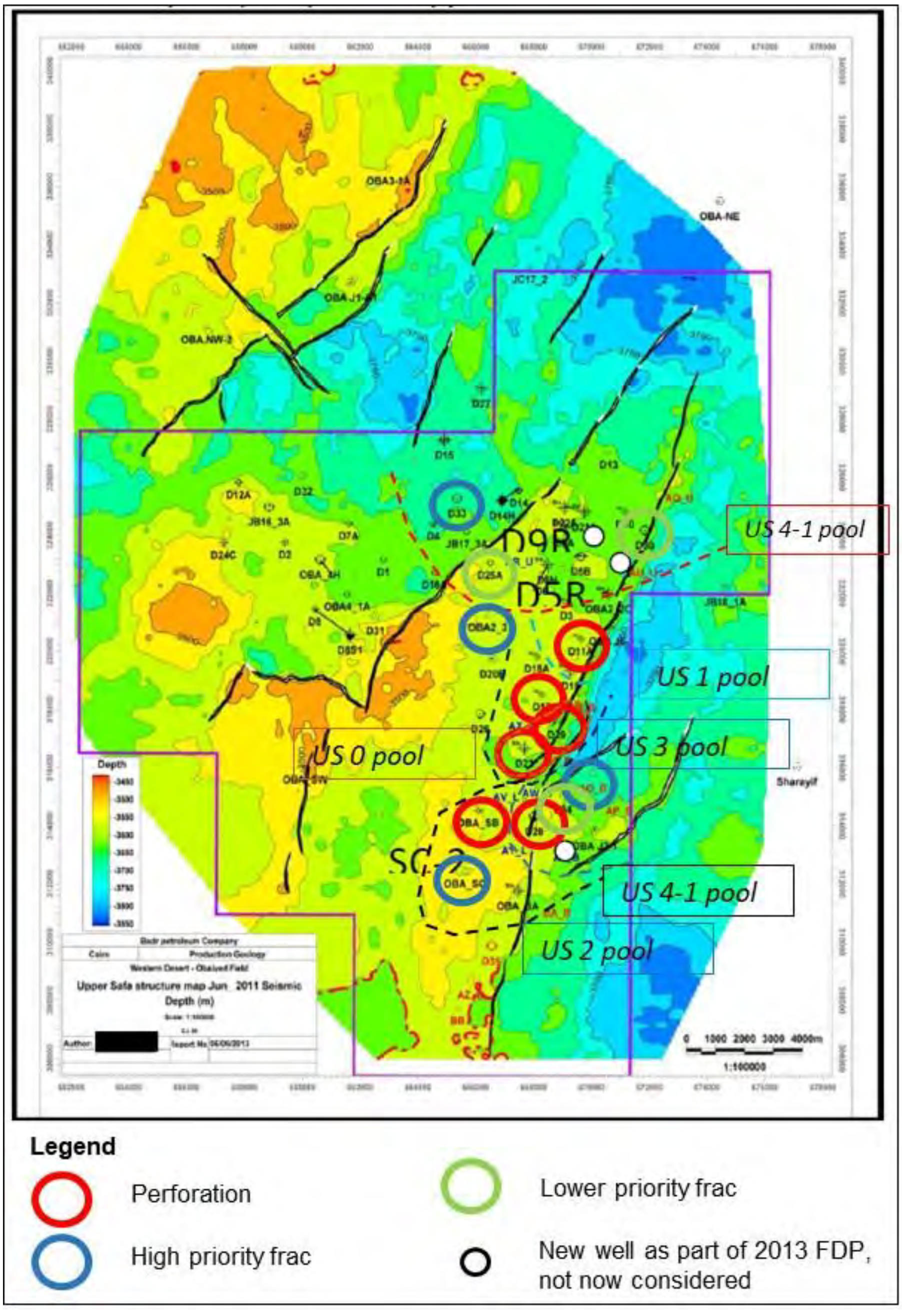
Cluster	Location	Well	Principal Reservoir	Ranking
J-14	J-14-6ST	Horiz	LS-3, LS-5	High
Core (north)	BZ	Vert	LS1-3	Moderate
Core (north)	CB	Vert	LS1-3	Moderate
Core (north)	CA	Vert	LS1-3	Moderate
Core (North)	BG	Vert	LS1-3	Moderate
Core (Southeast)	BX	Vert	LS-5	Moderate
SW Flank	S11	Horiz	LS-5	Moderate
SW Flank	S7	Horiz	LS-5	Moderate
SW Flank	H-1	Horiz	LS-5	High
SW Flank	H-10	Horiz	LS-5	High
SW Flank	H-16	Horiz	LS-5	High
SW Flank	H-14	Horiz	LS-5	Moderate
SW Flank	H23	Horiz	LS-5	High
NW Flank	S3	Horiz	LS1-3	Moderate
NW Flank	S17	Horiz	LS-5	Moderate
NW Flank	S2	Horiz	LS-5	Moderate
NW Flank	S12	Horiz	LS-5	Low
NW Flank	J9-1ST	Horiz	LS-5	Moderate
Northeast	BP	Vert	LS-3, LS-5	Low
East	BS	Vert	LS-1-2	Low
East	BT	Vert	LS-1-3	Low
SW Flank	47-ST	Vert	LS-5	Low
SW Flank	BU	Vert	LS-5	Low
SW Flank	BV	Vert	LS-5	Low

As noted earlier in the report, only 5 core locations (BZ, CB, CA, BG, BX), and 7 flank wells are included in the Consortium's 5 year plan. The latter would be expected to be selected from the locations graded "high" or "moderate" in the above analysis. Other locations represent future upside possibilities.

Upper Safa Formation

In its current "infill" plans, the Consortium proposes a campaign of 20 recompletions and fracking of existing completions to exploit the Upper Safa Formation (Figure 9). Production to date has been small. Although new well locations are discussed in the original 2013 FDP, these are not understood to be part of the Vendor's current plan and hence, not part of the Consortium's plan. The Consortium's plan highlights 12 opportunities that would be initially targeted, notionally from those flagged as "good" and "moderate" in the succeeding analysis.

Figure 9: Upper Safa Formation, Future Development Locations



Source: Vendor VDR

GaffneyCline has examined the detail of the activities planned and notes that the bulk of the resources are aimed at two main sand bodies, the Upper Safa 4-1 sand in the north, and the Upper Safa 2 sand in the south. Approximate estimates of GIIP for each of the sand units suggests that the incremental RF expected to be achieved ranges between 26-36%. Higher values are expected where a particular pool is targeted by activities in several wells.

The main risks are associated with the marginal reservoir quality and the performance of the frac, where this is planned. In general, however, GaffneyCline has been able to confirm the validity of the targets proposed (Table 15).

Table 15: Obaiyed Field. Assessment of Planned Upper Safa Recompletions

Sandstone unit	Well	Type of activity	Estimated CGR (Bbl/MMscf)	GaffneyCline Ranking/Comment
US0	D29	Perf	>100	Moderate
	D11	Perf	>100	Good
	D23	Perf	>100	Poor
US1 north	OBA 2-3	Frac	80-90	No well information
US1 south	SC	Frac	90-100	Good. Open completion
US2 south	SB	Perf	>100	Poor
	SC	Frac	80-90	Good. Open completion
	D37	Frac	90-100	Location and pool ID tentative. Open completion
	D34	Frac	80-90	Good. Open completion
US 3 north	D30	Frac	<80	D30 already marked as open in US4-1. US3 looks like very minimal target. Poor.
US3 south	D17	Perf	>100	Good
US4-1 north	D33	Frac	90-100	No open completion shown
	D25	Frac	<80	Good. Open completion
US4-1 south	D28	Perf	>100	Moderate
US4-2 north	D25	Frac	<80	Good. Open completion

1.2.6 Production Forecasts

For the profiles contributing to the Reserves cases, GaffneyCline carried out its own analysis based on historical well performance and analogues, using a combination of Decline Curve Analysis (DCA) for existing wells and analogue type wells to estimate the performance of the planned new wells and workovers.

The predicted technical recovery factors (to end of the licence, with no consideration of any economic cut-off) in the Lower Safa reservoir are approximately 71% for the Core area, which has most of the current producing wells and possess good reservoir properties, and 38% for the Western Flank area, taking into account the tight reservoir and the need for long reaching hydraulically fractured wells to recover the volumes.

The remaining recoverable gas and condensate volumes are shown in Table 16 and Table 17.

Table 16: Remaining Technically Recoverable Gas Volumes by Case, Obaiyed as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
NFA	280.8	305.6	329.1
Infill LS Core	17.6	35.7	54.1
Infill LS Flanks	54.9	68.2	81.1
Infill US	24.7	30.9	37.1
LLP project	7.9	9.6	11.3
SI wells Re-activation	23.9	25.2	26.5
Total	409.8	475.3	539.3

Notes:

1. The volumes in this table are to the end of August 2029; no economic cut off has been applied.
2. The volumes are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 17: Remaining Technically Recoverable Condensate Volumes by Case, Obaiyed as at 31st December 2019

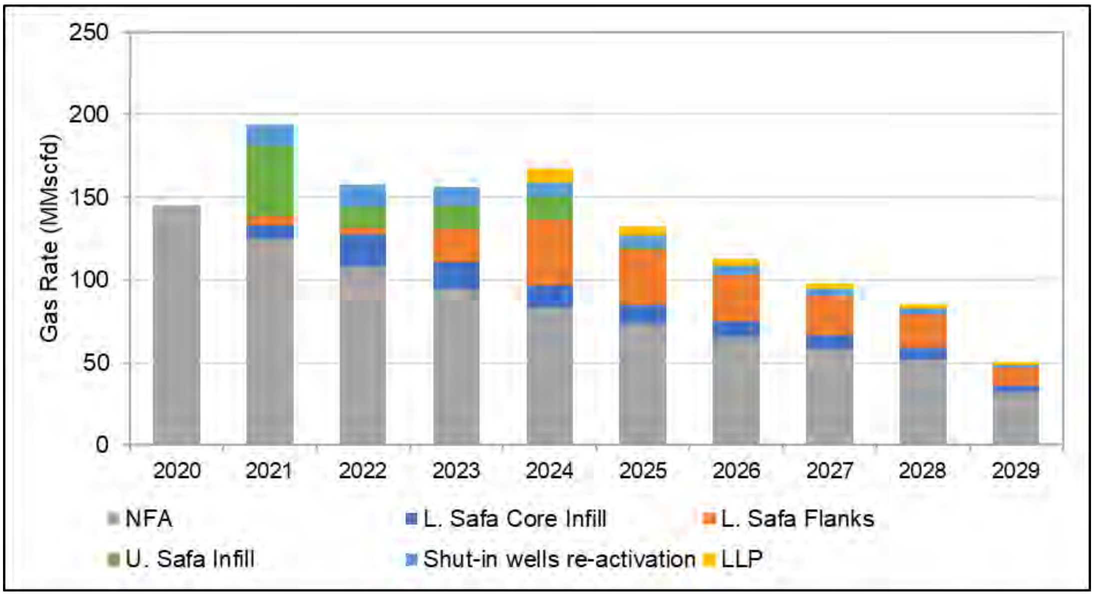
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NFA	10.1	11.4	12.3
Infill LS Core	0.9	1.6	2.4
Infill LS Flanks	2.4	3.1	3.9
Infill US	2.5	4.6	6.6
LLP project	0.3	0.4	0.5
SI wells Re-activation	0.9	1.0	1.0
Total	**17.1**	**22.2**	**26.8**

Notes:

1. The volumes in this table are to the end of August 2029; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 10 and Figure 11 show the Best Case gas and condensate forecasts for Obaiyed by activity wedge.

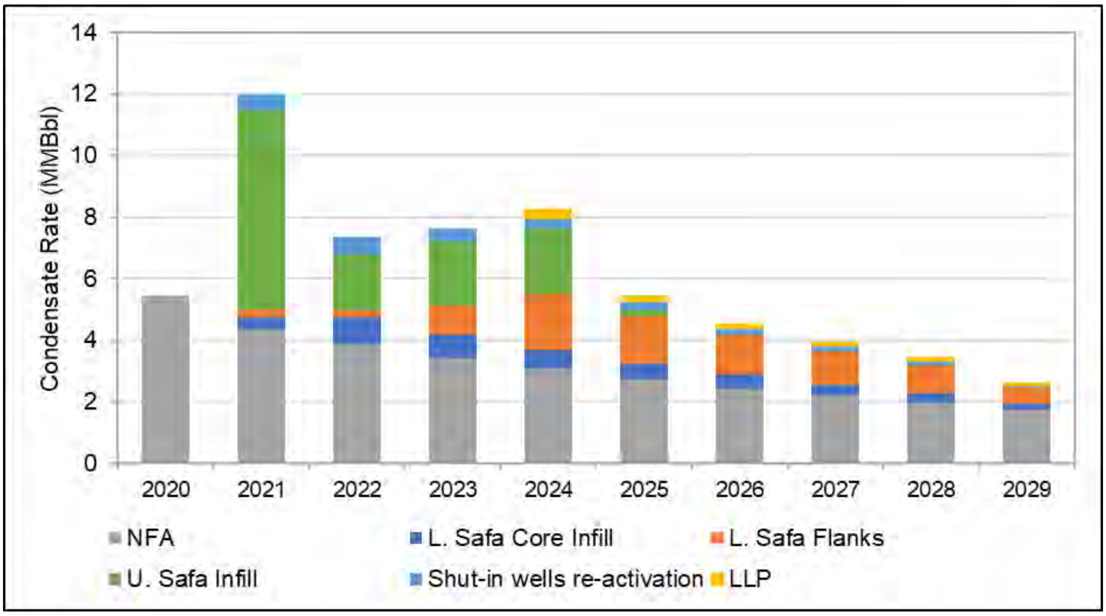
Figure 10: Best Case Gas Production Forecast, Obaiyed



Notes:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 11: Best Case Condensate Production Forecast, Obaiyed

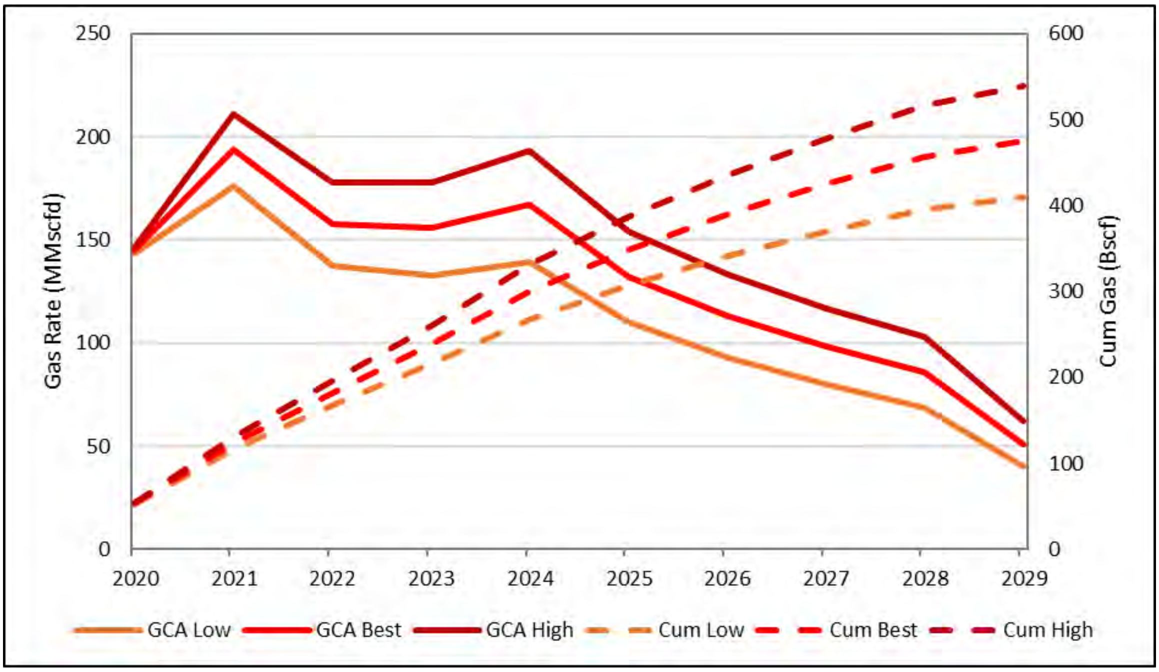


Note:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.

Figure 12 and Figure 13 show the Low, Best and High gas and condensate production forecasts for Obaiyed.

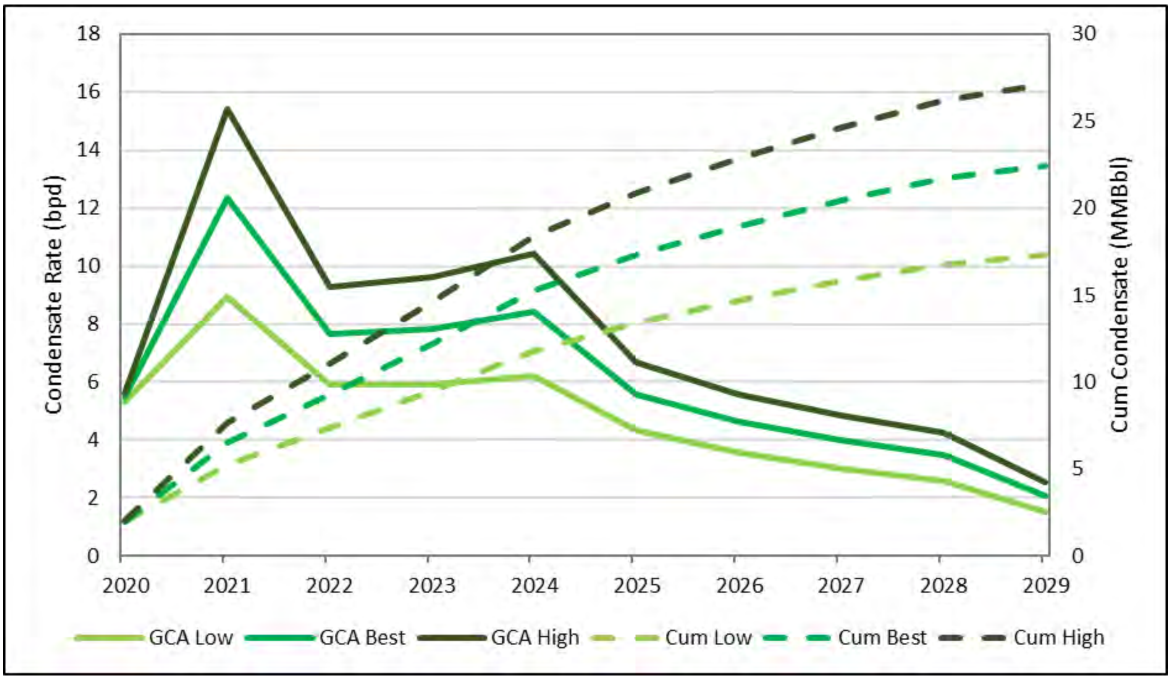
Figure 12: Gas Production Forecasts, Obaiyed



Notes:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 13: Condensate Production Forecasts, Obaiyed



Note:

1. The values in this figure are annual average rates and in 2029 include only 8 months of production (to the end of August 2029); no economic cut off has been applied.

1.2.7 Contingent Resources

Contingent Resources were assigned to well locations where low ranking was applied, or which have not yet been fully defined. Further modelling work is required to bring these opportunities to a higher level of confidence. There are seventeen upside (low ranking) locations in this category.

Activities currently envisaged more than 5 years in the future (2025 onwards) were also considered as Contingent Resources. These comprise an additional six infill wells in the Lower Safa (LS), plus twelve re-completions in the Upper Safa (US) formation. Table 18 and Table 19 show the gross gas and condensate Contingent Resources.

Table 18: Gross Gas Contingent Resources, Obaiyed, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Lower Safa	56.2	85.6	116.0
Upper Safa	16.4	20.4	24.5
Total	**72.5**	**106.1**	**150.6**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 19: Gross Condensate Contingent Resources, Obaiyed, as at 31st December 2019

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Lower Safa	2.5	3.9	5.4
Upper Safa	1.6	3.1	4.4
Total	**4.2**	**7.0**	**9.7**

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

1.3 North Matruh (NM)

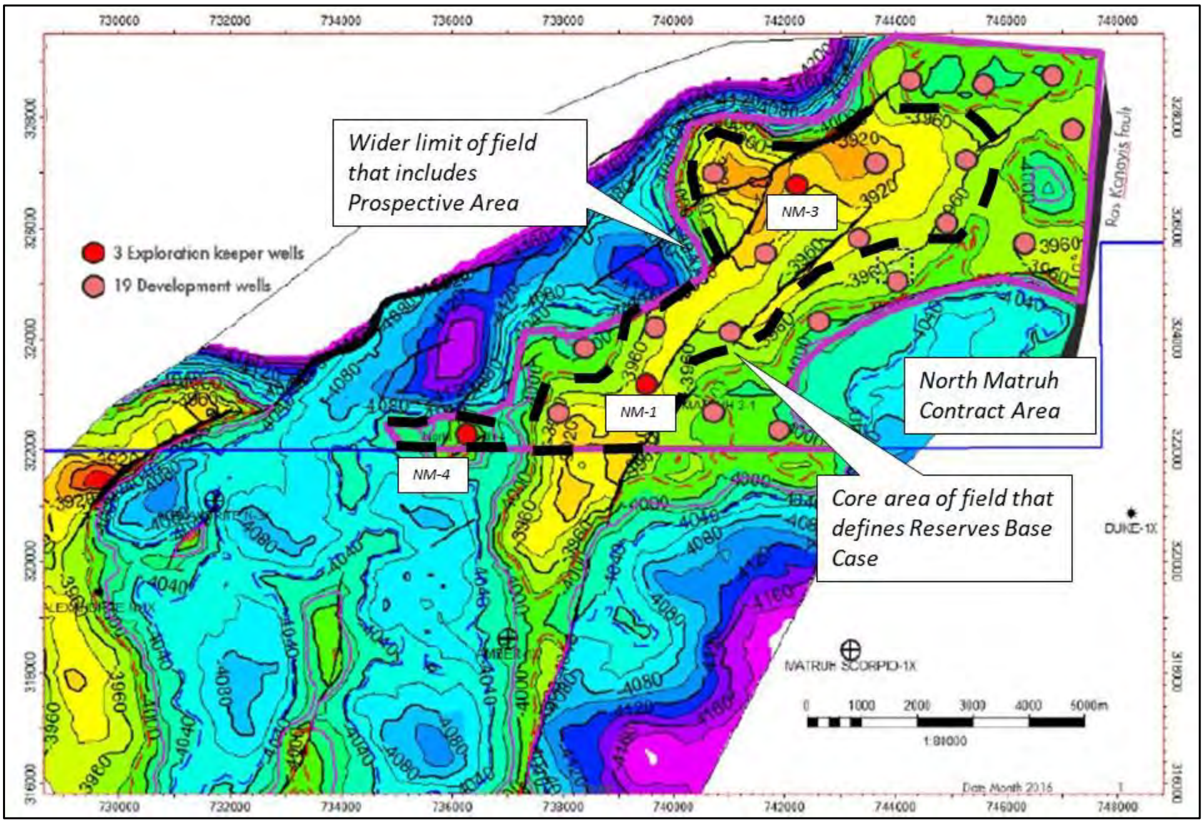
1.3.1 Asset Description

1.3.1.1 Structure/trap

The NM contract area lies on the eastern margin of the Matruh Trough. Its main asset is the Teen gas condensate Discovery, adjacent to its south central boundary, but does contain other prospects identified by the vendor.

Teen consists of a broadly ENE-WSW trending fault block, bounded to the west by a normal fault, which merges southwards with a more N-S oriented trend to the south of the contract area boundary. In detail, however it comprises a series of fault terraces, including a separate satellite to the west drilled by well NM-4, and these show evidence of fault bounded compartments leading to distinct GWC. A depth structure map on the Upper Safa is presented in Figure 14.

Figure 14: NM (Teen) Discovery. Top Upper Safa Formation Depth Structure (m), showing Proposed Development Locations



Source: Vendor VDR with GaffneyCline annotation

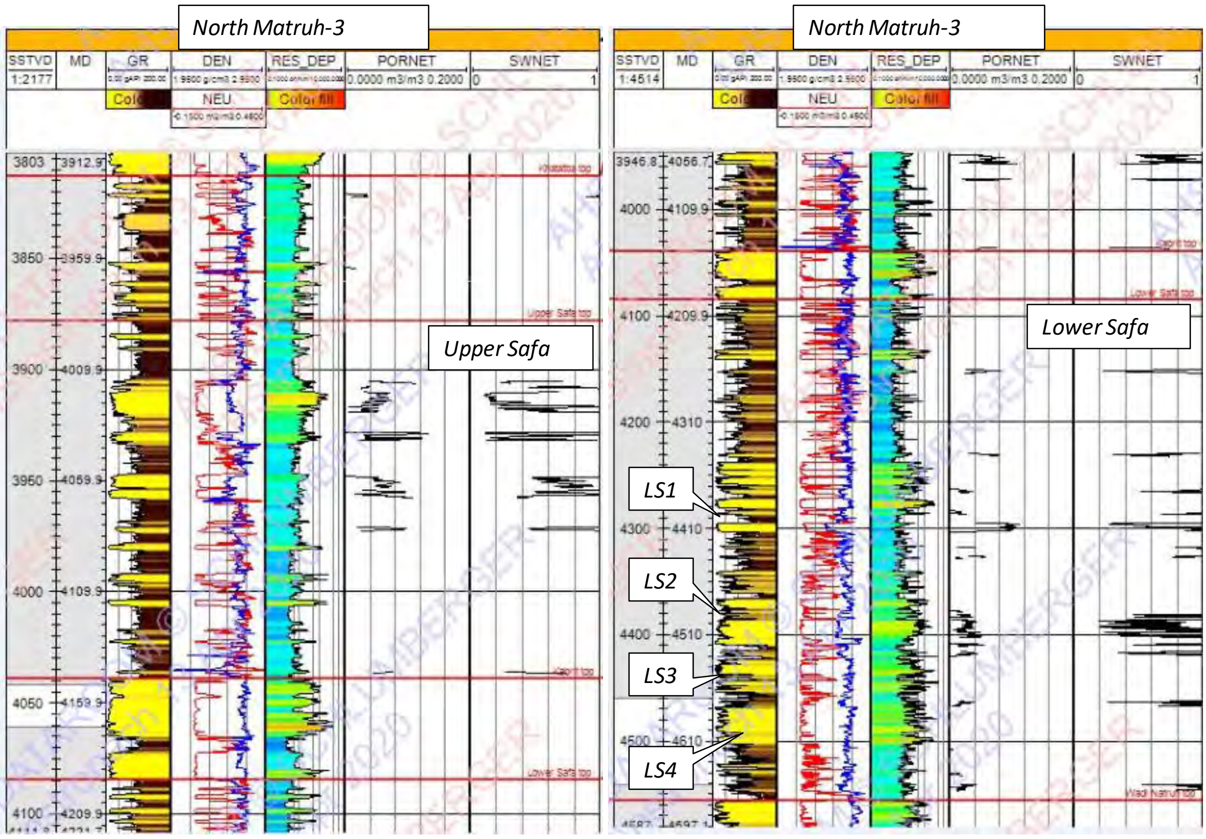
There are three wells in the NM area: NM-1, NM-3 and NM-4 (Figure 14). All are suspended as potential gas and condensate producers:

- NM-1 (Teen-1): Drilled at the southern end of the main structure and discovered gas in the Upper and Lower Safa Formation, although the former was not tested. In two tests, LS1 flowed at 9 MMscfd and LS2-5 flowed at 1.3 MMscfd. Neither unit was fracked. Gas condensate content in the Lower Safa is modest at 20-30 Bbl/MMscf.
- NM-3 (Teen North, or Teen-2): Discovered gas in both Lower and Upper Safa at the northern end of the main structure. The LS2 sand was fracked, but without significant flow. LS1 flowed at 8-18 MMscfd, without frac. A later workover was undertaken on the Upper Safa and this flowed at 9 MMscfd with significant (200 Bbl/MMscf) condensate content. There is also a small pool of oil in the Alam el Bueib Formation, although this was tight on MDT, so is likely of little significance.
- NM-4 (Teen 3): Drilled in a small satellite structure to the west. It discovered an estimated 40 m of net pay in the Lower Safa Formation and 31 m in the Upper Safa, but was not tested. It remains to be confirmed if the lower GWCs interpreted here are relevant to the wider Teen structure, or are local to this smaller feature.

1.3.1.2 Reservoir

PVT samples from NM-1 are summarized in Table 20. Test results suggest slightly higher CGR than that sampled and a value of 36 Bbl/MMscf has been used in the evaluation. Much higher condensate content (200 Bbl/MMscf) in the Upper Safa is suggested by the test at NM-3, generally in line with the variation seen at Obaiyed. A CO_2 content of around 6 mol% is indicated by the sample data. Wireline pressure data is sparse, but suggests strongly over-pressured and isolated reservoir bodies in the Upper Safa Formation at NM-4, but normal pressure gradients elsewhere and in the Lower Safa Formation.

Figure 15: NM (Teen) Discovery. Representative Reservoir Section



Source: Vendor VDR

1.3.1.3 Reservoir and Fluid Properties

PVT samples from NM-1 are summarized in Table 20. Test results suggest slightly higher CGR than that sampled and a typical value of 36 Bbl/MMscf has been used in the evaluation. Much higher condensate content in the Upper Safa is suggested by test at NM-3 of 200 Bbl/MMscf, generally in line with the variation seen at Obaiyed. A CO_2 content of around 6 mol% is indicated by the sample data. Wireline pressure data is sparse, but suggests strongly overpressured and isolated reservoir bodies in the Upper Safa Formation at NM-4, but normal pressure gradients elsewhere and in the Lower Safa Formation.

Table 20: Teen: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Teen	Lower Safa	4,306	149.2	6,596	Not known	0.0036	18	0.01	0.75

1.3.1.4 Production Facilities

Gas production is expected to be via a future trunk line to the Obaiyed gas processing facility (see section 1.2).

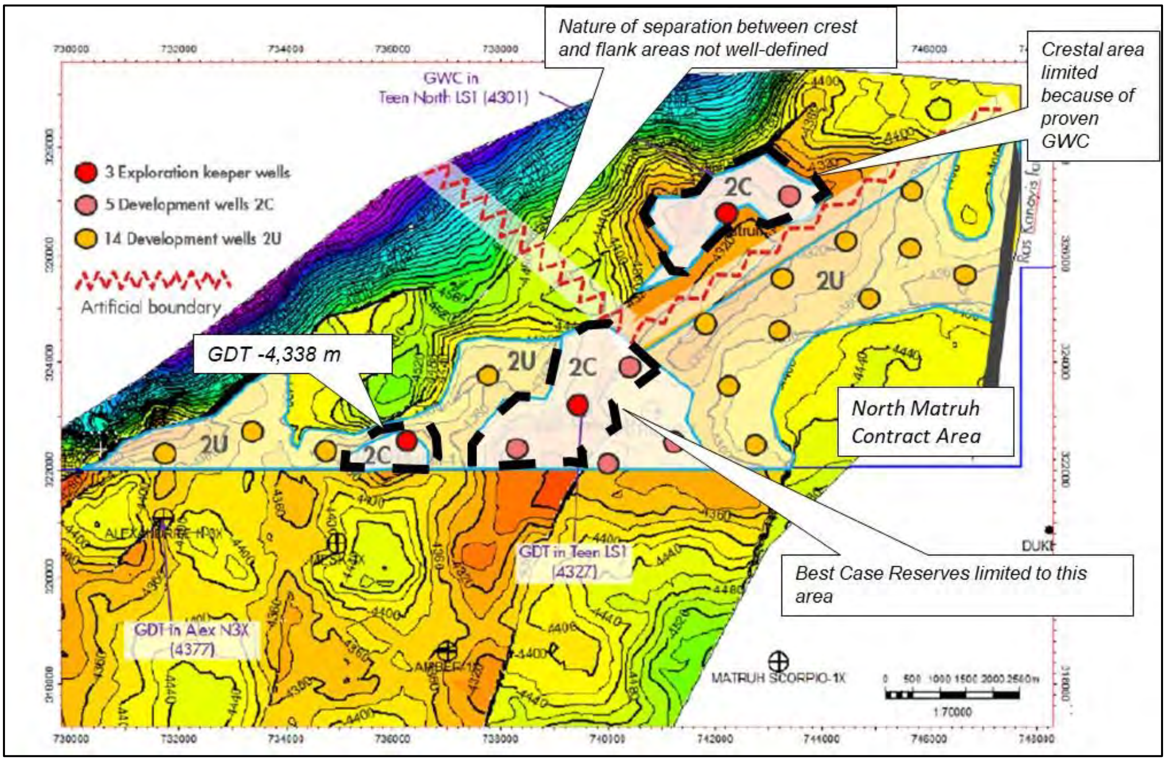
1.3.2 HIIP

HIIP is assessed from the Contingent Resources statement provided by the vendor, along with certain supporting data. There are no static models at this point to aid volumetric assessment. The vendor includes a large area of the structure in its analysis and includes volumes deemed to contribute both to Contingent Resources (i.e. discovered volumes) and to Prospective Resources (undiscovered). In its assessment, GaffneyCline has opted to focus on Best Case volumes that can realistically contribute to Reserves (Figure 14 illustrates the area for the Upper Safa, and Figure 16 for the Lower Safa). It thus specifically excludes (Figure 16):

- Volumes in the far NE of the structure near the limit of the mapping.
- Volumes below the proven GDT and below the apparent mapped spill point of the structure to the south.
- Volumes in fault terraces to the east below the GWC seen in the Lower Safa Formation at NM-3.
- Volumes in the vicinity of and below the legacy well at Mutrah 3-1 (to the east of NM-1, Figure 14), suggested to be water-bearing on test.

Differences between the GaffneyCline assessment and the vendor assessment are considered to lie in the Prospective category. HIIP are summarized in Table 21.

Figure 16: NM (Teen) Discovery. Lower Safa Formation Depth Structure and Areas included in Volume Assessment



Source: Vendor VDR with GaffneyCline annotation

Table 21: NM (Teen) Discovery. Hydrocarbons-initially-in-place

Reservoir	Source		GIIP (Bscf)			Notes
			Low	Best	High	
Upper Safa	Vendor CR Statement 2019	**Total**	**75**	**153**	**286**	
	GaffneyCline Estimate	NM-1, NM-3	-	107	-	
		NM-4	-	21	-	
		Total	**-**	**128**	-	GaffneyCline estimate broadly validates vendor estimate. Adopted in analysis as it excludes area in north east of structure
Lower Safa	Vendor FDP 2013	LS 1	43	65	83	
	GaffneyCline Estimate		-	27	-	Vendor estimate appears to overestimate 2C area
	Vendor FDP 2013	LS 2-3	102	148	198	
	GaffneyCline Estimate		-	38	-	Vendor estimate appears to overestimate 2C area, and net pay
	Vendor FDP 2013	LS 4-5	0	0	0	No resources in LS4-5 because of poor reservoir quality
	GaffneyCline Estimate		-	0	-	

Source: Vendor VDR and GaffneyCline estimates

1.3.3 Asset Streams

The categories described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 22.

Table 22: NM: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Notes
NM General	Upper Safa Development	Defined well locations in core of field	**Reserves** GaffneyCline concludes development should be considered as being limited to core areas of field only.
	Lower Safa Development	Defined well locations in core of field	
	Upper and Lower Safa eastern flank		**Prospective Resources**

1.3.4 Historical Field Performance

There is no production to date. Test results are described in section 1.3.1, above.

1.3.5 Field Development Plan

The Vendor has described a development consisting of 24 wells, including reactivation of the suspended exploration and appraisal wells and the drilling of 21 new locations. In GaffneyCline's view, it is inappropriate to consider this plan to be wholly firm as it clearly targets areas outside of the main proven areas (see Figure 14 above). Thus, only 12 well locations in the forward plan are deemed as firm and as potentially contributing to Reserves or Contingent Resources. Other proposed locations are considered as contributing only to Prospective Resources and are not considered further here, as they lie in separate structural or stratigraphic pools. In addition to the 12 previously proposed locations, efficient exploitation of the area around NM-4 is planned by the Consortium to require another well to target the Upper Safa Formation. Thus there are 13 locations in total. No grading of locations is attempted for this field.

Three of the 13 wells are the original exploration and appraisal wells, and ten are additional locations.

1.3.6 Production Forecast

The Consortium's five year future development plans for the fields thus includes the following activities:

Lower Safa:

- Three suspended gas wells in NM-1,3 and 4 plus three relatively low risk development locations, all within GDT as demonstrated at NM-1, NM-3, NM-4 and principal spill point. All six of these wells in the Lower Safa are part of the consortium's five year plan.

- Although NM-4 has not been tested, on the basis of petrophysics, MDT results and analogue with the rest of the field, it is nonetheless regarded as contributing to Reserves.
- Sixteen high risk locations, designated as outside of the vendor's 2C area (see Figure 16), are not considered as Reserves or Contingent Resources due to these wells being high risk.

Upper Safa:

- The three suspended gas wells (NM-1, NM-3 and NM-4) are not planned for early completion of the Upper Safa, so new wells will be required.
- Although NM-4 has not been tested, on the basis of petrophysics, MDT results and analogue with the rest of the field, the area around it is regarded as contributing to Upper Safa Reserves.
- Ten wells in the Upper Safa are relatively low risk development locations, within GDT as demonstrated at NM-1, NM-3 and NM-4, and the principal spill point. Locations are shown on Figure 14, to which is added a twin of the NM-4 well. All of these lie within the five year plan and are considered as contributing to reserves. Two further wells outside of the five year plan are included as Contingent Resources only (see below).
- A further ten high risk locations, located outside of the core area (see Figure 16), are not considered as contributing to Reserves or Contingent Resources.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of re-entries and new production wells are summarised in Table 23.

Table 23: NM Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Upper Safa	0	0	0	5	5	**10**
Lower Safa	0	0	0	3	3	**6**
Total	**0**	**0**	**0**	**8**	**8**	**16**

Note:

1. The first three wells targeting the Lower Safa are expected to be re-entries of the existing exploration and appraisal wells.

The remaining recoverable gas and condensate volumes are shown in Table 24 and Table 25 as of the 31st December 2019 until the end of 2047.

Table 24: Remaining Technically Recoverable Gas Volumes, NM as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
Upper Safa	30.9	54.5	101.5
Lower Safa	19.9	30.9	49.1
Total	**50.8**	**85.5**	**150.6**

Notes:

1. The volumes in this table are to the end of 2047; no economic cut off has been applied.
2. The volumes are prior to the deduction of fuel and shrinkage, estimated at 7.5% in 2020-2023 and 8% from 2023 onwards (Fuel = 4% and shrinkage due to CO_2 removal = 3.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 25: Remaining Technically Recoverable Condensate Volumes, NM as at 31st December 2019

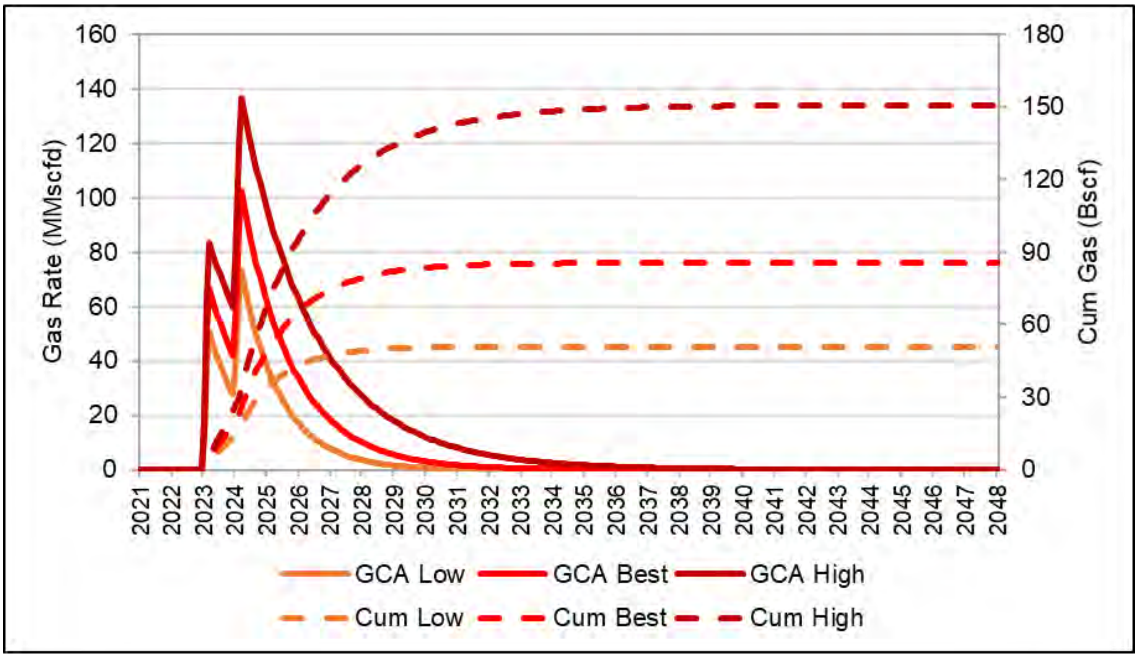
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Upper Safa	4.6	9.5	20.3
Lower Safa	0.4	0.8	1.5
Total	**5.0**	**10.3**	**21.8**

Notes:

1. The volumes in this table are to the end of 2047; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 17 and Figure 18 show Low, Best and High gas and condensate forecast production profiles for NM.

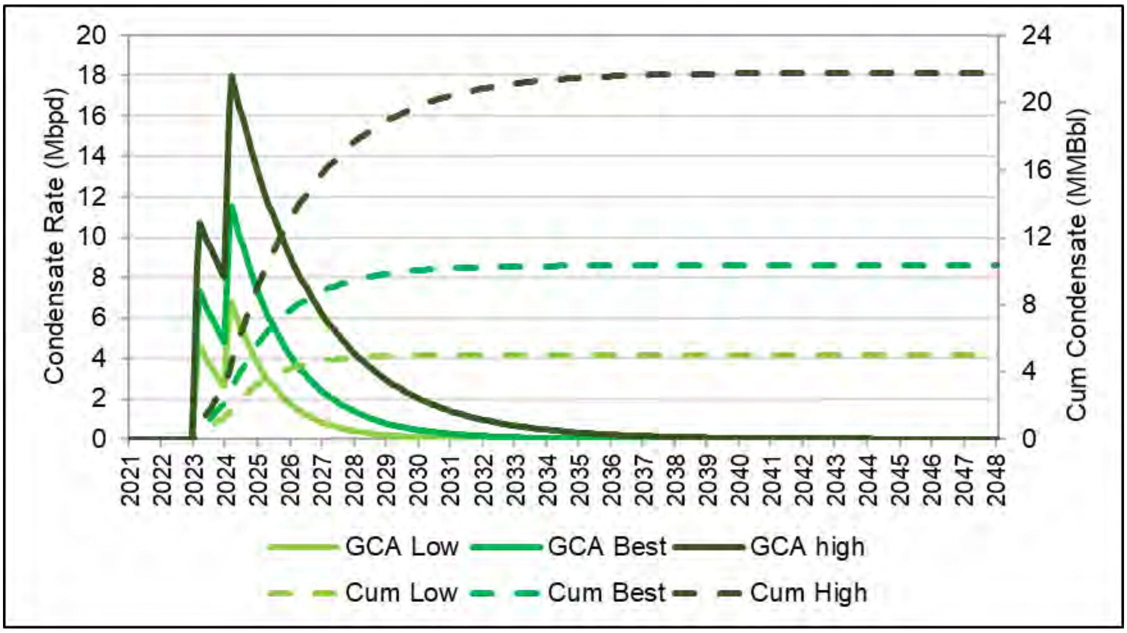
Figure 17: Gas Production Forecasts, NM



Notes:

1. The values in this figure are annual average rates; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 10% in 2020-2023 and 10.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

Figure 18: Condensate Production Forecasts, NM



Note:

1. The values in this figure are annual average rates; no economic cut off has been applied.

1.3.7 Contingent Resources

Contingent Resources were assigned to well locations which lie beyond the five-year threshold for inclusion as Reserves. Two additional infill wells in the Upper Safa starting in 2025 were thus considered as Contingent Resources, notionally located in the vicinity of the existing NM-1 and NM-3 exploration/appraisal wells. No Contingent Resources are assigned to the Lower Safa.

The Contingent Resources for gas and condensate for the Upper Safa Formation are shown in Table 26 and Table 27 respectively.

Table 26: Gross Gas Contingent Resources, NM, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Upper Safa	6.2	10.9	20.3

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.

Table 27: Gross Condensate Contingent Resources, NM, as at 31st December 2019

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Upper Safa	0.9	1.9	4.1

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.

1.4 North Umbaraka

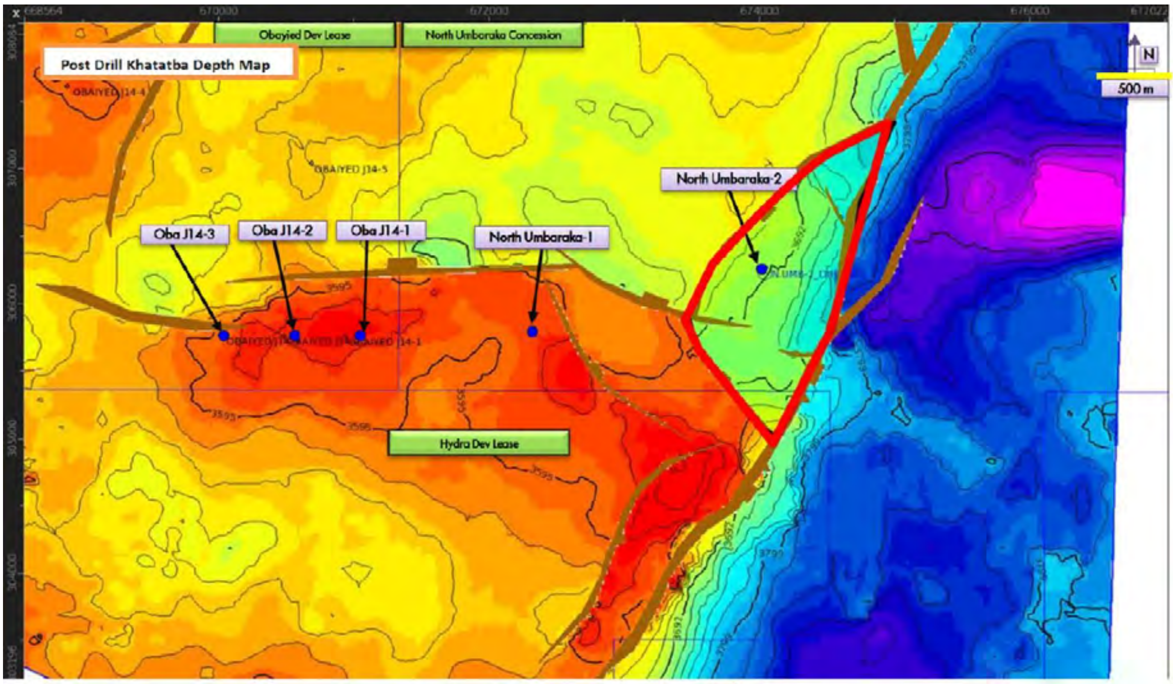
1.4.1 Asset Description

The North Umbaraka (NUMB) contract area is formed of a number of separate blocks, both to the east and west of the Obaiyed Field. It thus comprises areas which are essentially satellites to the Obaiyed Field, with a mix of Reserves and Contingent Resources, and other areas which are the realm of exploration prospects.

1.4.1.1 *Structure and Trap*

The proven Obaiyed satellites comprise the NUMB-1 pool, which is essentially an extension of the J-14 fault block in Obaiyed, and the NUMB-2 pool, which is a small separate downthrown fault block to the east (Figure 19).

Figure 19: NUMB-1, NUMB-2: Top Khatatba Formation, Depth Structure (m)

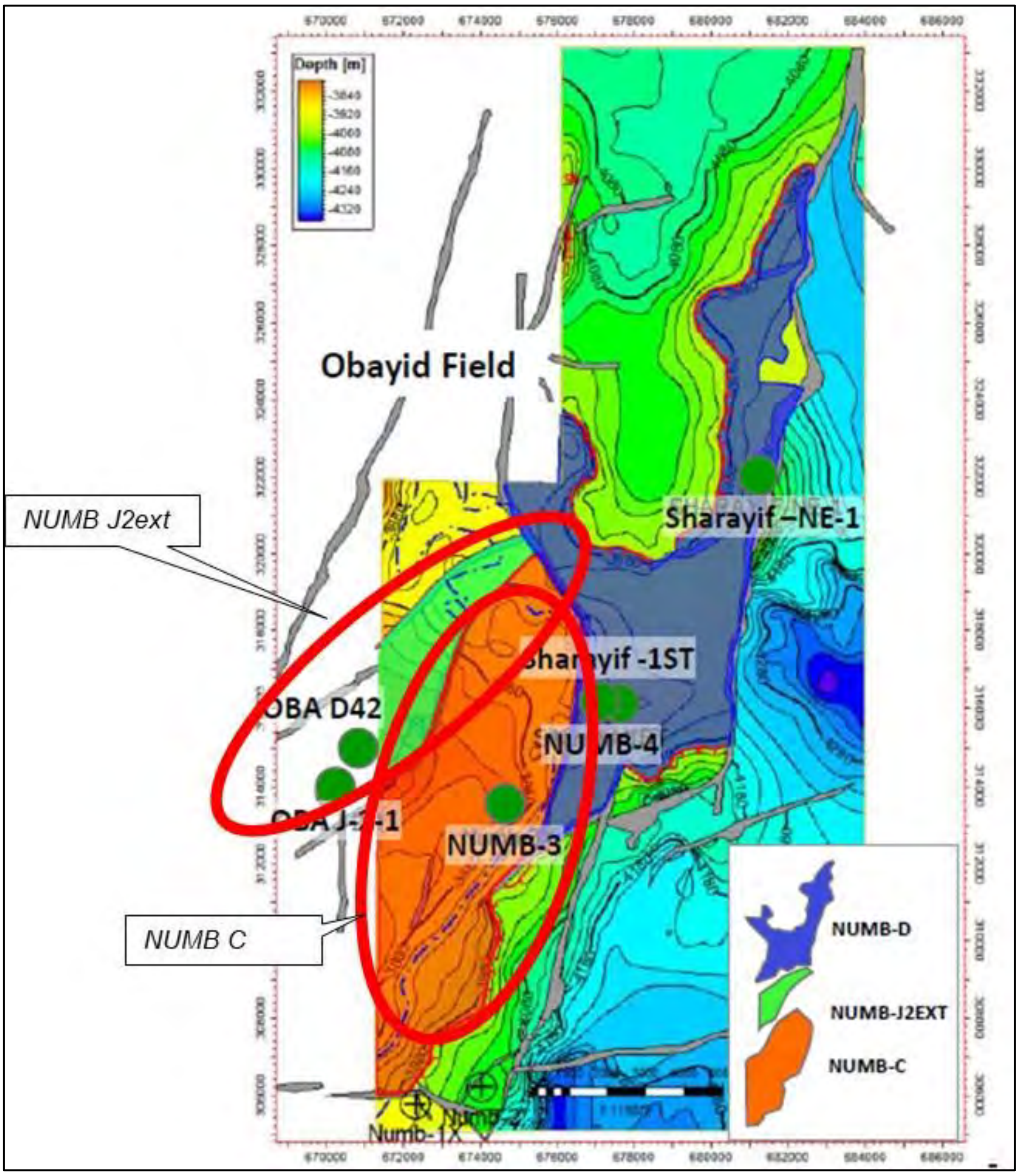


Source: Vendor VDR

To the north are two separate fault blocks, designated as NUMB-C and NUMB-J2ext (Figure 20). Both of these are designated as containing Reserves. In the case of NUMB-C, this is based on the discovery at NUMB-3, which tested up to 3.5 MMscfd from the Lower Safa Formation, and in the case of NUMB-J2ext, the area is an extension of the area proven by wells Obaiyed D-42 and J2-1.

The Consortium also proposes a further fault block to the north (NUMB-D), but this has not shown gas production to surface in three wells, and along with structural uncertainties, it has been eliminated from consideration here.

Figure 20: NUMB-C, NUMB-J2ext: Top Khatatba Formation, Depth Structure (m)



Source: Vendor VDR

1.4.1.2 Reservoir

NUMB 1 produces from both Upper and Lower Safa, but NUMB 2 only from the Upper, with the Lower being water-bearing.

The Upper Safa is shown to be tight at NUMB-3 and is not viewed as part of the reservoir fairway at J2ext.

1.4.1.3 Reservoir and Fluid Properties

PVT data are available from bottom hole samples at NUMB-2 and NUMB-3, as illustrated in Table 28. A 5.1-6.6 mol% content of CO_2 is indicated from separator gas analysis. Pressure and temperature gradients are normal.

Table 28: NUMB 2 and 3: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
NUMB 2	Upper Safa	3,844	141.9	5,974	Not known	0.0039	52	0.01	0.79
NUMB 3	Lower Safa	3,493	130.4	5,131	Not known	Not known	63	0.01	0.85

1.4.1.4 Production Facilities

Gas production is via the Obaiyed gas processing facility (see section 1.2).

1.4.2 HIIP

Analysis of HIIP of each of the fault blocks is presented by the Vendor, with modification for NUMB-C and NUMB-J2ext conducted by the Consortium. GaffneyCline has reviewed and confirmed these results and they are presented here (Table 29).

Table 29: NUMB: GIIP

Reservoir	Source		GIIP (Bscf)			Notes
			Low	Best	High	
Safa Formation	Vendor VDR	NUMB-2	6.8	9.3	12.3	Upper Safa Formation only
	Consortium	NUMB C	40.8	94.2	193.8	Upper Safa Formation only included in High Case
		NUMB J2ext	12.2	23.6	51.7	

1.4.3 Asset Streams

The categories described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 30.

Table 30: North Umbaraka Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NFA	Existing NFA	Continuing production from NUMB-2	**Reserves**
Exploration	Near Field Exploration	Pools included are only satellites to Obaiyed Field where activities are appraisal and development	**Reserves.** The separation of near field appraisal from wildcat prospect locations is key to understanding potential.
	Exploration	All other prospects in west of contract area	**Prospective Resources**

1.4.4 Historical Field Performance

The NUMB production history is from one well (NUMB-2) which was drilled in February 2018. NUMB-2 is produced through the existing Obaiyed J14 manifold and routed to the Obaiyed facilities 20 km away where the gas and condensate are processed. The production peaked at 24 MMscfd in July 2017. The well currently producing at 18 MMscfd with a CGR of 20 MMscf/Bbl as shown in Figure 21.

Figure 21: Historical Gas Production Rate and CGR for NUMB-2

1.4.5 NUMB 3 Well Test Results

A summary of the well test results from the NUMB 3 well post /pre Frack are as follows:

Pre-Frack

- Completion 4 ½ ”
- TPC Perforation Perf Interval 4,112-4,115 m and 4,118-4,127 m
- Gas Rate: 1.5-3.5 MMscfd
- WHP: 100-1,500 psi
- Water Rate <10 bpd
- Very low Condensate (CGR<1 Bbl/MMscf)

Post-Frack

- Completion 3 ½ ”
- Gas Rate: 1.5 -1.8 MMscfd
- WHP: 80-800 psi
- Water Rate: 50-150 Bbl/d
- Very Low CGR <1 Bbl/MMscf)

- Possible Frac into water, which caused an increase in water production and a reduction in gas rate

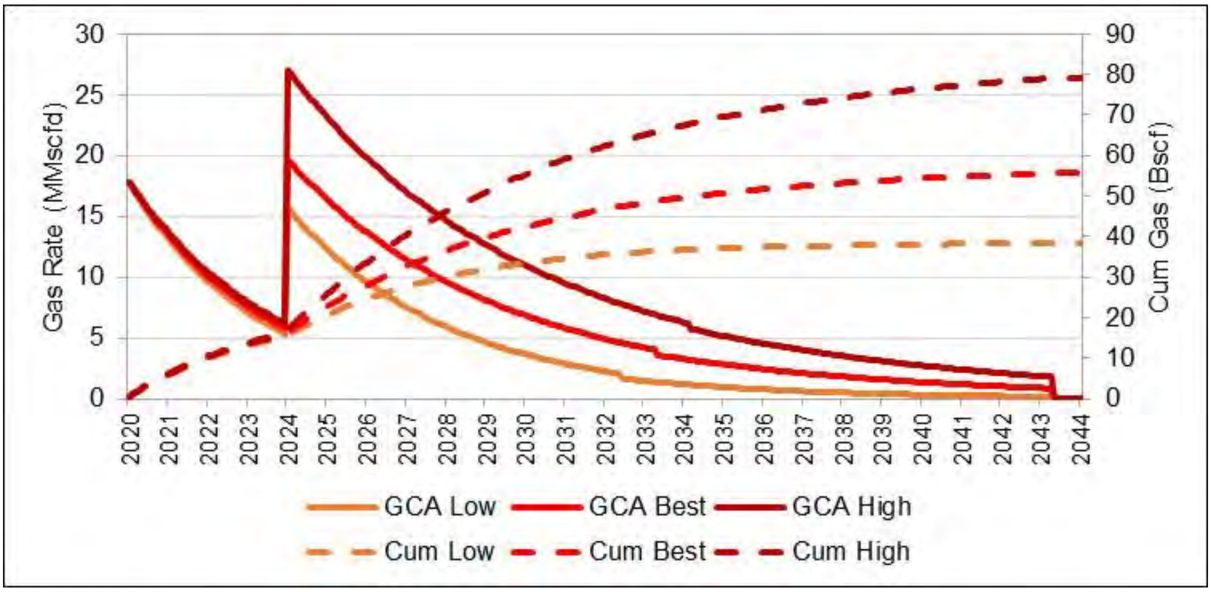
1.4.6 Field Development Plan

The Consortium's five year development plans for the field (Figure 22) includes the following activities:

- Eight Wells in the NUMB-C area.
- Two wells in the NUMB J2X area.

Figure 22 shows Low, Best and High gas forecast production profiles for NUMB.

Figure 22: NUMB Gas Production Forecasts



Notes:

1. The values in this figure are annual average rates and in 2043 include only 4 months of production (to the end of April 2043); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel and shrinkage, estimated at 4% in 2020-2023 and 4.5% from 2023 onwards (Fuel = 4.9% and shrinkage due to CO_2 removal= 5.6%).

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of new production wells are summarised in Table 31.

Table 31: NUMB Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
NUMB-C	0	0	0	5	3	**8**
NUMB J2X	**0**	0	0	2	0	**2**
Total	**0**	**0**	**0**	**7**	**3**	**10**

The remaining recoverable gas and condensate volumes are shown in Table 32 and Table 33.

Table 32: NUMB Remaining Technically Recoverable Gas Volumes, as at 31st December 2019

Case	Low Case (Bscf)	Best Case (Bscf)	High Case (Bscf)
NFA	21.0	22.5	23.9
NUMB-C/J2X Infill	17.4	33.1	55.2
Total	**38.4**	**55.6**	**79.1**

Notes:

1. The volumes in this table are to the end of April 2043; no economic cut off has been applied.
2. The volumes are prior to the deduction of fuel and shrinkage, estimated at 7.5% in 2020-2023 and 8% from 2023 onwards (Fuel = 4% and shrinkage due to CO_2 removal = 3.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 33: NUMB Remaining Technically Recoverable Condensate Volumes, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NFA	0.3	0.4	0.4
NUMB-C/J2X Infill	0.0	0.0	0.0
Total	**0.3**	**0.0**	**0.4**

Notes:

1. The volumes in this table are to the end of April 2043; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

1.4.7 Contingent Resources

Contingent Resources are assigned to wells where locations have not yet been defined. Further modelling work is required to bring to these opportunities to a higher level of confidence.

An additional three infill wells in the Lower Safa NUMB-C area, planned from 2025 were considered as Contingent Resources.

The gas Contingent Resources for the Lower Safa reservoir are shown in Table 34.

Table 34: Gross Contingent Gas Resources, NUMB, as at 31st December 2019

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Lower Safa	7.4	14.0	23.4

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2 Abu Gharadig Basin

2.1 Regional Geology

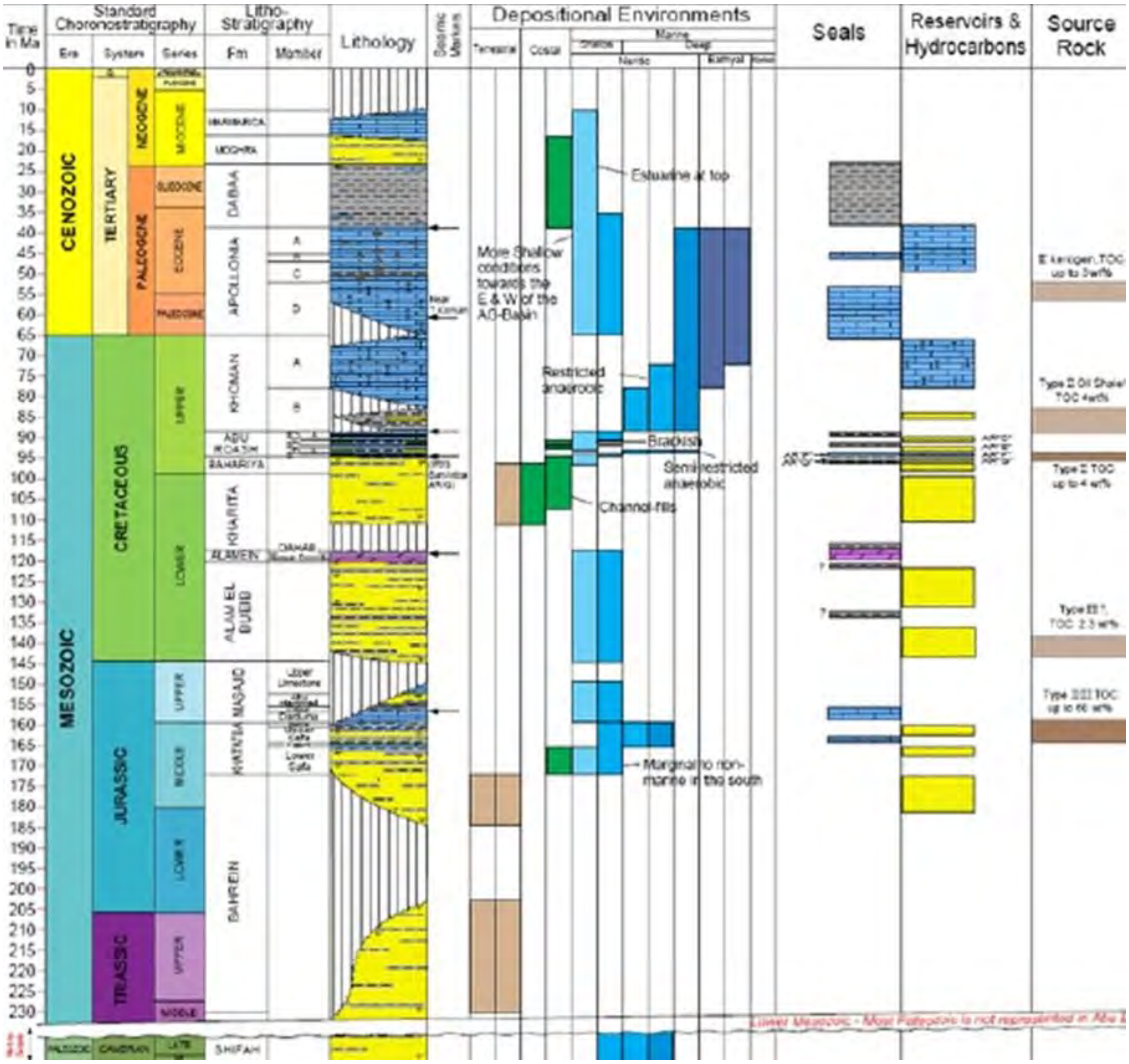
Assets in the BED, Sitra, NAES and NAEG all lie within the Abu Gharadig sedimentary basin. This forms an approximately ENE-WSW oriented depression within the platform of the Western Desert. It probably relates to an ancestral Palaeozoic basin, but owes its current form to transtensional rifting during the Triassic, Jurassic and Cretaceous. Overall the basin is controlled by approximately E-W basement faults, but the rifting has opened an extensional fabric of approximately NW-SE trending normal faulting. Rifting continued until the end of the Early Cretaceous, followed by a brief phase of passive subsidence, followed in the latest Cretaceous by a phase of inversion tectonics, created by phases of Tethyan continental convergence to the NE. From the latest Eocene to the present day, the area has seen a reversion to passive margin subsidence on the southern coast of the Mediterranean.

The overall representative stratigraphy for the area is shown in Figure 23. An initial phase of Triassic to lower Middle Jurassic sandstones represents the earliest rift phase. This was followed by carbonates in the remainder of the Middle and Upper Jurassic. Clastics dominate the Lower Cretaceous, with a mix of clastic and carbonate sedimentation in the Middle Cretaceous in the transition to post-rift phase, as a result of the complex interplay of local rifting and overall sea level. Regional carbonate sedimentation dominates the later stages of the basin's history.

Reservoirs occur principally in the sandstones of the Lower and Middle Cretaceous in the Kharita, Bahariya and Abu Roash Formations. The latter also contains some limestone reservoir interbeds. Recent discoveries have highlighted the deep potential of the Middle Jurassic Khatatba/Safa Formation sandstones and there remains other carbonate reservoir potential, deep in the Lower Cretaceous section in the Alamein Dolomite, and also in the shallow chalks of the Apollonia and Khoman Formations.

Hydrocarbon charge is complex and varies within and between each field. Sourcing is of mixed oil and gas from kitchens in the Khatatba Formation and the Abu Roash Formation, with several other subordinate source rock horizons.

Figure 23: Abu Gharadig Basin Stratigraphy



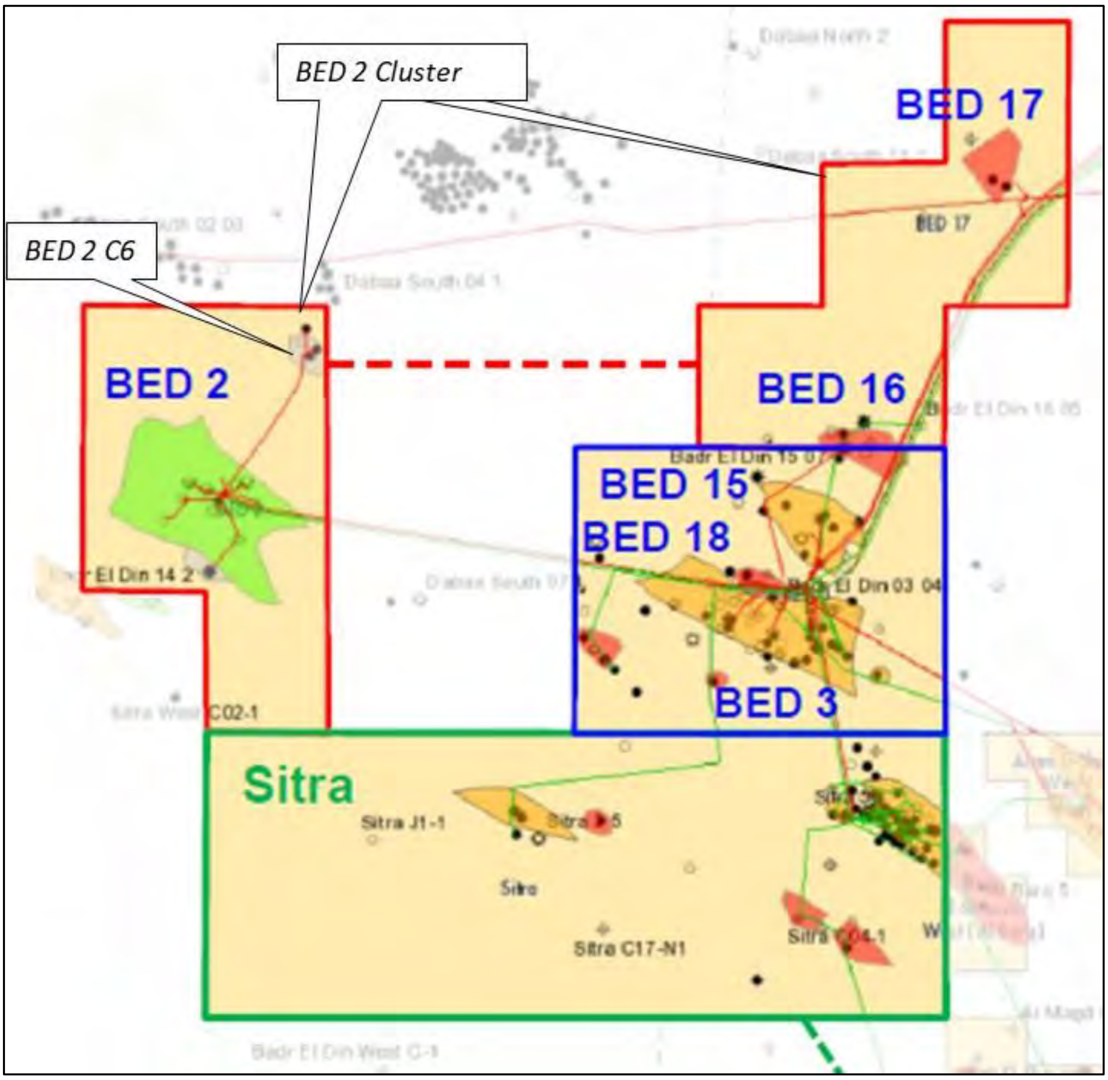
Source: Vendor VDR

2.2 BED 2 Cluster

2.2.1 Asset Description

The BED 2 cluster, as described by the vendor, consists of the BED 2, BED 16 and BED 17 development leases (Figure 24). These are considered together despite the distance of approximately 25 km between the BED 2 and BED 16 blocks.

Figure 24: BED 2 Cluster Location Map

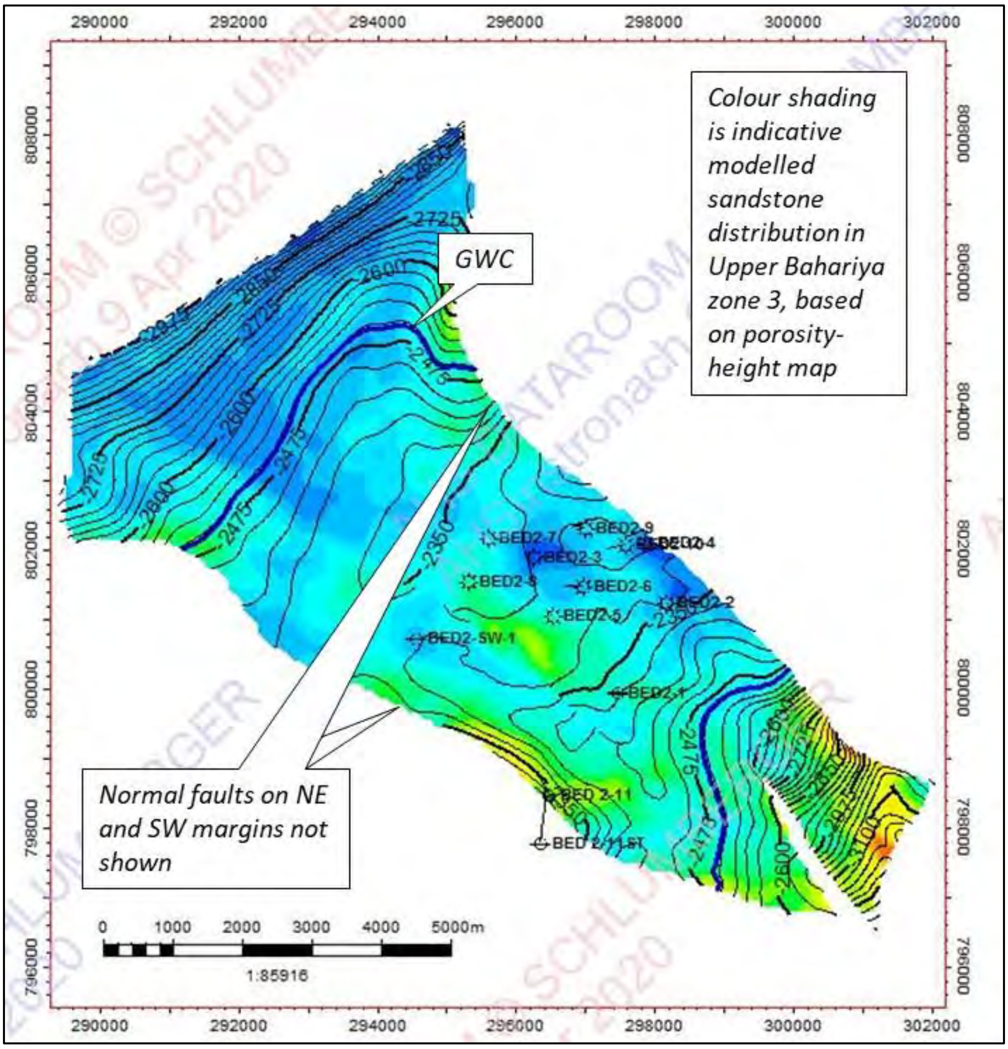


Source: Vendor VDR

2.2.1.1 Structure and Trap

BED 2 is a well-established gas field, It is a horst block structural trap, constrained by normal faults on SW and NE margins, but dip-closed to the NW and SE (Figure 25). Previous drilling has focused on the axial crest of the structure, but leaves flank areas poorly developed.

Figure 25: BED 2 Top Bahariya Depth Structure Map (m) and Modelled Sand Distribution Upper Bahariya 3 Zone



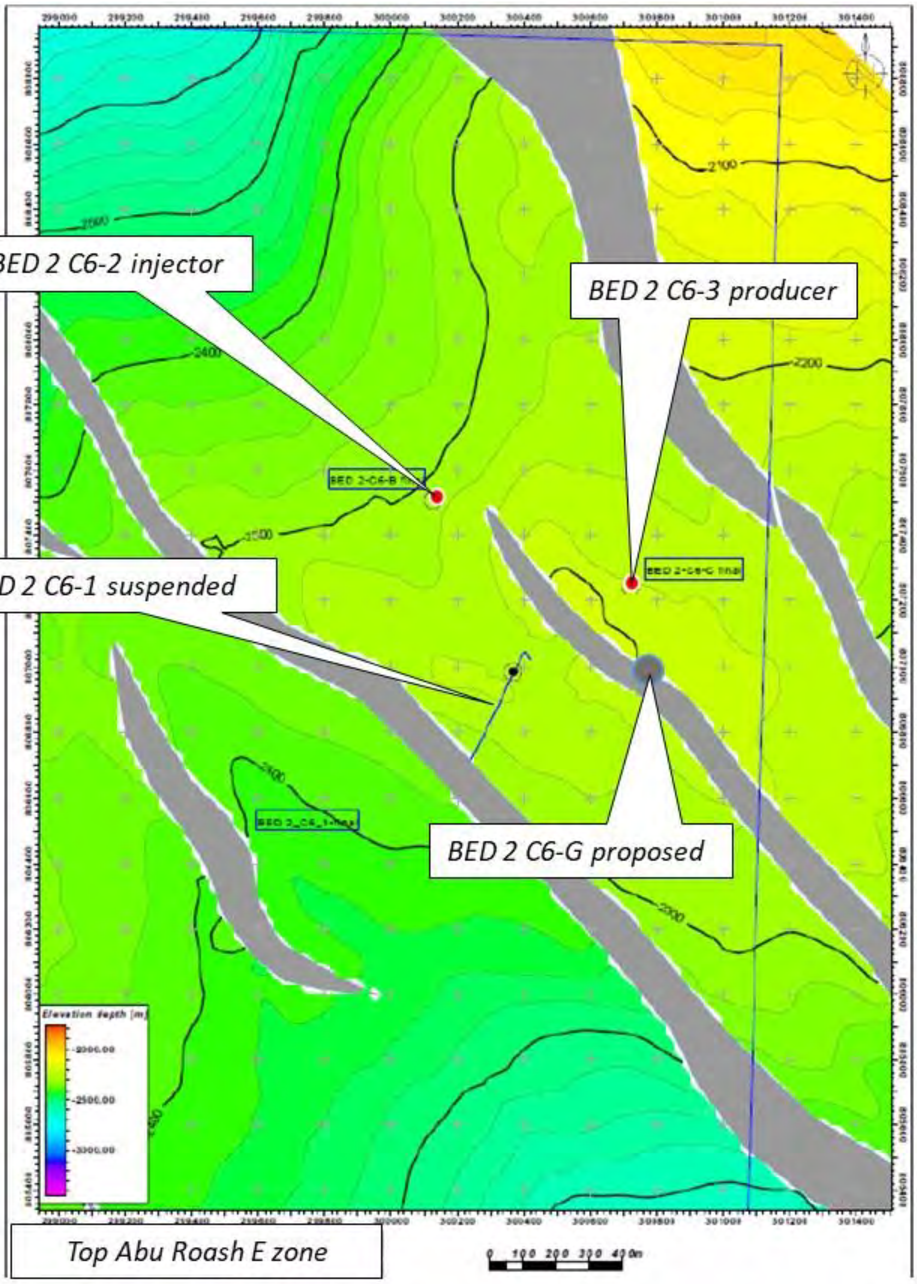
Source: Vendor vPDR

BED 2 C6 is a separate field, located approximately 6 km to the NE of the main BED 2 field. This is also controlled by normal faults to the NE and SW, and 2-way dip closure (Figure 26).

BED 16 is a structural trap, fault-closed by two normal faults to the south, but dip-closed to the north.

BED 17 is also a structural trap, controlled by a major normal fault on its northwestern boundary, but consisting of a complex of fault terraces bounded by an array of approximately NW-SE trending faults. Closures exist both in footwall and hangingwall traps.

Figure 26: BED 2 C6 Top Abu Roash E Depth Structure Map (m)



Source: Vendor vPDR

2.2.1.2 *Reservoir*

BED 2 is productive from sandstone reservoirs in the Abu Roash B, C, D, E and G zones, the Bahariya, and Kharita Formations.

BED 2 C6 produces primarily oil from Abu Roash E sandstones, with some additional potential in the carbonates of the Abu Roash D zone. Existing wells appear to define a NE-SW alignment of the Abu Roash E sandstones. There is thus question of continuity of reservoir onto the undrilled SE flank of the field.

BED 16 contains gas in the lower reservoirs of the field, the Bahariya and Kharita Formations, but oil in the Abu Roash C, E and G zones.

Oil reservoirs at BED 17 occur in the Abu Roash C and G zones, and in the Bahariya, but one zone in the Abu Roash E is gas-bearing.

2.2.1.3 Reservoir and Fluid Properties

PVT data are available from a small number of wells in the BED 2 cluster (Table 35). Gas compositions reported from separator gas are low in CO_2 (BED 2 ARG 0.52 mol%, BED 2-3 LBAH 1.33%), except at BED16, where 5.03 mol% CO_2 is reported. Overall pressure and temperature gradients are normal.

Table 35: BED 2 Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BED 2-2	ARG	No data	86.9	3,186	3,186	Not known	43	0.02	Not known
BED 2-3	LBAH	2,437	97.2	3,631	3,610	Not known	19	0.02	0.66
BED 16-3	KHAR	Not known	141.1	6,367	4,862	Not known	24	Not known	0.67

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
BED 2 C6-1	ARE	2,222	86.9	3,379	508	1.10	130	1.91	30
BED 16-4	ARC	Not known	120.6	5,186	1,305	1.28	381	0.55	39

2.2.1.4 Production Facilities

At Badr El-Din 2 (BED 2), the remote gathering station separates production fluids from the BED 2 area before export via pipeline to the BED 3 processing plant for further treatment (see section 2.3).

2.2.2 HIIP

GaffneyCline checked the petrophysical interpretations made by the Vendor by making an independent analysis of data available for three wells BED 2-2, Sitra 8-18 and Sitra 8-33. This generally validated the Vendor analyses for the BED/Sitra area and gave confidence in the petrophysical inputs to the static models and the targets identified for recompletions. It should be noted however, that data quality and coverage is only moderate, with limited log and core data available and poor borehole quality in some wells.

Particular attention was paid to assessment of the Marginal and Low Resistivity Pay (LRP) that it is used by the Vendor to ascribe upside potential to the Bahariya and Kharita Formations. The reports provided describing the Vendor's analysis and showing the presence of thin hydrocarbon-bearing reservoirs were reviewed by GaffneyCline. Thin-bedded reservoirs do appear to be present, and hydrocarbon volume in these intervals would be under-estimated by conventional log analysis methods.

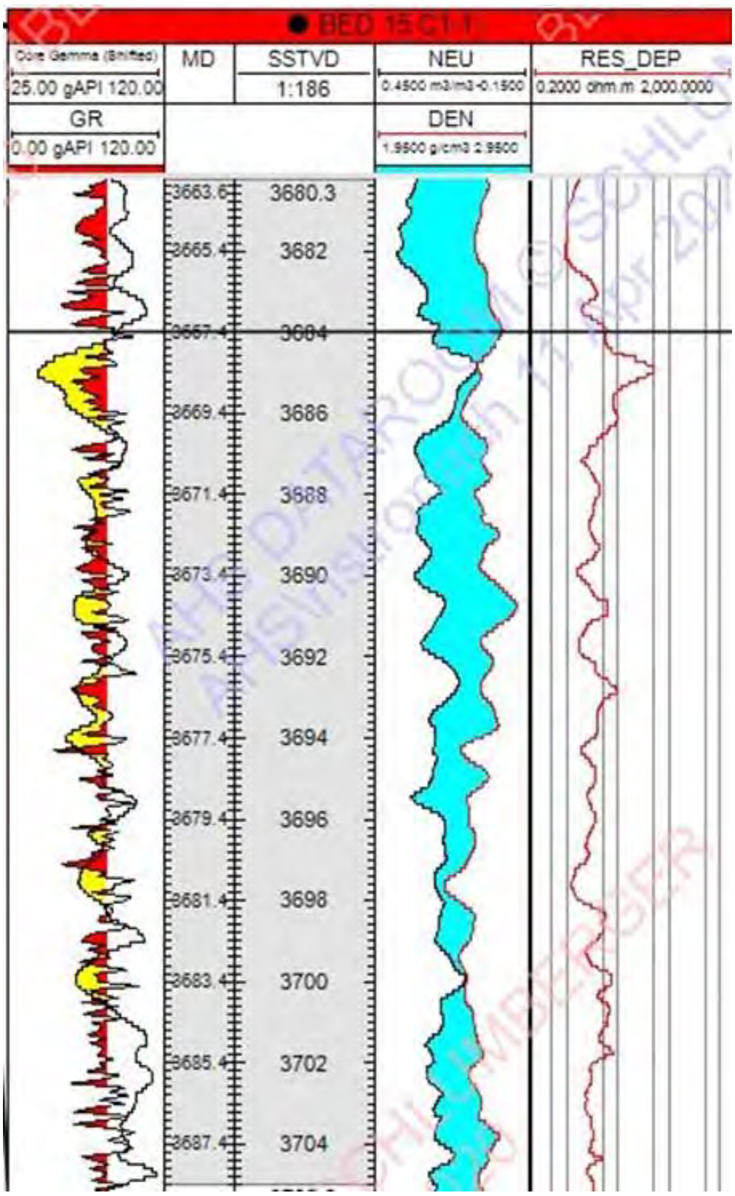
HIIP has not been closely re-evaluated by GaffneyCline for the established producing reservoirs, but it has been for the Bahariya Formation, where significant upside is described by the vendor. This relies on the recognition of poor quality and "low resistivity pay" (LRP) intervals that have not been currently exploited. As well as resulting from errors and uncertainties in previous petrophysical analysis, newly recognized LRP may result from:

- Thin beds not fully resolved by wireline log data;
- Clay (illite) bound water;
- Structural water in mixed-layer clays – basement for this reportedly at 3,500 m.

Comparison of core and wireline log data from the BED 15 area (Figure 27) show that indeed thin sandstone beds may not be fully recognised in the latter dataset, but also that overall bed thickness may be exaggerated. Certain zones (e.g. the Uppermost Bahariya 0 unit, Figure 28) may have substantial gas unrecognised because of high clay content. The Vendor claim uplifts of GIIP by including LRP ranges from 16 to 34%. The main Upper Bahariya 3 unit seems to be associated with 46% increase. A 2017 study by the Vendor records a general 40% increase. GaffneyCline's review suggests that this resource may be present and indicative volume uplift may be correct, but poor reservoir connectivity and predictability suggests that its effect on recoverable gas volumes may be relatively small.

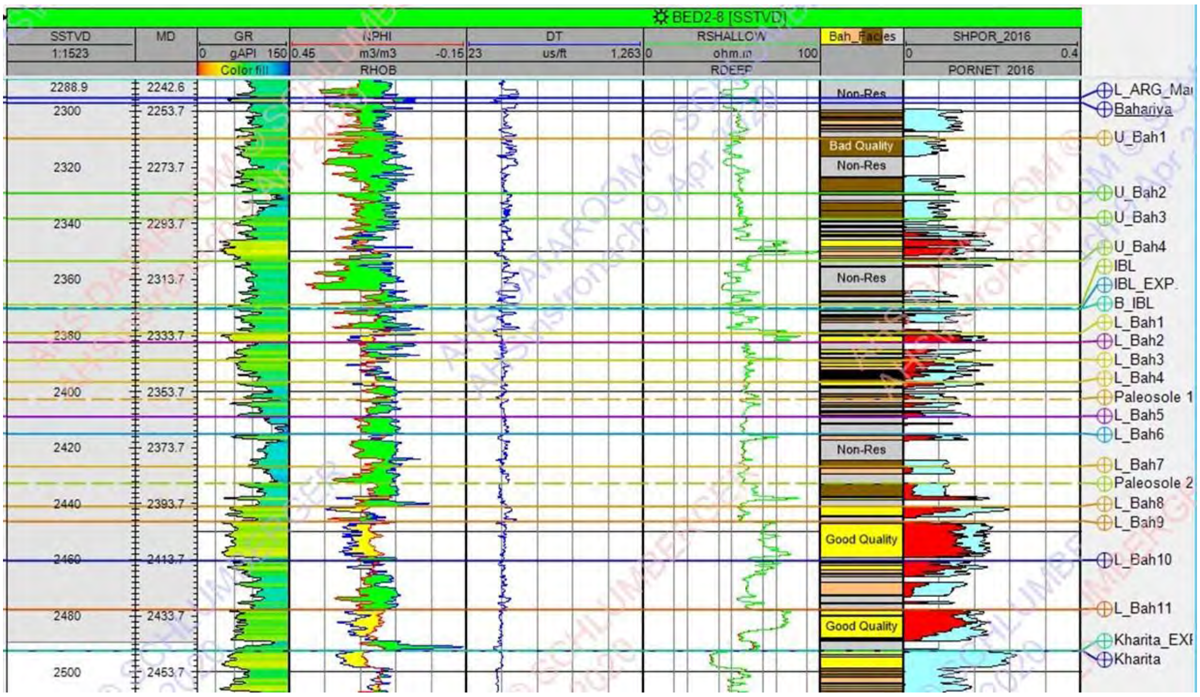
A summary of GIIP estimates for BED-2 is shown in Table 36 and STOIIP in Table 37.

Figure 27: BED 15 C1-1. Comparison of Core and Wireline Gamma Log, Upper Bahariya Formation



Source: Vendor vPDR

Figure 28: BED 2-8: Bahariya Formation Reservoir Section



Source: Vendor vPDR

Table 36: BED 2 Cluster GIIP

Location	Source	Reservoir		GIIP (Bscf) Low	Best	High	Notes
BED 2 T	Vendor VDR	Apollonia		43.8	76.1	139	Total volume of seismic anomaly, covering three fault blocks
BED 2	Vendor VDR	Abu Roash BCD		85.7	101	116	
		Abu Roash E		88	97	108	
		Abu Roash G		141	159	177	
	GaffneyCline Estimate in Best Case. Low and High from vendor VDR.	Upper Bahariya	Good sand facies	1,268	119	1,384	Based on 2017 modelling study and on calculations in vPDR database. Total GIIP to be targeted by new drilling is 707 Bscf in “poor” and “LRP” reservoir facies. Low and High case ranges not defined for each category. The range quoted by vendor does not fully express uncertainty in “poor” and “LRP” facies.
			Poor sand facies		273		
			LRP		197		
		Lower Bahariya	Good sand facies		499		
			Poor sand facies		138		
			LRP		99		
BED 2 C4	Vendor VDR	Abu Roash D		14.3	46	92.3	
BED 2 J11	Vendor VDR	Upper Safa		4.4	18.5	35.3	
BED 16	Vendor VDR	Bahariya and Kharita		-	106	-	
BED 17	Vendor VDR	Abu Roash E		-	21	-	

Table 37: BED 2 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
BED 2C6	Vendor volume calculation and Vendor FDP	Abu Roash B	4.4	7.1	11.3	From mix of material balance and static calculations, generally validated by GaffneyCline.
		Abu Roash C	-	4.9	9.5	
		Abu Roash D	3.6	5.5	8.1	
		Abu Roash E	1.7	3.1	3.7	
BED 2 C4	Vendor VDR	Abu Roash E	3.1	9.5	20.8	
BED 2 C3-1	Vendor VDR	Lower Bahariya	7.9	10.6	13.9	
BED 16	Vendor VDR	Abu Roash C	-	4	-	
		Abu Roash E	-	6	-	
		Abu Roash G	-	9	-	
BED 17	Vendor VDR	Abu Roash C	-	3	-	
		Abu Roash G	-	4	-	
		Bahariya	-	2	-	

2.2.1 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 38.

Table 38: BED 2 Cluster: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
BED 2 NFA	BED 2 NFA		**Reserves**
BED 16 NFA	BED 16 NFA		**Reserves**
BED 17 NFA	BED 17 NFA		**Reserves**
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
BED 16 infill	BED 16 infill		**Reserves**
BED 2 infill	BED 2 infill (BED 2C6 and BED 2-C3)	Additional drilling in Abu Roash E reservoir	**Reserves**
General infill	Not included	All development activity viewed as covered by other categories.	N/A
BED 2 C2E	BED 2 NFE	Suite of discoveries requiring further appraisal and prospects.	Both **Contingent and Prospective Resources**
BED 17 C2E	BED 17 NFE	Satellite structures to	**Prospective Resources**
Upside	BED 2 upside	Bahariya Formation	**Contingent Resources.** Development plans require further detail in view of reservoir uncertainty.

2.2.2 Historical Field Performance

2.2.2.1 BED 2

Gas production from the Bahariya reservoir started in 1992 with well BED 2-1 and 10 further development wells were drilled by 2006. The BED 2 gas production history is shown in Figure 29.

Figure 29: Historical Gas and CGR Production Rates, BED 2 (Bahariya)

Oil production from the C6 reservoir commenced in 2014 and peak production of 1,400 bopd from four wells was reached in 2018. At end 2019, it was producing from one well BED 02 C6-3 with an average rate of 400 bpd and a watercut of 9.5%. The BED 2 oil production history is shown in Figure 30.

Figure 30: Historical Oil Production Rate, BED 2 (C6)

2.2.2.2 BED 16

Oil production commenced in 1990 and gas production in 2005. Oil production increased in 2006 to 750 bpd with the drilling of BED 16-4 and 16-8. Current production is from well BED 16-8 with rate of 400 bopd.

Figure 31 and Figure 32 show the gas and oil production history for the BED 16 field respectively.

Figure 31: Historical Gas and Water Production Rates, BED 16 Kharita and Bahariya Reservoirs

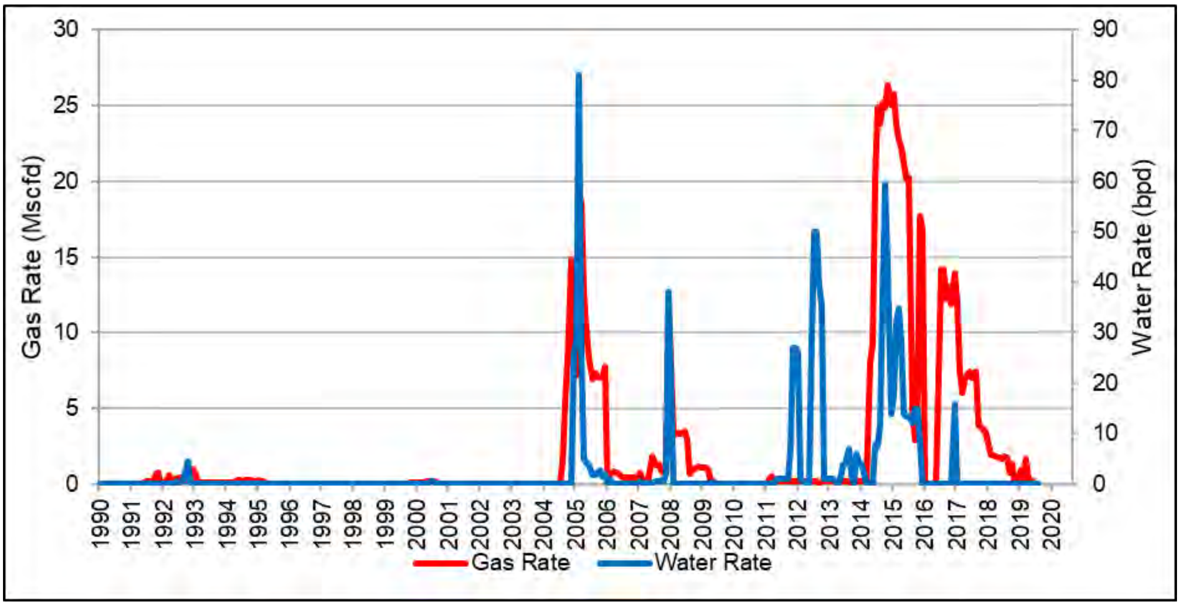
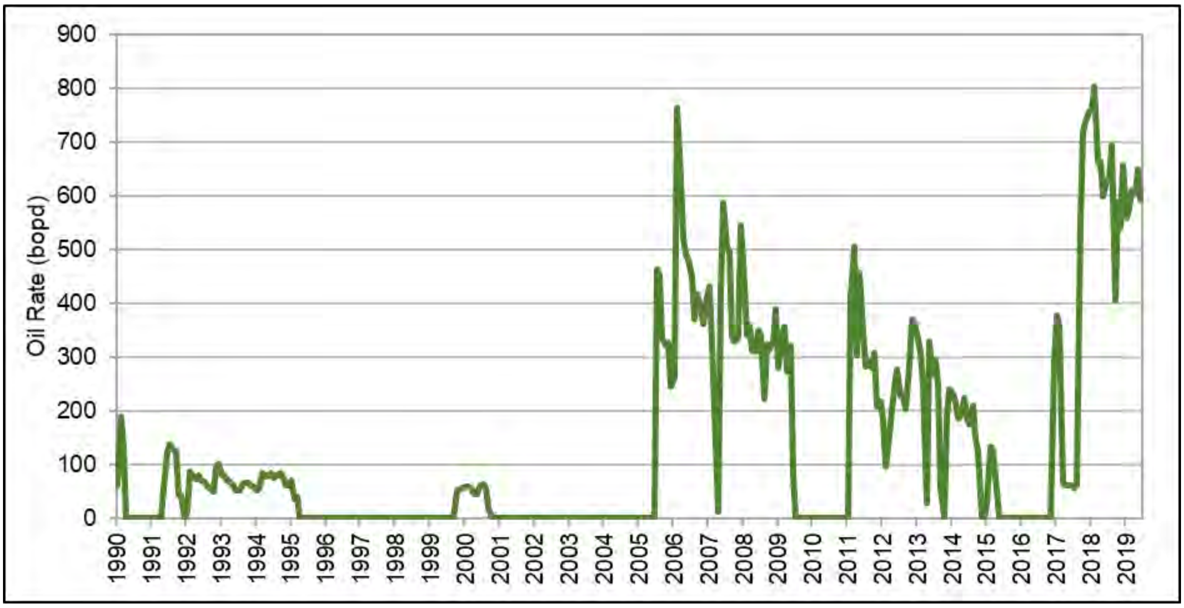


Figure 32: Historical Oil Production Rate, BED 16



2.2.2.3 Summary

The BED 2, 16 and 17 historical production performance is summarized in Table 39.

Table 39: BED 2, 16 and 17 Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
BED 2	12	1.5	830.5	530.4	13.8	951.8
BED 16	2	1.5	24.9	615.0	0.6	0.0
BED 17	1	0.2	5.8	147.7	0.0	2.0
Total	**15**	**3.2**	**861.2**	**1,293.1**	**14.5**	**953.8**

Note:

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

2.2.3 Field Development Plan

2.2.3.1 BED 2

The consortium's future development plans for the fields include the following activities:

- One new horizontal infill oil producer planned in the BED 2 C6 (ARE and ARD) area in 2020.

  At the Effective Date, BED 2 C6 was producing from a single producer-injector pair. A further production well was planned to target the crestal area of the main fault block and to improve drainage of the southeastern flank of the field, although there is some uncertainty over sand continuity into this area. This well has been drilled as BED 2 C6-5 in 1Q 2020, post the Effective Date of this report, and is successfully on stream as an oil producer.

- No new firm wells are planned in the Bahariya gas reservoirs. Eleven new wells and four workovers assumed in the Bahariya gas reservoir are considered as Contingent Resources.

  Modelled sandstone reservoir development is concentrated in the crestal parts of the field, with more limited and discontinuous sandstones on the flanks. The Consortium proposes the 11 well campaign to specifically target the untapped more marginal reservoirs and LRP (see above). No specific locations are defined but in general terms a small number of axial targets may be able to be defined using the existing dataset, but those on flank of field are high risk due to (i) poor reservoir presence, (ii) uncertain distribution of marginal facies and (iii) proximity to water. These resources have been estimated using the static model for the reservoir, but are here considered Contingent on demonstration of satisfactory targeting of undrained low quality reservoirs and demonstration of successful production performance.

- Appraisal and development of discoveries made in the Lower Bahariya.

  An oil discovery has been made at BED 2 C3-1 in the Lower Bahariya and Kharita Formations in the extreme south of the BED 2 block. A small 3-way dip closure is controlled by a normal fault on its NE margin. Two main sandstones are present with approximately 15 m of net pay, but with several subordinate units, and porosity is approximately 18%. Two further firm wells were planned to further appraise and develop this. Subsequent to the Effective Date of this Report, in 1Q 2020, wells BED 2 C3-2 and BED 2 C3-3 have been drilled, although the latter required sidetracking as BED 2 C3-3ST to find optimum reservoir. Both are successfully on stream as oil producers from the Lower Bahariya Formation. Thus two new wells as well as well BED 2 C3-1 have been included in the Reserves estimates. BED 2 C3 wells are verticals.

- Appraisal and development of discoveries made in the Apollonia Formation.

  The Consortium has provided a detailed model of reservoir development in the Apollonia Formation at BED 19. On this basis further potential is ascribed to similar structures at BED 2. Gas is discovered at BED 2-7 and mapping of seismic amplitude attributes suggests that the pool straddles three normal fault blocks extending northeastwards to BED 2 C6, where there are more tentative gas indications at BED 2 C6-2. The target is extremely shallow at around 800 m, so porosities may exceed 0.4, and the gas is dry. Only one well is currently scheduled, so the resources remain Contingent on firming a more complete development plan.

The schedule for the firm activities above has been defined in the consortium's Business Plan and is summarized in Table 40.

Table 40: BED 2 C6 and C3 Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	4	0	0	0	0	**4**
Injection Wells	0	0	0	0	0	**0**
Total	**4**	**0**	**0**	**0**	**0**	**4**

2.2.3.2 BED 16

The Consortium's future development plans for BED 16 includes four new infill wells in the Kharita and Bahariya gas reservoirs (Table 41) and three new infill wells in the ARG oil reservoir (Table 42). These are understood to be targeting western, crestal areas of the field.

Table 41: BED 16 Kharita and Bahariya Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	1	3	0	**4**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**1**	**3**	**0**	**4**

Table 42: BED 16 ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	3	0	0	**3**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**3**	**0**	**0**	**3**

2.2.3.3 BED 17

No new infill wells are planned in the near future. No Contingent Resources are included in the "near field exploration" programme.

2.2.4 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (10th April 2034).

Table 43 and Table 44 show the remaining technically recoverable gas and oil volumes for the BED 2 cluster.

Table 43: Remaining Technically Recoverable Gas Volumes, BED 2 Cluster, as at 31st December 2019

Area	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
BED 2	24.3	**31.0**	36.9
BED 16	4.4	**27.0**	51.1
BED 17	0.0	**0.0**	0.0
SI Re-activation	0.3	**0.3**	0.4
Total	**29.0**	**58.3**	**88.4**

Notes:

1. The volumes in this table are to April 2034; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 44: Remaining Technically Recoverable Oil and Condensate Volumes, BED 2 Cluster, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
BED 2	3.3	3.9	4.7
BED 16	0.8	2.1	3.3
BED 17	0.0	0.0	0.1
SI Re-activation	0.5	0.5	0.5
Total	**4.6**	**6.5**	**8.6**

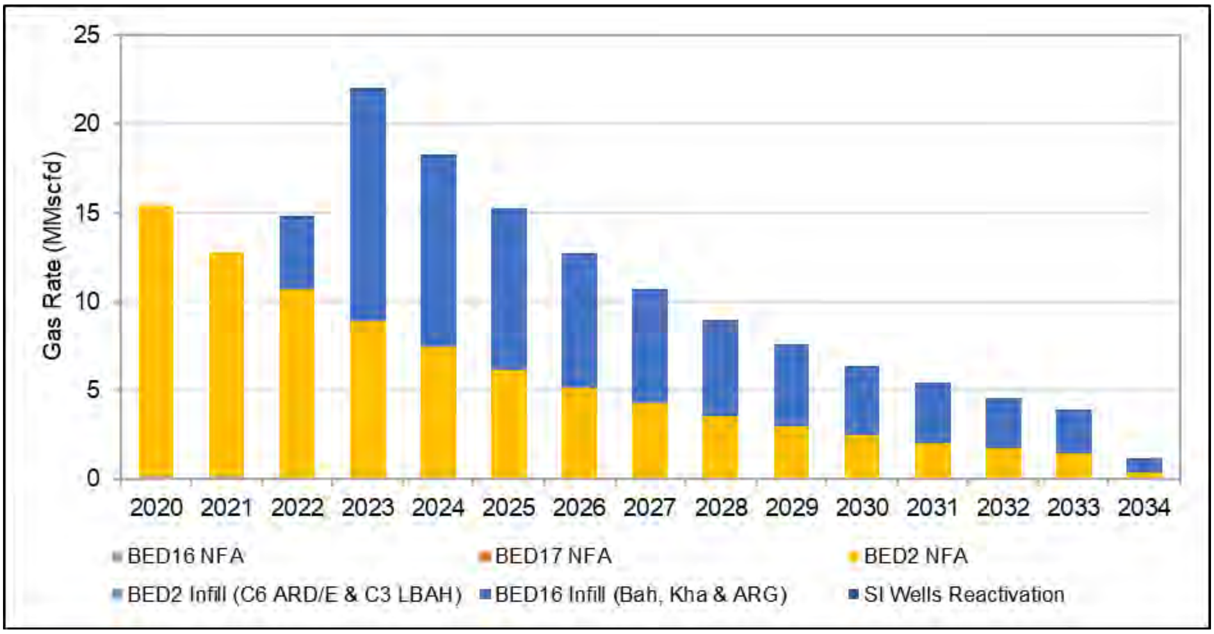
Notes:

1. The volumes in this table are to April 2034; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 33 and Figure 34 show the gas and oil production forecasts for the BED 2 cluster by activity.

Figure 35 and Figure 36 show the Low, Best and High production forecasts for the BED 2 cluster.

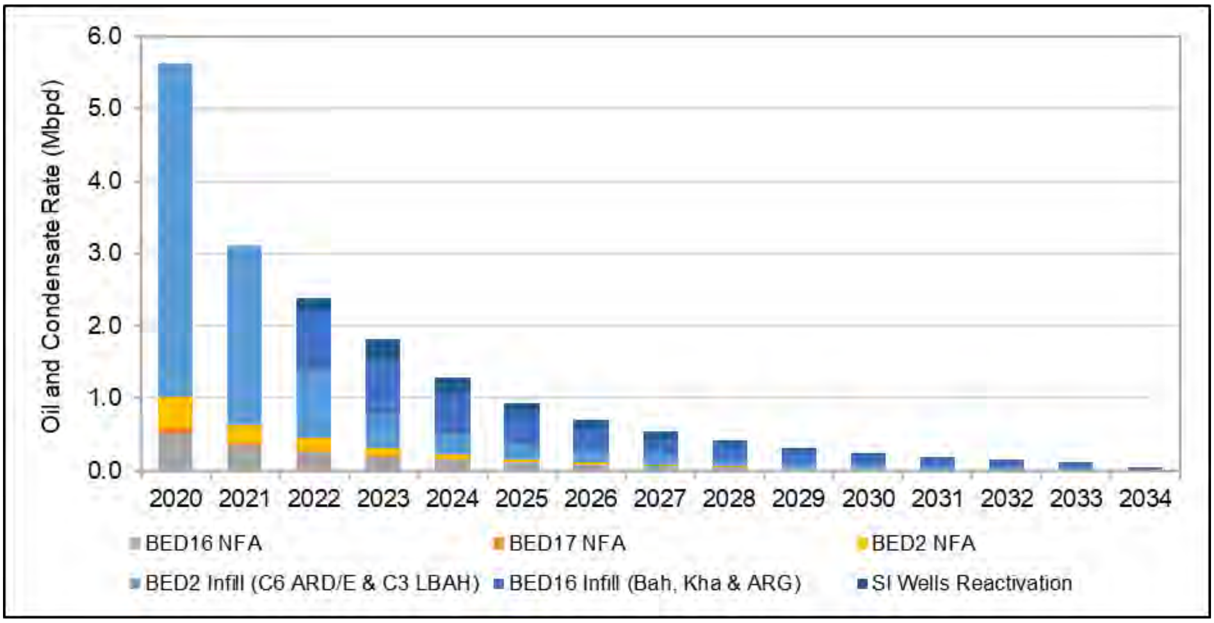
Figure 33: Best Case Gas Production Forecasts, BED 2 Cluster



Notes:

1. The values in this figure are annual average rates and in 2034 include production only until April; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

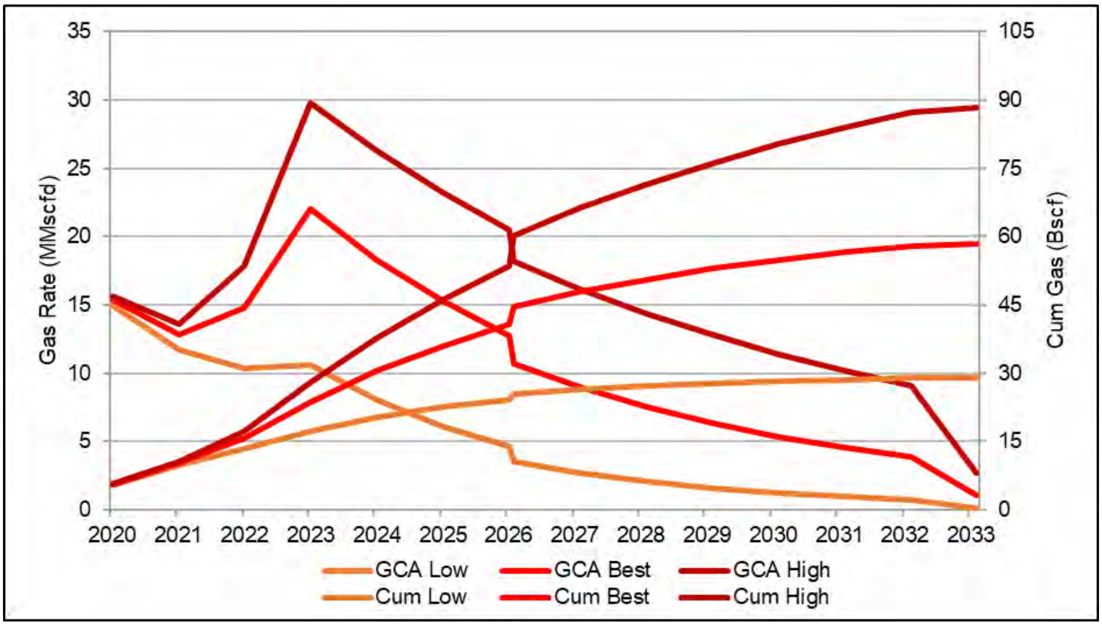
Figure 34: Best Case Oil and Condensate Production Forecasts, BED 2 Cluster



Note:

1. The values in this figure are annual average rates and in 2034 include production only until April; no economic cut off has been applied.

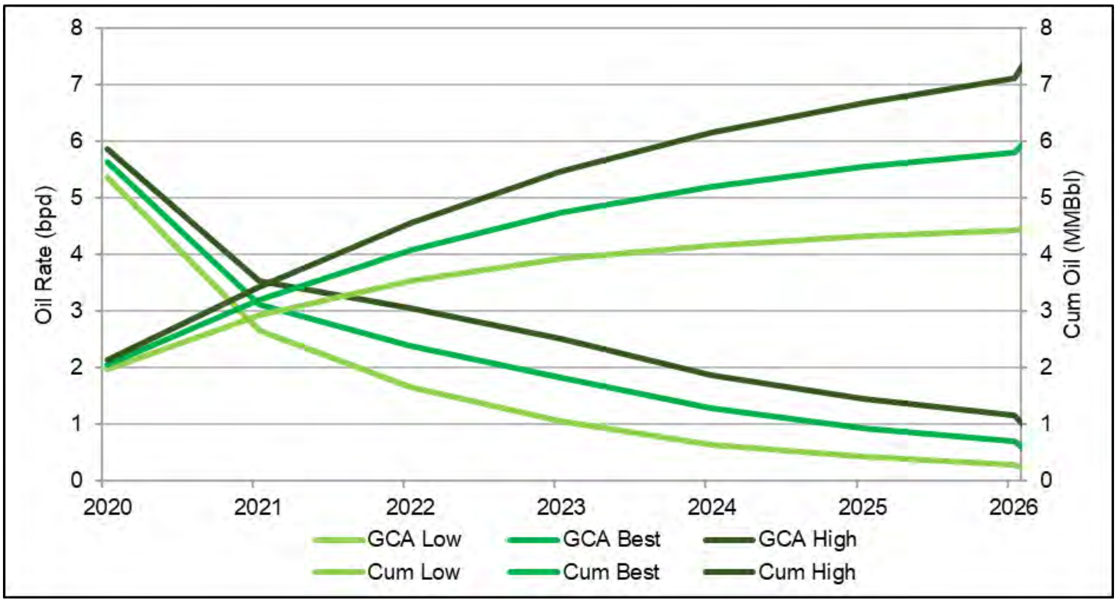
Figure 35: Gas Production Forecasts, BED 2 Cluster



Notes:

1. The values in this figure are annual average rates and in 2034 include production only to April; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 36: Oil and Condensate Production Forecasts, BED 2 Cluster



Note:

1. The values in this figure are annual average rates and in 2034 include production only to April; no economic cut off has been applied.

2.2.5 Contingent Resources

Contingent Resources were assigned to wells where further clarification of the development is required to address technical uncertainty. Further modelling work is required to bring to these opportunities to a higher level of confidence.

The incremental production from 11 infill gas wells in the BED 2 Bahariya reservoir are considered as Contingent Resources. In addition, the incremental production from four workovers is also considered as Contingent Resources.

There are Contingent Resources assigned to BED 2 in the Apollonia, ARB and ARD reservoirs.

The BED 2 Contingent Resources are summarized in Table 45.

Table 45: Gross Contingent Resources, BED 2 Cluster, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
BED 2 (Bahariya)	18.0	35.3	55.5
BED 2 (Apollonia)	8.3	23.3	52.3
BED 2 C6 (ARB)	0.0	0.0	0.0
BED 2 C6-HA (ARD)	0.0	0.0	0.0
Total	**26.3**	**58.6**	**107.8**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
BED 2 (Bahariya)	0.2	0.7	1.1
BED 2 (Apollonia)	0.0	0.0	0.0
BED 2 C6 (ARB)	0.5	0.7	1.1
BED 2 C6-HA (ARD)	0.6	0.9	1.5
Total	**1.3**	**2.3**	**3.7**

Notes:

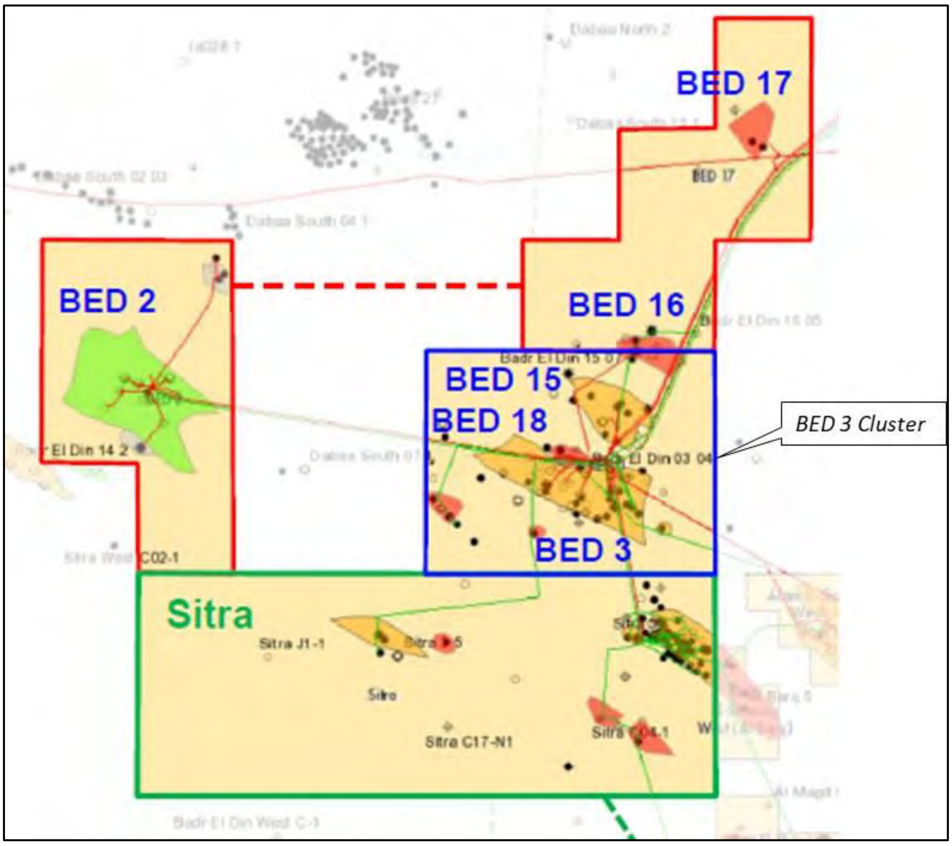
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.3 BED 3 Cluster

2.3.1 Asset Description

The BED 3 cluster, as described by the Consortium, consists of the BED 3, BED 15 and BED 18 development leases (Figure 37).

Figure 37: BED 3 Cluster Location Map



Source: Vendor VDR

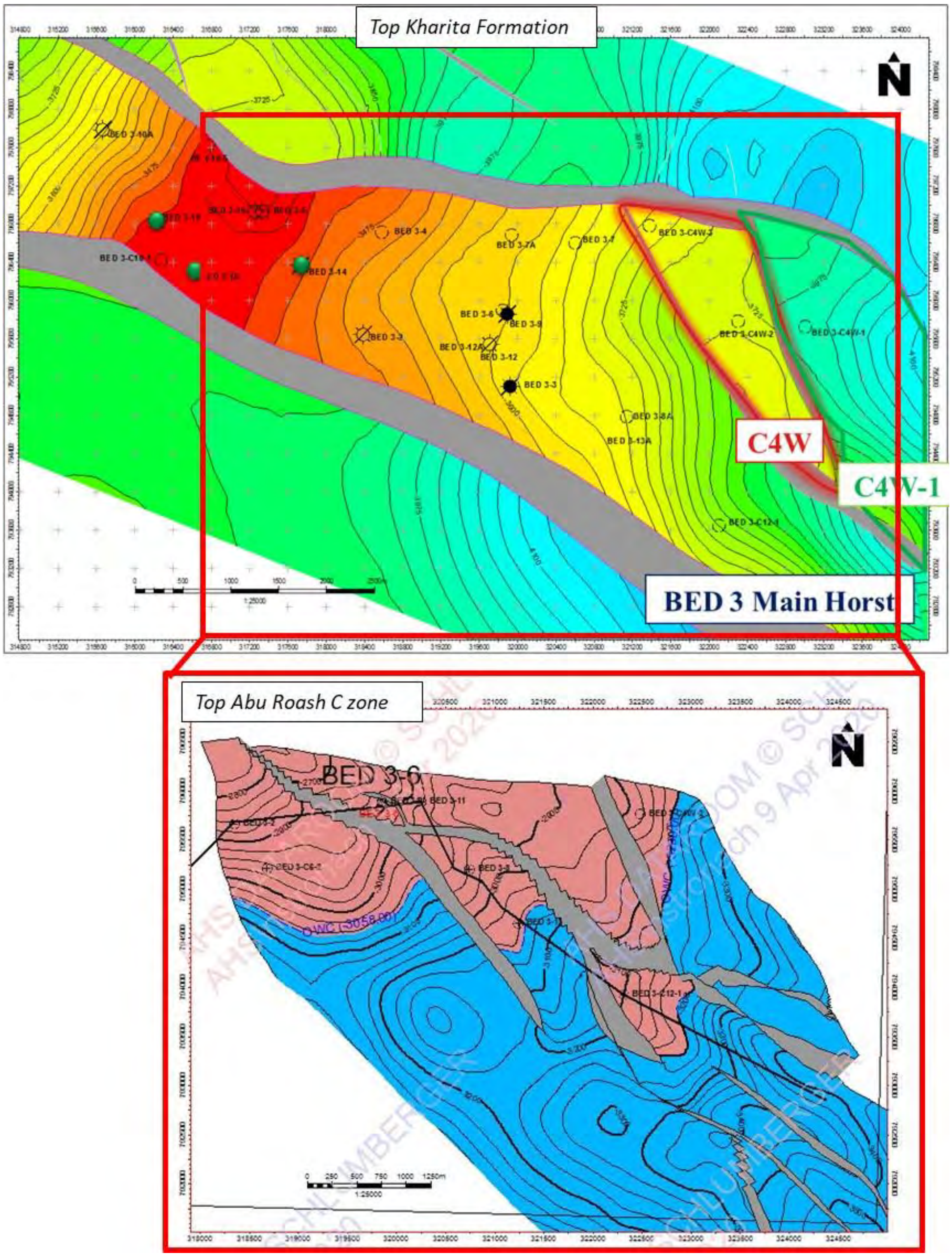
2.3.1.1 *Structure and Trap*

BED 3 is the principal field and comprises a complex of individual fault blocks, associated with a major NW-SE trending horst at depth whose bounding faults splay upwards and southwards. There is thus a relatively simple structure at Bahariya Formation level, but more complex fragmentation of the structure within the Abu Roash Formation. Individual fault blocks may thus have a component of NW or SE dip closure. The fault block and well nomenclature is complex, with individual component and satellite fault blocks carrying distinct names. Representative depth structure maps are shown in Figure 38.

BED 15 is controlled by a major NW-SE trending normal fault system. Closures in the deep section, at Kharita level are in the footwall of this fault, with dip closure to the NE. In the shallower, Abu Roash section, hydrocarbons also occur in the hangingwall section and appear to be partly stratigraphically controlled along N-S trending sandstone fairways.

BED 18 occupies the footwall of a major E-W trending fault. A N-S fault trend separates the field into west and east compartments. It appears that the orientation of the sandstone trend in the main Abu Roash G reservoir approximately aligns with the structural trend.

Figure 38: BED 3 Kharita Formation and Abu Roash C Reservoir, Depth Structure Maps (m)



Source: Vendor VDR and vPDR

2.3.1.2 Reservoir

BED 3 reservoirs are oil bearing in the Abu Roash C, E and G zones, and in the Upper Bahariya Formation, and gas-bearing in the Lower Bahariya and Kharita Formations. Most recent drilling success has been in the Abu Roash G. This unit consists of approximately NW-SE aligned shoreline trends, cut by orthogonal tidal channel and delta deposits. This creates a complex sand architecture which leads to uncertainty in volumetric estimates, but also further drilling opportunities.

Reservoirs at BED 15 are oil-bearing in the Abu Roash C and E zones and in the Upper Bahariya Formation, and gas-bearing in the Lower Bahariya and Kharita Formations. The principal oil bearing sandstone is oriented axially along the crest of the field.

BED 18 is an oil field in the Abu Roash E and G zones.

2.3.1.3 Reservoir and Fluid Properties

PVT data are available for representative medium and light oil samples in the Abu Roash Formation, and from gas in the deeper Bahariya and Kharita Formations (Table 46). In the gas reservoirs, CO_2 content in the samples ranges up to 4.87 mol% at BED 3-10 in the Kharita Formation. Pressure and temperature gradients are indicated to be normal.

Table 46: BED 3 Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BED 15-5	KHA	Not known	126.7	Not known	5,625	Not known	20	0.01	0.68
BED 3-10	KHA	Not known	Not known	Not known	Not known	Not known	80	Not known	0.69
BED 3-4	BAH	Not known	126.1	5,445	5,390	Not known	Not known	Not known	
BED 3-2	KHA	3,516	122.2	5,523	5,440	0.0040	44	Not known	0.66

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
BED 3 C6-1	ARG	3,345	121.7	5,250	1,668	1.22	303	1.98	33
BED 3 C9-1	ARG	Not known	115.6	4,980	4,100	1.75	1336	0.25	44
BED 18-2	ARG	3,275	119.7	5,347	1,675	1.32	433	0.69	32
BED 3-8	ARC	3,037	112	4,363	2,450	1.75	990	0.25	42
BED 3-6	ARC	2,808	106.7	Not known	2,243	1.75	1036	0.23	38

2.3.1.4 Production Facilities

The facilities at the BED3 main processing plant serve as the processing point for the BED3 area. The development of BED3 has grown organically and the main processing plant is supplied with production fluids from a number of remote gathering stations/facilities, namely:

- Badr El-Din 2 (BED2) facility;
- Sitra Early Production Facility (EPF);
- Al Barq facility (AESW);
- Bagha facility (AESW); and
- North East Abu Gharadig JD facility.

The BED 3 processing plant has three main gas processing trains operating at high pressure, medium pressure and low pressure. Each gas train separates, compresses (MP and LP trains only), dehydrates, and recovers NGLs to ensure the export gas is of sales quality. The BED3 plant has the potential to process up to 340 MMscfd of gas, and 30 MBbl/day condensate.

The treated gas from BED3 is then exported to Amereya. Condensate is stabilised and dehydrated before being exported to Hamra Terminal for offtake by tanker. Condensate from Bagha and Al Barq facilities are sent directly to the storage tanks at BED3.

2.3.2 HIIP

GaffneyCline has evaluated the HIIP provided by the Vendor, with particular emphasis on confirming the Best Case for the established oil reservoirs and the upside potential in the deep gas-bearing reservoirs. The lack of detailed reservoir maps and static models means that there is uncertainty around the precise HIIP in the more sedimentologically complex Abu Roash reservoirs, and this has not been fully evaluated in the Vendor dataset.

The gas and oil in place estimates are shown in Table 47 and Table 48.

Table 47: BED 3 Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			Notes
			Low	Best	High	
BED 3	Vendor VDR	Lower Bahariya	-	102	-	
		Kharita	-	1,200	-	
BED 15	Vendor VDR	Lower Bahariya	-	309	-	
		Kharita	-	263	-	Corroborated by GaffneyCline estimate

Table 48: BED 3 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
BED 3	Vendor VDR and FDP	Abu Roash C	4.8	12.8	17.3	Principally in BED 3-6 block (7 MMBbl) and in BED C6 block (6 MMBbl), where development activity anticipated
			-	5	-	Estimated additional volume in other fault blocks
		Abu Roash E	-	4	-	No range estimated.
		Lower Abu Roash G	5.5	8.7	27	BED C6 block only.
			-	4	-	Estimated additional volume in C18 block. No range estimated.
			-	24	-	Estimated additional volume including other BED 3 and satellite blocks. No range estimated.
		Upper Bahariya	-	20	-	No range estimated.
BED 15	Vendor VDR	Abu Roash C	-	45	-	No range estimated
		Abu Roash E/Upper Bahariya	-	21	-	No range estimated
BED 18	Vendor VDR	Abu Roash E	-	4	-	No range estimated
		Abu Roash G (West)	-	12	-	No range estimated
	GaffneyCline estimate	Abu Roash G (East)	-	4.3	-	No estimate provided by vendor. Approximate GaffneyCline estimate only.

2.3.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 49.

Table 49: BED 3 Cluster: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
BED 3 NFA	BED 3 NFA		**Reserves**
BED 15 NFA	BED 15 NFA		**Reserves**
BED 18 NFA	BED 18 NFA		**Reserves**
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
BED 3 infill	BED 3 infill		**Reserves**
BED 15 infill	BED 15 infill		**Reserves**
BED 18 infill	BED 18 infill	Mainly ARG wells to develop east of field.	**Reserves**
General infill	Not included	All development activity viewed as covered by other categories.	N/A
BED 3 C2E	BED NFE Included only in upside case	Mainly additional prospects in satellite structures (e.g. C9, C19)	**Prospective Resources**
Upside	BED 3 upside	Bahariya Gas	**Contingent Resources**. Development plans require further detail in view of reservoir uncertainty.
	BED 15 Upsides	Kharita Gas	

2.3.4 Historical Field Performance

2.3.4.1 BED 3

BED 3 production commenced in 1990 with BED 3-1 producing gas from the Kharita gas reservoir. Peak production of 200 MMscfd occurred during 1998 to 2001. The last well was drilled in 2011, adding 20 MMscfd.

BED 3 oil production started in 1991 with oil production in ARC, ARE and ARG reservoirs. Water injection in ARG began in 2012.

Historical field gas and oil production are shown Figure 39 and Figure 40 for the BED 3 field.

Figure 39: Historical Gas Production Rate and CGR, BED 3 (Kharita and Bahariya)

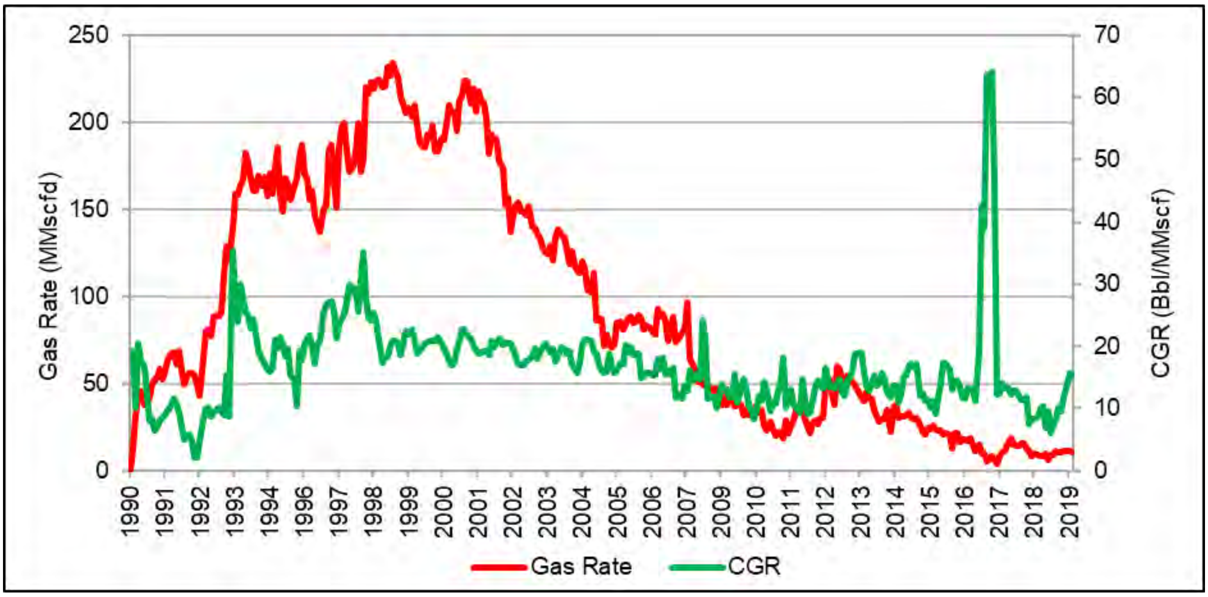
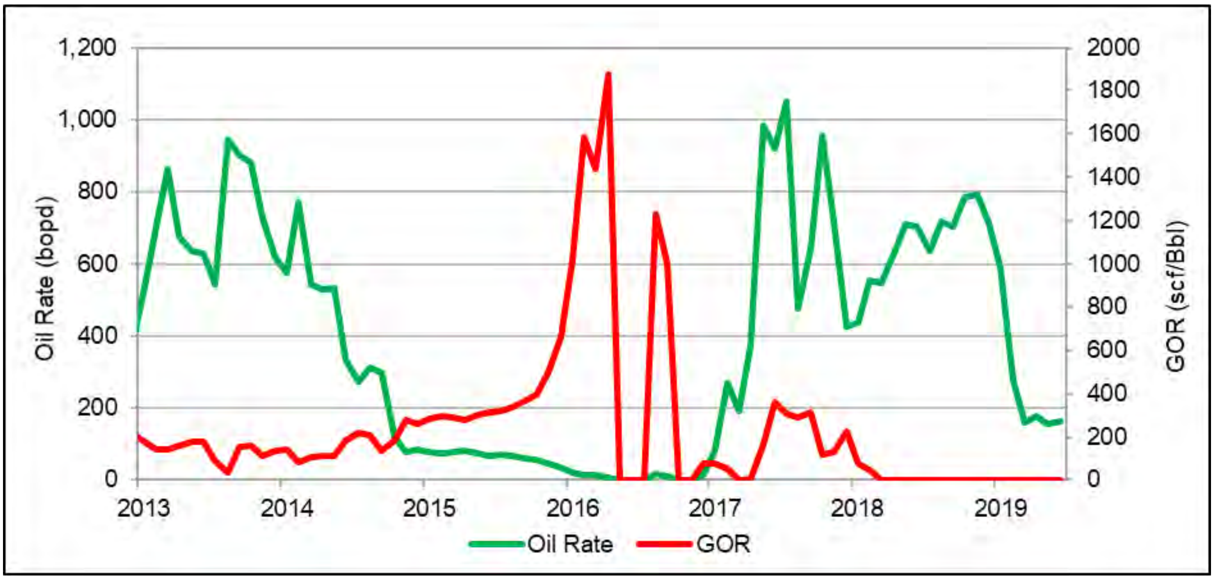


Figure 40: Historical Oil Production Rate and GOR, BED 3 (ARC and ARG)



2.3.4.2 BED 15

Oil production first started in 1989 with BED 15-1 well. Peak production of 5,000 bopd occurred in 1991 when BED 15-3 came on stream. Water injection started in 2003 with well BED 15-7, followed by well BED 15-8 in 2004 and well BED 15-9 in 2005. The last well was drilled in 2018 in a separate fault block.

First gas production came from the Kharita reservoir through well BED 15-5 in 1998 reaching a peak production of 45 MMscfd more than a year later. A second peak of production occurred in 2002 with the drilling of well BED 15-6. BED-11 and BED 15-12 followed in 2013 and 2018 respectively.

Historical field gas and CGR production profiles for the BED 15 Kharita gas are shown in Figure 41. Historical field oil and watercut production form the ARC formation are shown in Figure 42.

Figure 41: Historical Gas Production Rate and CGR, BED 15 (Kharita)

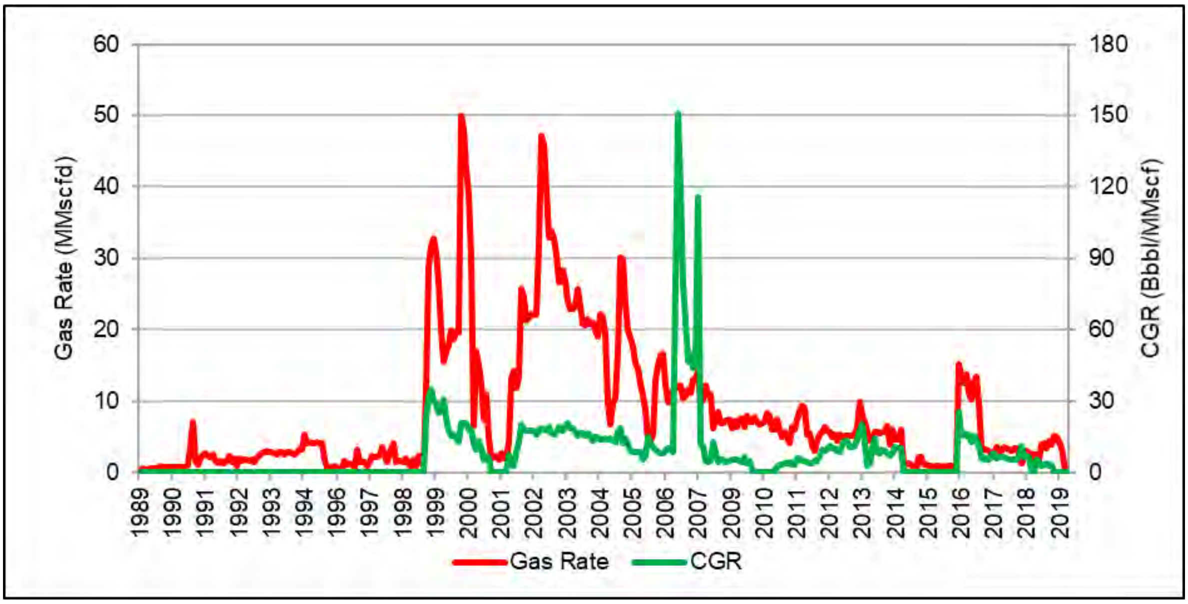
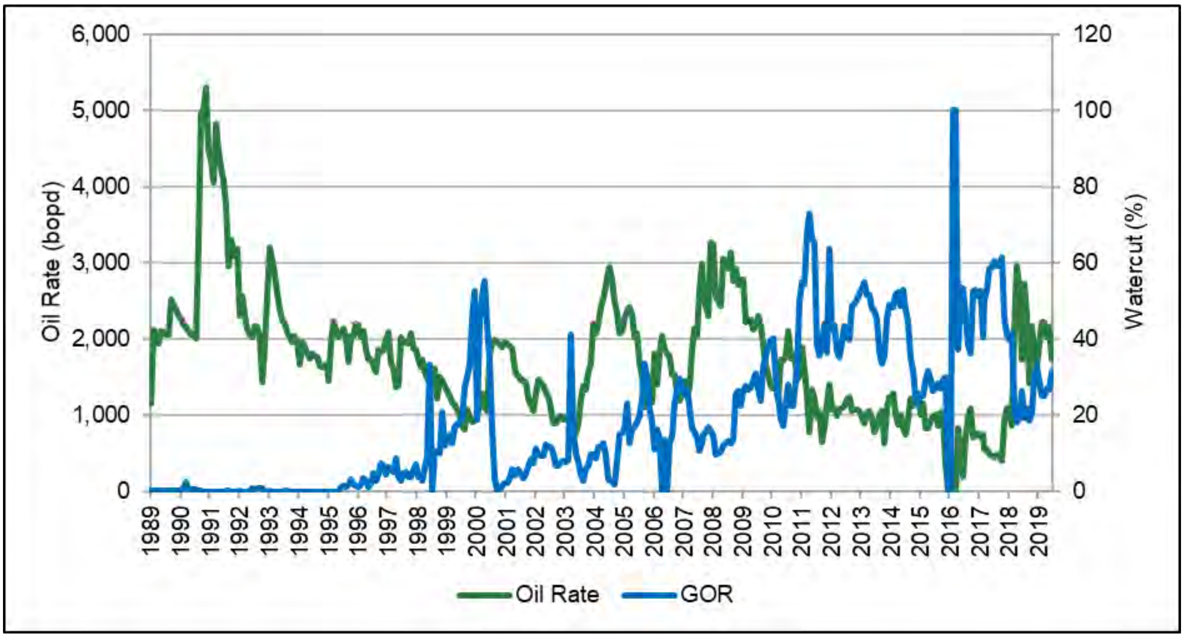


Figure 42: Historical Oil Production Rates and Water Cut, BED 15 (ARC)



2.3.4.3 *BED 18*

Oil production started in 2003 and peaked at approximately 1,300 bopd but had ceased by 2011. It restarted in 2013 and water injection commenced in 2016. Gas production commenced in 2004 but has been intermittent.

Historical Oil and water cut production profiles for BED 18 ARC are shown in Figure 43. Historical field gas production for BED 18 are shown in Figure 44.

Figure 43: Historical Oil Production Rates and Water Cut, BED 18 (ARG)

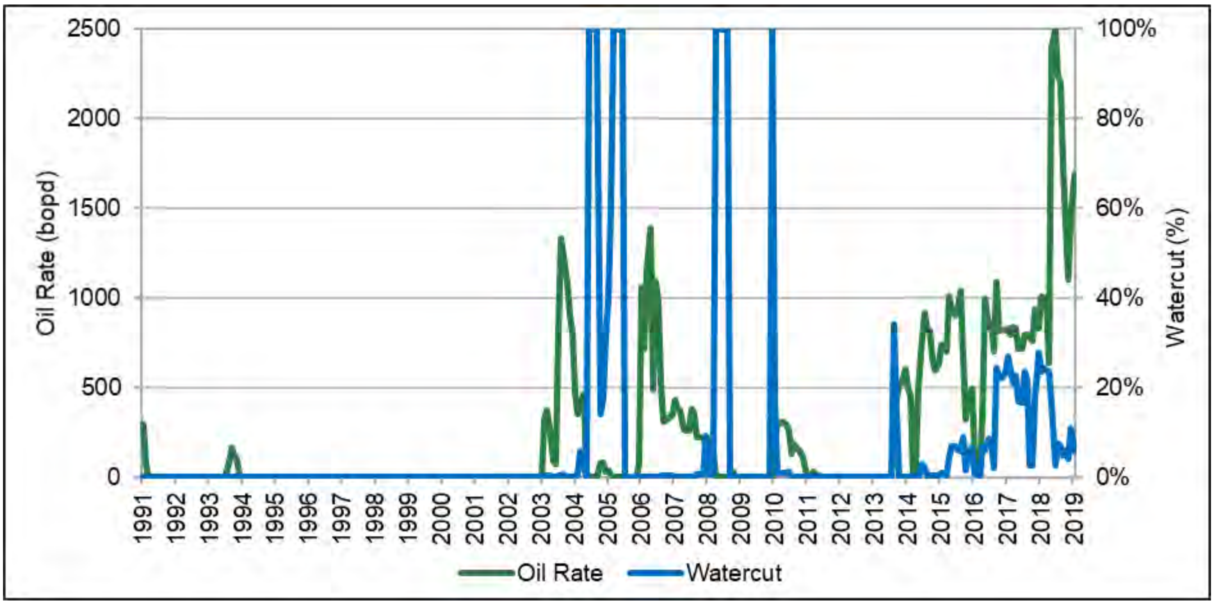
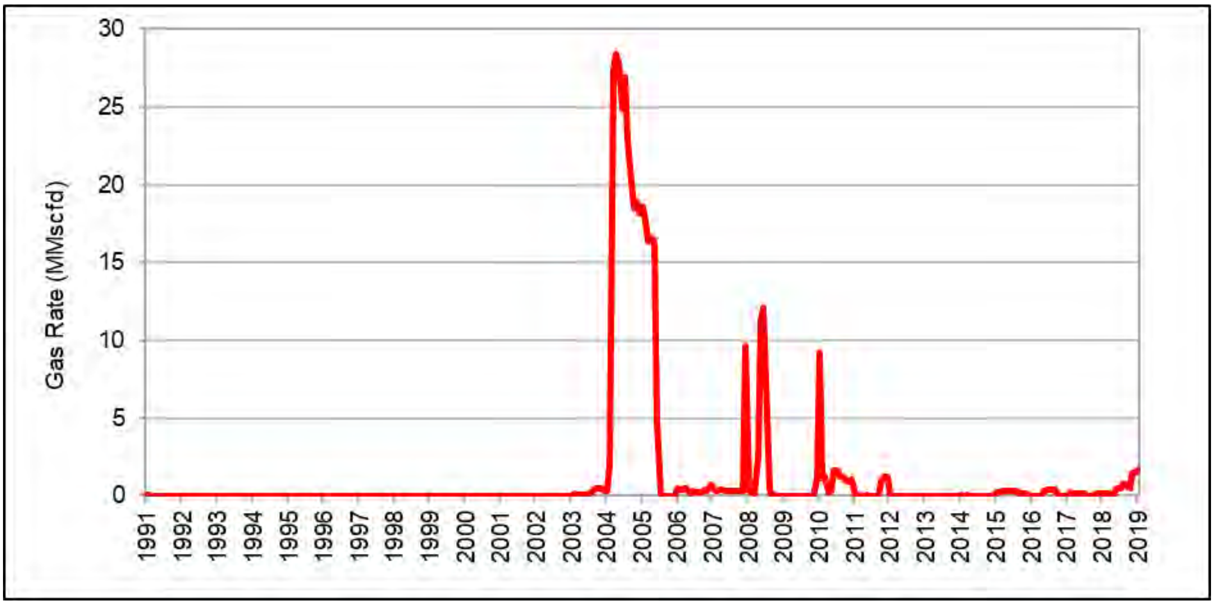


Figure 44: Historical Gas Production Rates BED 18 (ARG)



2.3.4.4 Summary

The cumulative produced gas and oil volumes as well as injected volumes for BED 3, BED 15 and BED 18 are summarized in Table 50.

Table 50: BED 3, 15 and 18 Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
		MMBbl	Bscf	bopd	MMscfd	bwpd
BED 3	20	34.4	1,032.0	5,087.3	33.5	2,096.5
BED 15	3	19.4	92.4	2,035.8	4.5	772.5
BED 18	5	21.8	105.1	3,447.6	5.8	876.5
Total	**28**	**75.6**	**1,229.5**	**10,570.8**	**43.8**	**3,745.5**

Note:

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

2.3.5 Field Development Plan

2.3.5.1 BED 3

Recent (2019) drilling has further developed reservoirs in the Abu Roash C and G, in particular the discovery of unusually thick sandstone development at BED 3-23. New views of the sandstone distribution, combined with the complex set of fault splays at this stratigraphic level has opened further possible drilling locations (Figure 45). These target attic oil, possibly underexploited fault blocks and/or parts of sandstone fairways.

The Consortium's future development plans for BED 3 thus include the following activities:

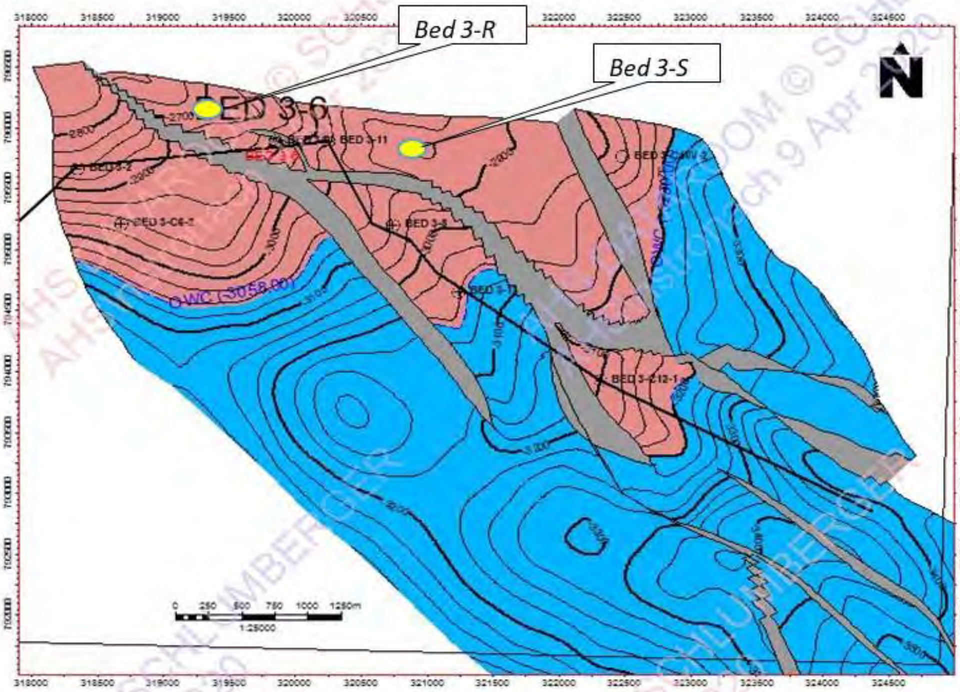
- One re-perforation plus four new infill wells are planned in the ARC. Of these, the Consortium has defined two locations in the BED 3-6 fault block in the Abu Roash C.
- Two new infills plus hookup of well BED 3-23 are planned in the ARG oil reservoir. Of these, one new location has been defined in the BED 3-C6 fault block in the Abu Roash G.
- The plan also includes one injector in the ARG (location AE), in the fault block containing well BED 3-18, and two in the ARC reservoir, the locations of which are yet to be confirmed.

Subsequent to the Effective Date of this report, in 1Q 2020, certain of the above activities have been completed, comprising:

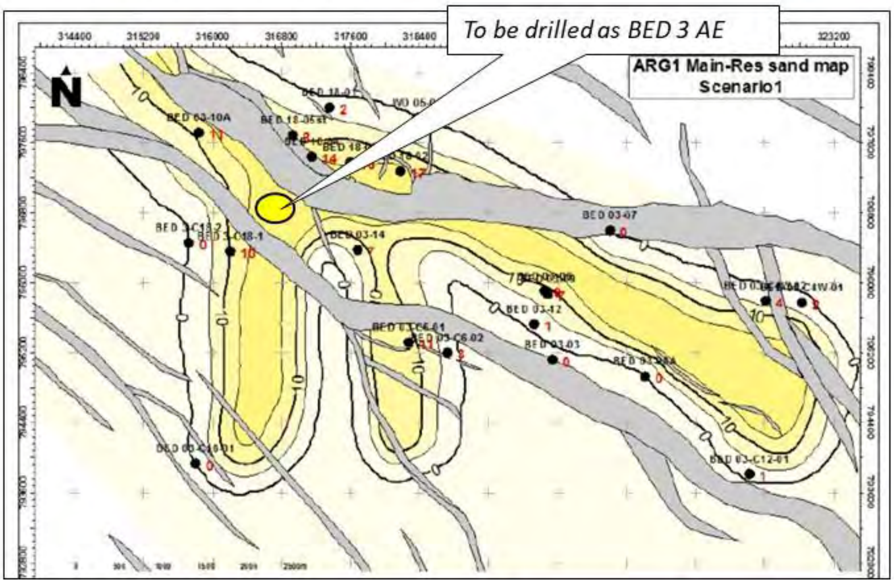
- The completion and hook-up of BED 3-23 as a successful oil production well.
- Drilling of location BED 3 AE as well BED 3-24. Although understood ultimately planned to be used as injection support to wells BED 3-18 and BED 3-19, the well has initially been successfully completed as an oil well.

Figure 45: BED 3 Abu Roash Drilling Locations

BED 3: Top Abu Roash C: Depth structure



BED 3: Abu Roash G: Modelled sandstone distribution scenario



Source: Vendor VDR

- No new firm wells are planned in the Kharita and Bahariya gas reservoirs.
- Three new wells to exploit upsides in the Bahariya gas reservoir are considered as Contingent Resources.

Although productive reservoir sweet spots occur, as at BED 3-14, reservoir quality is variable and much upside potential is attributed to successful targeting of low quality and "LRP" reservoirs. Studies have shown that these hydrocarbon volumes may be present, but the resources are at this stage considered contingent on definition of final drilling locations and demonstration of consistent productivity.

The schedule for the above activities has been defined in the Consortium's five year business plan. The drilling schedule is summarized in Table 51 and Table 52.

Table 51: BED 3 ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	1	0	0	0	**2**
Injection Wells	1	0	0	0	0	**1**
Total	**2**	**1**	**0**	**0**	**0**	**3**

Table 52: BED 3, ARC Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	4+1 re-perf	0	0	0	**5**
Injection Wells	0	2	0	0	0	**2**
Total	**0**	**7**	**0**	**0**	**0**	**7**

2.3.5.2 BED 15

The Consortium's future development plans for BED 16 include the following activities:

- Two new infill wells in the Kharita gas reservoir.

  Additional drilling is proposed to expand exploitation of the Kharita gas pool at BED 15. This involves 10 new wells in total, both in the main structure and in satellite fault blocks less well-defined with the available dataset. Only two wells are considered firm at this stage.

- Six new infill producers in the ARC and ARG reservoirs.

  As at BED 3, reconsideration of the latest understanding of sandstone distribution allows possibility of several new drilling locations in the Abu Roash. In this case, one location is currently specified as an updip attic target within the main Abu Roash C sandstone.

The drilling schedule is summarized in Table 53 and Table 54.

Table 53: BED 15, Kharita Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	2	0	0	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**2**	**0**	**0**	**2**

Table 54: BED 15, ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	6	0	0	0	**6**
Injection Wells	**0**	0	0	0	0	**0**
Total	**0**	**6**	**0**	**0**	**0**	**6**

2.3.5.3 BED 18

BED 18 consists of western and eastern areas, separated by a north-south oriented normal fault. Additional drilling is planned in the east for the Abu Roash G reservoir, where four production and two injection wells are planned. The key risks are both structural, in that the northern terrace of this area is not well-defined, and sedimentary, as the sand fairway appears oriented along the crest of the fault block, with the possibility of more marginal facies to the north. Subsequent to the Effective Date of this Report, in 1Q 2020, the first well, BED 18-15 has been completed. This confirmed the structural risks in this area, as it intersected a fault at Abu Roash G level. However, it was successfully completed as an oil producer in the Abu Roash E sandstone, thus opening a new hydrocarbon pool in the area.

The drilling schedule is summarized in Table 55.

Table 55: BED 18, ARG Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	2	0	0	0	**2**
Injection Wells	0	2	0	0	0	**2**
Total	**2**	**2**	**0**	**0**	**0**	**4**

2.3.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (April 2026).

Table 56 and Table 57, show the remaining technically recoverable gas and oil volumes for the BED 3 cluster.

Table 56: Remaining Technically Recoverable Gas Volumes, BED 3 Cluster, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
BED 3	29.6	36.3	43.1
BED 15	7.9	14.9	22.4
BED 18	0.1	0.6	1.2
SI Re-activation	13.1	13.8	14.5
Total	**50.7**	**65.6**	**81.2**

Notes:

1. The volumes in this table are to the end of April 2026; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 57: Remaining Technically Recoverable Oil and Condensate Volumes, BED 3 Cluster, as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
BED 3	6.1	8.4	10.8
BED 15	2.2	3.7	5.5
BED 18	1.1	1.9	3.0
SI Re-activation	1.5	1.6	1.7
Total	**10.9**	**15.6**	**21.0**

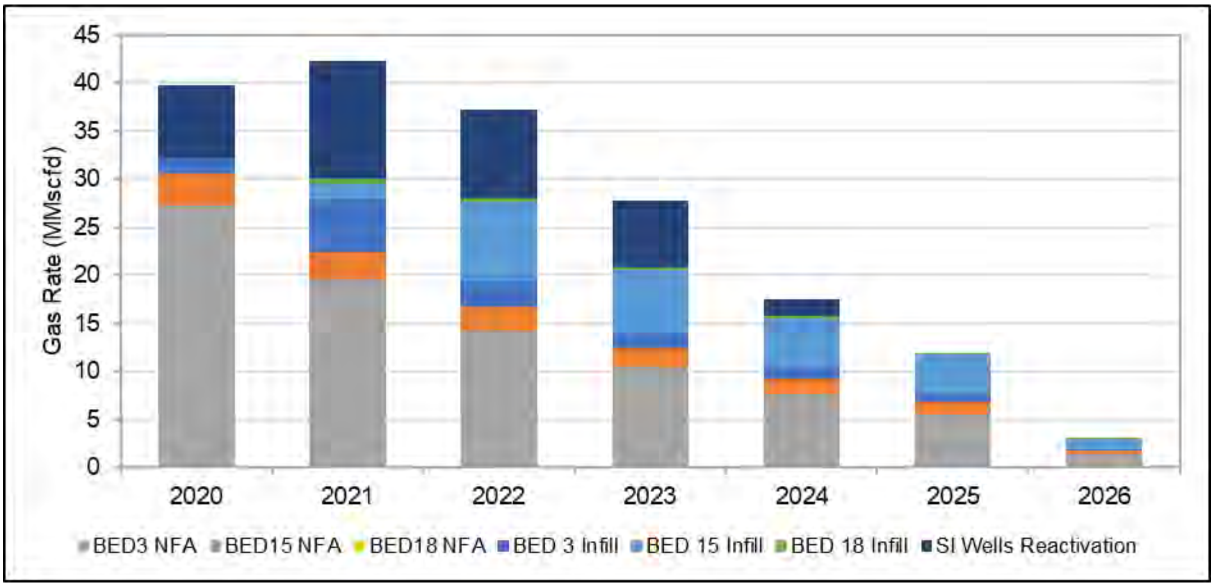
Notes:

1. The volumes in this table are to the end of April 2026; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 46 and Figure 47 show the gas and oil production forecasts for the BED 3 cluster by activity.

Figure 48 and Figure 49 show the Low, Best and High production forecasts for the BED 3 cluster.

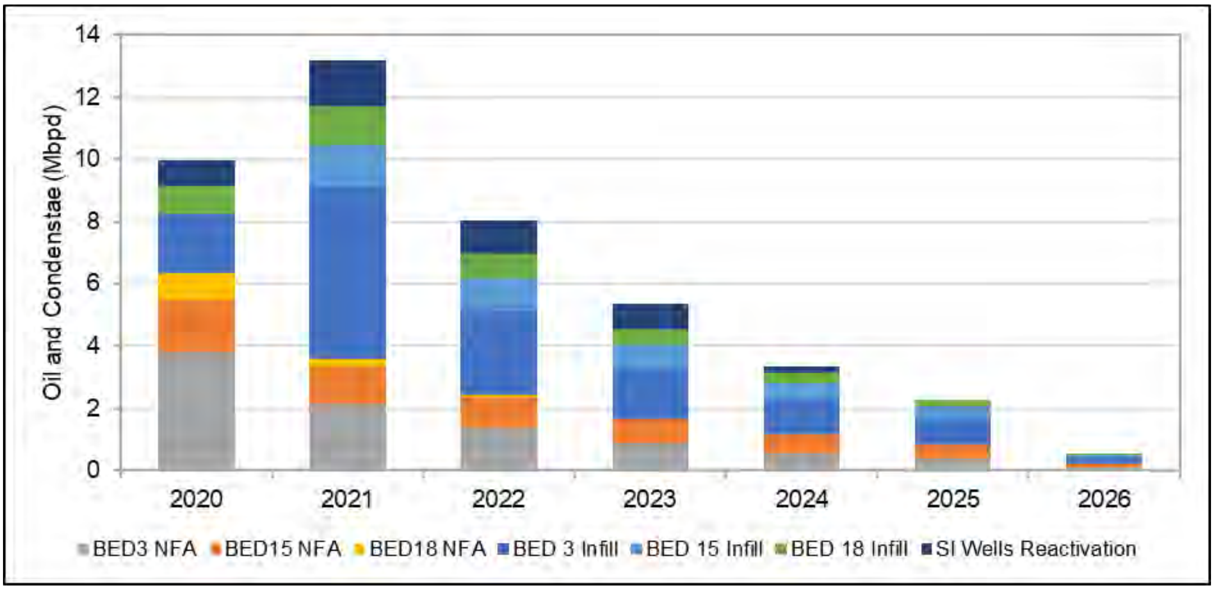
Figure 46: Best Case Gas Production Forecasts, BED 3 Cluster



Notes:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

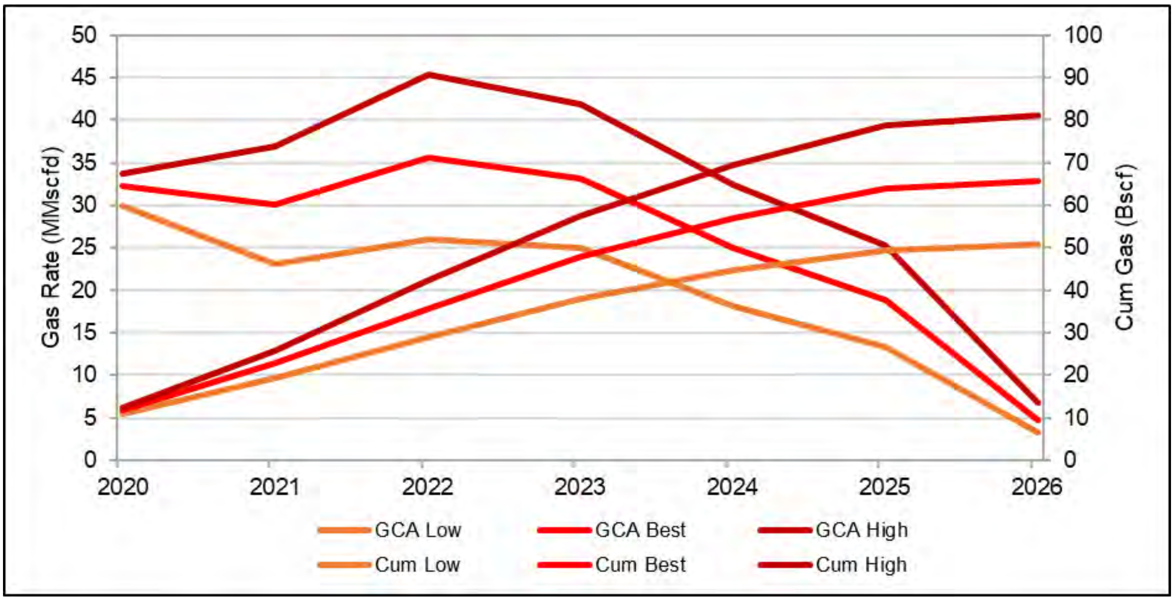
Figure 47: Best Case Oil and Condensate Production Forecasts, BED 3 Cluster



Note:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.

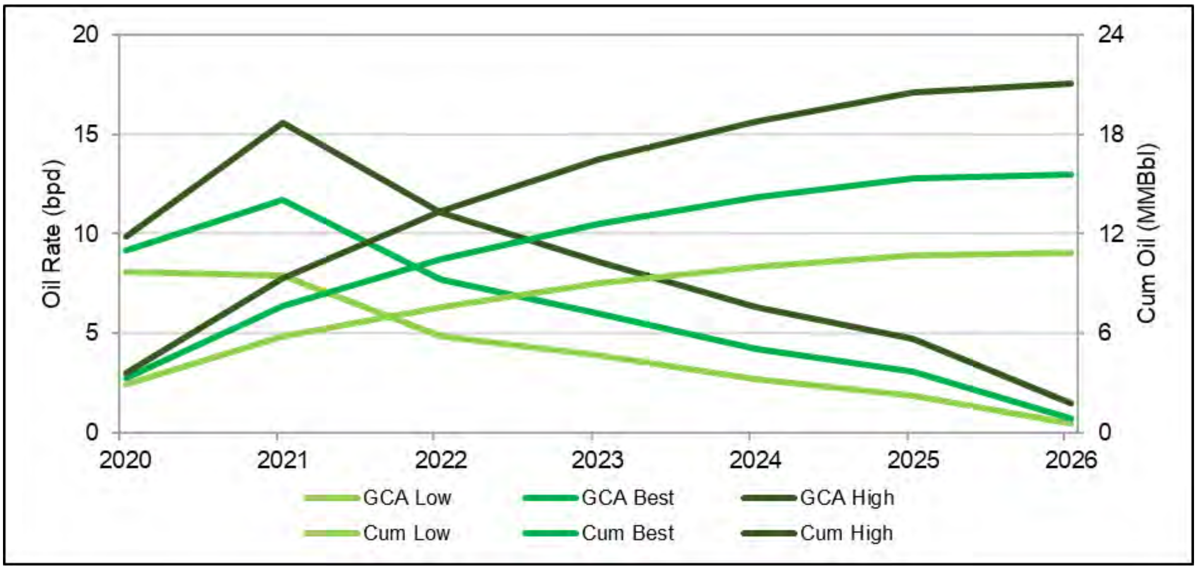
Figure 48: Gas Production Forecasts, BED 3 Cluster



Notes:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 49: Oil and Condensate Production Forecasts, BED 3 Cluster



Note:

1. The values in this figure are annual average rates and in 2026 include only 4 months of production (to the end of April 2026); no economic cut off has been applied.

2.3.7 Contingent Resources

Contingent Resources were assigned to wells for which locations have not yet been defined and where significant further modelling work is required to bring to these opportunities to a higher level of confidence.

The incremental production form three wells in the BED 3 Bahariya gas are considered as Contingent Resources. The incremental production of an additional eight infill producers in the BED 15 Kharita gas was also considered as Contingent Resources.

The BED3 Contingent Resources are summarized in Table 58.

Table 58: Gross Contingent Resources, BED 3 Cluster, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
BED3 Bahariya Gas	1.9	4.0	6.3
BED15 Kharita Gas	11.5	24.1	40.0
Total	**13.4**	**28.1**	**46.3**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
BED3 Bahariya Gas	0.0	0.1	0.1
BED15 Kharita Gas	0.2	0.5	1.0
Total	**0.2**	**0.6**	**1.1**

Notes:

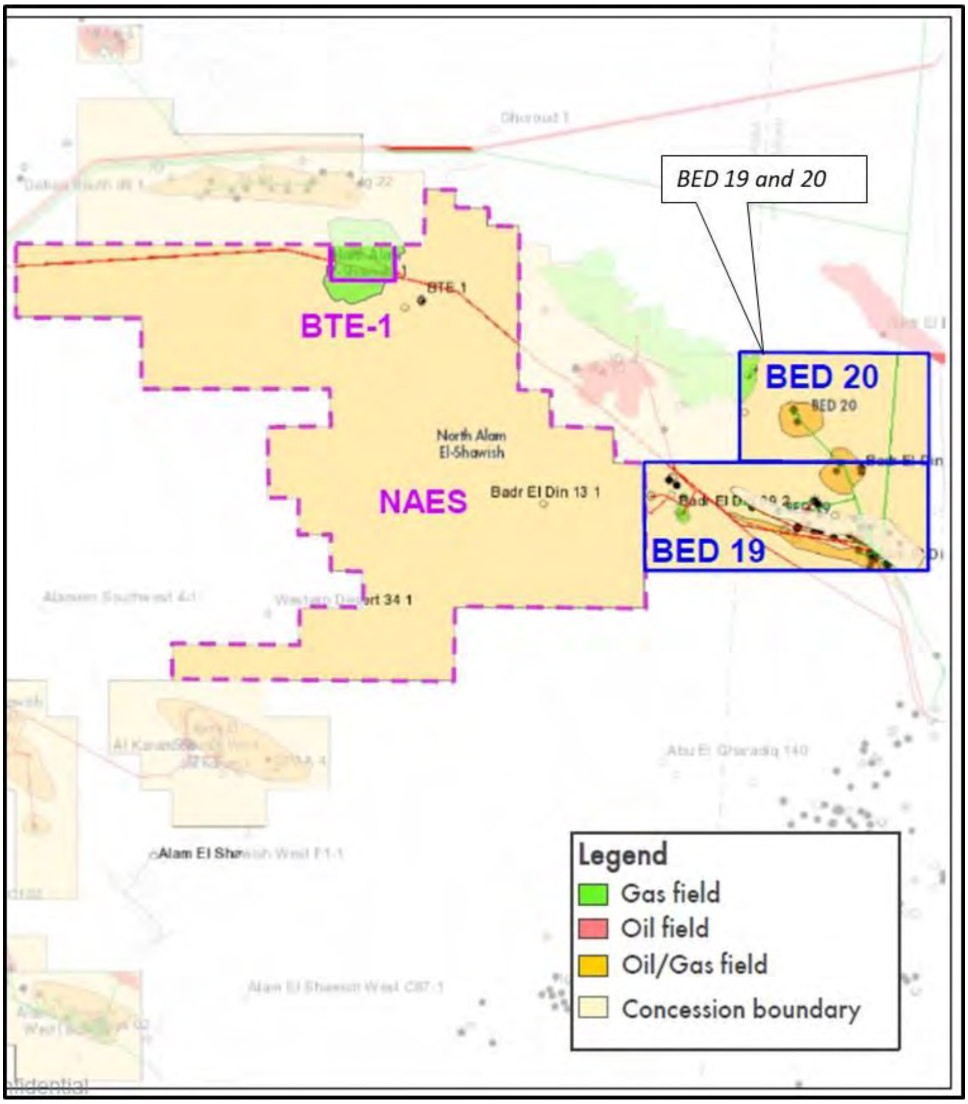
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.4 BED 19/20 Cluster

2.4.1 Asset Description

The BED 19/20 cluster, consists of the BED 19 and BED 20 development leases, located approximately 35 km to the east of BED 16 (Figure 50).

Figure 50: BED 19/20 Cluster Location Map



Source: Vendor VDR

2.4.1.1 *Structure and Trap*

The BED 19 and 20 structures are elongate structural traps with dip closure to the NE of down-to-the-SW normal faults. Trapping in the shallow plays is provided by dip-closed drape over underlying fault blocks.

2.4.1.2 *Reservoir*

Principal oil-bearing reservoirs are in the Lower Cretaceous Alam el Buieb sandstones, but with an emerging volatile oil play in the Jurassic Safa Formation, proved by the BED 20 J2-1 well. There is in addition a tight chalk play in the Upper Cretaceous Khoman Formation (oil) in BED 19, and in the pool immediately to the west, designated BED 9 for gas in the Cenozoic Apollonia Formation (gas).

2.4.1.3 Reservoir and Fluid Properties

No specific PVT data are available for the BED 19/20 area wells. Refer to the examples in the BED 3 dataset for illustrative information.

2.4.1.4 Production Facilities

Gas production is via the existing BED 19 line to the BED 3 processing plant (see section 2.3).

2.4.2 HIIP

As BED 19 and BED 20 were not prioritized for active development in the Consortium plans, HIIP has not been closely examined by GaffneyCline. The volumes reported by the Vendor are as in Table 59 and Table 60.

Table 59: BED 19/20 Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			
			Low	Best	High	Notes
BED 19	Vendor exploration overview	Khoman	7.5	14.2	21.7	Total HIIP attributed to two potential prospects
		Alam el Buieb				Not reported
BED 20-2	Vendor "CRIN", 2019	Alam el Buieb	5.3	7.5	10.4	Total for A2, A3, A4 and B sands
BED 20 J2-1	Vendor "CRIN", 2019	Safa and Kabrit Formations	2.4	10.5	24.9	

Table 60: BED 19/20 Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			
			Low	Best	High	Notes
BED 19 (BED 9)	Consortium after Vendor static model (2013)	Apollonia A5	54	75	109	GaffneyCline has validated estimates. Those for C12 assume optimum reservoir development.
		Apollonia C12	64	189	261	
BED 20 J2-1	Vendor "CRIN", 2019	Safa and Kabrit Formations	4.4	19.1	49.8	Gas associated with volatile oil

2.4.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 61.

As can be seen, after evaluation, no Reserves or Contingent Resources were attributed by the Consortium to the Best Case plan described here.

Table 61: BED 19/20: Resource Categories in Databook

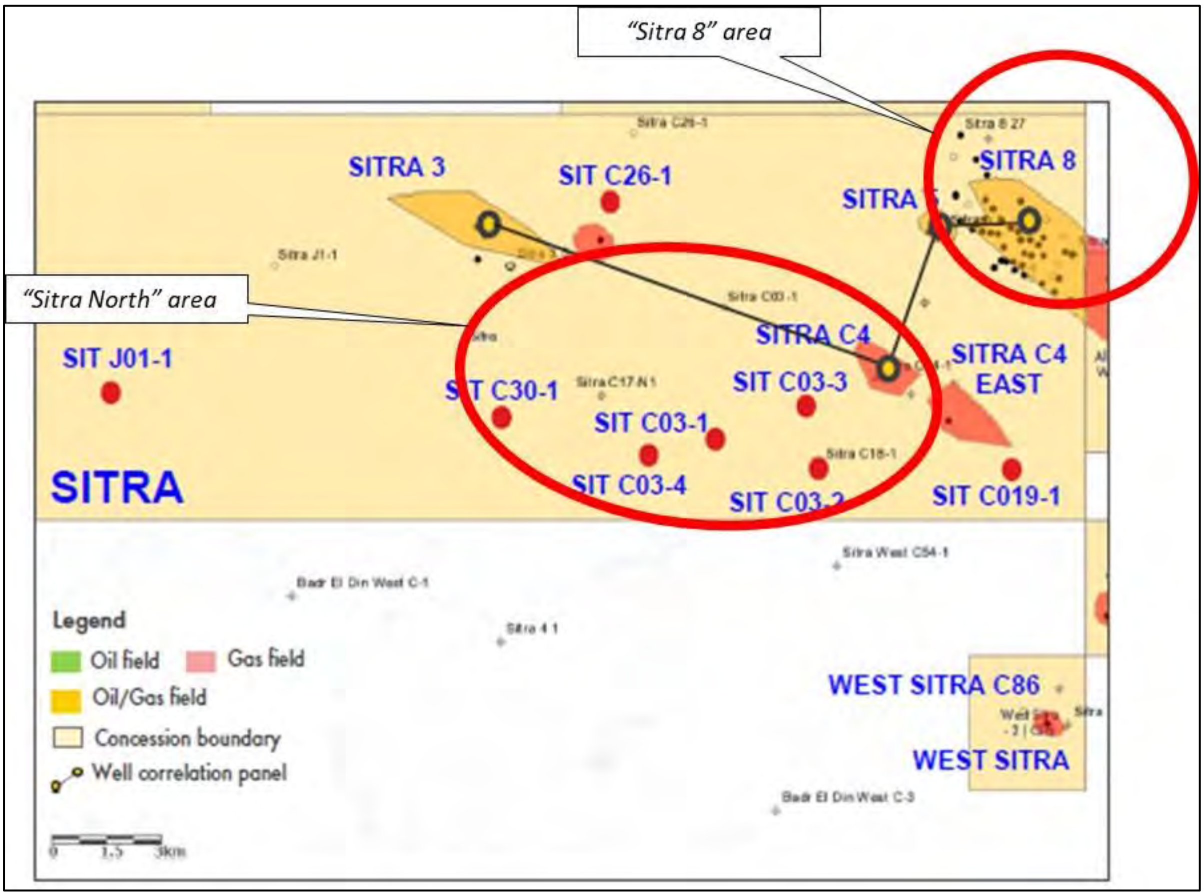
Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Notes
BED 9 NFA	Not included	Minor activities with insufficient materiality	N/A
BED 19 NFA	Not included		N/A
BED 20 NFA	Not included		N/A
General NFA	Not included		N/A
BED 20 infill	Not included	Further Alam el Bueib development. Not viewed as sufficiently material.	N/A
BED 19 C2E	Not included	Principally recovery of gas and oil from tight chalk plays (Apollonia and Khoman Formations)	**Contingent Resources**. Apollonia gas resources evaluated, but not viewed as part of key forward plan.
BED 20 C2E	Not included	Includes additional Alam el Buieb prospects and development of Safa Formation discovery (BED 20 J-1)	**Contingent Resources and Prospective Resources**. Awaiting further appraisal to finalise development plan.
Upside	Not included	No other upside defined	N/A

2.5 Sitra

2.5.1 Asset Description

The Sitra contract area contains a number of fields. The areas of focus here are Sitra 8 and the Sitra North cluster (Figure 51).

Figure 51: Sitra Fields Location Map



Source: Vendor VDR

2.5.1.1 Structure and Trap

Sitra 8 is a well-established field comprising stacked reservoirs in a closure controlled by the footwall of a major NW-SE normal fault. It is dip-closed to the NE. The North Sitra cluster is controlled by a major NW-SE trending normal fault which changes to a more E-W orientation in the east, along with various splays to create a number of individual closures. Of significance here are the Sitra 3/C30 closure and the C3 group, to the east.

2.5.1.2 Reservoir

Oil-bearing reservoirs at Sitra 8 occur in the Abu Roash Formation C, E and Upper G Zones, and in the Upper Bahariya. The Lower part of the Abu Roash G Zone is gas-bearing, as is the Lower Bahariya Formation. A full static model is available for Sitra 8, and this shows optimum sand development in the Abu Roash G reservoir over the crest of the field. Sitra 5 is a fault block immediately to the west of Sitra 8, but contains only smaller volumes of oil in Abu Roash C zone and Lower Bahariya, and gas in the Upper Bahariya Formation.

Although Abu Roash reservoirs are hydrocarbon-bearing at North Sitra, of greater significance here are oil and gas-bearing reservoirs in the Bahariya Formation.

2.5.1.3 Reservoir and Fluid Properties

Representative PVT samples are presented in Table 62. Reported CO_2 content is low, at 1.19 mol% in the Kharita Formation. Pressure and temperature gradients are normal.

Table 62: Sitra Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Sitra 3-2ST1	KHA	3,045	108.3	4,200	4,150	Not known	100	0.03	0.65

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
Sitra 3-1	BAH	Not known	107.2	4,264	4,045	1.63	861	Not known	40
Sitra 5-1	BAH	3,175	116.1	4,759	4,508	1.46	870	Not known	32
Sitra 8-4	ARE	2,880	114.1	4,438	2,248	1.41	740	Not known	39
Sitra 8-6	ARG	3,210	126.9	4,886	1,378	1.25	369	Not known	31

2.5.1.4 Production Facilities

The production fluids from Sitra are processed by the Sitra Early Production Facility, which separates the oil, gas and produced water before the oil and gas are exported via pipeline to the BED 3 processing plant for further treatment (see section 2.3). The Sitra produced water is then disposed of via evaporation ponds. The Sitra EPF is designed to treat 12 MBbl/day of condensate.

The Sitra EPF will be mothballed during 2020, on completion of the BED 3 produced water reinjection project. Sitra fluids will then all be separated and treated at the BED 3 processing plant.

2.5.2 HIIP

GaffneyCline has reviewed the Vendor's petrophysical interpretation and static models for the Sitra 8 field, which has allowed validation of the HIIP quoted by the Vendor. Final HIIP estimates are presented in Table 63 and Table 64. For other fields, a Vendor resource evaluation (the so-called Contingent Resource Information Note or CRIN) has been broadly validated by GaffneyCline's work.

Table 63: Sitra Cluster STOIIP

Location	Source	Reservoir	STOIIP (MMBbl)			Notes
			Low	Best	High	
Sitra 8	**Vendor IM**	Abu Roash C	-	34	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Abu Roash E	-	17	-	
		Upper Abu Roash G	-	39	-	
		Upper Bahariya	-	74	91	Static model describes 91 MMBbl, based on inclusion of more marginal reservoir facies.
Sitra 5	**Vendor IM**	Abu Roash C	-	7	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Lower Bahariya	-	9	-	
Sitra 3/C30	**Vendor Sitra "Mega CRIN"**	Lower Bahariya and Kharita Formations	-	12.6	-	Oil rim. See additional volumes in gas leg in Table 64.
Sitra C3E		Bahariya Formations	-	8.3	-	Minor additional condensate in Abu Roash G.

Table 64: Sitra Cluster GIIP

Location	Source	Reservoir	GIIP (Bscf)			Notes
			Low	Best	High	
Sitra 8	Vendor IM	Lower Abu Roash G	-	20	-	Value as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
		Lower Bahariya	-	181	278	High Case reflects uncertainty seen in analysis of field extent and reservoir definitions in static model.
Sitra 5		Upper Bahariya	-	25	-	Values as quoted in Vendor IM, corroborated by GaffneyCline review of static model in vPDR.
Sitra 3/C30	**Vendor Sitra "Mega CRIN"**	Lower Bahariya and Kharita Formations	-	82.9	-	Gas leg. See additional volumes in oil rim in Table 63.

2.5.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 65.

Table 65: Sitra: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
Sitra 8 NFA	Sitra NFA	All categories amalgamated, with focus on Sitra 8 as the largest active field	**Reserves**
Sitra 5 NFA			
Sitra C4 NFA			
Sitra 3 NFA			
Sitra C3 NFA			
Sitra C10/30 NFA			
General NFA			
Sitra 8 Infill	Sitra 8 Infill	Well infill programme in Sitra 8 field	**Reserves**
Sitra C18 infill	Not included	Reactivation of small discovery at Sitra C18-1	Minimal associated reserves and no expenditure committed in Consortium plan.
Sitra 1 infill	Not included	Reactivation of small discovery at Sitra 1-1	Minimal associated reserves and no expenditure committed in Consortium plan.
Sitra C10/C30 infill	Sitra 3 plus C30 infill	Major North Sitra infill programme at both Sitra 3/C30 and at C03E	**Reserves** at Sitra 3/C30. Sitra C10-1 is a dry hole whose location is unclear from the VDR data.
	Sitra C03 infill		
Sitra C2E	Not included	Other activities at Sitra C-19, C-26 and J-01	**Prospective Resource**
Sitra Upsides	Not included		

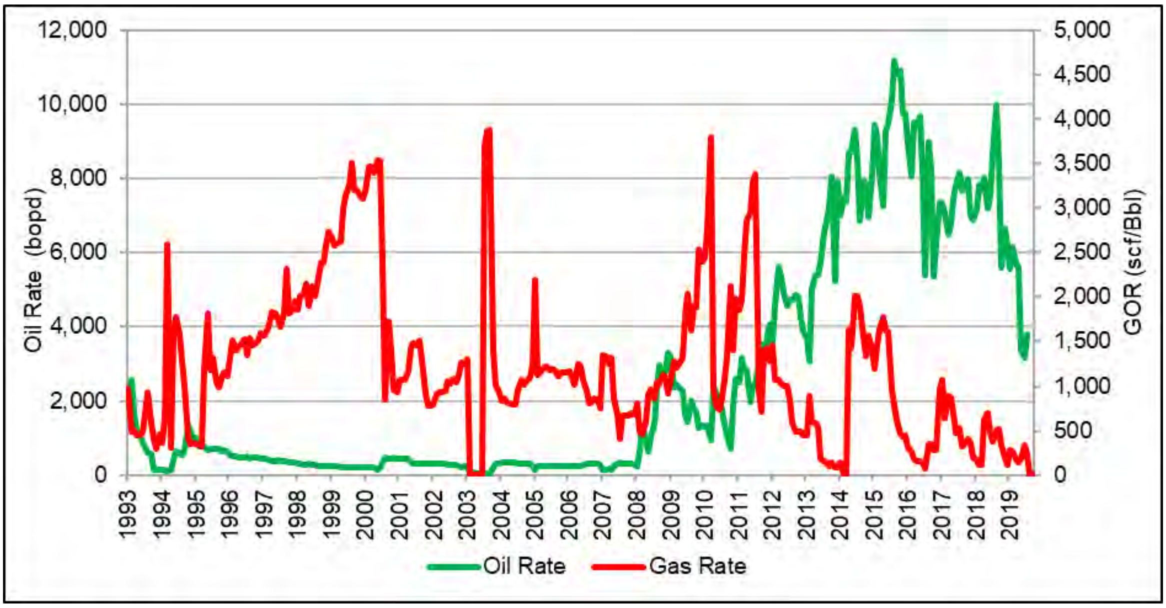
2.5.4 Historical Field Performance

2.5.4.1 Sitra 8

Production in Sitra 8 commenced in 1993 with the Sitra 8-1B well producing from the ARG Upper and ARG Lower commingled with the ARC. There was no drilling between 1994 and 2007. In 2008, appraisal and development wells were drilled in the area. In 2010, production increased form 150 bpd to 1,750 bpd as a result of 5 appraisal wells.

In 2010, 3 new wells were drilled and the oil rate reached 5,800 bpd in August 2012. In 2012, water injection began. The current oil production is approximately 1,500 bpd with an average water cut of 9% and an average GOR of 260 scf/Bbl. Figure 52 shows the historical oil production and GOR for Sitra 8.

Figure 52: Historical Oil Production Rate and GOR, Sitra 8



2.5.4.2 *Sitra North (Sitra 3, Sitra C3 and Sitra C30)*

Sitra North was discovered in 1982 by the Sitra 1-1 well. Production from the Bahariya formation started in 1990 using the Sitra 3-1 well but this was shut in a year later. Production restarted in 2015, and Sitra 3-4 and Sitra 3-5 commenced production in 2018. Sitra C30 started production from the Bahariya formation in 2019 with two wells, Sitra C3-1 and C3-2.

Figure 53 shows the historical oil and gas production for Sitra North and the historical production performance is summarized in Table 66.

Figure 53: Historical Oil and Gas Production Rate, Sitra North

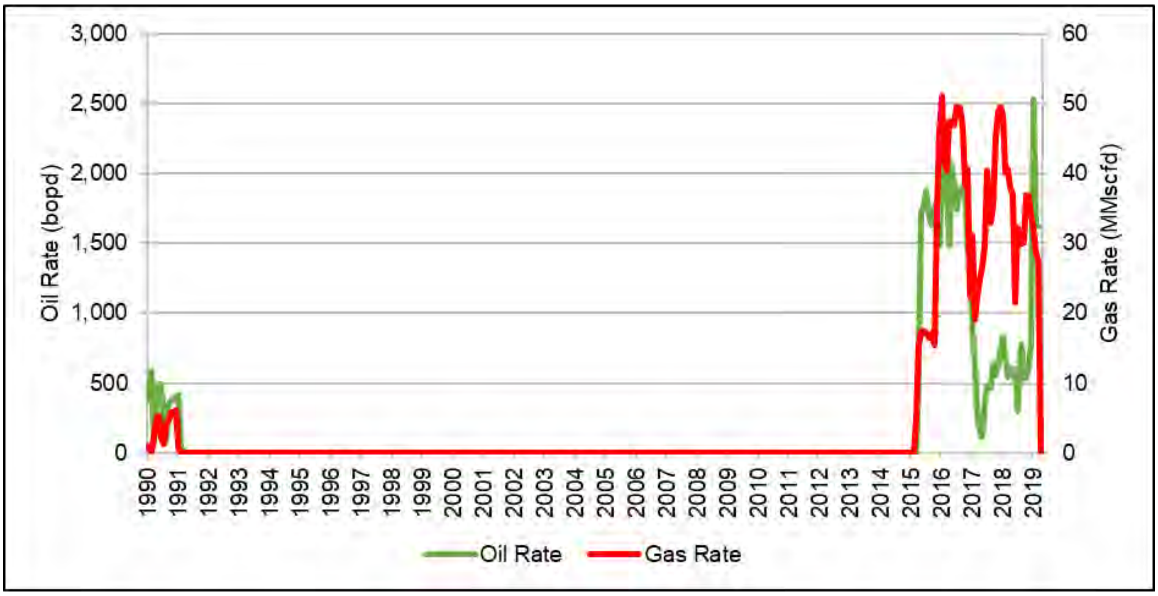


Table 66: Sitra Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate in 4Q 2019	Average Gas Rate in 4Q 2019	Average Water Rate in 4Q 2019
		MMBbl	Bscf	bopd	MMscfd	bwpd
Sitra 3	5	0.3	51.1	407.1	28.2	39.0
Sitra 5	1	1.6	3.2	83.0	0.0	220.5
Sitra 8	16	24.7	21.3	3,972.5	0.9	4,552.0
Sitra C4	1	0.8	0.2	382.6	0.0	1.0
Sitra C26	1	0.1	0.1	276.4	0.4	192.5
Sitra C3	1	0.1	0.4	904.4	2.3	40.3
Total	**25**	**27.6**	**76.1**	**6,026.0**	**31.8**	**5,045.3**

Note:

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

2.5.5 Field Development Plan

2.5.5.1 Sitra 8

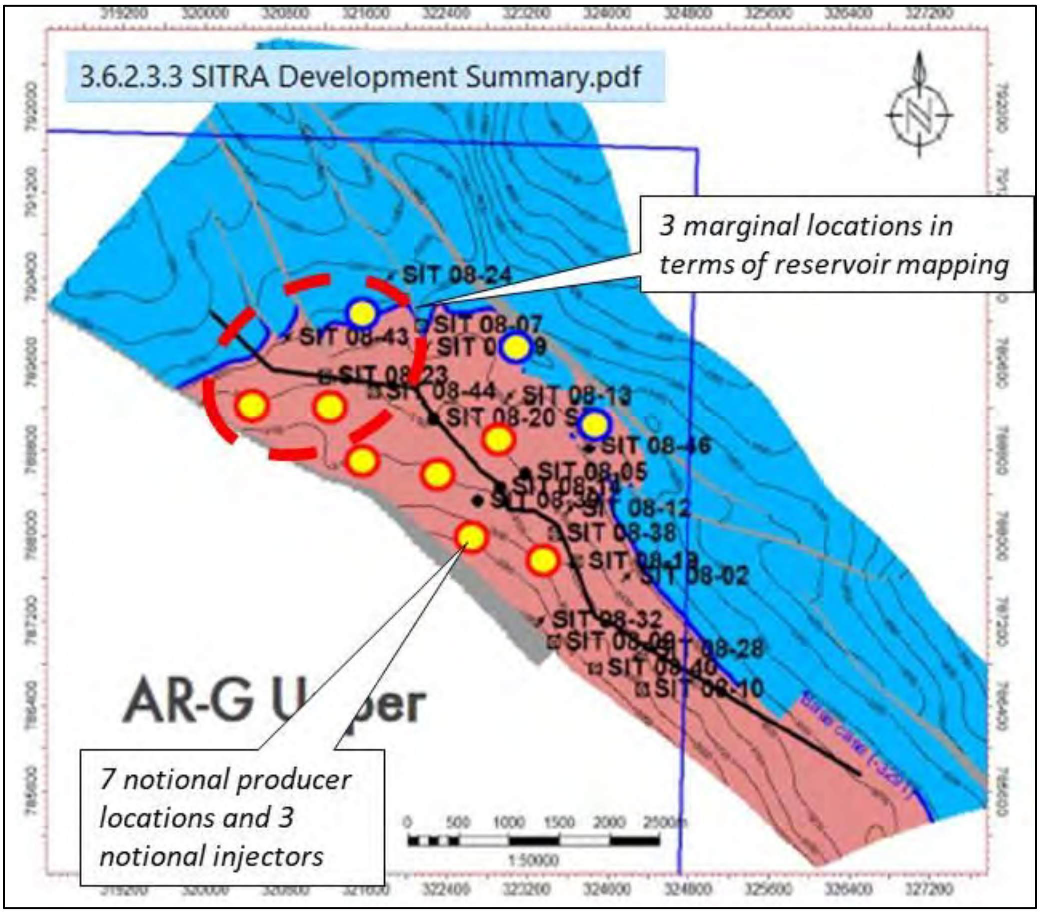
The Consortium's development plans for the Sitra 8 field include fourteen new infill oil producers in the Sitra 8 area, of which two infill wells are to be drilled in 2020, and five new injectors to be drilled in 2021, with the largest number for the Abu Roash G:

- Abu Roash C: 2 producers plus 1 injector;
- Abu Roash E: 1 producer;
- Abu Roash G Upper: 7 producers plus 3 injectors;
- Abu Roash G Lower (Gas): 1 producer; and
- Upper Bahariya (Sequence 3): 4 producers plus 1 injector.

Locations are not finalised but GaffneyCline accepts that this plan is feasible and that there is sufficient calibration of the reservoir model to be able to confidently locate this number of wells.

For the Abu Roash G, GaffneyCline has conducted a closer review. The bulk of the HIIP (40%) is within the uppermost ARG 0-1 unit, as this appears to cover the crestal part of the field, but also to extend south and north. The Vendor proposed 10 locations but this would require siting wells on the flanks, where the sandstone is less well demonstrated although there has some success, for example at the injection well at Sitra 8-46. GaffneyCline accepts that 7 locations can be considered as relatively low risk (Figure 54).

Figure 54: Sitra 8: Proposed Well Locations, Abu Roash G Zone



Source: Vendor VDR

The drilling schedule is summarized in Table 67.

Table 67: Sitra 8 Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	6	6	0	0	**14**
Injection Wells	0	2	3	0	0	**5**
Total	**2**	**8**	**9**	**0**	**0**	**19**

2.5.5.2 Sitra North

The Consortium's future development plans for the Sitra North fields include the following activities:

- One vertical gas well in C30 area to be drilled in 2020.

  The well is to be sited on the crest of the structure, NW of well Sitra C30-1, in a relatively low risk location, between the Sitra 3 and C30 areas.

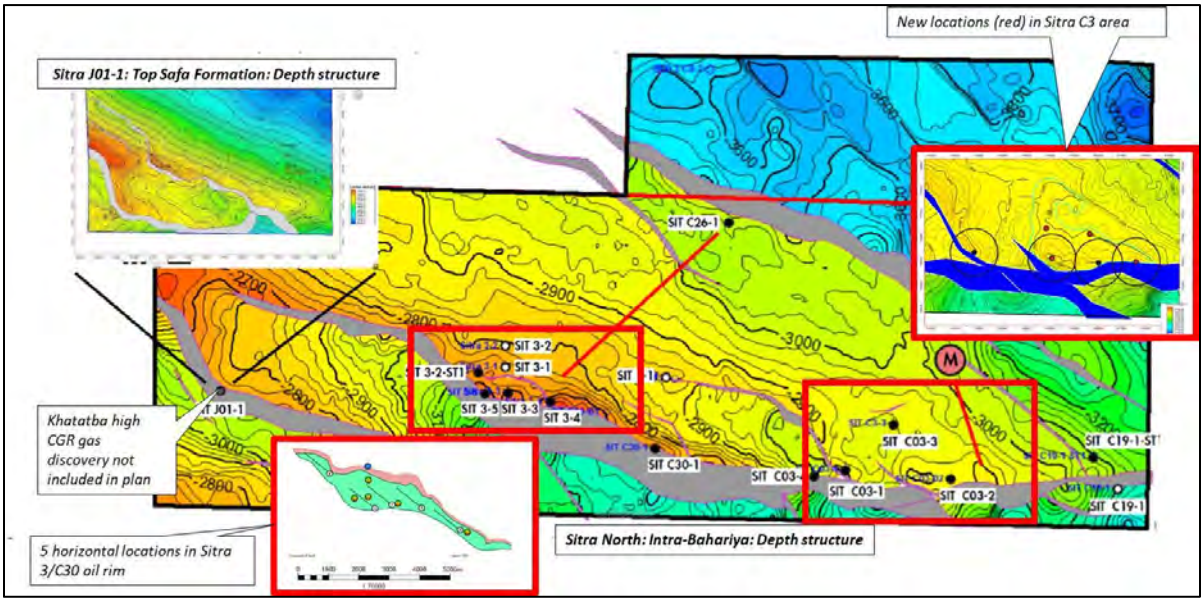
- Vertical wells in the C3 area.

Four wells are to be located in the Sitra C3E pool (Figure 54), which is the largest of this group of pools. There is some uncertainty over structure, position of the wells with respect to the position of the OWC on the lower relief northern terrace, and reservoir continuity.

- Horizontal wells in the Sitra 3 oil rim.

In addition to the further development of the gas pool in the Bahariya/Kharita Formations at Sitra C30, it is understood from discussions with the Consortium during the vPDR process that the focus of future drilling in the Sitra 3/C30 field is on exploiting the oil rim within the Bahariya and Kharita Formations. This is an 18-25 m thick column that straddles the Lower Bahahriya and Kharita Formations beneath the thicker gas leg. GaffneyCline has not been able to evaluate this in detail, but can see support for the 5 horizontal well locations that are notionally proposed (Figure 55). Detailed siting of wells within the variable sandstone facies of the Lower Bahariya may prove challenging.

Figure 55: North Sitra: Proposed Well Locations



Source: Vendor VDR

The drilling schedule is summarized in Table 68.

Table 68: Sitra North Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	7	2	-	-	**10**
Injection Wells	-	-	-	-	-	**0**
Total	**1**	**7**	**2**	**-**	**-**	**10**

There is in addition a deep discovery in the Jurassic (Sitra J01-1) that is considered as a high risk development and is not considered further here.

2.5.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (1st December 2025).

Table 69 and Table 70, shows the remaining technical recoverable volumes for the Sitra 8, Sitra 3, Sitra C3 and Sitra 30 fields.

Table 69: Remaining Technically Recoverable Gas Volumes, Sitra, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
Sitra NFA	21.8	25.7	29.2
Sitra 8	0.5	2.6	6.0
Sitra 3 & C3 Infill	0.5	1.0	1.8
Sitra 30 Infill	2.0	4.3	7.3
SI Wells Re-activations	0.1	0.1	0.1
Total	**24.9**	**33.7**	**44.4**

Notes:

1. The volumes in this table are to the end of November 2025; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 70: Remaining Technically Recoverable Oil and Condensate Volumes, Sitra, as at 31st December 2019

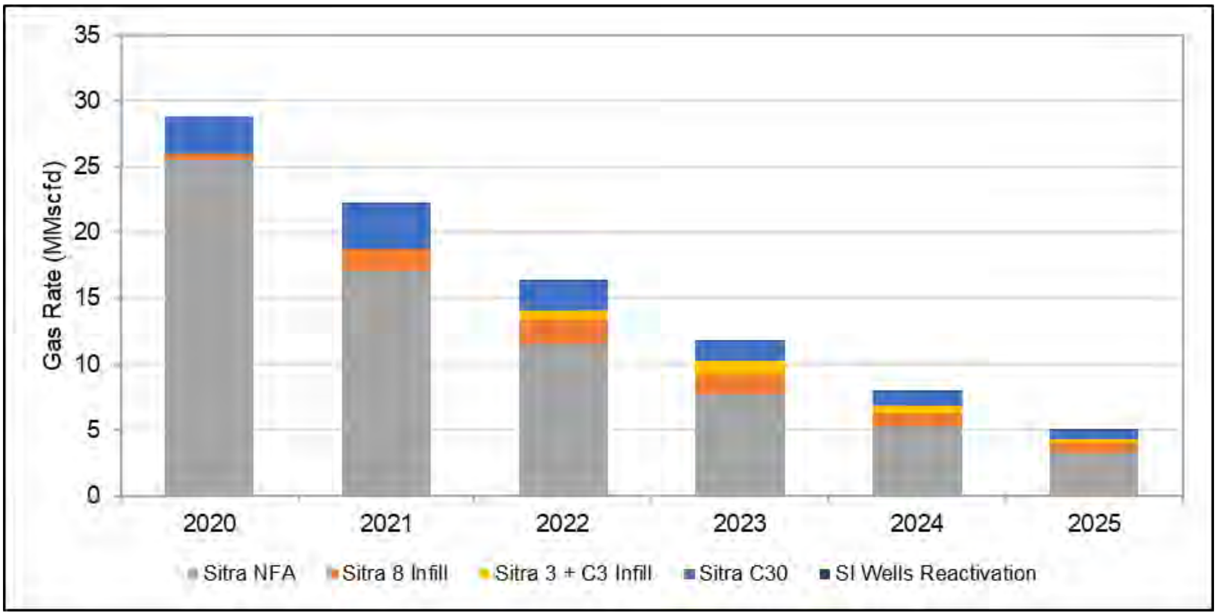
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Sitra NFA	3.9	4.7	5.4
Sitra 8	1.7	4.5	7.4
Sitra 3 & C3 infill	1.2	2.3	4.0
SI Wells Re-activations	0.4	0.4	0.4
Total	**7.2**	**11.9**	**17.2**

Notes:

1. The volumes in this table are to the end of November 2025; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 56 and Figure 57 shows the gas and condensate forecasts for the Sitra area Best case.

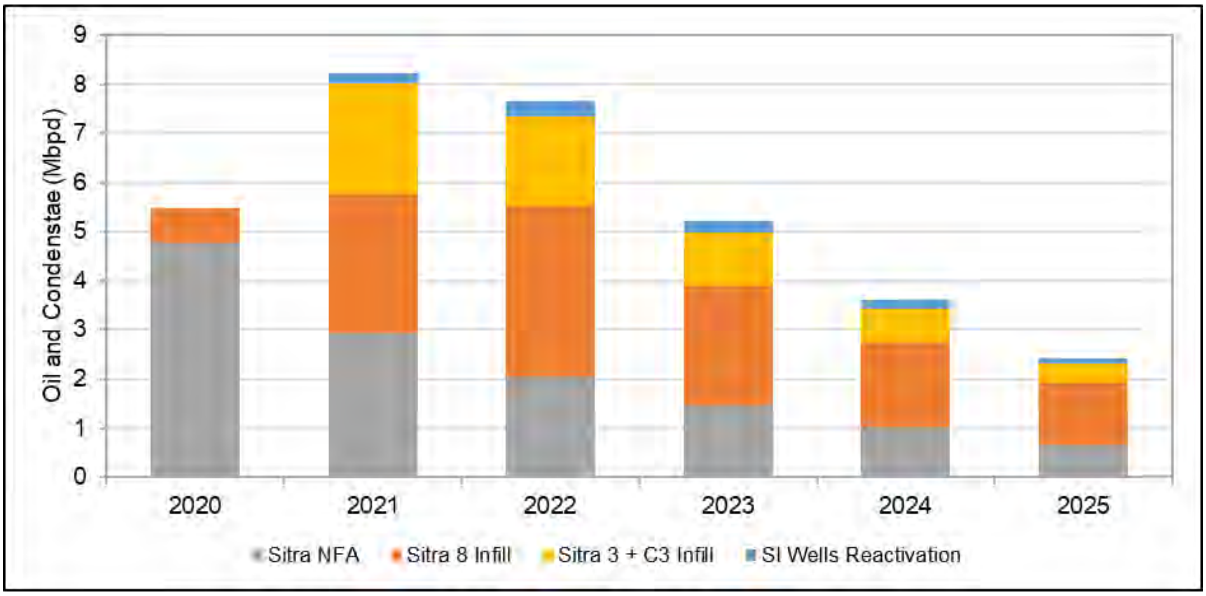
Figure 56: Best Case Gas Production Forecast, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 57: Best Case Oil and Condensate Production Forecast, Sitra

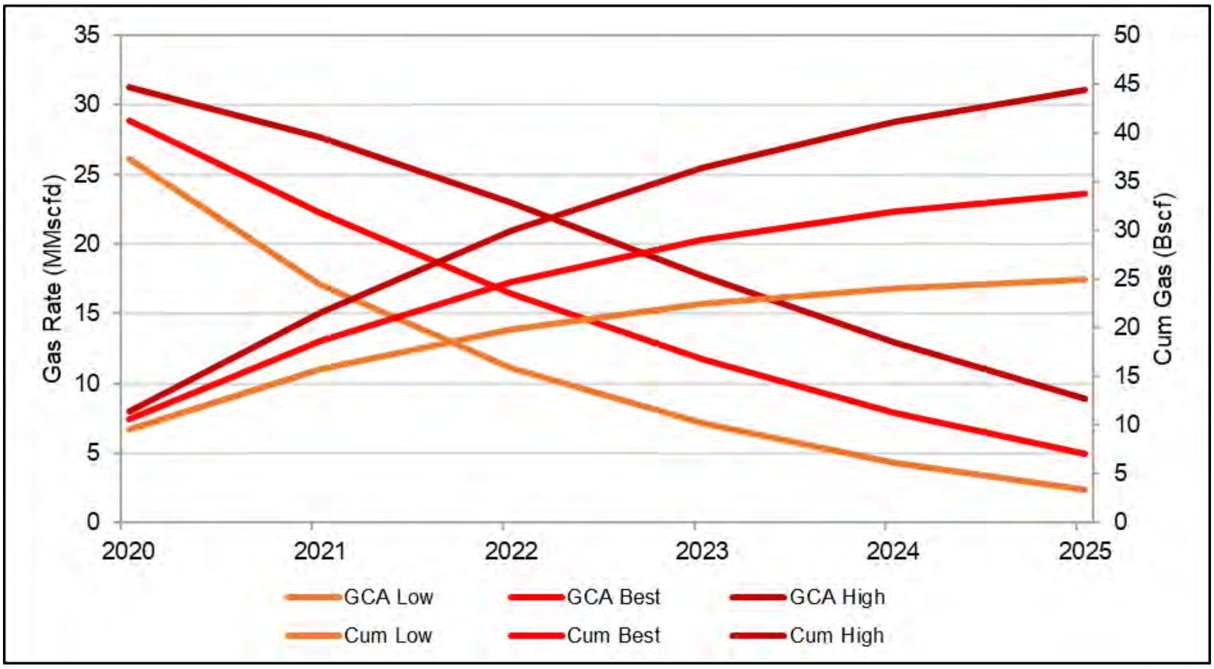


Note:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.

Figure 58 and Figure 59 show Low, Best and High forecast production profiles for Sitra area.

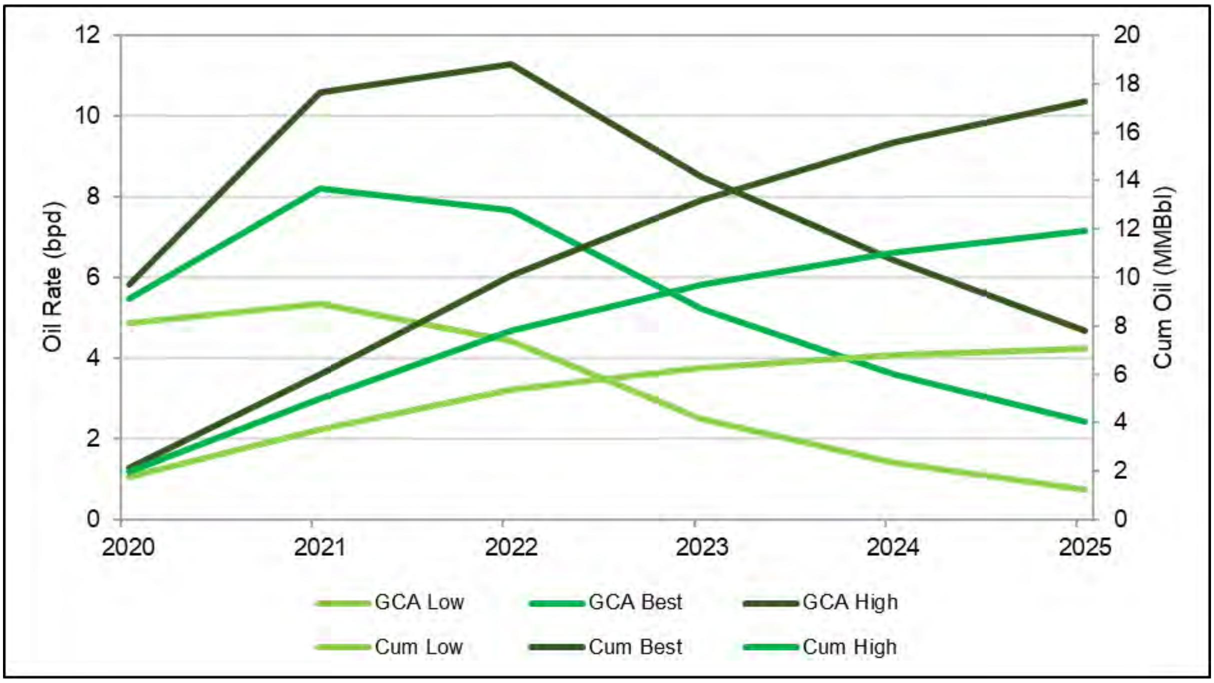
Figure 58: Gas Production Forecasts, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

Figure 59: Oil and Condensate Production Forecasts, Sitra



Notes:

1. The values in this figure are annual average rates and in 2025 include only 11 months of production (to the end of November 2025); no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards.

2.5.7 Contingent Resources

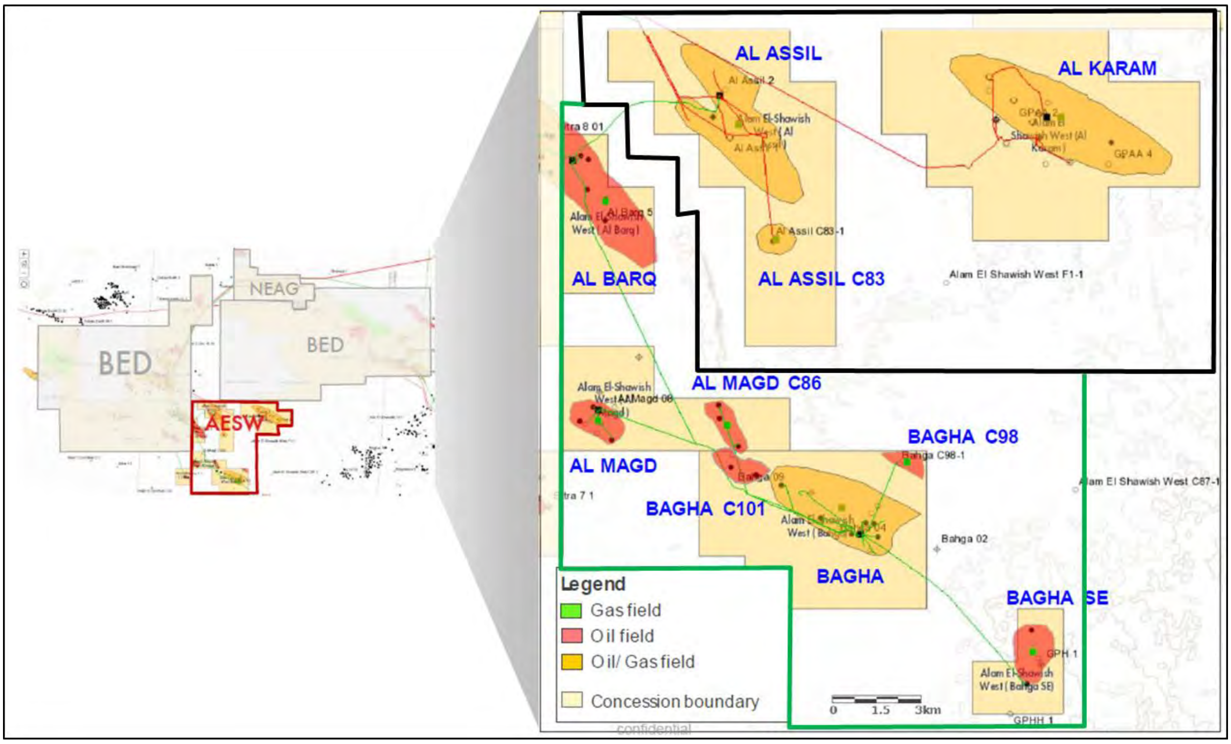
No Contingent Resources were assigned to this asset.

2.6 Alam El Shawish West (AESW)

2.6.1 Asset Description

AESW is composed of 10 fields, which are broken up into two general areas. The Assil Field and its satellite (C83) and the Al Karam Field make up the northern area. The southern AESW area is comprised of the Al Barq, Al Magd and Bagha Fields and their satellites. All of the fields and satellites are located within a relatively well constrained area of approximately 20 km by 18 km. Figure 60 presents a location map of the fields and satellites in AESW.

Figure 60: AESW Location Map

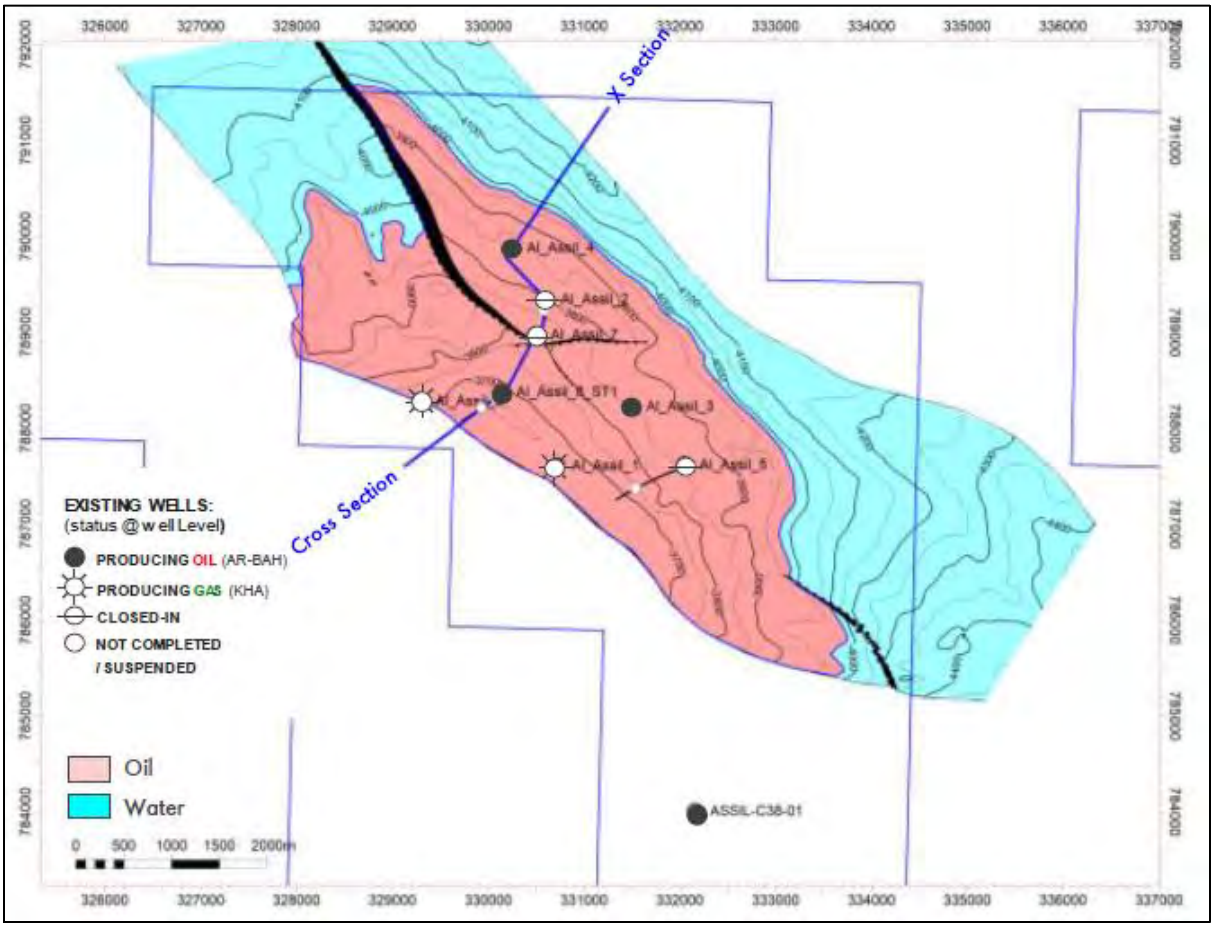


Source: Vendor IM

At Assil and Al Karam the development of the Kharita gas reservoirs has been the focus to date. Up to January 2019, a combined 338 Bcf of gas has been produced from the Kharita reservoirs. The short term future focus at Assil and Al Karam is the development of the larger oil reservoirs through water flood and infill drilling of the gas reservoirs.

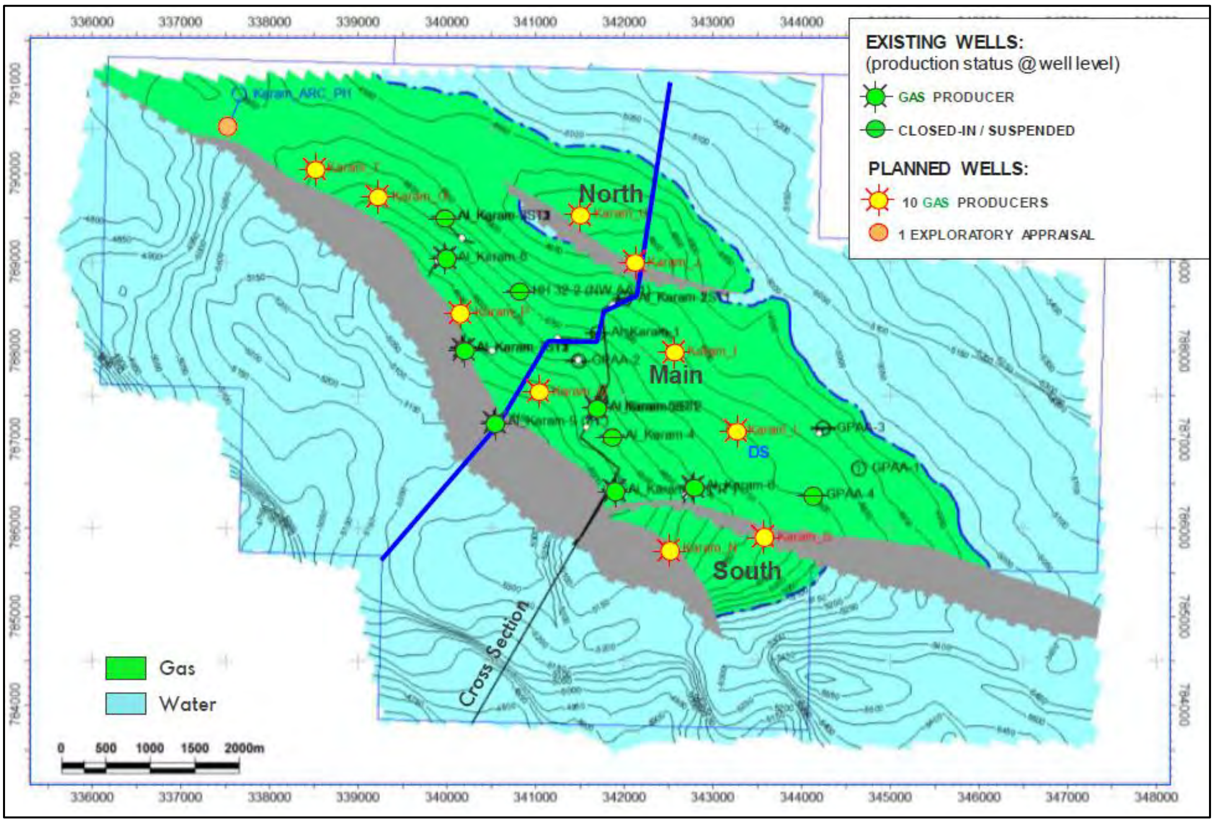
Assil and Al Karam are both fault bound (to the south), 3-way dip closed structures, which are elongate in a NW to SE orientation. The Assil primary reservoir is the Bahariya, which lies at a depth of approximately 3,800 mTVDss. The primary reservoir at Al Karam is the Kharita, which is situated at approximately 4,860 mTVDss. Drilling has generally focused on the structural crests, but the near term wells are targeted at drilling more of the un-drilled areas. Figure 61 and Figure 62 present structural maps of the Assil and Al Karam Fields respectively.

Figure 61: Assil Structural Configuration – Bahariya Reservoir Level



Source: Vendor VDR

Figure 62: Al Karam Structure Map – Kharita Reservoir Level



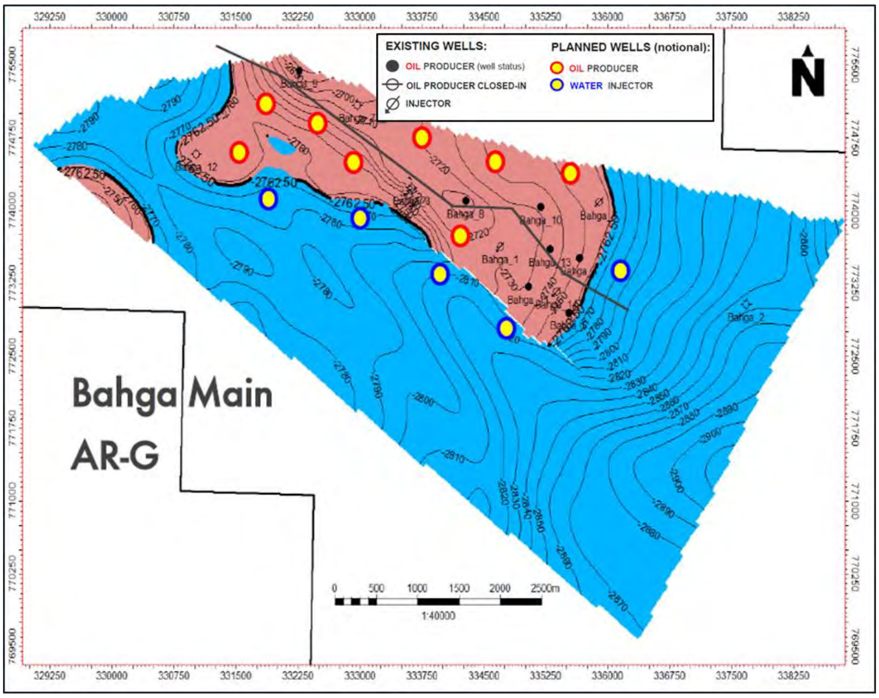
Source: Vendor VDR

Hydrocarbons at Al Magd and Bahga are primarily oil and a relatively small amount of oil production has taken place. A combined 10 MMBbl has been produced up until January 2019 and recovery factors generally remain low compared to the in-place volumes. The vast majority of this production has taken place from the Bahga Field. Near term, future plans consist of water floods for the oil reservoirs and production of gas from the deeper gas targets at Bahga.

2.6.1.1 Structure and Trap

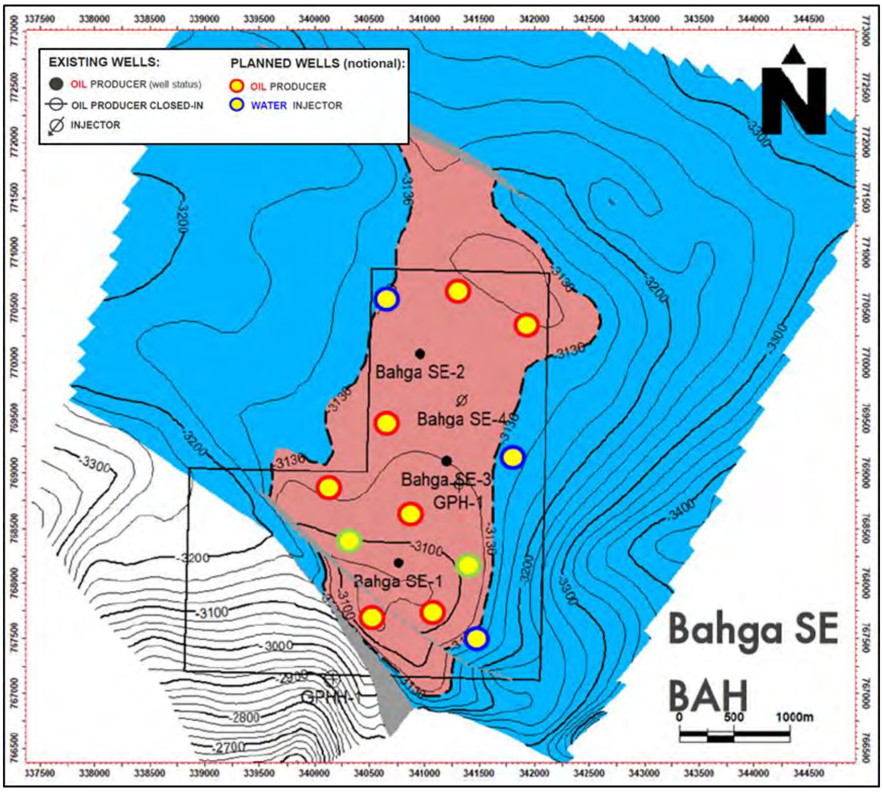
The trapping mechanism at Al Magd, Al Bahga and Al Barq and their satellites is 3-way dip structures, closed against a bounding fault, which is typical for fields in this trend. The Bahga Fields consist of the Main Field and three satellite fields (Bahga C98, Bahga C101 and Bahga SE), these are shown in Figure 63 to Figure 66. The Al Magd Main Field and Al Magd C86 Satellite Fields are shown in Figure 67. The Al Barq Field is presented in Figure 68.

Figure 63: Bahga Main Field Location Map – Abu Roash-G Reservoir Level



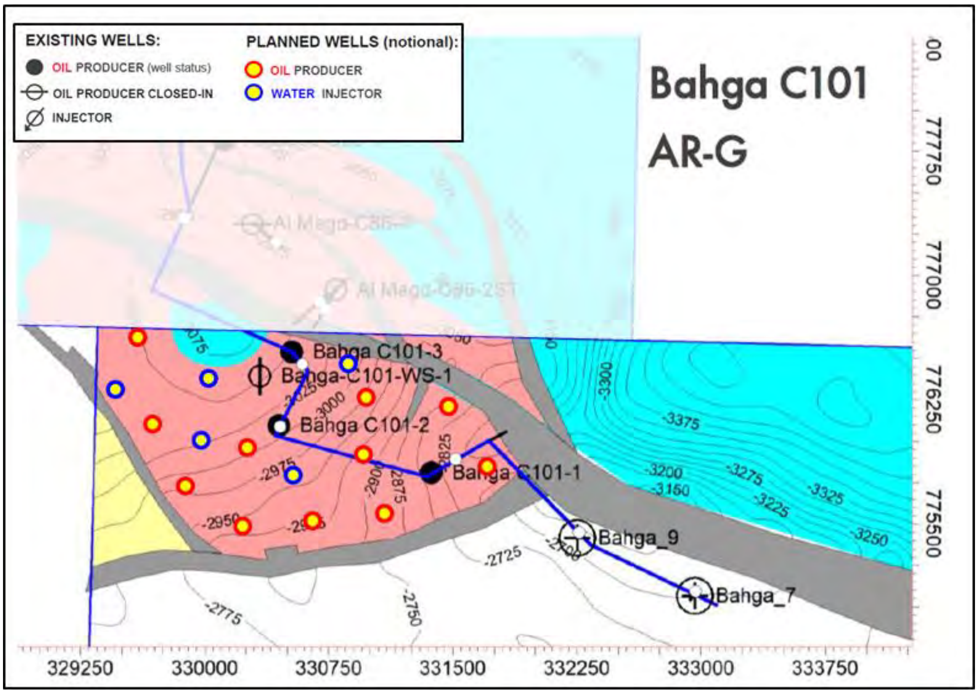
Source: Vendor VDR

Figure 64: Bahga SE Field Location Map – Bahariya Reservoir Level



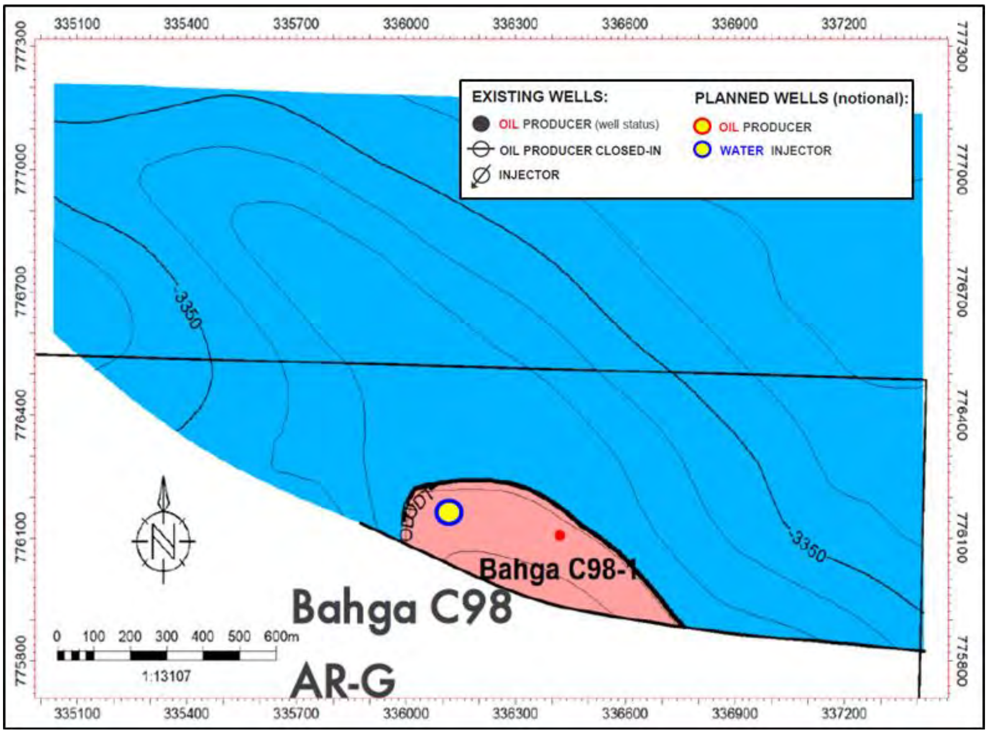
Source: Vendor VDR

Figure 65: Bahga C101 Field Location Map – Abu Roash-G Reservoir Level



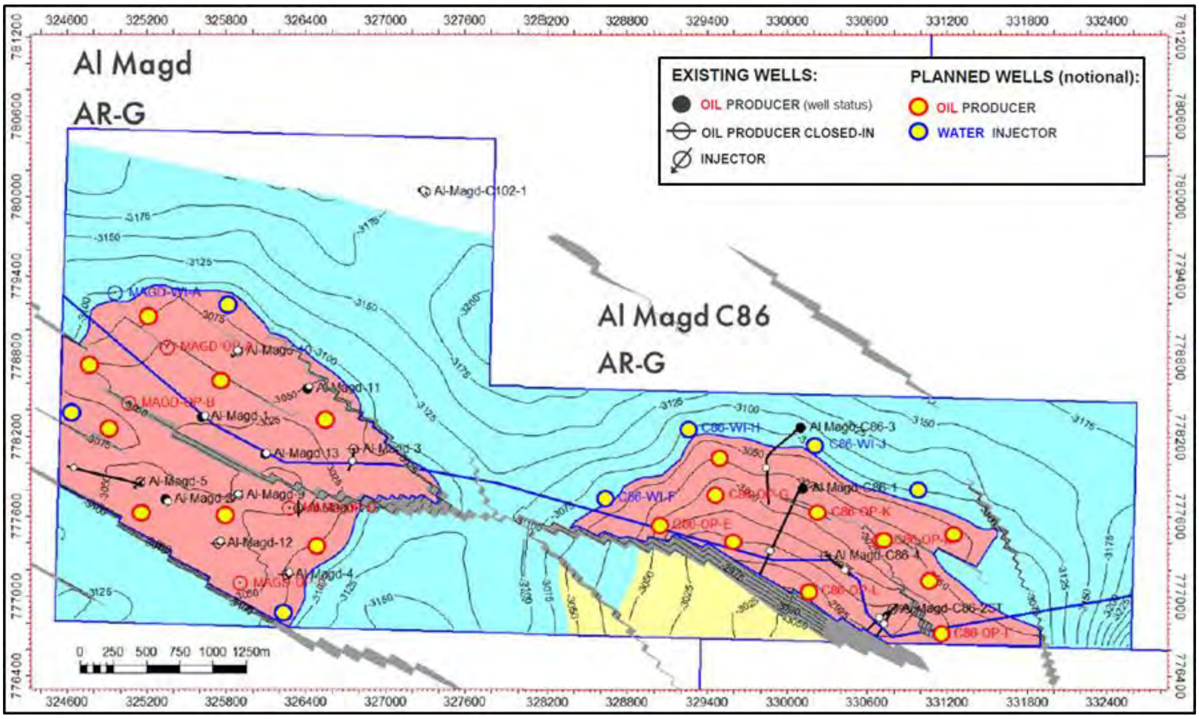
Source: Vendor VDR

Figure 66: Bahga C98 Field Location Map – Abu Roash-G Reservoir Level



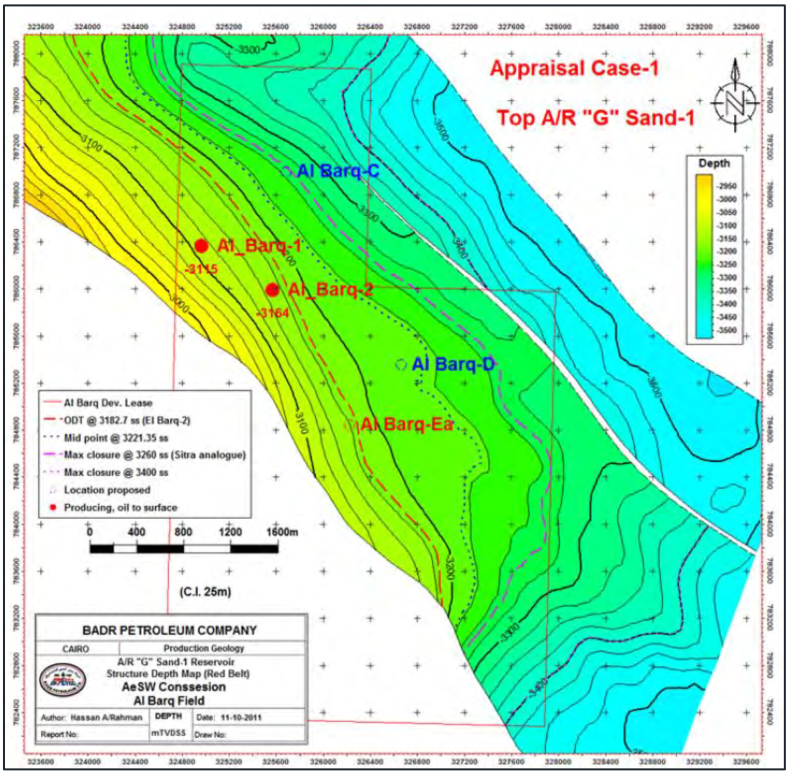
Source: Vendor VDR

Figure 67: Al Magd and Al Magd C86 Fields – Abu Roash-G Reservoir Level



Source: Vendor VDR

Figure 68: Al Barq Field – Abu Roash-G Reservoir Level



Source: Vendor VDR

2.6.1.2 Reservoir

The primary reservoir, in all the fields, is either the Abu Roash G or Bahariya. Top reservoir depths are typically 2,500 m to 3,500 mTVDss. Secondary reservoirs are the Bahariya and Kharita levels.

2.6.1.3 Reservoir and Fluid Properties

Representative PVT data are presented in Table 71. Data from Assil in the Kharita Formation show CO_2 contents of 5.6 mol%. In general pressures and temperatures suggest normal gradients, but there is evidence of moderate overpressuring in Abu Roash Formation reservoirs at Assil and Al Karam.

Table 71: AESW Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
Assil-1	KHA	4,125	143.3	6,258	4,553	Not known	67	0.04	0.62
Karam-6	KHA	4,825	158.9	7,560	3,415	Not known	10	0.03	0.69
Karam-3	ARG	4,400	148.9	10,000	6,643	Not known	97	0.06	0.72

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
Assil-2	ARC	3,300	118.9	6,500	4,995	2.90	3500	0.14	47
Assil-2	ARG	3,650	124.2	6,500	1,795	1.33	550	0.50	37
Karam-1	ARG	4,425	147.8	10,280	4,401	2.78	3915	0.07	47
Al Magd-1	ARG	3,000	113.9	4,490	736	1.18	211	0.95	33
Bahga C101-1	KHA	3,175	115.6	4,027	2,071	1.51	813	0.44	40
Bahga-4	ARG	2,900	113.9	4,150	618	1.17	187	1.14	33
Al Barq-1	ARE	No data	112.8	4,485	2,075	1.31	549	0.46	39
Al Barq-1	ARG	No data	115.6	4,760	360	1.09	83.6	2.18	32

2.6.1.4 Production Facilities

At AESW, there are two small remote gathering facilities. These are located in the Al Barq and Bagha areas. The facilities separate the production fluids from their respective areas. The Bagha facility designed to process 6 Mbpd of condensate, and the Al Barq facility is designed to process 3 Mbpd of condensate. Condensate is stored and exported via pipeline to the BED 3 processing plant; gas is used for local power generation and flared if in excess. Produced water is sent for reinjection for disposal, and any excess is routed to evaporation ponds.

2.6.2 HIIP

Where sufficient information was provided in the VDR and or the vPDR, GaffneyCline carried out an independent assessment of the hydrocarbons initially in-place (HIIP) for the volumetrically significant reservoirs using a probabilistic approach.

Logs, core and other data from AESW wells were provided within the VDR. They have been reviewed and a petrophysical interpretation has been performed to provide suitable parameters (e.g. porosity, water saturation, net-to-gross) for the reservoirs of interest, that have been incorporated in the volumetric assessment performed by GaffneyCline. The Assil-4 well was selected to perform a spot-check of the Vendor's petrophysical analysis. Petrophysical parameters were further spot checked by analysis of well logs and or zone averages in any Petrel models that were available.

Gross rock volume (GRV) values presented in the VDR were checked by running any Petrel models or generating estimates of map based GRV using the volumetric tool in Petrel and any associated structural surfaces. Structural surfaces were also checked to see if they honoured well control.

Table 72 and Table 73 present comparisons of the Operator's HIIP estimates, the Vendor's estimates and GaffneyCline's independent estimates. GaffneyCline did not derive independent estimates for minor reservoirs or where data in the VDR and vPDR were not sufficient.

Relatively large differences are observed in the different volumetric estimations at Assil ARG and BAH reservoirs, between the Operator and the Vendor. This is largely due to differences in the depth map used, where different depth maps were tied to different sets of wells. GaffneyCline has taken a range of uncertainty into account in its analysis.

Larger estimates for the Vendor and GaffneyCline at the Al Karam Field are due to recent drilling encountering deeper contacts and more optimistic fault positions that post-date the Operator's estimate.

No geological model was provided for the C101 area and so GaffneyCline made a structural model in order to quality check the GRV and subsequently reduced the GRV in its independent estimate. This ultimately resulted in a reduction to HIIP of approximately 20%.

Table 72: Comparison of HIIP Estimates – Assil and Al Karam

a) Oil (MMBbl)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Assil [ARC]	1.3	N/A	N/A	N/A	N/A
AESW Assil [ARE]	7	N/A	N/A	N/A	N/A
AESW Assil [ARG]	32	62	22	48	93
AESW Assil [BAH]	71	40	21	41	70
AESW Assil C83 [ARE/G]	11	N/A	N/A	N/A	N/A
AESW Karam [ARC]	10	N/A	N/A	N/A	N/A
AESW Karam [ARE]	5	N/A	N/A	N/A	N/A

b) Gas (Bcf)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Assil [KHA] (Bcf)	335	369	213	350	535
AESW Karam [ARG] (Bcf)	143	N/A	N/A	N/A	N/A
AESW Karam [BAH] (Bcf)	182	N/A	N/A	N/A	N/A
AESW Karam [KHA] (Bcf)	1,230	1,797	1,146	1,726	2,480

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Table 73: Comparison of HIIP Estimates – Al Magd, Bahga and Al Barq

a) Oil (MMBbl)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Al Magd [ARG]	14	17.8	12	17	24
AESW Al Magd C86 [ARG]	13	10.2	7	10	14
AESW Bahga [ARG]	34	38	25	36	50
AESW Bahga [BAH&KHA]	11	N/A	N/A	N/A	N/A
AESW Bahga SE [ARG&BAH]	13	12.2	8	12	16
AESW Bahga C98 [ARG]	2	5.4	4	5	7
AESW Bahga C101 [ARG*KHA]	15	14.9	8	12	17
AESW Al Barq [ARE]	3	N/A	N/A	N/A	N/A
AESW Al Barq [ARG]	2	N/A	N/A	N/A	N/A
AESW Al Barq [BAH]	3	N/A	N/A	N/A	N/A

b) Gas (Bcf)

Reservoir Unit	Operator (Bapteco) HIIP Estimate	Vendor VDR Estimate	GaffneyCline Estimate		
			Low	Best	High
AESW Bahga C98 [BAH&KHA] (Bcf)	18	N/A	N/A	N/A	N/A
AESW Al Barq [ARG] (Bcf)	2	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

2.6.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 74.

Table 74: AESW: Resource Categories in Databook

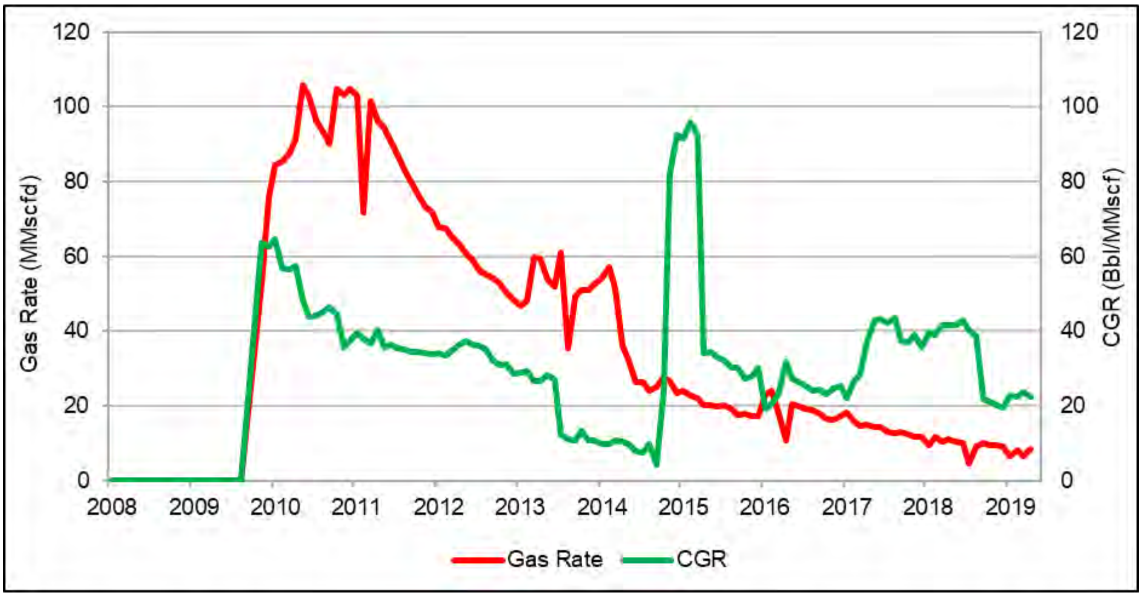
Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
Bahga NFA	Bahga NFA		Reserves
Al Barq NFA	Al Barq NFA		Reserves
Assil NFA	Assil NFA		Reserves
Al Magd NFA	Al Magd NFA		Reserves
Al Karam NFA	Al Karam NFA		Reserves
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
Al Karam infill	Al Karam infill (gas)		Reserves and Contingent Resources
	Al Karam upside (oil)		Contingent Resources
Assil infill	Assil infill (gas)		Reserves
	Assil upside (oil)		Contingent Resources
Al Magd infill	Al Magd infill		Reserves
Bahga infill	Bahga infill		Reserves
General infill	Not included	All development activity viewed as covered by other categories.	N/A
Not included	Shut in wells reactivation	Additional activity developed with client	Reserves
Assil C2E	Near Field Exploration		Prospective Resources
Bahga C2E			
Al Barq C2E			

2.6.4 Historical Field Performance

2.6.4.1 Assil

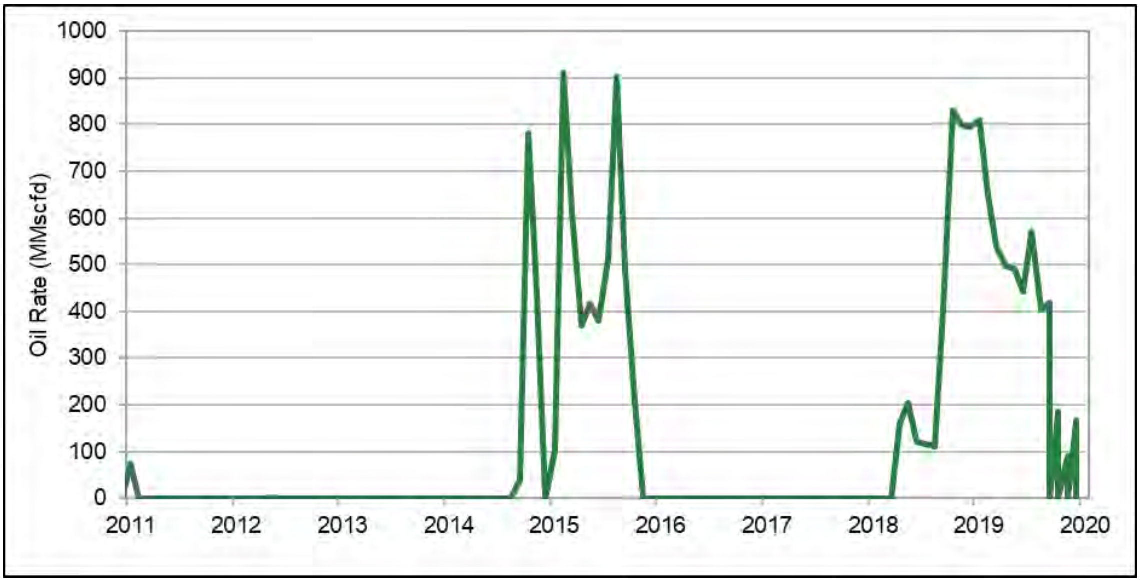
Assil field was discovered in 2007 and production started in July 2010. The development of the Kharita reservoir started with Assil-1, Assil-5 and Assil-6. Peak production was reached in 2011 with a gas production of 106 MMscfd after Assil-7 came on production, see Figure 69. The average gas production and CGR are 8 MMscfd and 21.9 Bbl/MMscf respectively over the last 6 months of production. The gas production is mainly from the Kharita formation.

Figure 69: Historical Gas Production Rate and CGR, Assil (Kharita)



The oil production is mainly from the C83 field from well C83-1 ARG and Assil -03 ARC and Assil-08 wells. The average oil production over the last six months is 160 bpd (Figure 70).

Figure 70: Historical Oil Production Rate, Assil

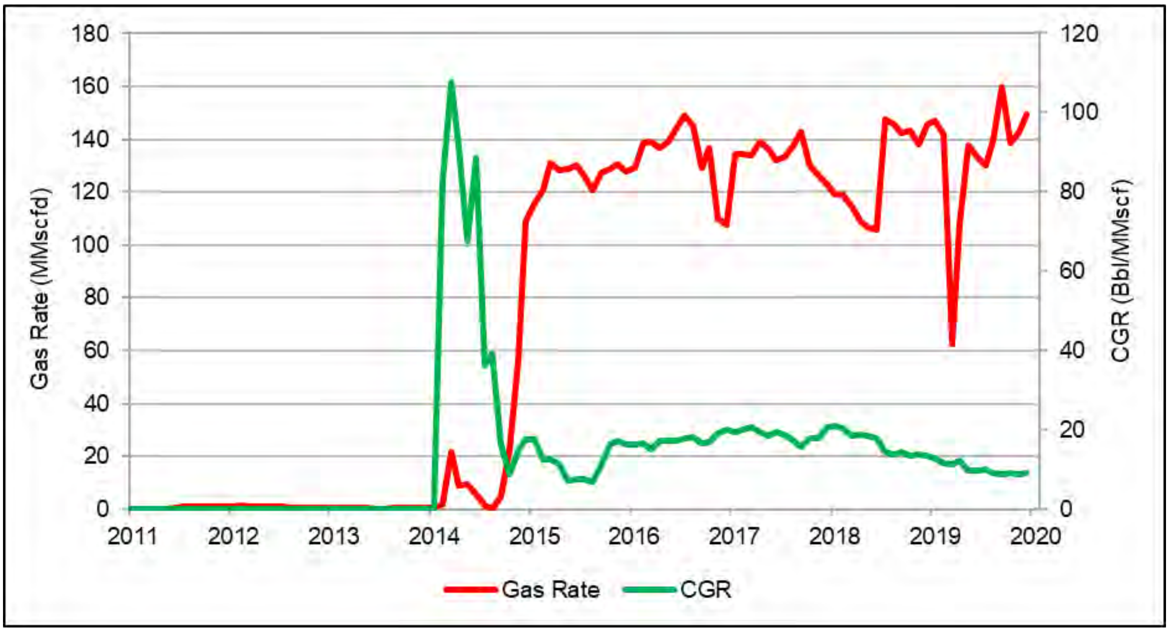


2.6.4.2 Al Karam

The development of the Kharita reservoir stated in 2014 with three wells. In 2016 a fourth well was drilled and a final well drilled in 2018. The plateau gas rate has been maintained at 120-150 MMscfd since start of production.

Figure 71 and Figure 72 show the gas and oil production history respectively from the Al Karam field.

Figure 71: Historical Gas Production Rate and CGR, Al Karam



The oil production commenced in 2008 reaching a peak production of 471 bopd and has since ceased. Oil production mainly from Karam-02ST in the ARG formation.

Figure 72: Historical Oil Production Rates, Al Karam

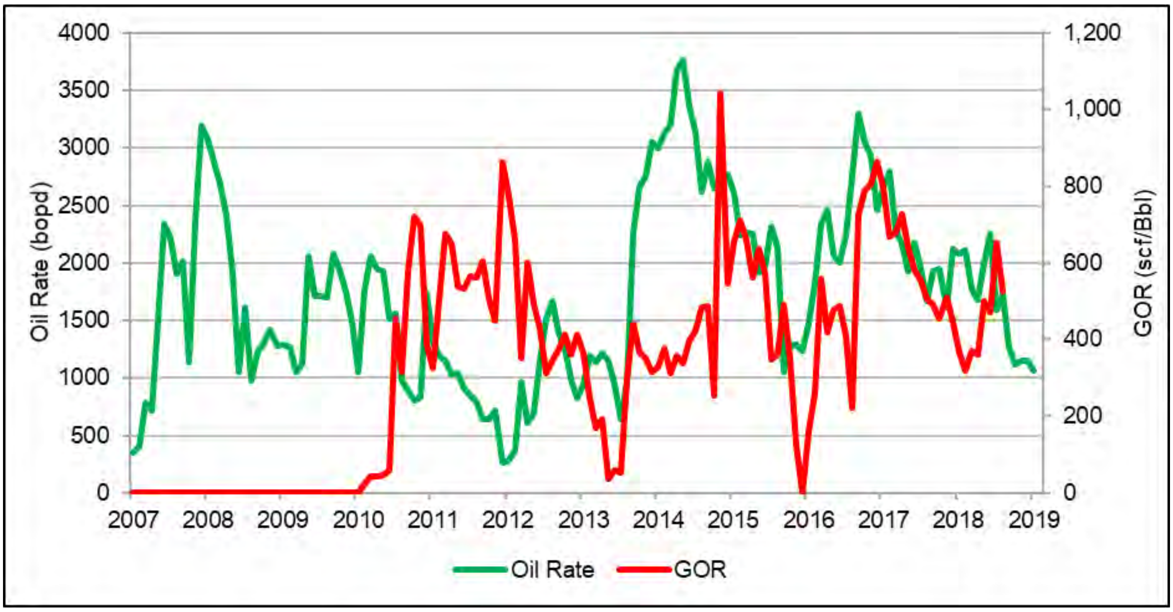
2.6.4.3 Bahga

Bahga includes four sub reservoirs: Bahga Main, Bahga Southeast (SE), Bahga C101 and Bahga C98. Bahga Main production started in December 2007 with the Bahga-01 well. Water injection pilots started in 2012 and a water flood scheme was implemented 2014. Bahga South East (SE) began in 2010 through Bahga SE-1, with additional wells adding to production Bahga SE-2 in 2017 and Bahga SE-3 in 2019.

Bahga C101 was producing from three wells (C101-1, C101-2 and C101-3), currently producing from one well C101-1.

Figure 73 shows the total production history for Bahga, which includes, Bahga Main, Bahga SE and Bahga C101.

Figure 73: Historical Oil Production Rates, Bahga (Main, SE and C101)

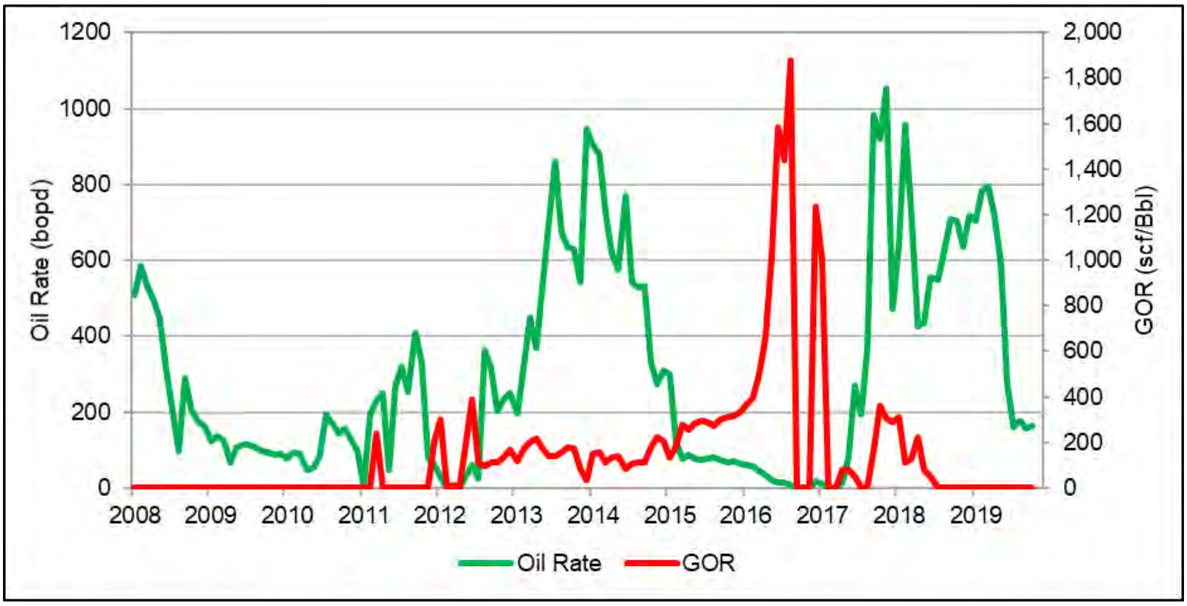


2.6.4.4 Al Magd

Al Magd include two sub reservoirs, Al Magd Main and Al Magd C83.

Al Magd Main began production in early 2008, waterflood commenced in 2014 with the conversion of Al Magd-3 producer to an injector. Al Magd C83 started production in 2012. Figure 74 shows the Al Magd production history.

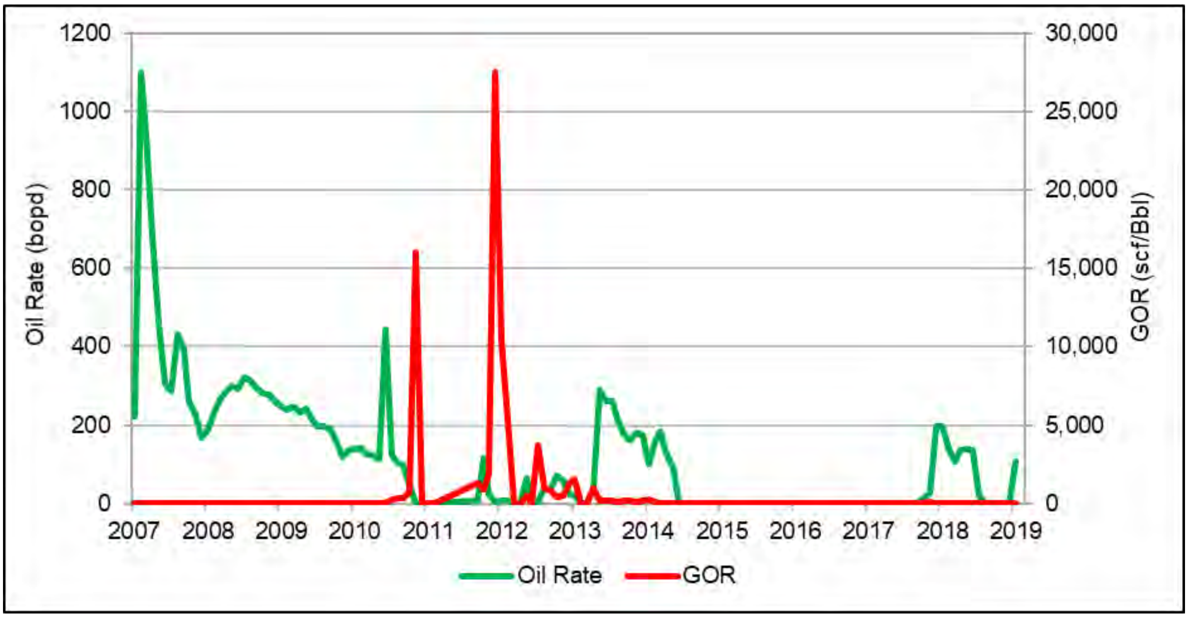
Figure 74: Historical Oil Production Rates and GOR, Al Magd



2.6.4.5 Al Barq

Al Barq production commenced in 2007 with a peak production of 1,100 bpd with two wells (Barq-01 and Barq-02 in the ARG and ARC reservoirs, it since has declined very sharply. Three more wells were drilled in 2012 (Barq-03, 04 and 05) with similar performance to the original two wells. Figure 75 shows the Al Barq production history.

Figure 75: Historical Oil Production Rates and GOR, Al Barq



2.6.4.6 Summary

Total cumulative oil and water production for AESW, along with recent rates are shown in Table 75.

Table 75: AESW Fields Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
Al Assil	5	0.5	146.6	215.7	7.5	92.5
Al Karam	6	0.5	247.2	0.0	147.7	816.0
Bahga	10	7.7	2.7	1,122.1	0.8	356.3
Al Magd	5	1.3	0.1	164.1	0.0	32.5
Al Barq	1	0.5	0.0	26.6	0.0	0.0
Total	**27**	**10.4**	**396.7**	**1,528.5**	**156.0**	**1,297.3**

Note:

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

2.6.5 Field Development Plan

Where available in the VDR, proposed drilling locations for the Fields in AESW are shown in Figure 61 to Figure 68.

2.6.5.1 Assil

The Consortium's future development plans for the Assil field include two infill wells in the Kharita gas reservoir in Assil Main and one well in C83 area targeting the ARG oil reservoir.

The first of the Assil Main wells has been drilled after the Effective Date of this Report in 1Q 2020 as Assil-9. This is located on the southern crestal area of the field and successfully produces gas from the Kharita Formation. A later well will target the northern fault block of the field.

Also during 1Q 2020, well Assil C83-2, has been drilled and brought on stream as an Abu Roash G oil producer.

The drilling schedules for the Kharita and ARG reservoirs are summarized in Table 76 and Table 77.

Table 76: Assil, Kharita Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	0	0	1	0	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**1**	**0**	**0**	**1**	**0**	**2**

Table 77: Assil, ARG Oil Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	1	0	0	0	0	**1**
Injection Wells	0	0	0	0	0	**0**
Total	**1**	**0**	**0**	**0**	**0**	**1**

2.6.5.2 Al Karam

The Consortium's future development plans for Al Karam include eight new infill wells in the Kharita gas reservoir and six new infill wells in the ARG/BAH gas reservoir. The drilling schedules are summarized in Table 78 and Table 79.

Table 78: Al Karam, Kharita Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	4	3	1	0	**8**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**4**	**3**	**1**	**0**	**8**

Table 79: Al Karam, ARG/BAH Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	3	3	0	**6**
Injection Wells	**0**	0	0	0	0	**0**
Total	**0**	**0**	**3**	**3**	**0**	**6**

2.6.5.3 Bahga

The Consortium's future development plans for Bahga include six infill producer wells and three injectors in Bahga Main, seven infill producers and one injectors in Bahga SE, and eleven infill producers and three injectors in Bahga C101. No new infill wells planned for C98. The drilling schedules are summarized in Table 80, Table 81 and Table 82 respectively.

Table 80: Bahga (Main), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	1	5	0	0	**6**
Injection Wells	**0**	0	3	0	0	**3**
Total	**0**	**1**	**8**	**0**	**0**	**9**

Table 81: Bahga (SE), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	2	3	2	0	**7**
Injection Wells	0	0	1	0	0	**1**
Total	**0**	**2**	**4**	**2**	**0**	**8**

Table 82: Bahga (C101), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	1	1	0	7	**11**
Injection Wells	0	0	0	0	3	**3**
Total	**2**	**1**	**1**	**0**	**10**	**14**

2.6.5.4 Al Magd

The Consortium's future development plans for the fields include the following activities:

- Seven Infill producer wells and two injectors planned in Al Magd Main;
- Seven infill producers and two injectors planned in Al Magd C86.

The schedule and number of new production wells for Al Magd Main and Al Magd C86 reservoirs are summarized in Table 83 and Table 84 respectively.

Table 83: Al Magd (Main), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	7	0	**7**
Injection Wells	0	0	0	2	0	**2**
Total	**0**	**0**	**0**	**9**	**0**	**9**

Table 84: Al Magd (C86), Oil Producers and Water Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	4	0	0	3	0	**7**
Injection Wells	0	0	0	2	0	**2**
Total	**4**	**0**	**0**	**5**	**0**	**9**

2.6.5.5 Al Barq

No further development is planned for Al Barq oil reservoir.

2.6.6 Production Forecasts

GaffneyCline carried out its own analysis based on historical performance and analysis of analogue cases, using a combination of Decline Curve Analysis (DCA) for existing wells and type curves to estimate the performance of the planned new infill wells and work-overs to which Reserves are attributed. Forecasts were produced for the period from 2020 to the expiry of the PSA (April 2033). Al Bagha PSA expiry is 28th May 2032.

Table 85 and Table 86 shows the remaining technical recoverable volumes for Assil and Al Karam.

Table 85: Remaining Technically Recoverable Gas Volumes, AESW, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
Al Karam	514.1	637.5	796.4
Assil	55.3	69.4	90.3
Bagha	1.0	2.6	5.5
Al Magd	0.0	0.0	0.0
Al Barq	0.0	0.0	0.0
SI Re-activation	1.4	1.5	1.6
Total	**571.8**	**711.0**	**893.8**

Notes:

1. The volumes in this tables are to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. The volumes shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO_2 removal.
3. Totals may not exactly equal the sum of individual entries due to rounding.

Table 86: Remaining Technically Recoverable Oil and Condensate Volumes, AESW, as at 31st December 2019

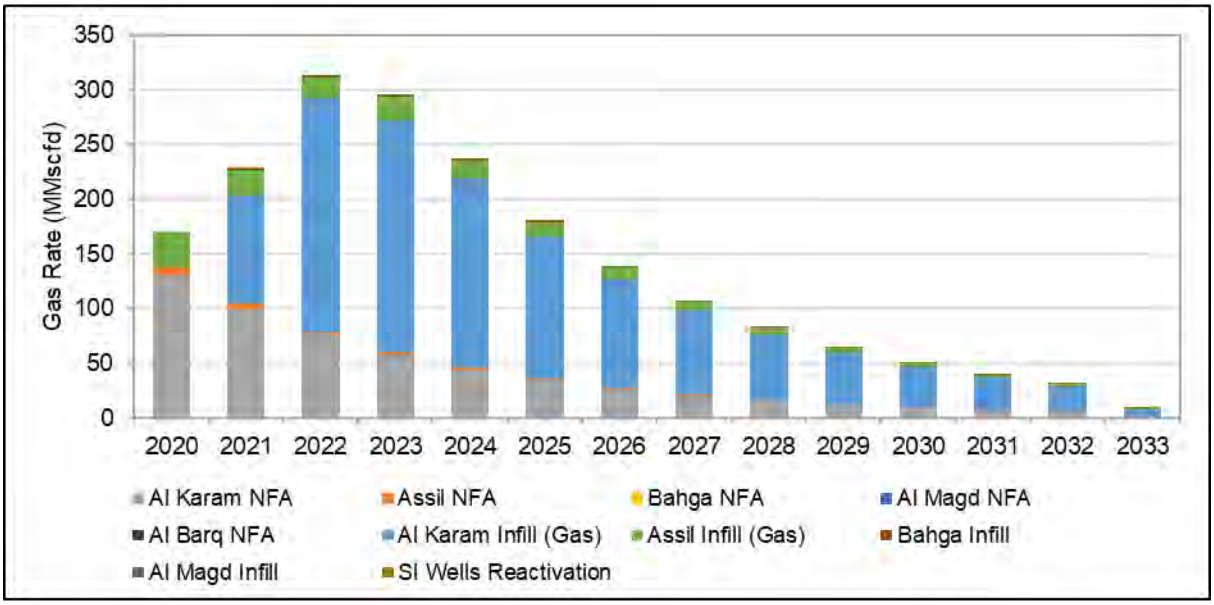
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
Al Karam	5.9	9.7	12.6
Assil	3.9	5.2	7.1
Bagha	2.9	7.5	13.4
Al Magd	0.9	3.7	7.5
Al Barq	0.1	0.1	0.1
SI Re-activation	4.1	4.3	4.5
Total	**17.8**	**30.5**	**45.2**

Notes:

1. The volumes in this tables are to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 76 and Figure 77 shows the best case gas and condensate production forecasts for AESW by activity.

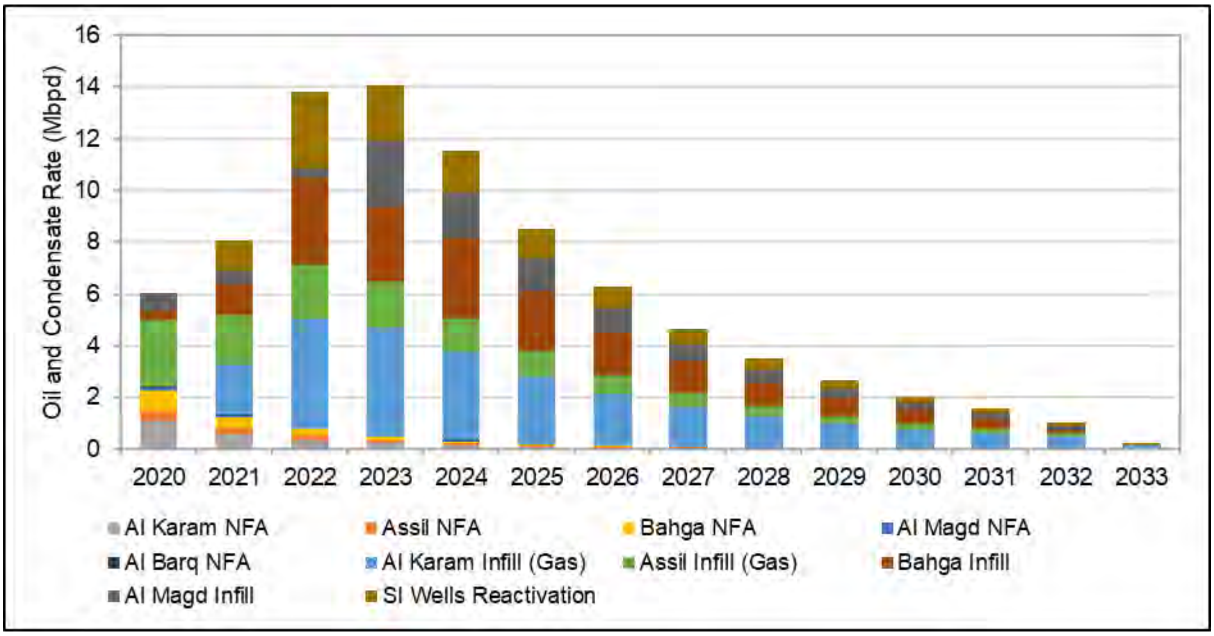
Figure 76: Best Case Gas Production Forecast, AESW



Notes:

1. The values in this figure are annual average rates to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.
2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO2 removal.

Figure 77: Best Case Oil and Condensate Production Forecast, AESW

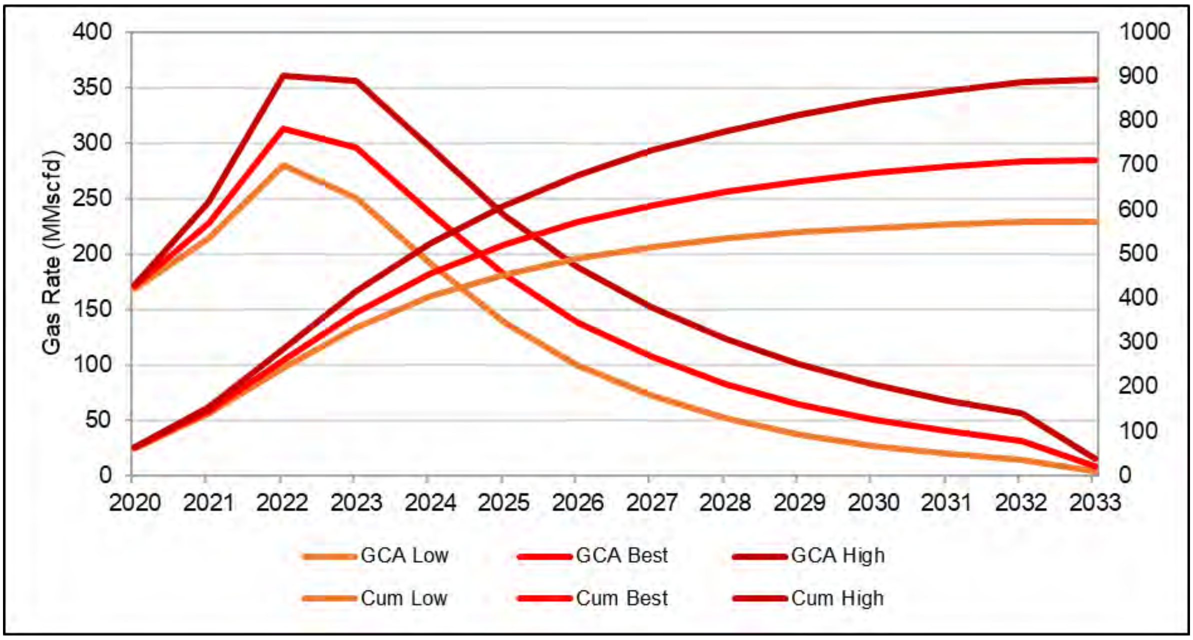


Note:

1. The values in this figure are annual average rates to end of May 2032 for Bagha & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.

Figure 78 and Figure 79 show the Low, Best and High production forecasts for AESW.

Figure 78: Gas Production Forecasts, AESW

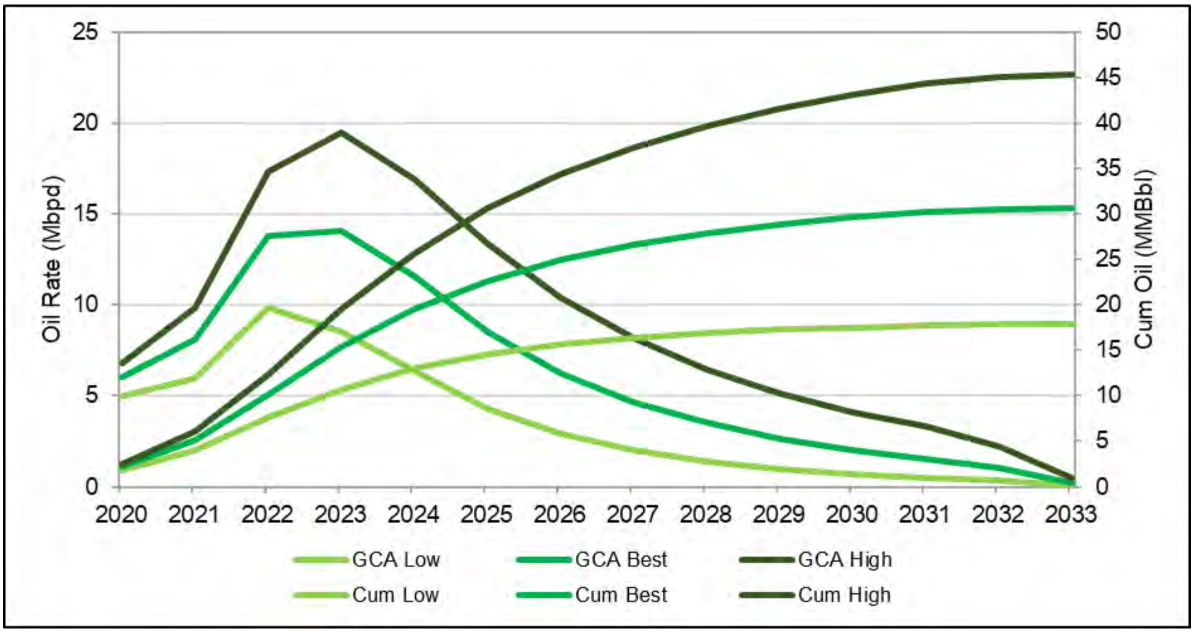


Notes:

1. The volumes in this figure are annual average rates to end of May 2032 for Bahga & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.

2. The values shown are prior to deduction of fuel, estimated at 4.5% in 2020-2023 and 5% from 2023 onwards for all the fields. Al Karam has an additional ~7.5% of shrinkage due to CO_2 removal.

Figure 79: Oil and Condensate Production Forecasts, AESW



Note:

1. The volumes in this figure are annual average rates to end of May 2032 for Bahga & Al Barq and to end of April 2033 for the remaining fields; no economic cut off has been applied.

2.6.7 Contingent Resources

Contingent Resources have been assigned to wells for which locations have not yet been defined. Further modelling work is required to bring to these opportunities to a higher level of confidence. The Contingent Resources are assigned to:

- Incremental oil production from 14 infill wells in Assil (Main), in the ARC and Bahariya formations, as well as 8 new injectors;
- Gas and condensate from two wells in the Al Karam Kharita gas; and
- Oil production form three infill wells in the Al Karam ARC reservoir.

The AESW Contingent Resources are summarized in Table 87.

Table 87: Gross Contingent Resources. AESW, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
A Karam Kharita	76.6	92.4	116.2
Al Karam ARC	0.0	0.0	0.1
Assil	0.1	0.4	1.1
Total	**76.7**	**92.8**	**117.4**

(b) Oil and Condensate

Case	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Al Karam Kharita	1.1	1.8	2.3
Al Karam ARC	0.3	1.0	1.9
Assil	0.7	2.1	3.6
Total	**2.1**	**4.9**	**7.8**

Notes:

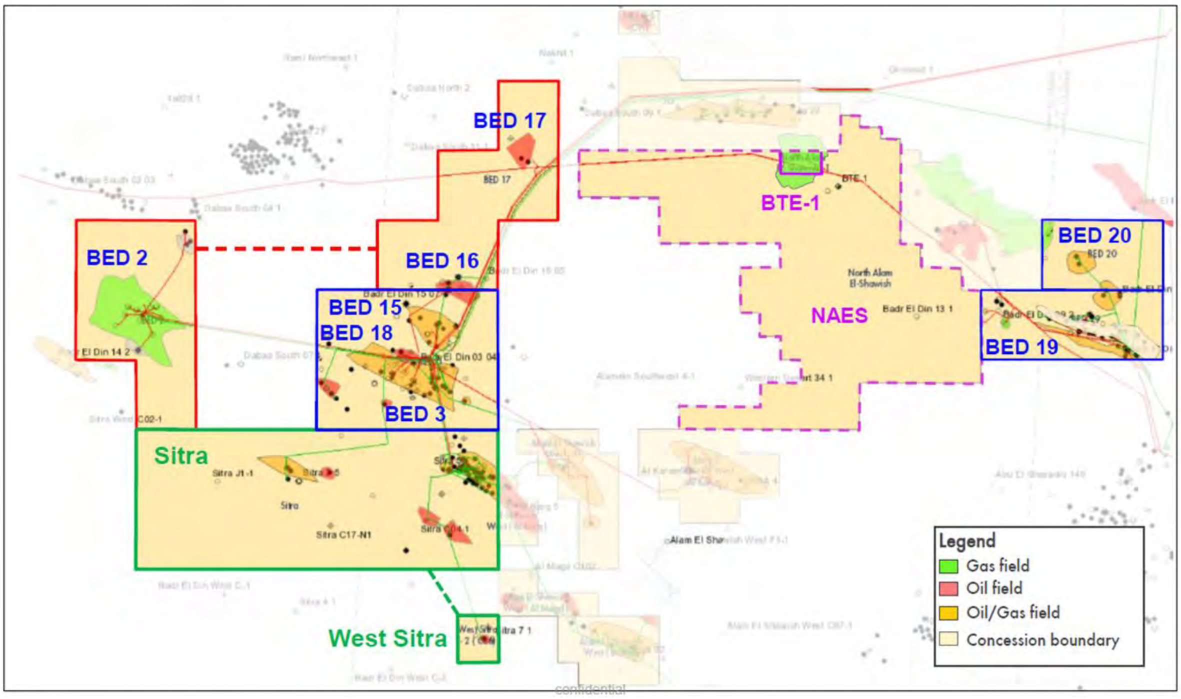
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no “Chance of Development” factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.7 North Alam El Shawish (NAES)

2.7.1 Asset Description

The NAES concession is located close to the BED and Sitra areas (see Figure 80). The primary component of the concession is the BTE Field. The BTE gas field was discovered in 2016 by the BTE-2 well. Following a production test from the BTE-2 well, the concession was converted into a development lease in 2017. Up to January 2019, some 9.8 Bscf had been produced from the BTE-2 well. Production from this single well is ongoing.

Figure 80: NAES Concession – Location Map



Source: Vendor VDR

There is significant uncertainty associated with the volumetric estimation of the field. The BTE-4 appraisal well was drilled in a down-dip location in 2019/2020 and encountered more than 200 m of net pay and successful production tests were run in several intervals.

2.7.1.1 *Structure and Trap*

The trapping mechanism is a 3-way dip closure, which is ultimately bound to the NE by a large fault. The structure itself is further faulted by several smaller faults. The Field is currently under-appraised as only 2 wells penetrate the reservoir and the field appears to cover a relatively large geographical area, of more than 30 km^2. Figure 81 shows a top reservoir structure map and the location of the two wells. The initial results suggest that the first two wells are potentially not in communication with each other. Due to the nature of the reservoir and structural configuration of the field, it is likely that the ultimate dynamic behaviour of the reservoir will show some compartmentalization.

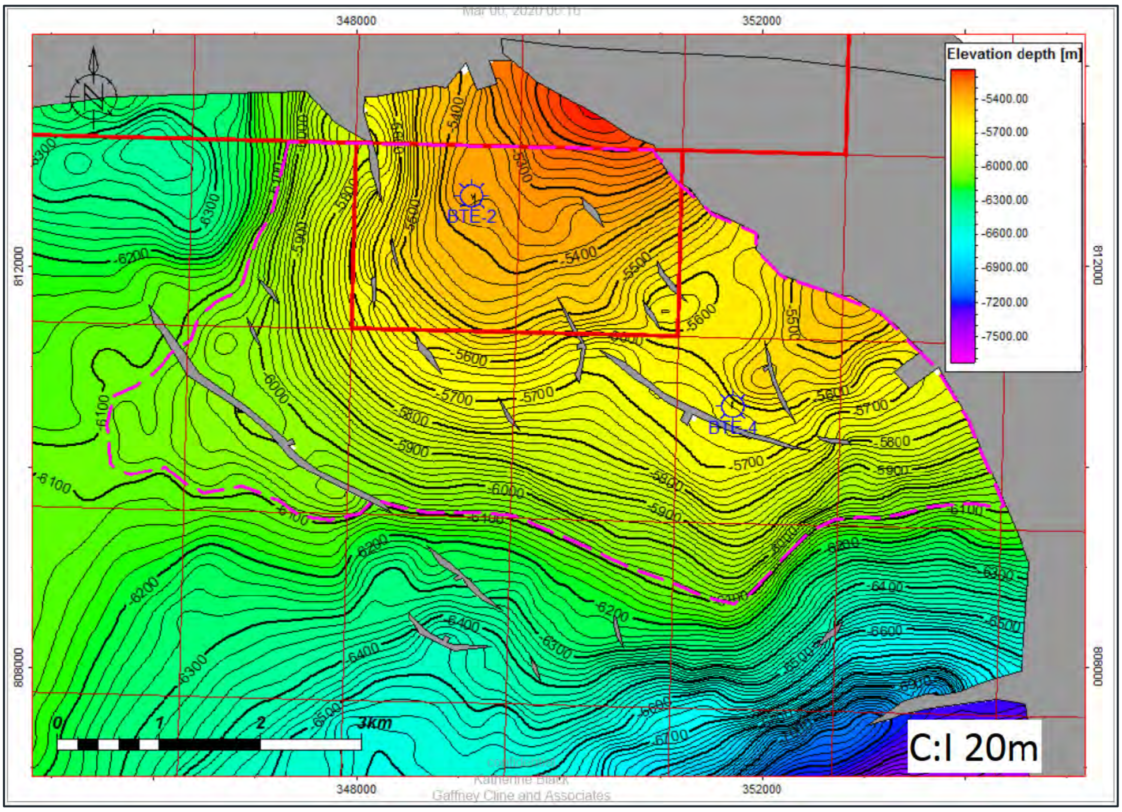
2.7.1.2 *Reservoir*

The primary reservoirs at BTE are the tight Kharita reservoir intervals, which have been found to contain gas. The Kharita reservoirs are Early Cretaceous in age and consist of sandstones deposited in a mixture of shallow marine to terrestrial environments. Secondary reservoirs in the Abu Roash C and E intervals are thought to contain oil based on interpretation of log data. The Kharita gas reservoirs are situated at a depth range of 5,200 to 6,000 mTVDss. The reservoir quality is considered to be tight with porosities typically ranging from 4 to 7% and permeability is approximately 10 mD.

Both the BTE wells drilled to date have been tested with the following results:

- BTE-2:
  - Zone K7 test: Gas: 20 MMscfd, Condensate: 0.5 Bbl/MMscf, Water: 100 bpd.
- BTE-4:
  - Zone K5 test: 27 MMscfd;
  - Zone K7 test: Very low gas rates.

Figure 81: BTE Field – Top Kharita-3 Reservoir Structure Map and Drilled Well Locations



2.7.1.3 Reservoir and Fluid Properties

Representative PVT sample data are presented in Table 88. Reported CO_2 content is moderate in the sample data, ranging from 2.1 to 3.4 mol%, but higher values have been reported on test from BTE-4 of up to 8.0 mol%. There is evidence of moderate overpressuring in both Abu Roash and Kharita Formations, and of a slightly lower geothermal gradient than in adjacent fields.

Table 88: NAES Area: Representative Pressure and Fluid Composition Data

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
BTE-4	KHA	Not known	Not known	Not known	Not known	Not known	2	Not known	0.78
BTE-4	KHA	5,735	157.7	8,809	Not known	Not known	32	Not known	0.68
BTE-4	ARC	4,560	131.7	9,247	Not known	Not known	85	0.01	0.67
BTE-2	KHA	4,795	143.9	11,972	Not known	Not known	79	0.01	0.80

2.7.1.4 Production Facilities

Gas is evacuated via the BED 19 pipeline to BED 3 gas processing facility (see section 2.3).

2.7.2 HIIP

GaffneyCline carried out some high level petrophysical analysis of the recently drilled BTE-4 well, which, at the time of writing, had not been fully integrated into the technical work of the Operator.

In total, 212 m of Kharita pay were interpreted in 10 sub-layers. All the interpreted reservoir intervals are tight. Using a 3% porosity cut-off the average net pay porosity is approximately 5%. The K5 interval that tested good rates has 58 m of interpreted net pay with 6% average porosity, while the K7 interval that exhibited very low flow rate has 32 m of interpreted net pay with 5% average porosity. The K8 and K9 intervals were tested but did not flow; a total of 49 m of net pay is interpreted, with 4-5% average porosity. The K4 interval was not tested but has an average porosity similar to K5 (16 m of interpreted pay with 6% average porosity) and so might be expected to flow in a similar way to the K5 reservoir.

Different pressure measurements in BTE-4 and BTE-2 within the K5 zone indicates compartmentalization (as is listed as a risk by the vendor).

The Petrel model provided in the vPDR, did not incorporate the findings of the BTE-4 well and the structural surfaces did not tie the well. Therefore, GaffneyCline derived an independent estimate of HIIP. GRV was derived from hand digitised and well-tied structural surfaces.

- A Low Case GRV was taken as the GDT or top of next reservoir unit down;
- A High Case GRV was taken at the spill point of each reservoir level, based on the depth maps generated;
- The Base Case GRV was taken as a combination of the Low and High Cases;
- Reservoir parameters were derived from the petrophysical averages from the BTE-2 and BTE-4 wells;

- Wide parameter ranges were used due to the apparent subsurface variability of the Kharita reservoir and small number of well penetrations in the field, which itself covers a relatively large area.

Based on the limited data available, GaffneyCline included the following intervals in its assessment:

- Low Case reservoirs: K3, K5 and K7;
- Base Case reservoirs : K3, K4, K5 and K7;
- High Case reservoirs: all interpreted net pay intervals (K6 has none).

A Monte Carlo analysis was then performed using a Crystal Ball model for each reservoir level to derive estimates of GIIP. Table 89 presents a comparison of the Operator's, Vendor's and GaffneyCline's results.

Table 89: Comparison of GIIP Estimates (Bscf) – BTE Field

Reservoir Unit	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
			Low	Best	High
NAES BTE Kharita	1,122	697	573	649	953

GaffneyCline's estimate is broadly similar to that of the Vendor. It is thought that the Operator's estimate does not take into account the observations of the BTE-4 well. Oil phase hydrocarbons potentially identified on well logs at shallower intervals have not been quantified here.

2.7.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 90.

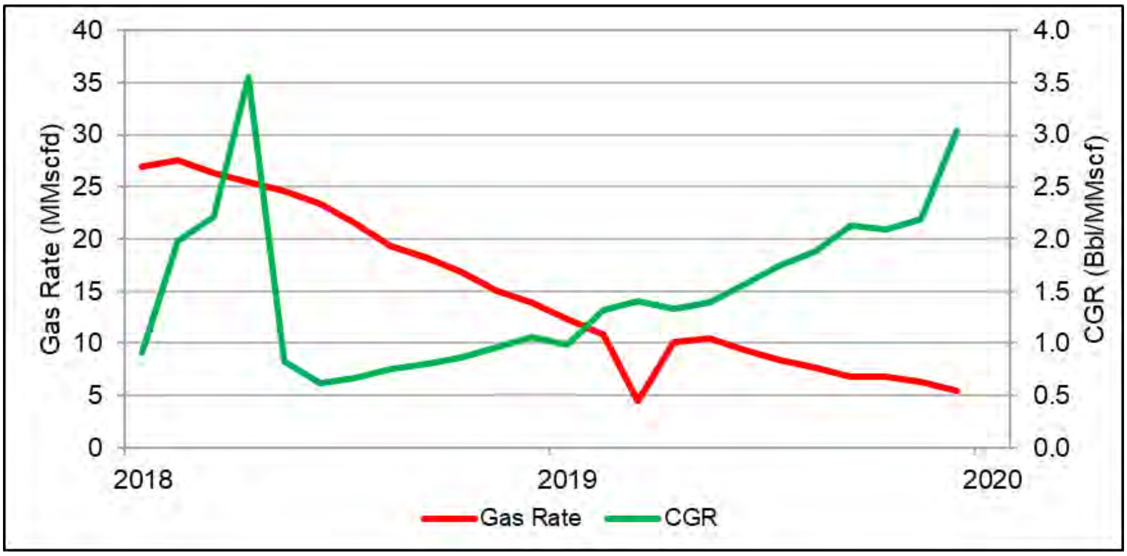
Table 90: AESW: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline Interpretation	Categorisation/Notes
NFA	NFA		Reserves
Exploration	Near Field Exploration	Included under this vendor description, although includes appraisal and development following the BTE-4 well.	Reserves

2.7.4 Historical Field Performance

Production from the BTE-2 well started in November 2018. The initial production rate was 27.5 MMscfd and has subsequently fallen to 5.5 MMscfd (Figure 82). The current CGR is 3 Bbl/MMscf. The cumulative gas production to the end of 2019 is 10.9 Bscf.

Figure 82: Historical Gas Production Rate and CGR, BTE-2 (NAES)



2.7.5 Field Development Plan

Reserves are attributed to 2 additional wells which are in the Consortium's 5 year business plan. The last technical study presented by the Operator is dated 2017, prior to the drilling of the BTE-4 well, and outlined a notional 8-well development plan, but gave no locations for these wells. Further work is needed to define a more complete development plan, with the next few development wells acting to appraise the field.

Table 91: BTE Gas Producers Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	0	2	**2**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**0**	**0**	**2**	**2**

2.7.6 Production Forecasts

GaffneyCline produced production forecasts for the existing BTE-2 well and the future infill wells for the period from 2020 to the expiry of the PSA (September 2042). Based on the performance of BTE-2 well, an EUR of 13 Bcf/well is assumed. Table 92 shows the remaining technical recoverable volumes for Assil and Al Karam.

Table 92 shows the remaining technical recoverable volumes for BTE.

Table 92: Remaining Technically Recoverable Gas Volumes by Case, BTE, as at 31st December 2019

Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
NFA	1.9	2.8	3.8
Infill	14.0	25.8	40.9
Total	**15.9**	**28.6**	**44.7**

Notes:

1. The values in this table are to the end of September 2042; no economic cut off has been applied.
2. The volumes are prior to deduction of fuel and shrinkage, estimated at 12% in 2020-2023 and 12.5% from 2023 onwards (Fuel = 4.5% and shrinkage due to CO_2 removal= 7.5%).
3. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 83 shows the Best Case gas production forecast for BTE by activity.

Figure 83: Best Case Gas Production Forecast, BTE

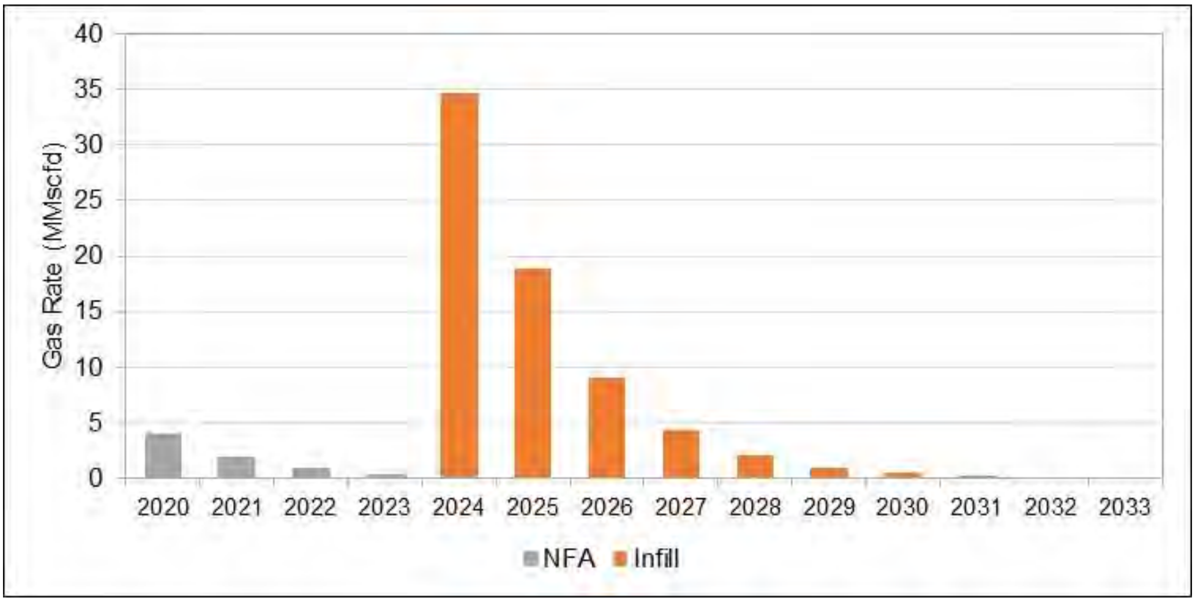
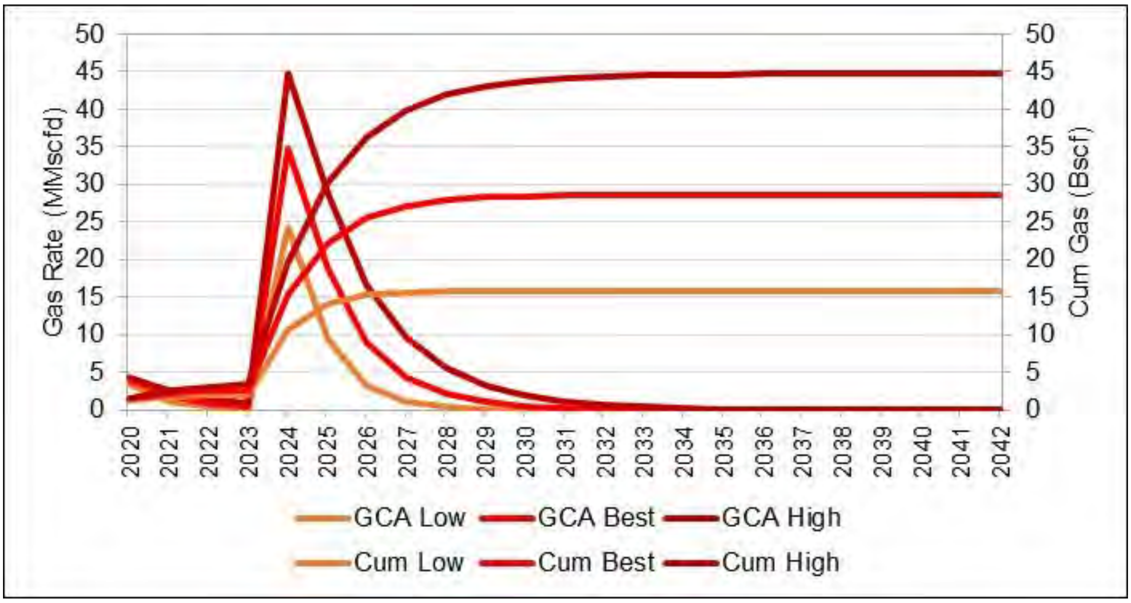


Figure 84 shows the Low, Best and High gas production forecasts for BTE.

Figure 84: Gas Production Forecasts, BTE



Notes:

1. The values in this table are to 17th of September 2042; no economic cut off has been applied.
2. The values are prior to deduction of fuel and shrinkage, estimated at 12% in 2020-2023 and 12.5% from 2023 onwards (Fuel = 4.5% and shrinkage due to CO_2 removal= 7.5%).

2.7.7 Contingent Resources

The full potential of the BTE field is as yet unclear but based on the estimates of GIIP and assuming reasonable overall recovery factors suggests a full field development might require in the order of 20 wells (Table 93).

Table 93: GIIP, EUR and RF, BTE, as at 31st December 2019

Case	Low	Best	High
GIIP (Bcf)	573	649	953
EUR (Bcf)	171.9	259.6	476.5
RF (%)	30	40	50

Contingent Resources have been assigned to 17 infill wells in the BTE area, where modelling and well locations have not yet been fully matured (Table 94).

Table 94: Gross Contingent Resources, BTE, as at 31st December 2019

(a) Natural Gas

Case	1C (Bscf)	2C (Bscf)	3C (Bscf)
Gas	118.6	219.1	347.9

(b) Condensate

	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Condensate	0.1	0.2	0.5

Notes:

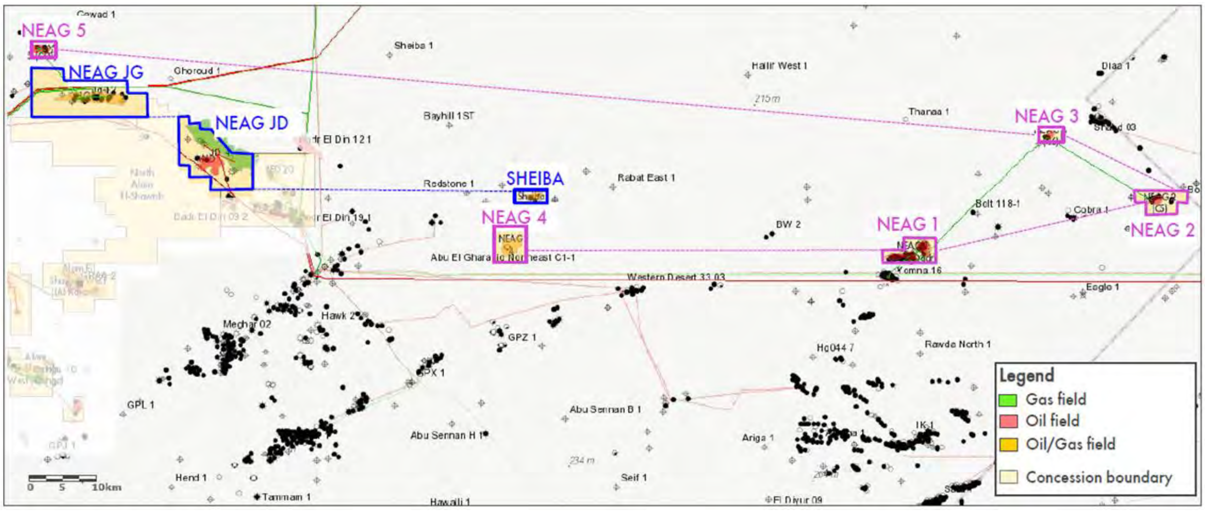
1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

2.8 North East Abu Gharadig Extension and Tiba (NEAG Ext and NEAG Tiba)

2.8.1 Asset Description

The NEAG group of assets is comprised of several concessions and fields distributed over a large geographical area of some 5,000 km^2. There are two main components to the NEAG area. The NEAG Ext consists of five fields (NAEG 1 to 5) which are distributed primarily in the east of the area, with one field in the west and NEAG Tiba, which consists of three fields, in the west of the area. Figure 85 presents a map of the entire NEAG area and the various components. The NEAG Ext is shown in pink and NEAG Tiba is shown in blue in Figure 85.

Figure 85: NEAG Ext and NEAG Tiba – Location Map



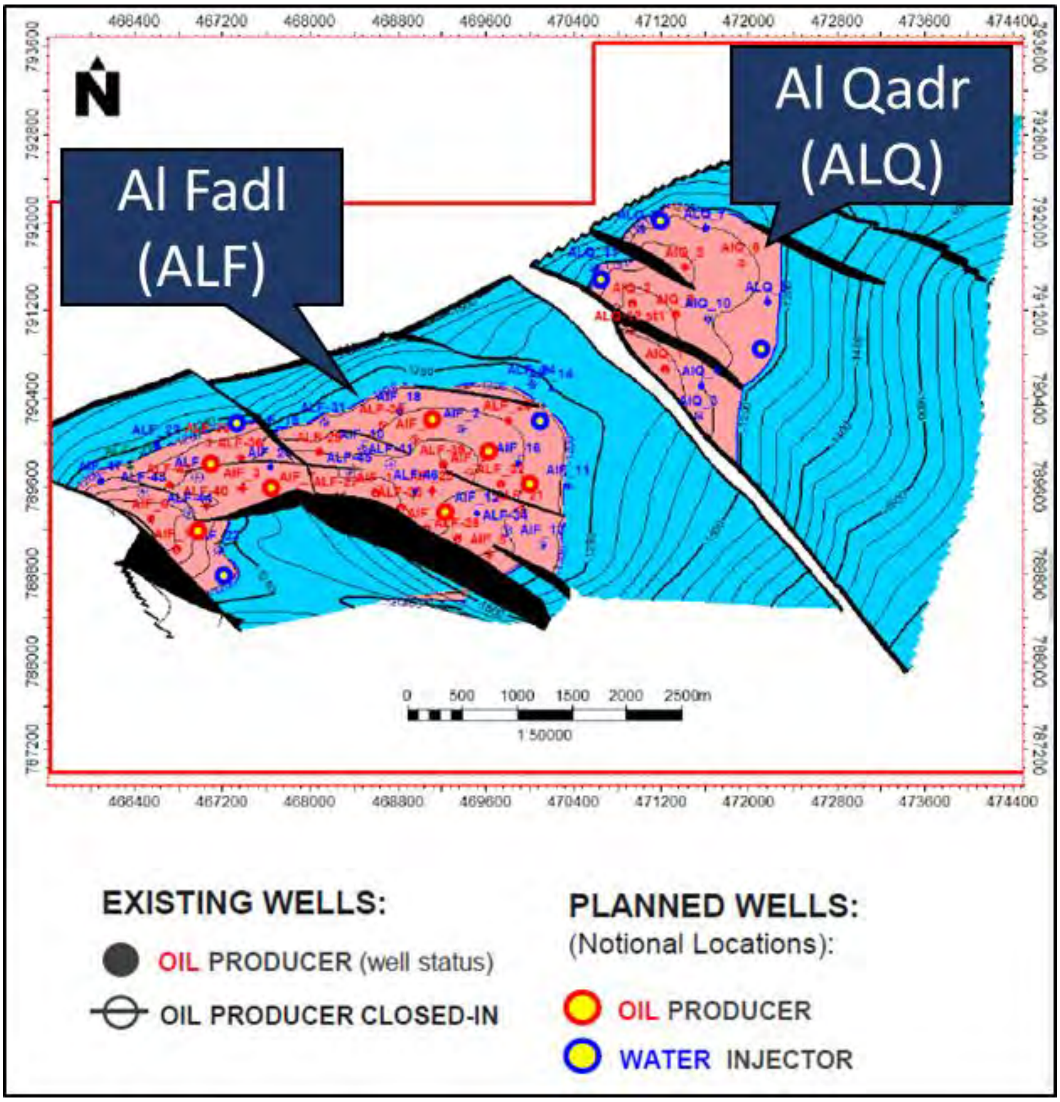
Source: Vendor VDR

In the NEAG Ext area the focus to date has been the production of oil from the Bahariya reservoirs in NEAG 1 & 2, where some 35 MMBbl oil have been produced up to January 2019. 2 MMBbl of oil have also been produced from each of NEAG 3 and NEAG 5. No production has taken place from NEAG 4, which is primarily a gas field and is somewhat stranded in the centre of the NEAG area. Future development plans focus on the implementation and expansion of water flood in the NEAG 1 and NEAG 5 Fields and infill drilling at NEAG 2 & 3.

2.8.1.1 Structure and Trap

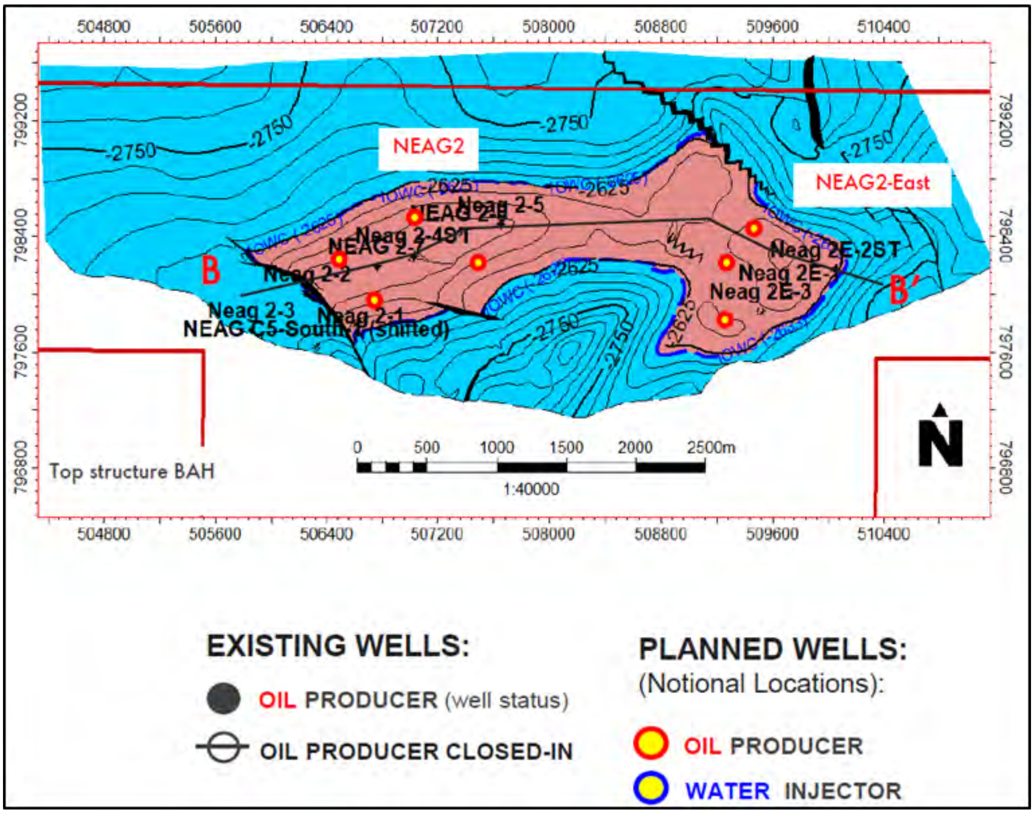
Trapping mechanisms are structural with either 3 or 4-way closed structures, variably relying on up-dip faults for ultimate seal. NEAG 1 consists of two Fields, named Al Fadl and Al Qadr. NEAG 2 is further divided into main and eastern areas across a structural saddle. NEAG 3, 4 and 5 each consist of a single hydrocarbon accumulation. Figure 86 to Figure 90 present maps of each of the Fields in the NEAG Ext. Figure 91 and Figure 92 present structural maps of the JG and Sheiba Fields in NEAG Tiba.

Figure 86: NEAG 1 (Al Fadl & Al Qadr Fields) – Bahariya Reservoir Level



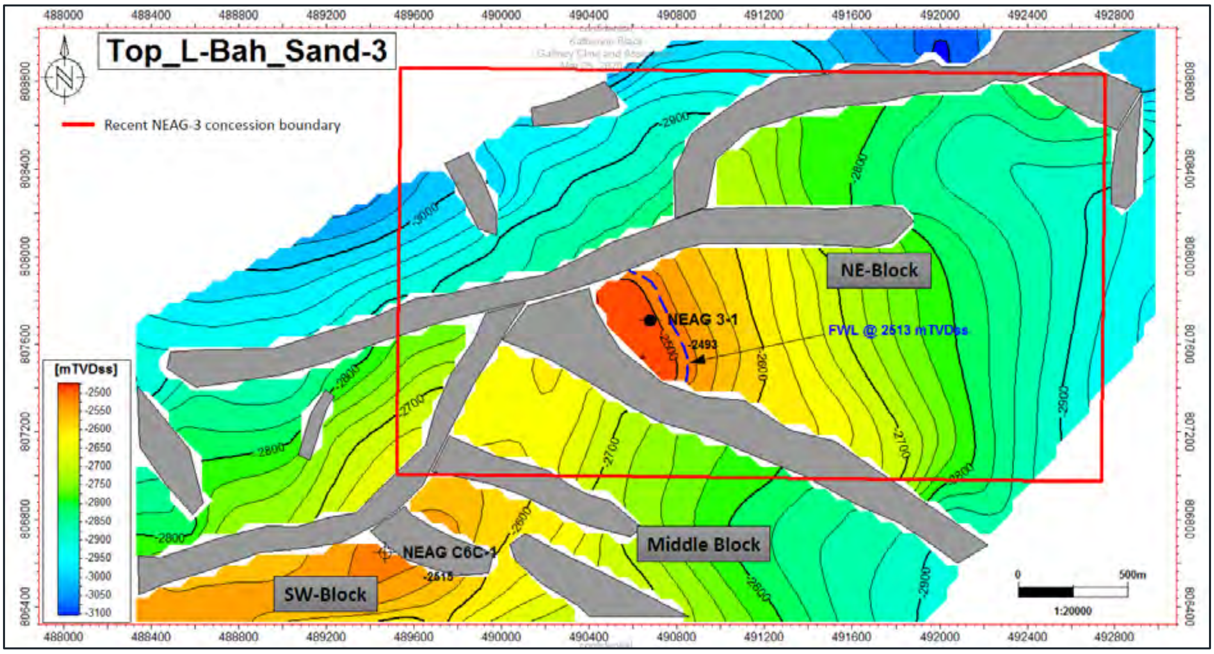
Source: Vendor VDR

Figure 87: NEAG 2 (East & West Areas) – Bahariya Reservoir Level



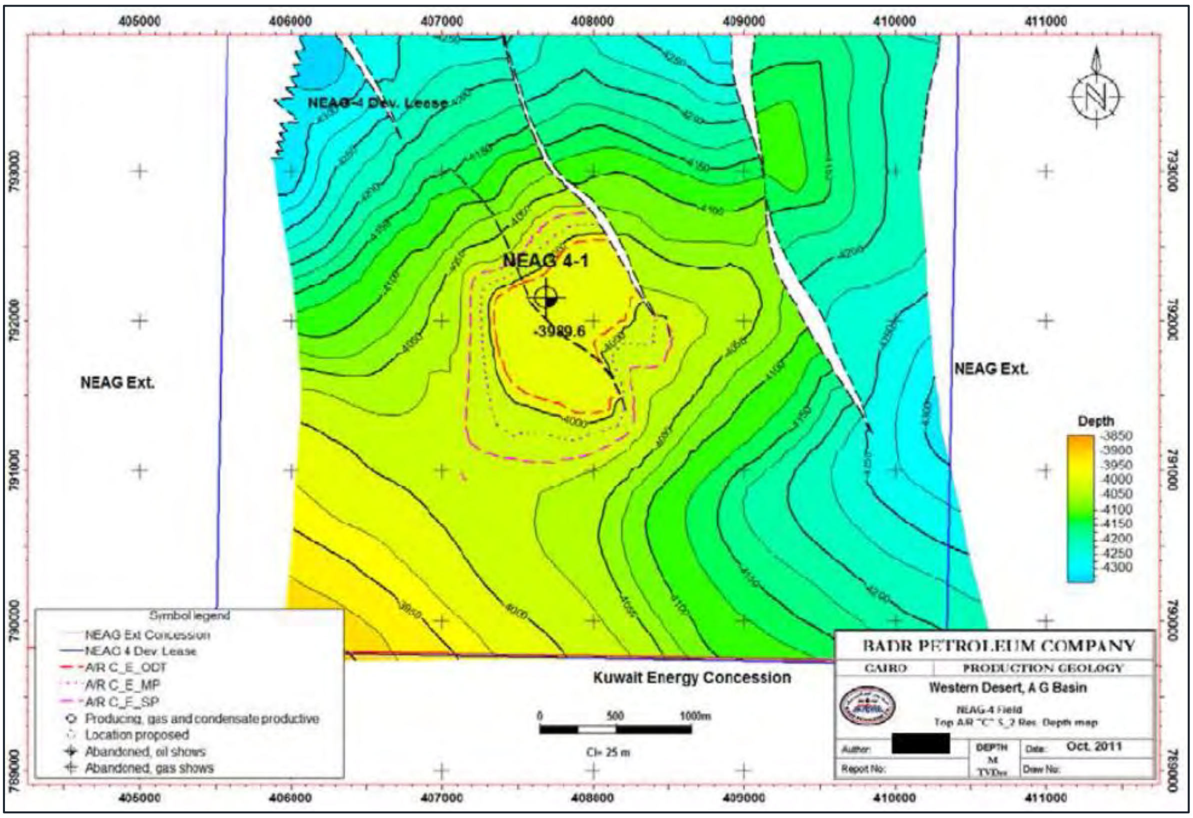
Source: Vendor VDR

Figure 88: NEAG 3 – Bahariya Reservoir Level



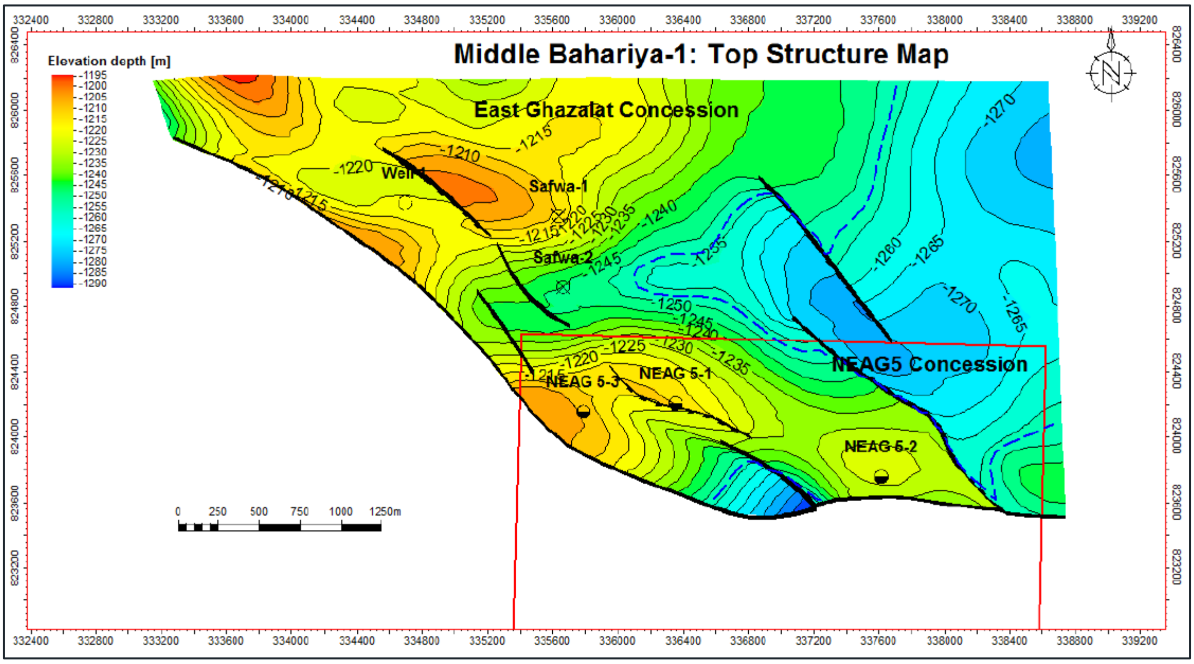
Source: Vendor VDR

Figure 89: NEAG 4 – Abu Roash 'C' Reservoir Level



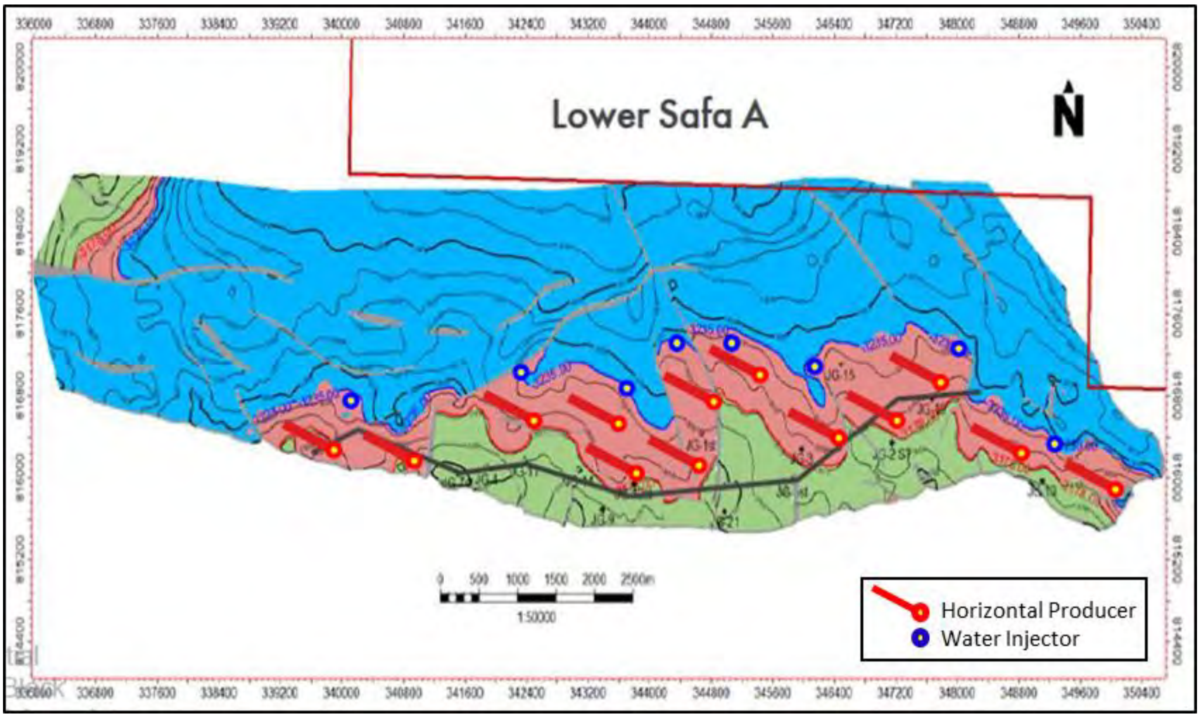
Source: Vendor VDR

Figure 90: NEAG 5 – Bahariya Reservoir Level



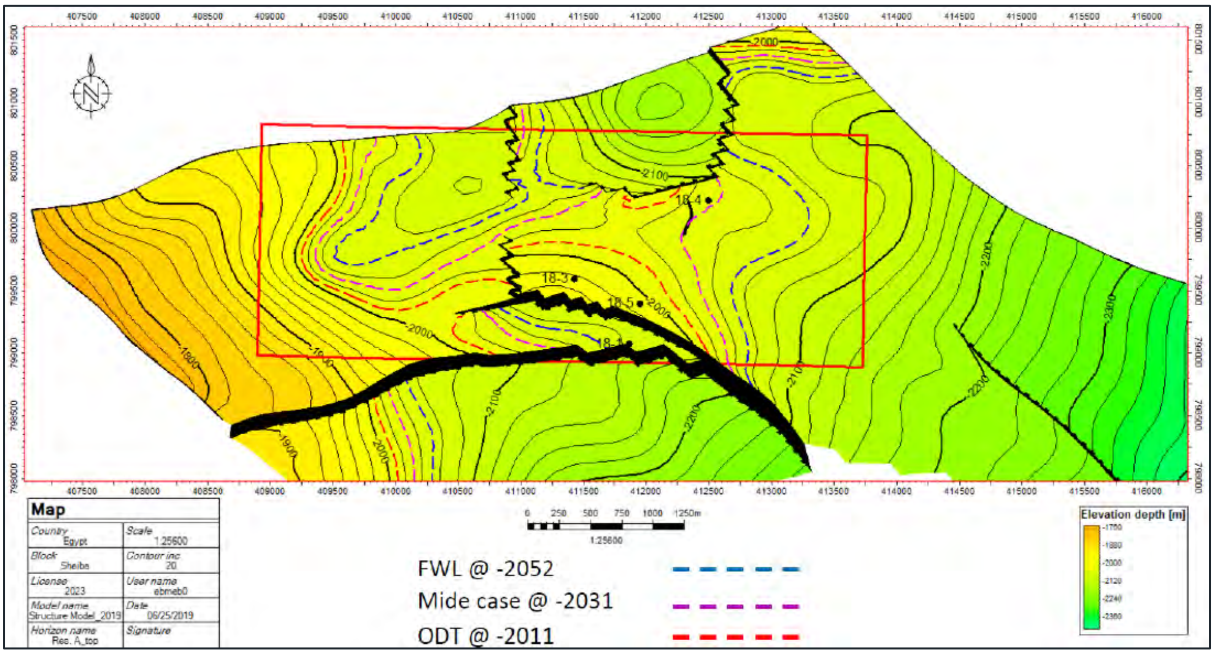
Source: Vendor VDR

Figure 91: NEAG Tiba (JG Field) – Lower Safa Reservoir Level



Source: Vendor VDR

Figure 92: NEAG Tiba (Sheiba Field) – Bahariya Reservoir Level



Source: Vendor VDR

2.8.1.2 Reservoir

The primary reservoirs in NEAG 1, 2, 3 and 5 are the shallow marine to terrestrial clastic sandstones of the Cenomanian aged, Bahariya interval. Secondary reservoirs in NEAG 1 and 2 are the tight Albian, Kharita sandstones. NEAG 4 has reservoirs in the Abu Roash C & E intervals.

The primary reservoirs at JG are the Middle Jurassic, Upper Safa sandstones, which lie at a depth of approximately 3,100 mTVDss. Secondary reservoirs at JG are the Lower Safa sandstones. At Sheiba, the primary reservoirs are in the Bahariya interval (Cenomanian). The Paleocene to Eocene aged, Apollonia carbonate (chalk) reservoirs are the primary target at the JD Field. The JG and Sheiba Fields consist of hydrocarbon accumulations in single structures, where the trapping mechanism is 3-way dip closure, relying on major faults for ultimate seal. The precise trapping structure at JD is yet to be fully understood, but is likely to be a combined trapping mechanism with stratigraphic and structural elements.

2.8.1.3 Reservoir and Fluid Properties

Representative PVT data are presented in Table 95. Reported CO_2 content is moderately low at 2.1 mol% at JG-9. Apart from some evidence of anomalously high temperatures in the shallow Bahariya Formation reservoirs, pressure and temperature gradients are normal.

Table 95: NEAG Area: Representative Pressure and Fluid Composition Data

a) Gas

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bg	CGR	Viscosity	S.G. Gas
		mss	°C	psig	psig	rcf/scf	Bbl/MMscf	cP	
NEAG JG-9	Not known	Not known	Not known	Not known	Not known	Not known	67	Not known	0.71

b) Oil

Field	Reservoir	Depth	T_{res}	P_{res}	P_{sat}	Bo	GOR Scf/Bbl	Viscosity	Gravity
		mss	°C	psig	psig	rb/stb	scf/Bbl	cP	°API
NEAG C3-1	BAH	1,075	64.4	1,700	253	1.05	45	1.82	40
NEAG C4-1	BAH	1,150	64.4	1,700	305	1.07	72	1.50	41
NEAG C5-1	BAH	2,650	93.6	3,924	Not known	1.13	116	Not known	43
NEAG C9-1-1	BAH	1,025	67.2	1,823	319	1.13	133	1.57	38
NEAG JG-2	KHAT	3,325	114.4	4,851	4,640	1.68	1419	0.33	38
NEAG JG-7	LSAF	3,250	114.4	4,830	2,256	1.50	804	0.35	42
NEAG JG-13	USAF	2,950	106.7	4,371	3,335	1.55	1085	Not known	36

2.8.1.4 Production Facilities

The NEAG area has three remote processing facilities, namely:

- o NEAG-1 facility;
- o NEAG-2 Early Production Facility (EPF); and
- o NEAG-JD facility.

The NEAG-2 EPF dewaters the NEAG-2 area production fluids before co-mingling them with the NEAG-1 production fluids for processing at the NEAG-1 facility. The NEAG-1 facility has a design capacity of 6 Mbpd of condensate. The NEAG-2 EPF has a design capacity of 24 Mbpd of gross liquids (condensate and water). The produced water separated at NEAG-2 EPF is disposed of via evaporation ponds. The NEAG-1 facility heats the condensate and further separates out produced water from the condensate stream, with any associated gas vented to atmosphere. The produced water from NEAG-1 is disposed of via soakaways. The treated condensate from NEAG-1 is exported to the Karama gathering centre, before forwarding to the Qarun station and on to the terminal at Dashour for offloading to tanker for export.

Production fluids from NEAG-JG and NEAG-5 are gathered at the NEAG-JG facility. The NEAG-JG facility separates the produced water from the condensate stream and disposes of it via reinjection. The dewatered condensate and associated gas is exported via multiphase pipeline to the BED3 processing plant for further treatment.

2.8.2 HIIP

Where sufficient information was provided in the VDR and or the vPDR, GaffneyCline carried out an independent assessment of the HIIP for the volumetrically significant reservoirs. As far as data allowed, a Crystal Ball model was generated for each of the reservoirs and fields.

Petrophysical parameters where spot checked at two wells. Well ALF-41 from the Al Fadl Field in NEAG 1 and well JG-23 from the JG Field in NEAG Tiba. Reservoir average values were further spot checked by analysis of well logs and or zone averages in any Petrel models that were available.

The ALF-41 and JG-23 wells had input logs and petrophysical interpretation reports, the wells also had top depths provided. The input logs typically included GR, Density, Neutron, Resistivity & Photoelectric Factor.

GaffneyCline relied on input parameters, such as grain density, formation water salinity, Archie parameters etc., provided in the core analysis reports, where available. If such data were unavailable, then the parameters were derived by GaffneyCline independently using provided logs, from cross-plots, or from neighbouring wells, where such parameters were known. The main intervals of interest were Lower Safa in JG-23, Bahariya in ALF-41.

Gross rock volume (GRV) values presented in the VDR were checked by running any Petrel models or generating estimates of map based GRV using the volumetric tool in Petrel and any associated structural surfaces. Structural surfaces were also checked to see if they honoured well control.

Relatively wide values of reservoir parameters were used and the ranges were made wider if there was sparse well information or if the reservoir quality was particularly variable. Models were populated using log normal or normal parameter distributions. Input variables were input to Crystal Ball models as the P90, P50 and P10 values.

Each of the models was run with 100,000 trials and the resulting P90, P50 and P10 results were extracted and used as the Low, Best and High Case estimates respectively. Table 96 and Table 97 present comparisons of the Operator's STOIIP estimates, the Vendor's estimates and GaffneyCline's independent estimates. GaffneyCline did not derive independent estimates for minor reservoirs or where data in the VDR and vPDR was not sufficient. GaffneyCline was unable to validate the estimate of 221 Bscf in NEAG JG LSA from the Petrel model provided. However, 195 Bscf has reportedly already been produced from this reservoir, and the Vendor carries a GIIP estimate of 233 Bscf. No meaningful data were provided in order to independently verify in-place hydrocarbon estimates at Sheiba and JD.

Table 96: Comparison of HIIP Estimates – NEAG Ext

(a) Oil (MMBbl)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG 1 ALF [BAH]	58	58	34	51	73
NEAG 1 ALQ [BAH]	19	17	13	20	28
NEAG 2 Main [BAH]	45	42	24	40	61
NEAG 2 East [BAH]	6	8	5	7	11
NEAG 3 [BAH]	4	N/A	N/A	N/A	N/A
NEAG 4 [ARC/E]	4	N/A	N/A	N/A	N/A
NEAG 5 [BAH]	17	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

(b) Gas (Bscf)

Reservoir	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
Unit			Low	Best	High
NEAG 4 [ARC/E]	56	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Table 97: Comparison of STOIIP Estimates – NEAG Tiba

(a) Oil (MMBbl)

Reservoir Unit	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
			Low	Best	High
NEAG JG [LSA]	77	83	50	72	100
NEAG JG [LSC]	20	24	15	21	29
NEAG JG [LSA0]	8	5	3	5	6
NEAG JG [US]	11	15	11	15	20
NEAG Sheiba [BAH]	8	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

(b) Gas (Bscf)

Reservoir Unit	Operator (Bapteco) Estimate	Vendor VDR Estimate	GaffneyCline Estimates		
			Low	Best	High
NEAG JG [LSA]	221	233	N/A	N/A	N/A
NEAG JD [APP]	352	N/A	N/A	N/A	N/A

Notes:

1. N/A in 'Vendor VDR' Column - Not carried out due to insufficient information or asset volume is assumed to be very small.
2. N/A in GaffneyCline Estimate Column – Estimate not derived due to insufficient information.

Overall, there appears to be relatively consistent volumetric estimates across the different methods and companies.

2.8.3 Asset Streams

The various resources described in the Initial Vendor Databook and their interpretation following GaffneyCline's evaluation are listed in Table 98.

In the NEAG Tiba area, the JG Field has been the primary focus to date. Gas phase hydrocarbons have been produced from all reservoirs at JG, a total of some 195 Bcf up to January 2019. A very small amount of production has taken place from the Sheiba Field, which is located in the central part of the NEAG area and is somewhat stranded. The JD Field contains a potentially significant volume of gas, in the shallow Apollonia reservoirs, but is yet to be exploited and represents upside. The Operator has stated the plan for future work will be to focus on exploitation of the oil rim at JG through horizontal wells and water flood. A small number of infill wells are also planned for the Sheiba Field. The JD Field is likely to require further appraisal.

Table 98: NEAG: Resource Categories in Databook

Item in Initial Vendor Databook	Item in Final Consortium Databook	GaffneyCline interpretation	Categorisation/Notes
NEAG (Tiba)			
JG NFA	JG NFA		Reserves
JG Infill	JG Infill		Reserves and Contingent Resources
Sheiba infill	Sheiba infill		Reserves
General infill	Not included	All development activity viewed as covered by other categories.	N/A
JD C2E	Near Field Exploration	Only includes Apollonia gas development	Contingent Resources
JG C2E			Prospective Resources
Upsides	Not included	All development activity viewed as covered by other categories.	N/A
NEAG (Ext)			
NEAG 1 NFA	NEAG 1 NFA		Reserves
NEAG 2 NFA	NEAG 2 NFA		Reserves
NEAG 3 NFA	NEAG 3 NFA		Reserves
NEAG 5 NFA	NEAG 5 NFA		Reserves
General NFA	Not included	All development activity viewed as covered by other categories.	N/A
NEAG 1 infill	NEAG 1 infill		Reserves
NEAG 2 infill	NEAG 2 infill		Reserves
NEAG 3 infill	NEAG 3 infill		Reserves
NEAG 5 infill	Not included	Minor activities with insufficient materiality	N/A
General infill			
NEAG 1 C2E			
NEAG 2 C2E			
GW C2E			

2.8.4 Historical Field Performance

2.8.4.1 NEAG Ext

NEAG 1 includes Al Fadil and Al Qadr. Al Fadil production started in 2008 with wells NEAG 1-1 and 2. Peak production of 5,000 bopd was reached in 2015. Current production is 1,700 bopd with a watercut of 76%.

AL Qadr production started in 2008 and peaked in 2009 with a maximum oil rate of 2,600 bpd. The current oil production is approximately 500 bopd with a watercut of 80%.

Figure 93 and Figure 94 show the oil production history and watercut for Al Fadil and Al Qadr reservoir respectively.

Figure 93: Historical Oil Production Rate and Watercut, Al Fadil

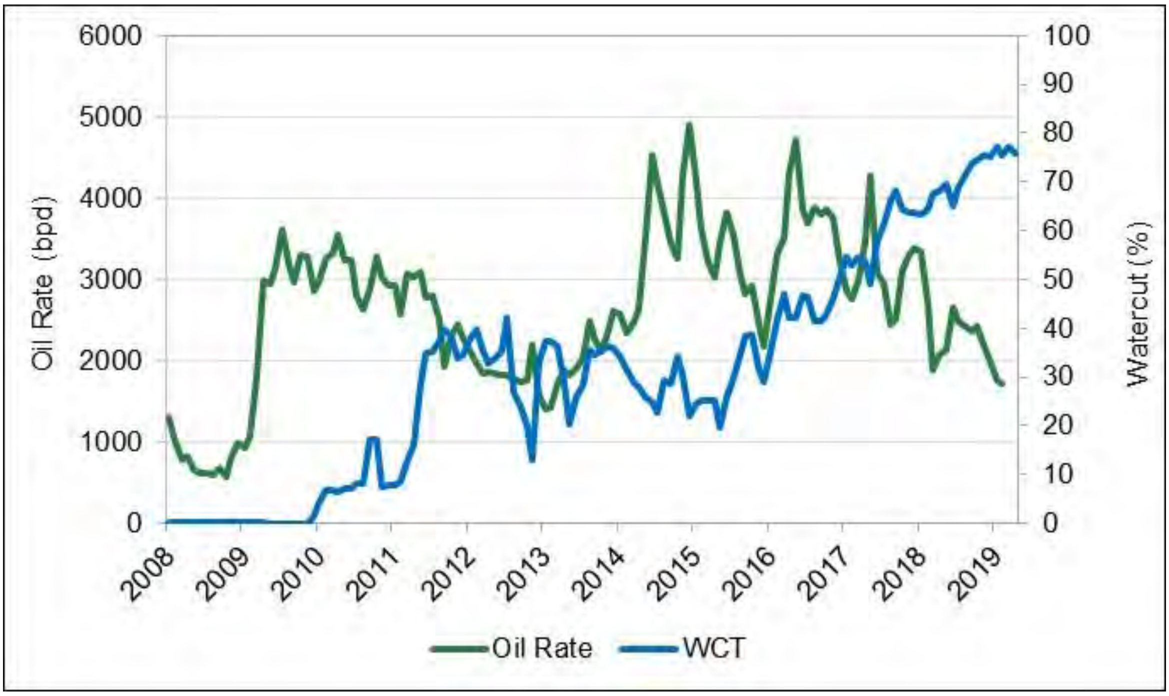
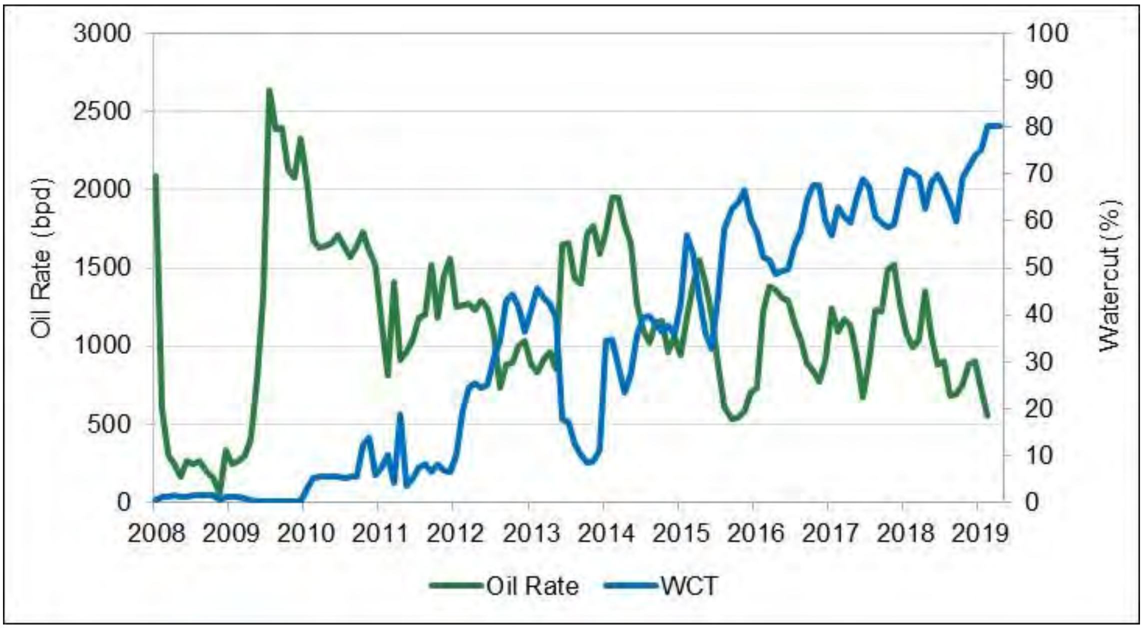


Figure 94: Historical Oil Production Rate and Watercut, Al Qadr



NEAG 2 includes NEAG 2 Main and NEAG 2 East. Production started in 2010 with well NEAG C5-1, and was ramped up in 2011 by bring well NEAG C5-2 on stream. Peak production of 13,600 bopd was reached in 2016 with the drilling of wells NEAG C5-4 and NEAG C5-5. Currently production is from four wells with an average rate of 3,950 bopd and a watercut of 85.5%.

NEAG 3 production commenced in 2010 with the drilling of well NEAG C6-1 in the Bahariya reservoir. A further well (NEAG C6-2) was drilled in the Bahariya formation in 2018. The Field is currently producing only from one well (NEAG C6-2) at an average rate and watercut of 950 bopd and 65% respectively.

NEAG 5 production commenced in 2013 from the NEAG 5-1 well. The field is currently producing with three wells with an average rate and watercut of 500 bopd and 39% respectively.

Figure 95, Figure 96 and Figure 97 show the oil production history and watercut for NEAG 2, NEAG 3 and NEAG 5 reservoir respectively.

Gaffney Cline

Figure 95: Historical Oil Production Rate and Watercut, NEAG 2 (Main and East)

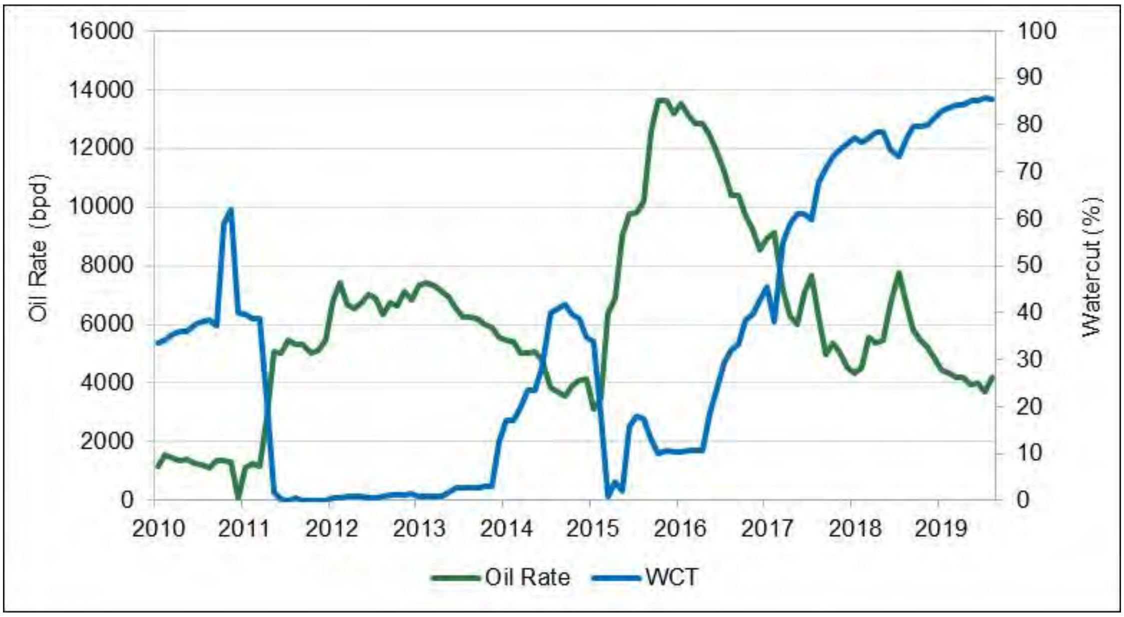


Figure 96: Historical Oil Production Rate and Watercut, NEAG 3

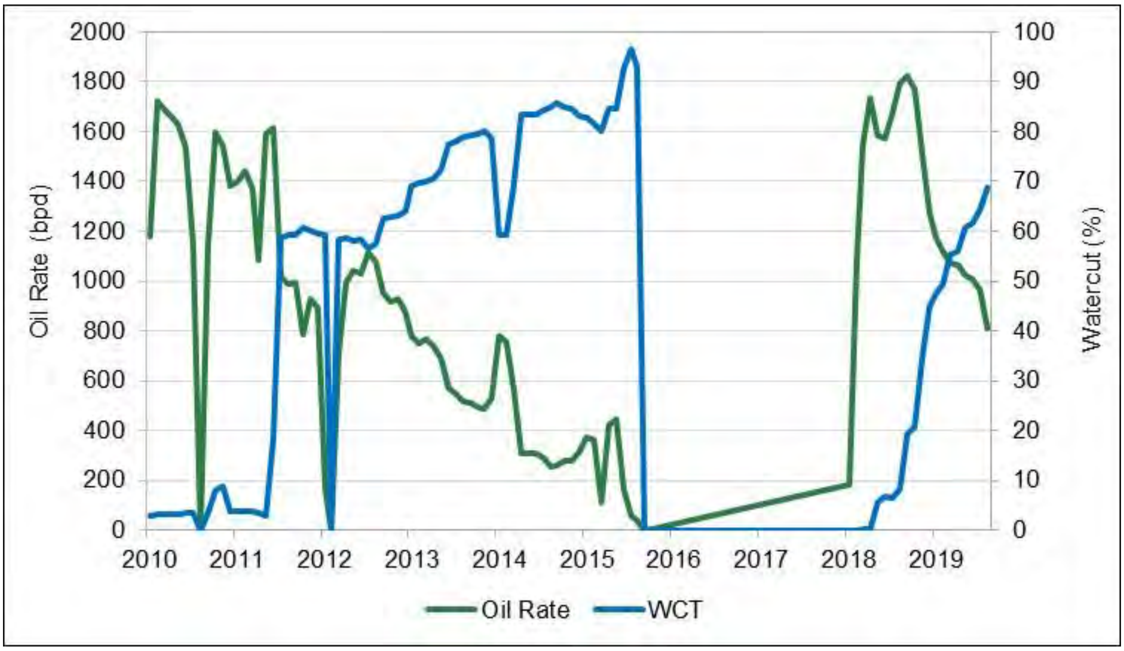
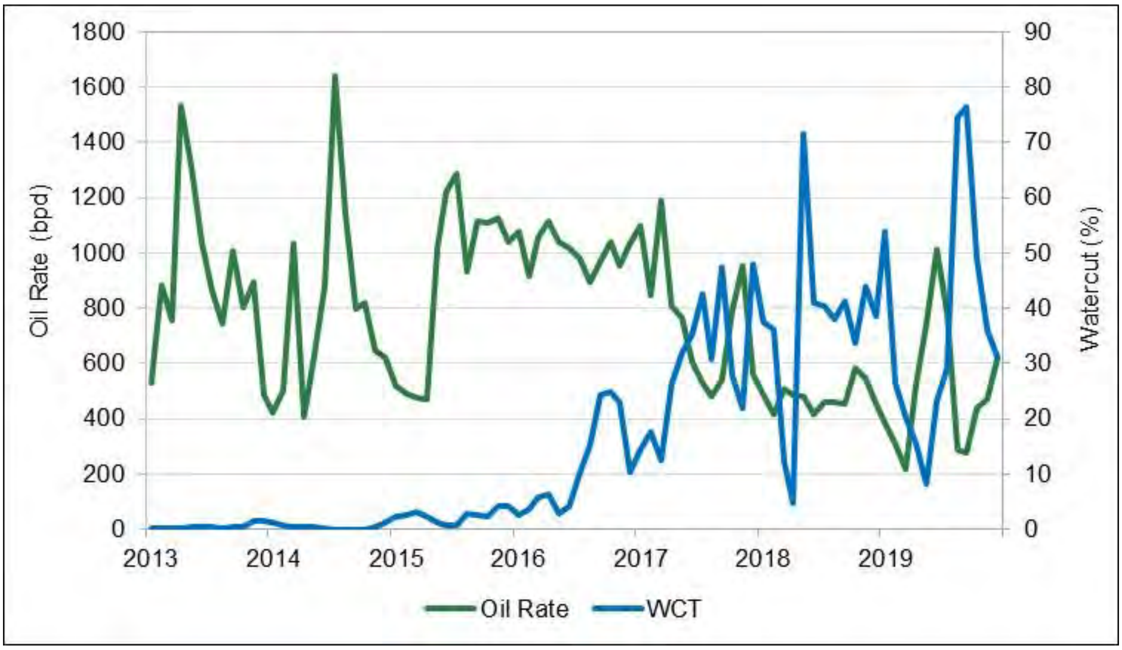


Figure 97: Historical Oil Production Rate and Watercut, NEAG 5



The cumulative oil production for NEAG Ext, along with recent rates are summarized in Table 99.

Table 99: NEAG Ext Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Average Oil Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	bopd	bwpd
NEAG 1 (Al Fadil)	17	1.10	1,700	6,140
NEAG 1 (Al Qadr)	4	4.76	505	2,560
NEAG 2	4	2.15	3,960	23,300
NEAG 3	1	1.65	929	1,720
NEAG 5	3	1.96	510	320
Total	**29**	**11.62**	**7,604**	**34,040**

Note:

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

2.8.4.2 NEAG Tiba

The developed reservoirs in NEAG Tiba are quite mature. Production from NEAG Tiba JG (the currently active field) started in 2002 with well NEAG JG. JG reached a peak rate of 7,900 bopd in 2009. Water breakthrough in LSC wells was observed in 2009 in which the watercut increased from zero to 70%. Three wells stopped producing in 2019.

The historical production for JG and Sheiba fields is shown in Figure 98 and Figure 99.

Production in NEAG Sheiba commenced in 2004 from two wells (SHB-18-1 & SHB-18-3) in the Bahariya formation. A further well was drilled in 2005 (SHB-18-5). Production declined and finally ceased in 2014.

Figure 98: NEAG Tiba JG Historical Oil Production Rate and Watercut

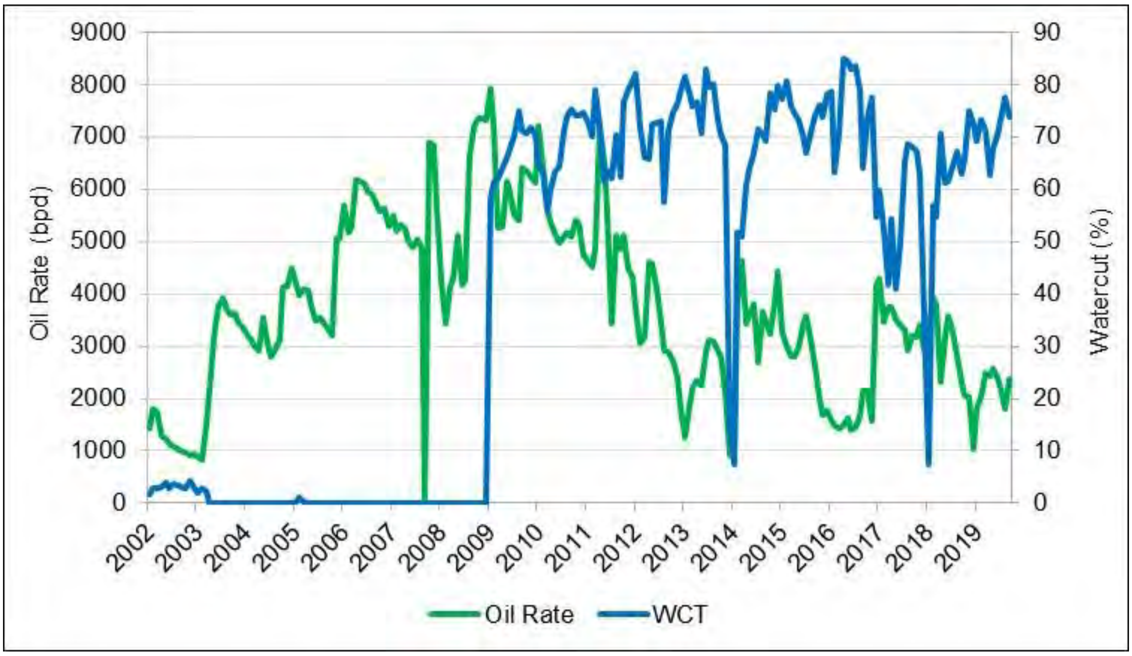
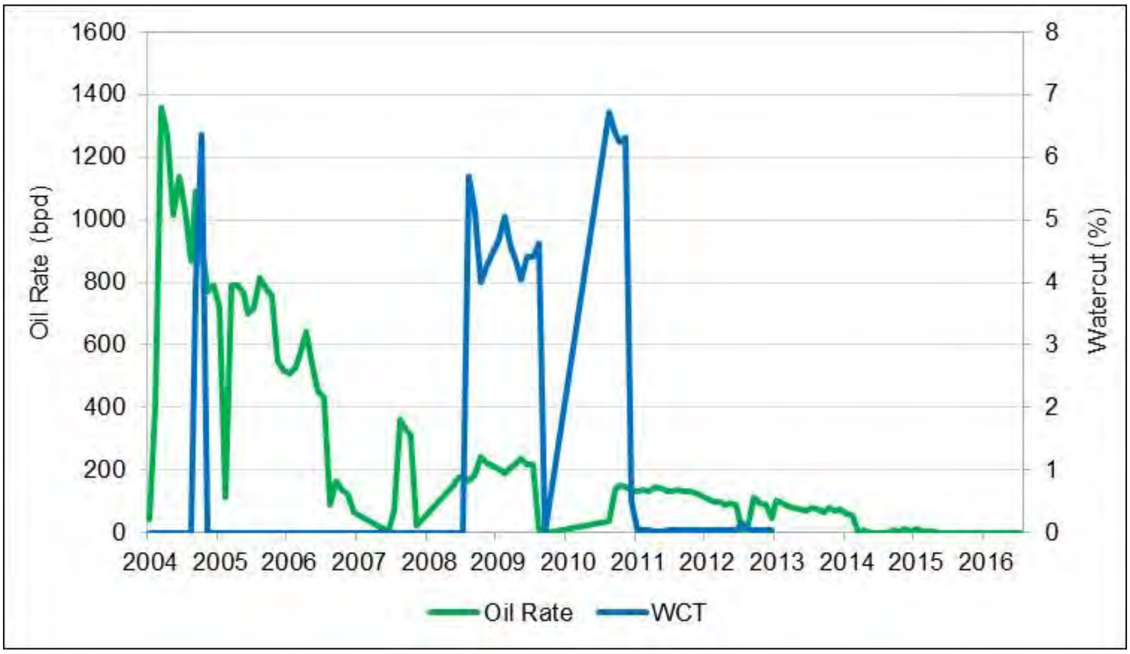


Figure 99: Historical Oil Production Rate and Watercut, NEAG Sheiba



The cumulative production, along with recent rates for NEAG Tiba fields are summarized in Table 100.

Table 100: NEAG Tiba Field Production Performance as at 31st December 2019

Field	Active Well Count	Cumulative Oil Production	Cumulative Gas Production	Average Oil Rate (4Q 2019)	Average Gas Rate (4Q 2019)	Average Water Rate (4Q 2019)
	Number	MMBbl	Bscf	bopd	MMscfd	bwpd
JG	8	24.0	194.8	2,164.8	13.2	6,194.3
Sheiba	0	1.0	0.5	0.0	0.0	0.0
Total	**8**	**25.0**	**195.3**	**2,164.8**	**13.2**	**6,194.3**

Note:

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

2.8.5 Field Development Plan

2.8.5.1 NEAG Ext

The Consortium's business plans for the NEAG 1 fields (Al Fadil and Al Qadr) includes the following activities:

- Seven infill wells and three injectors in Al Fadil;
- Three injectors in Al Qadr.

The schedule and number of new production wells are summarized in Table 101.

The infill well locations for NEAG 1 (Al Fadil and Al Qadr) are shown in Figure 86.

Table 101: NEAG 1 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	6	1	0	**7**
Injection Wells	0	0	3	3	0	**6**
Total	**0**	**0**	**9**	**4**	**0**	**13**

The future development plan for NEAG 2 fields (Main and East) includes the following activities:

- Four infill wells in NEAG 2 Main;
- Three infill in NEAG 2 East.

The schedule for the above activities has been defined in the Consortium's five year Business Plan. The schedule and number of new production wells are summarized in Table 102.

The infill well locations for NEAG 2 (East and West Areas) are shown in Figure 87.

Table 102: NEAG 2 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	0	7	0	**7**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**0**	**7**	**0**	**7**

In NEAG 3, there is just 1 producer planned to be drilled, as shown in Table 103.

Table 103: NEAG 3 Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	0	1	0	0	**1**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**0**	**1**	**0**	**0**	**1**

2.8.5.2 NEAG Tiba

The Consortium's future development plan for NEAG Tiba JG field includes the following activities:

- Three vertical producers and two injectors in the NEAG JG Lower Safa O (LSO) formation;
- Nine Horizontal Infill wells in NEAG JG LSA, along with two vertical injectors.

The schedules for these activities are shown in Table 104 and Table 105.

Table 104: NEAG Tiba JG LSO Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	1	0	0	2	**3**
Injection Wells	0	1	0	0	1	**2**
Total	**0**	**2**	**0**	**0**	**3**	**5**

Table 105: NEAG Tiba JG LSA Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	2	1	0	3	3	**9**
Injection Wells	**0**	0	0	2	4	**6**
Total	**1**	**1**	**0**	**5**	**7**	**15**

The infill well locations for NEAG Tiba JG (LSA) are shown in Figure 91.

Three infill wells are planned in NEAG Sheiba field. The proposed drilling schedule for is presented in Table 106.

Table 106: NEAG Sheiba Producers and Injectors Drilling Schedule

Year	2020	2021	2022	2023	2024	Total
Production Wells	0	3	0	0	0	**3**
Injection Wells	0	0	0	0	0	**0**
Total	**0**	**3**	**0**	**0**	**0**	**3**

2.8.6 Production Forecasts

2.8.6.1 NEAG Ext

GaffneyCline carried out its own analysis using a combination of DCA for existing wells and type wells to estimate the performance of the planned new infill wells.

Forecasts were produced for the period from 2020 to the expiry of the PSAs (varying from November 2032 to November 2036).

Table 107 shows the remaining technically recoverable volumes for NEAG 1, NEAG 2, NEAG 3 and NEAG 5.

Table 107: Remaining Technically Recoverable Oil Volumes, NEAG Ext, as at 31st December 2019

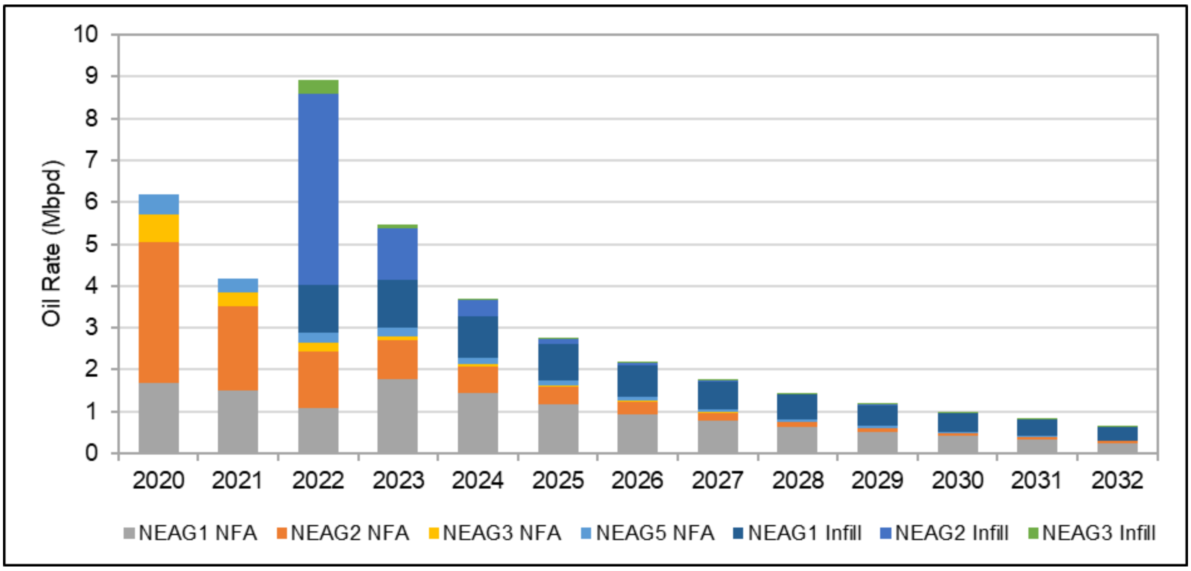
Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NEAG 1	5.7	7.5	9.1
NEAG 2	4.0	5.8	8.7
NEAG 3	0.6	0.7	0.9
NEAG 5	0.5	0.7	0.8
Total	**10.8**	**14.7**	**19.5**

Notes:

1. The volumes in this table are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

The Best Case oil production forecasts for NEAG Ext are shown in Figure 100 by activity.

Figure 100: Best Case Oil Production Forecast, NEAG Ext

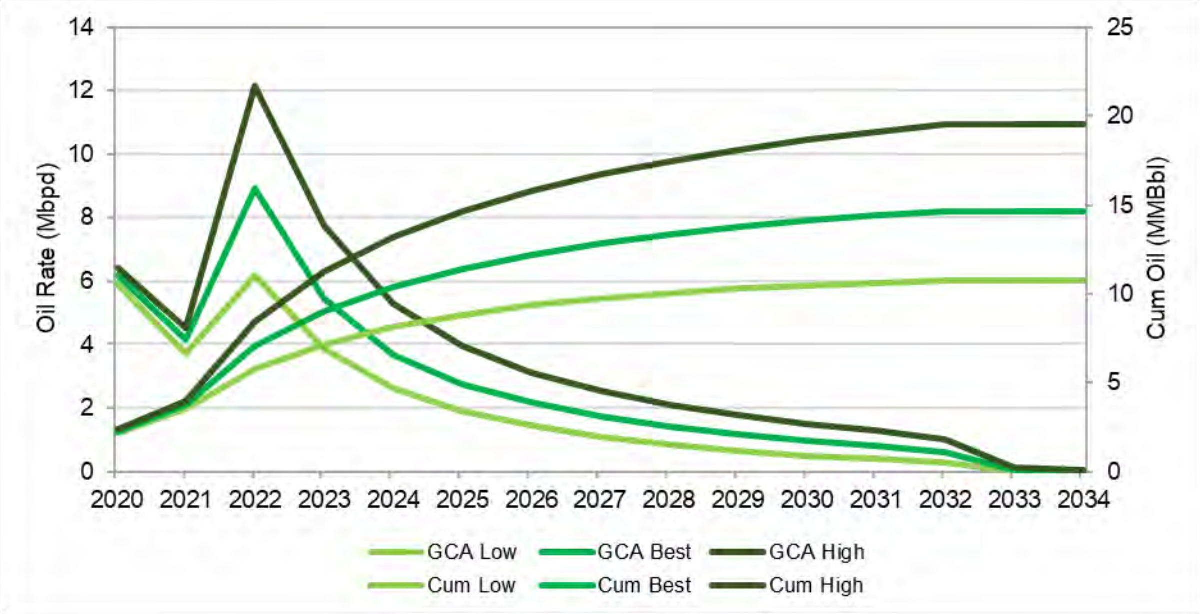


Note:

1. The volumes in this figure are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.

Figure 101 shows the Low, Best and High production forecasts for NEAG Ext.

Figure 101: Oil Production Forecasts, NEAG Ext



Note:

1. The volumes in this figure are to the licence expiries of the individual fields, which vary from November 2032 to November 2036; no economic cut off has been applied.

2.8.6.2 NEAG Tiba

GaffneyCline carried out its own analysis using a combination of DCA for existing wells and type wells to estimate the performance of the planned new infill wells.

Forecasts were produced for the period from 2020 to the expiry of the PSAs, in February 2027 for JG and May 2029 for Sheiba.

Table 108 and Table 109 show the remaining technical recoverable volumes for JG and Sheiba.

Table 108: Remaining Technically Recoverable Oil Volumes, NEAG Tiba as at 31st December 2019

Case	Low Case (MMBbl)	Best Case (MMBbl)	High Case (MMBbl)
NEAG Tiba JG	5.8	8.3	11.3
NEAG Sheiba	0.2	0.7	1.4
Total	**6.0**	**9.0**	**12.7**

Notes:

1. The volumes in this table are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Table 109: Remaining Technically Recoverable Gas Volumes, NEAG Tiba as at 31st December 2019

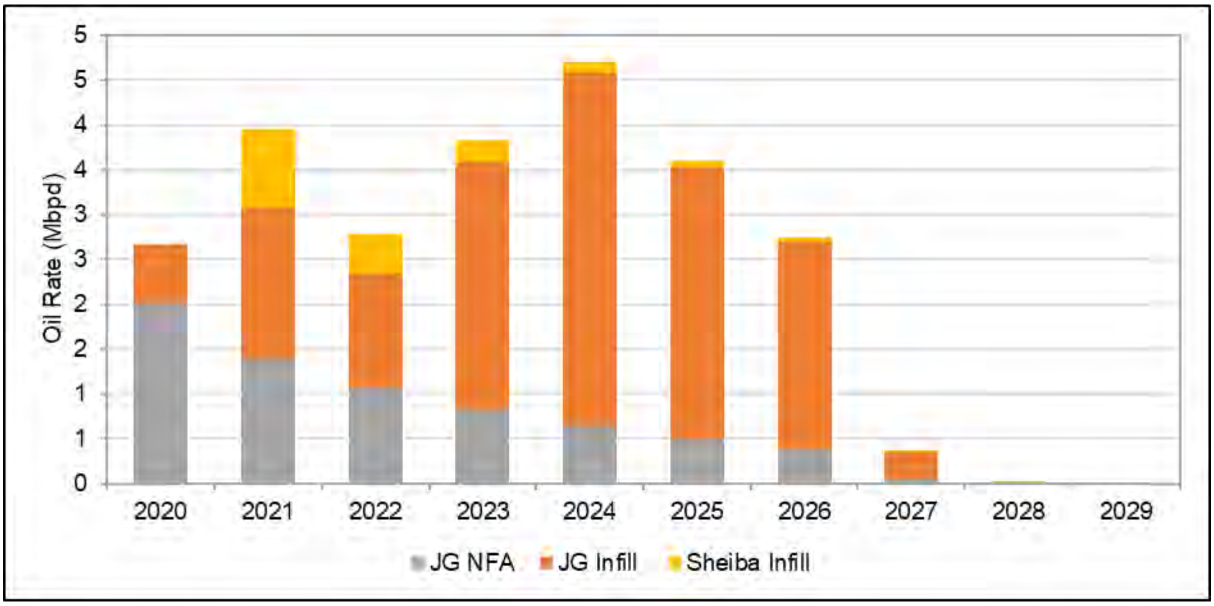
Case	Low Case (Bcf)	Best Case (Bcf)	High Case (Bcf)
NEAG Tiba JG	16.6	22.6	30.4
NEAG Sheiba	0.2	0.7	1.8
Total	**16.8**	**23.3**	**32.2**

Notes:

1. The volumes in this table are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.
2. Totals may not exactly equal the sum of individual entries due to rounding.

Figure 102 and Figure 103 show the Best Case production forecasts for NEAG Tiba, by activity.

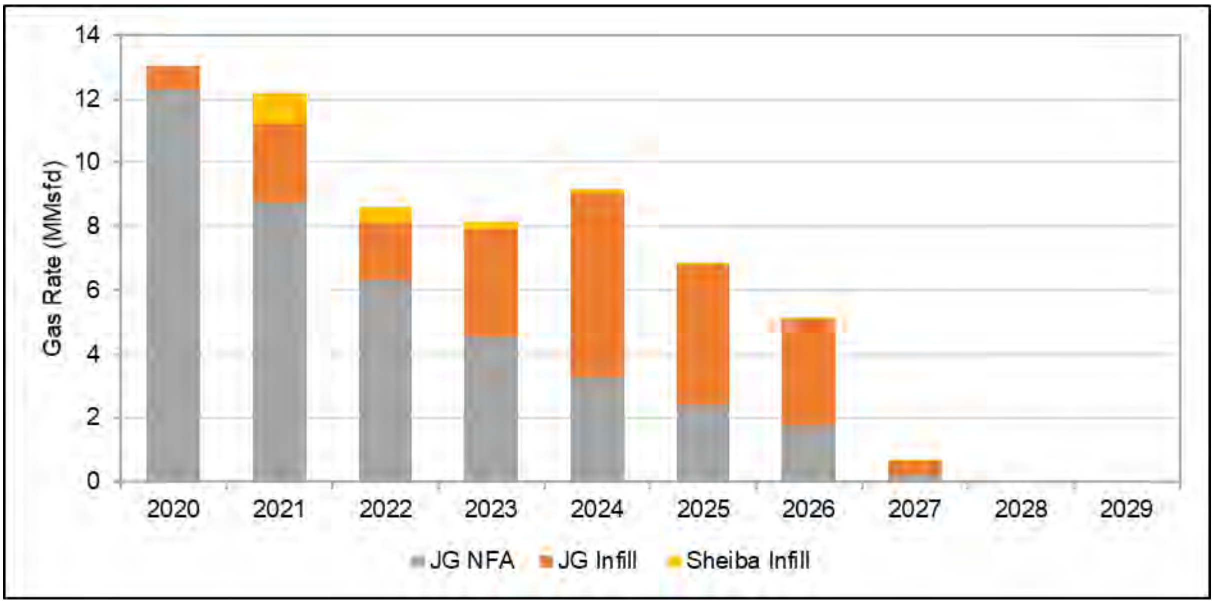
Figure 102: Best Case Oil Production Forecast, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 103: Best Case Gas Production Forecast, NEAG Tiba

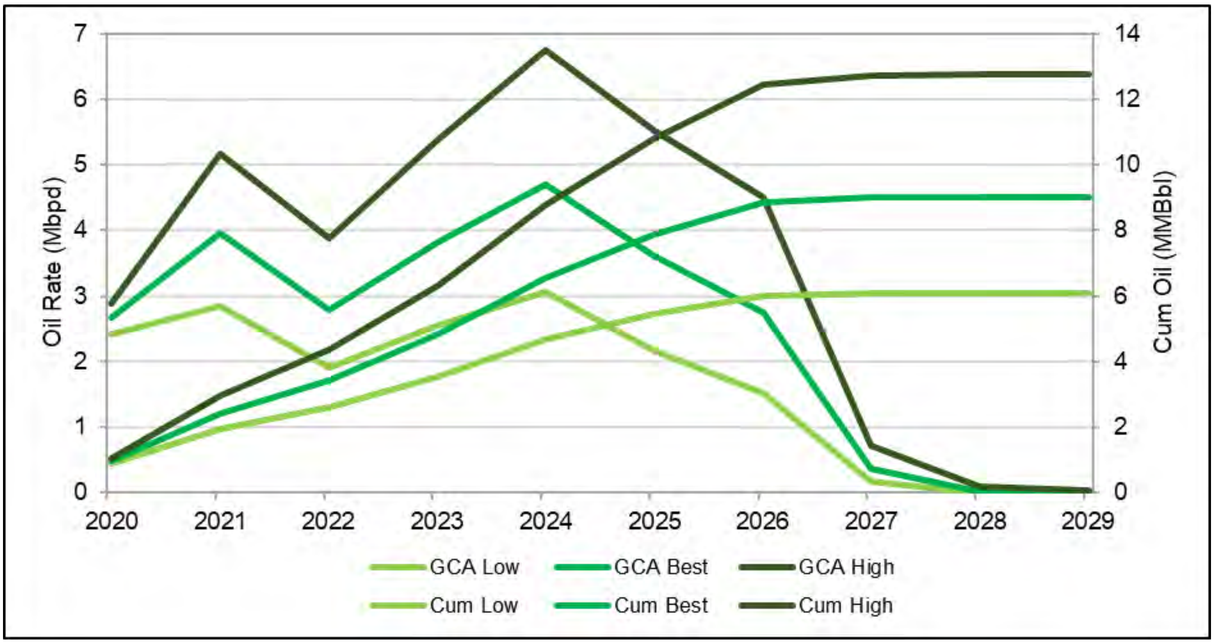


Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 104 and Figure 105 show the Low, Best and High oil and gas production forecasts for NEAG Tiba.

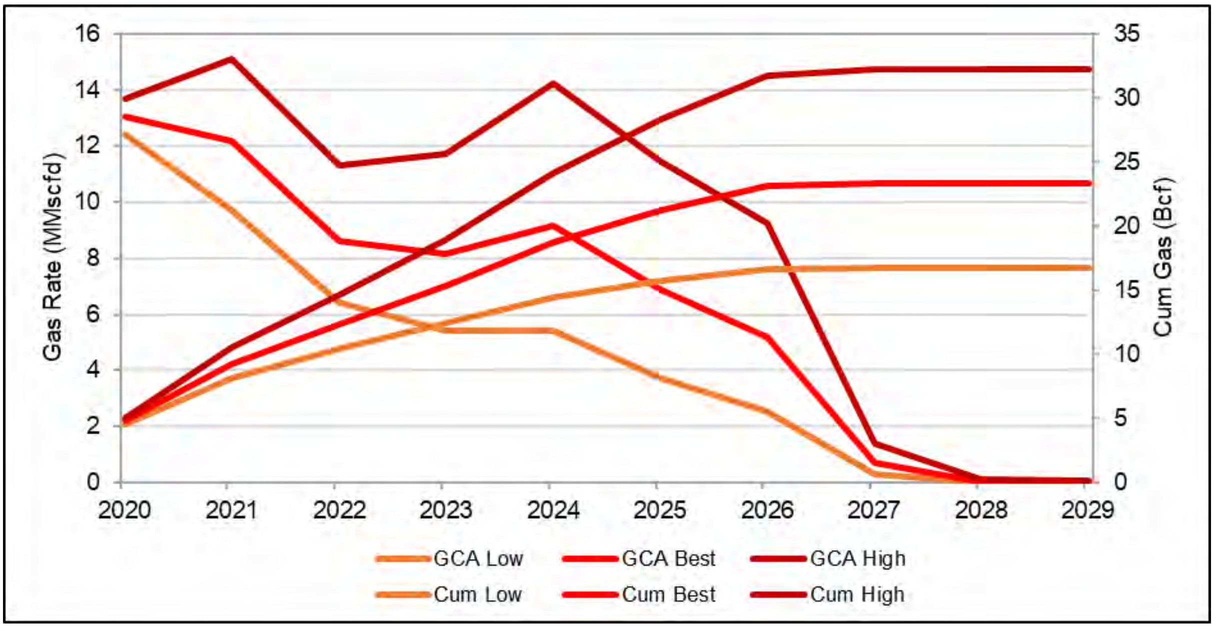
Figure 104: Oil Production Forecasts, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

Figure 105: Gas Production Forecasts, NEAG Tiba



Note:

1. The values in this figure are to end of February 2027 for JG and the end of May 2029 for Sheiba; no economic cut off has been applied.

2.8.7 Contingent Resources

Six wells in the NEAG Tiba JG which are envisaged more than 5 years in the future (2025 onwards) have been considered as Contingent Resources. These wells include four horizontal wells in the Lower Safa of NEAG Tiba JG and two vertical wells in the Upper Safa. The Contingent Resources also include the effect of two water injectors in the Lower Safa, two water injectors in the LSO and one water injector in the Upper Safa.

Table 110 shows the Low, Best and High Gross Contingent Resources for the NEAG Tiba.

Table 110: Gross Oil and Gas Contingent Resources, NEAG Tiba, as at 31st December 2019

(b) Oil and Condensate

1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
0.9	1.0	1.5

(a) Natural Gas

1C (Bscf)	2C (Bscf)	3C (Bscf)
1.2	1.8	3.1

Notes:

1. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the asset in the event that the associated projects go ahead.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the projects may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

3 Capital Expenditure (CAPEX) and Operating Expenditure (OPEX)

GaffneyCline has conducted a review of the Consortium's proposed CAPEX and OPEX estimates for the concession areas. The review was based upon GaffneyCline's understanding of the market conditions, the Consortium's operating philosophy and forward looking development plans.

3.1 CAPEX Program

There are three main areas of CAPEX for the concession areas in support of the fields' future production and development plans:

- Well and hook-up costs;
- Facilities Projects; and
- Asset Integrity/HSSE costs.

3.2 Well and Hook-up Costs

Table 111 provides a summary of estimated development wells for each of the different concession areas. The well costs have been benchmarked by GaffneyCline against the current Vendor's operating asset performance, and adjusted considering the market conditions (e.g. rig rates and contract renegotiation) and the Consortium's analogous drilling performance in the Western Desert.

There is a number of well reactivations to support the Consortium's production plan during the period of 2021-2023. These reactivation costs are accounted for in the OPEX as an additional expenditure on top of the "business as usual" workover costs included in the baseline operating cost.

Table 111: Development Well CAPEX Estimates

Concession Area	Description	CAPEX US$ MM
Obaiyed		
Lower Safa Flank	Production Well (Horizontal)	6.0
Lower Safa Core	Production Well (Vertical)	2.8
Lower Safa Core	Production Well (Horizontal)	5.3
Upper Safa	Well Recompletions	1.1
NM		
Lower Safa	Production Well (Vertical)	4.2
NUMB		
Lower Safa	Production Well (Vertical)	4.2
BED 3		
BED3, BED15, BED18	Production Well (Vertical)	1.5
BED3, BED18	Water Injection Well (Vertical)	1.0
BED 2		
BED2	Production Well (Horizontal)	3.5
BED 16	Production Well (Vertical)	1.5
Sitra		
Sitra3	Production Well (Horizontal)	3.5
Sitra8, SitraC30, SitraC3	Production Well (Vertical)	1.8
Sitra8	Water Injection Well (Vertical)	1.0
AESW		
Bagha, Al Magd, Assil	Production Well (Vertical)	1.5
Al Karam (Note 2)	Production Well (Vertical)	9.0
Bagha, Al Magd	Water Injection Well (Vertical)	1.0
NAES		
BTE	Production Well (Vertical)	6.0
NEAG		
NEAG1, NEAG2, NEAG3	Production Well (Vertical)	1.5
NEAG-JG	Production Well (Horizontal)	3.7
NEAG JG	Production Well (Vertical)	2.4
NEAG1	Water Injection Well (Vertical)	1.0

Notes:

1. All well costs include contingency
2. Al Karam wells consider efficiency improvements year on year based on feedback from Vendor on performance of BTE-4 well new design. The improvements are applied as a reduction of US$1 MM on the well cost each year over the 3 year period of drilling.

GaffneyCline reviewed the Vendor's hook-up costs and optimisations. Table 112 provides a summary of the CAPEX for hook-up of new development wells.

Table 112: Hook-up Capital Costs

Hook-up Type	CAPEX (US$ MM)
Gas Production Well	1.21
Oil Production Well	0.41
Water Injection Well	0.20

3.3 Facilities and Infrastructure Projects CAPEX

The Consortium's cost program for facilities and infrastructure was reviewed by GaffneyCline against the expected development plan and production. Table 113 provides a summary of the expected CAPEX for projects to support the production and development plan for each of the concession areas.

Table 113: Summary of CAPEX by Concession Area for Future Development Projects

Concession Area	Project Description	CAPEX (US$ MM)
Obaiyed		
	LLP Compression Project	28.8
	Life Extension Project	12.0
NM		
	NM (Teen + Tamr) Development Project	63.7
BED 3		
	Sitra PWRI Project at BED3 (completion in 2020)	7.98
	BED3 LLP Compression Project (completion in 2020)	3.0
	BED3 Mercury Removal Project (completion in 2020)	4.53
	Oil Capacity Debottlenecking Project	5.0
	BED3 Electrification Project	15.0
BED 2		
	BED2 LLP Compression Project	9.3
AESW		
	Gas Debottlenecking Project	2.95
	AESW Electrification Project	10.9
	Al Barq Electrification (rental unit)	0.29/yr
	Bagha Electrification (rental unit)	0.29/yr
	Al Barq Facility Improvement Projects	4.5
	Bagha Facility Improvement Projects	6.2
NEAG		
	NEAG-1 Water Disposal Project (completion in 2020)	0.8
	NEAG-1 & NEAG-2 Water Disposal Projects	1.2
	NEAG-2 Electrification Project	1.5
	NEAG-JG Water Disposal Projects	5.3
	NEAG-JG Electrification	3.5

The following sections provide an outline of each project and expected completion dates.

3.4 Current Development Projects Status

GaffneyCline notes that there are a number of current projects being executed by the Vendor as part of the ongoing field development. Table 114 provides an overview of the status of these projects as advised by the Vendor and their expected completion dates. GaffneyCline has estimated for 2020 the expected expenditure for each of these projects, and included these in Table 114.

Table 114: Current Development Projects Status

Project	Status	Business Plan CAPEX (US$ MM)
Sitra PWRI Project at BED3	Construction ongoing – expected completion 09/2020	39.9
BED3 Mercury Removal Project	Vessel fabrication ongoing, tie-ins completed – expected completion 11/2020	15.1
BED3 / BED 2 LLP	Units purchased – expected delivery 9/2020 Installation planned only for BED 3 by 12/2020	18.6
BED / Sitra Electrification (3.5MW)	Completed installation 100%	-

3.5 Planned Future Development Projects

3.5.1 Obaiyed Concession Area Projects

Life Extension Projects – the current Obaiyed facility has a number of life extension projects to increase reliability and capacity (up to 450 MMscfd) on the existing Obaiyed plant. These include for items such as the upgrade of gas turbines, DCS systems, compressor controls, recycle compressor re-wheeling, and other minor repairs. The projects are planned for completion in 2024 with capital phased across 4 years.

LLP Compression Project – this project comprises of the installation of LLP compression (up to 54 MMscfd) at Train 1 of the Obaiyed facility to allow for the drawdown of lower pressure wells and includes the necessary pipeline and separation facilities at the Obaiyed facility. The project is planned to be completed by 2024, with capital expenditure phased across 4 years.

3.5.2 NM Concession Area Projects

NM (Teen + Tamr) Development Project – this project supports the development of the NM area, and the planned wells. The project includes for the infrastructure to transport the well fluids (via an 86 km pipeline) to the Obaiyed facility, where they will be separated with the gas compressed to allow it to be treated in the main Obaiyed plant. The compression is designed to operate in LLP (10 bar) and LP (29 bar) modes to support a reconfiguration parallel to series operation as wellhead pressures declines in future. The project is phased to allow for an initial 81 MMscfd (3 x 27 MMscfd) of compression to be installed by 2023 to support the production profile, with a final LLP compressor installed by 2025 to allow series operation of the units to draw down the wells.

3.5.3 BED 3 Projects

BED3 Oil Capacity Debottlenecking – this project allows the capacity of oil export to exceed 30 Mbpd at the BED3 facility by inclusion of separation, and an additional export pump. The project is expected to be complete by 2022, with capital phased over 2 years.

BED3 Electrification Project – this project targets the electrification of the ESP pumped wells in the BED 3 area. It targets a reduction in diesel consumption and improvement in ESP availability. It includes for installation of gas engines and the transmission system to support the existing 23 ESP pumped wells plus an additional margin for an extra 10 future ESP pumped wells. The project is phased over 4 years, and expected completion of all electrification in 2024.

3.5.4 BED 2 Projects

BED2 LLP Compression – this project supports the reduction in pressure in some of the BED2 wells and compresses up the gas back up to export pressure to ensure delivery at the BED3 facility. The compression is designed for 12.5 MMscfd. The project is expected to complete in 2021.

3.5.5 AESW Projects

AESW Gas Debottlenecking Project – this project supports the use of ullage in the Assil pipeline to transport Karan gas to the CO_2 Removal Plant for treatment. A crossover link between the Assil pipeline and Karan pipeline is included as well as an additional lease amine unit to treat gas in 2022/2023 to treat the gas that exceeds the CO_2 removal plant capacity. The project is expected to be complete by 2022 phased over 2 years.

AESW Electrification Project – this project targets the electrification of the ESP pumped wells in the AESW area. It targets a reduction in diesel consumption and improvement in ESP availability. It includes for installation of gas engines and the transmission system to support the existing 14 ESP pumped wells plus an additional margin for an extra 10 future ESP pumped wells. The project is phased over 4 years, with expected completion of all electrification in 2027.

Al Barq Facility Improvement Projects – these projects target improvement in the water handling and disposal capacity at the Al Barq facility, as well as increased capability and capacity to separate well fluids, and export oil. There are a total of 6 minor projects as part of the improvement plans, all of which are phased over the period from 2021 to 2024.

Bagha Facility Improvement Projects – these projects target improvement in the water handling and disposal capacity at the Bagha facility, as well as increased capability and capacity to separate the well fluids. There are a total of 4 minor projects as part of the improvement plans, all of which are phased over the period from 2021 to 2023.

3.5.6 NEAG Projects

NEAG-1 Water Disposal Project – this project is designed to provide an addition of 12 Mbpd water disposal at the NEAG-1 facility. The project has carried over from 2019, and a portion of the capital expenditure is included in 2020 for completion of the project.

NEAG-1 & NEAG-2 Water Disposal Project – this project provides an additional 13 Mbpd gross separation capacity and 15 Mbpd water disposal capacity at the NEAG-1 facilities and disposal of water into watered out wells at NEAG-2. This project is expected to compete in 2024, with the capital phased over 2 years.

NEAG-2 Electrification Project – this project provides additional gas engine power at the NEAG-2 facility as part of the overall field electrification project to reduce diesel and improve reliability. This project is expected to complete in 2022, with the capital phased over 2 years.

NEAG-JG Water Disposal Projects – these projects provide addition of 30 Mbpd water separation, handling and disposal via injection wells. The project is expected to complete in 2023 and is phased over 2 years.

NEAG-JG Electrification Project – this project provides 2.4 MW of power for the NEAG JG area to provide electrification to ESP wells. The capital is spread over a 5 year period as part of a DBOOT contract model, with the commencement of the contract in 2021 running to 2025. On completion, the power generation facilities will be transferred and form part of the concession assets.

3.6 Asset Integrity and HSSE CAPEX

Table 115 provides a summary of the asset integrity and HSSE CAPEX for the different asset areas.

The asset integrity costs are part of an ongoing program, and cover a number of activities at Obaiyed, BED 3 and NEAG to assure asset integrity of the facilities and infrastructure for future production years. Included in the program are the integrity management of the following main aspects:

- Pipelines;
- Plant static and rotating machinery;
- Electrical and instruments;
- Civils;
- Fire and gas;
- Firefighting; and
- Waste, accommodation and movables.

The HSSE costs cover the costs associated with well integrity restoration and ground contamination remediation, and cover a number of the concession areas as summarised in Table 115.

The asset integrity program is executed over a 6 year period starting in 2021 and the well integrity restoration and ground contamination program is executed over a 5 year period starting 2021.

Table 115: Summary of CAPEX by Concession Area for Asset Integrity and HSSE Projects

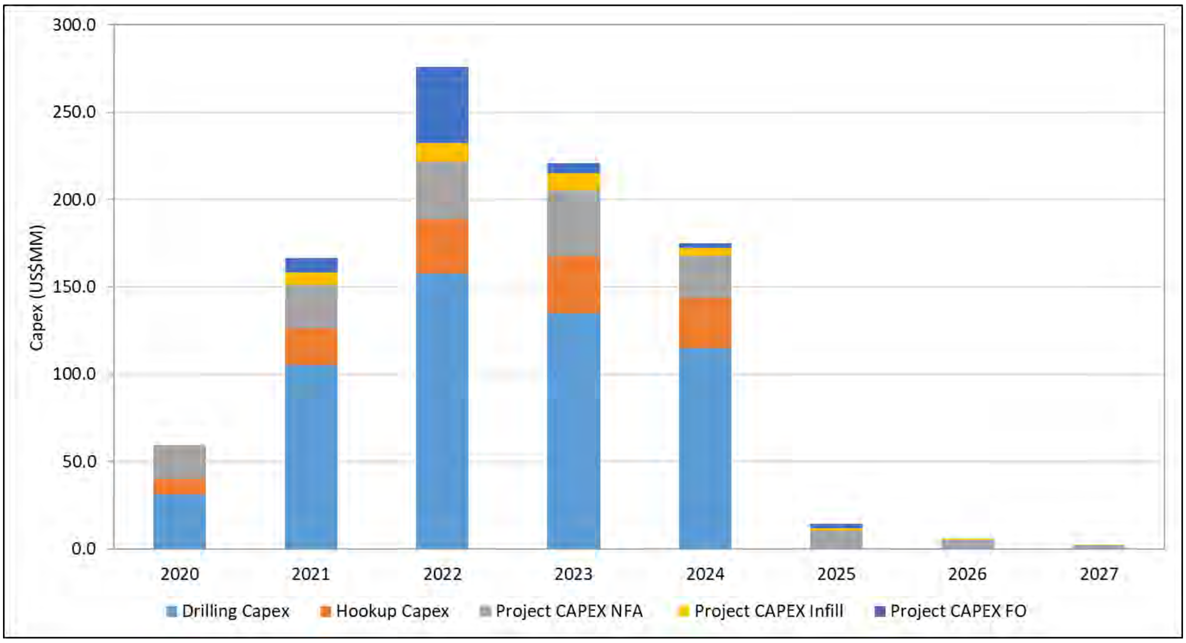
Concession Area	Description	CAPEX (US$ MM)
Obaiyed		
	Asset Integrity	13.2
	Well Integrity and Ground Remediation	1.0
BED 3		
	Asset Integrity	28.4
	Well Integrity and Ground Remediation	3.4
BED 2		
	Well Integrity and Ground Remediation	2.7
Sitra		
	Well Integrity and Ground Remediation	1.1
NEAG		
	Asset Integrity	3.9
NEAG Ext	Well Integrity and Ground Remediation	5.0
NEAG Tiba	Well Integrity and Ground Remediation	4.9
AESW		
	Well integrity and Ground Remediation	0.4

The annual CAPEX for all assets combined is provided in Table 116 and Figure 106. The annual CAPEX breakdown per asset is shown in Appendix III.

Table 116: Total Annual CAPEX All Assets

	2020	2021	2022	2023	2024	2025	2026	2027
Drilling Capex	31.3	105.4	157.8	134.7	114.8			
Hookup Capex	8.7	20.9	31.0	33.0	28.9			
Project CAPEX NFA	19.2	24.9	32.7	37.6	24.1	10.6	5.1	2.2
Project CAPEX Infill		6.8	10.7	9.8	4.6	1.2	0.9	0.6
Project CAPEX FO		8.8	43.8	5.8	2.7	2.7		
Total (US$ MM)	**59.3**	**166.8**	**276.1**	**221.0**	**175.1**	**14.5**	**6.0**	**2.8**

Figure 106: Total Annual CAPEX All Assets



3.7 OPEX

The OPEX forecasts have been developed based on an evaluation of the existing operating costs, taking into consideration the lower oil price environment and market conditions. The OPEX estimates for the fields were evaluated by GaffneyCline for the 5 years, 2021-2025, taking into consideration the planned activities/work programs of the development outlined by the Consortium.

Table 115 summarises the baseline OPEX for 2021 – 2025. After the 5 years, and in line with declining production, GaffneyCline considered the variable aspect of the operating costs to decline up to the end of concession.

The CAPEX and OPEX profiles, along with the Low, Best and High production profiles by asset are shown in Appendix II.

Included within the OPEX profiles are the additional well reactivation costs, as these are considered by GaffneyCline over and above the "business as usual" workover allowance in the baseline OPEX breakdown included in Table 117. Table 118 includes details of the additional OPEX included in the profiles, and the years they are realised.

Table 117: Five Year OPEX Breakdown

	Costs (US$ MM)				
	2021	**2022**	**2023**	**2024**	**2025**
Governance Costs – Consortia Group	3.5	3.0	2.5	2.5	2.5
Joint Venture Excess – Local Staff	3.5	3.5	3.5	3.5	3.5
Reclassed Overheads	16.5	16.5	16.5	16.5	16.5
Reclassed Workovers	9.0	9.0	9.0	9.0	9.0
Reclassed Petroleum Engineering Studies	0	0	0	1.0	1.0
Direct OPEX					
Aircraft	3.3	3.3	3.3	3.3	3.3
Catering & Cleaning Services	7.0	7.0	7.0	7.0	7.0
Diesel Fuel	12.0	6.0	2.2	2.2	2.2
Other (e.g. Wellhead, Maintenance and Contract Services)	45.4	43.4	46.4	46.4	43.4
Workovers	12.0	2.0	2.0	2.0	8.0
BAPETCO Overheads					
Aircraft Lease	2.0	2.0	2.0	2.0	2.0
Catering	1.8	1.8	1.8	1.8	1.8
Other (e.g. personnel salaries & wages)	50.6	50.6	50.6	50.6	50.6
Pipeline Tariffs	-17.6	-17.6	-17.6	-17.6	-17.6
Total OPEX (Note 1)	**149.0**	**130.5**	**129.2**	**130.2**	**133.2**

The baseline operating cost was developed with input from the Consortium to ensure it encompassed their organisation and company philosophies, and reflected a realistic level of savings considering market conditions and the current Vendor's operation. The original baseline developed, as shown in Table 118, did not fully reflect the ramp up of the North Matruh development from 2023-2025 when developed. Due to this, there will be minor variances in the operating costs for the profiles reflected in Appendix II.

Table 118: Well Reactivation OPEX

Year	Well Reactivation Concession Area	OPEX (US$ MM)
2021	Obaiyed	3.4
2022	Badr El Din 3	13.9
2022	Badr El Din 2	2.05
2021	Sitra	1.4
2021	AESW	11.4

4 Economic Assessment

GaffneyCline has conducted an economic analysis in order to assess the economic limit for production, the net Reserves entitlements due to Shell's interests and reference Net Present Values (NPVs) for each of the reserves cases. The economic limit is defined as the point in time when the Contractor's maximum cumulative net cash flow occurs for a project (after this time, the Contractor's forward-looking pre-tax operating cash flow is negative). The Entitlement volumes are made up of Cost Petroleum plus Profit Petroleum due to Shell under various Concession Agreements that govern the assets. It should be noted that the agreements governing the licenses are named Concession Agreements but in practice function similarly to global Petroleum Sharing Contracts (PSCs) and may be referred to as PSCs throughout this report.

These assessments have been based upon GaffneyCline's understanding of the fiscal and contractual terms governing these assets, and the various economic and commercial assumptions described herein.

4.1 Price Assumptions

For the economic limit, NPV and entitlement calculations, GaffneyCline's own 1Q 2020 Brent Crude oil price scenario has been used as the reference oil price. This scenario is shown in Table 119.

Table 119: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2020	63.38
2021	64.50
2022	67.25
2023	70.00
2024+	+2% per annum

The oil prices realised or expected from the sale of crude produced from the various license areas is based on information provided by the Vendor and the Consortium and are summarized in Table 120.

Table 120: Crude Differentials to Brent

Crude	Differential (US$/Bbl)
NEAG Tiba & NEAG Ext	-1.85
Western Desert Discount (All other licenses)	-2.20

For the cash flow calculations, all costs have been inflated at 2% per annum from 2021 onwards.

The gas price assumed is based on various Gas Sales Agreements executed with the Egyptian General Petroleum Corporation (EGPC) and information from the Vendor. The gas price and energy content of natural gas assumed for each asset are summarized in Table 121.

Table 121: Natural Gas Price and Energy Content

Concession	Gas Price (US$/MMBtu)	Energy Content (MMBtu/Mscf)
Obaiyed	2.65	1.118
NUMB	2.65	1.160
NM	2.65	1.150
BED 2	2.65	1.087
BED 3	2.50	1.087
Sitra	2.50	1.085
NAES	2.65	1.085
NEAG Tiba	2.50	1.085
NEAG Ext	2.50	1.085
AESW	2.65	1.085

In compliance with instructions and the accepted definitions for Reserves, we have evaluated the Reserves within this report as of the Effective Date, 31st December 2019, using a reasonable oil and gas price outlook as of that date. We would note that since the Effective Date, various events have result in a material downward movement in the oil price. If the oil price remains significantly below the scenario used here and the long-term price expectation is revised downward, there may be a material revision to the volumes classified as Reserves and the NPVs stated herein. In light of such volatility and at the request of the client, a sensitivity analysis assuming a US$10/Bbl decrease to the oil price is included in Section 4.3 below.

4.2 Fiscal Assumptions

The fiscal terms applied to the various cases are based on the Concession Contracts governing the areas. The key elements of the various applicable fiscal terms are summarized in Table 122.

Table 122: Fiscal Terms

Concession	Obaiyed	NUMB	NM	BED 2	BED 3	Sitra	NAES	NEAG Tiba	NEAG Ext.	AESW
Shell Working Interest	100%	100%	100%	100%	100%	100%	100%	52%	52%	40%
Assumed License End[1]	2029	2043	2045	2034	2026	2025	2042	2034	2036	2033
Cost Recovery Cap	30%	30%	25%	35%	35%	35%	30%	40%	40%	30%
Capex Amortization Period (Years)	5	5	5	5	5	5	5	5	5	5
Contractor Excess Cost Recovery Share	Same as Profit Share	10%	0%	Same as Profit Share	Same as Profit Share	Same as Profit Share	0%	Same as Profit Share	Same as Profit Share	0%
Contractor Liquids Profit Share[2]	20%-12.5%	23%-10.5%	20%-17.5%	17%	17%	17%	20%-17.5%	23%-14%	23%-14%	17%-15%
Contractor Gas Profit Share[2]	20%	23%-19%	20%-18%	17%	17%	17%	20%-18%	25%	25%	17%-15%
Income Tax	Borne by EGPC on behalf of the Contractor									
Historic Costs Recoverable (US$MM)[3]	86.0	18.6	19.6	27.1	147.9	122.3	39.6	19.3	52.3	359.0

Notes:

1. This is a somewhat simplified assumption as some fields within the concession have varying license ends and some 5 or 10 year extensions are included for concessions that include such a provision for extension at the election of the Contractor.
2. The profit share shown is the full possible range in the relevant contract, where it is defined in tranches based primarily on daily production and in a couple of instances also on liquids price. In most of the Reserves cases, the average applicable Contractor share is close to the higher end of the range shown.
3. This amount is based on information provided by the Vendor and the Consortium and is the sum total of cost recovery due and carried at the end of 2019 as well as the amortization yet to be recoverable from CAPEX incurred before the end of 2019.

For the economic analysis, all operating costs are assumed to be recoverable except a US$1.0/Bbl terminal fee, which is considered non-recoverable. Historically, a portion of Shell operating costs was non-recoverable, primarily associated with G&A. However, it is understood that the extent to which forward-looking operating costs will be recoverable will be based on discussions between the new owner and EGPC, GaffneyCline has not included any assumption on the level of potential non-recoverable operating costs in this report.

4.3 Results

The economic limit for production for each Reserves case is shown in Table 123.

The resulting Reserves, both gross (100%) and net to Shell's interest, are shown in Table 2 in the Executive Summary. The corresponding NPVs at a discount rate of 10%, net to Shell's interest, are shown in Table 4.

Table 123: Economic Limits

Assets	Economic Limit (End of Year)		
	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	2029	2029	2029
NUMB	2023	2023	2023
NM	2029	2029	2029
BED 2	2021	2027	2031
BED 3	2025	2025	2025
Sitra	2023	2025	2025
NAES	2020	2028	2028
NEAG Tiba	2026	2026	2027
NEAG Ext	2025	2027	2030
AESW	2028	2031	2032

4.4 Sensitivity Analysis

As mentioned above, GaffneyCline reran the economic analyses using a Brent Crude oil price scenario US$10/Bbl lower than that shown in Table 119. As in the base case oil price scenario, costs were escalated at 2.0% p.a. from 2021, with no adjustment for the higher or lower oil price. The differentials to Brent for each asset and the assumed gas prices were left unchanged.

The economic limit was found to fall one year earlier than it did in the base case in a few cases, but most were unchanged, and the only significant change was for the Sitra Proved Reserves case, where it fell at end 2020 instead of end 2023. Resulting Reserves under this lower oil price scenario are shown in Table 124, and the corresponding NPV10s in Table 125.

Table 124: Summary of Reserves as at 31st December 2019 under a US$10/Bbl Lower Oil Price Scenario

(a) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	17.1	22.2	26.8	100.0	6.6	7.9	8.9	50.0	3.3	3.9	4.4
NUMB	0.2	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.1	0.1	0.1
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.6
BED 2	2.9	5.8	8.2	100.0	1.3	2.5	3.3	50.0	0.6	1.3	1.6
BED 3	10.7	15.3	20.5	100.0	4.9	6.9	8.3	50.0	2.5	3.5	4.1
Sitra	1.8	11.9	17.3	100.0	0.8	5.5	7.3	50.0	0.4	2.7	3.6
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	6.0	8.9	12.7	52.0	1.6	2.0	2.5	26.0	0.8	1.0	1.2
NEAG Ext.	8.1	12.2	17.5	52.0	2.3	3.1	4.2	26.0	1.1	1.6	2.1
AESW	16.9	29.6	45.1	40.0	2.8	4.8	6.0	20.0	1.4	2.4	3.0
Total	**68.8**	**116.1**	**168.1**		**22.4**	**36.4**	**45.7**		**11.2**	**18.2**	**22.9**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% of Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	367.1	425.7	483.0	100.0	142.6	152.9	162.7	50.0	71.3	76.5	81.4
NUMB	14.5	15.0	15.5	100.0	6.7	6.9	7.1	50.0	3.4	3.5	3.6
M	46.4	76.8	128.0	100.0	18.5	27.1	34.3	50.0	9.3	13.6	17.1
BED 2	9.3	38.7	72.4	100.0	4.0	17.2	29.6	50.0	2.0	8.6	14.8
BED 3	47.1	60.8	75.0	100.0	21.7	27.7	30.5	50.0	10.9	13.9	15.2
Sitra	9.1	32.1	42.3	100.0	4.2	14.8	18.1	50.0	2.1	7.4	9.1
NAES	1.1	24.6	36.7	100.0	0.5	10.8	16.1	50.0	0.2	5.4	8.1
NEAG Tiba	16.7	23.1	32.2	52.0	4.4	5.3	6.6	26.0	2.2	2.7	3.3
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	473.3	603.4	785.8	40.0	77.6	97.3	105.2	20.0	38.8	48.7	52.6
Total	**984.7**	**1,300.3**	**1,670.9**		**280.2**	**360.1**	**410.2**		**140.1**	**180.0**	**205.1**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 125: Summary of Post-Tax NPV10 of Future Cash Flow from Reserves, as at 31st December 2019, under a US$10/Bbl Lower Oil Price Scenario

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	263.0	319.6	373.3	131.5	159.8	186.7
NUMB	17.9	18.6	19.2	8.9	9.3	9.6
NM	-5.0	59.2	120.5	-2.5	29.6	60.3
BED 2	25.8	48.2	70.3	12.9	24.1	35.2
BED 3	60.9	154.2	211.2	30.4	77.1	105.6
Sitra	10.6	96.0	171.8	5.3	48.0	85.9
NAES	0.7	4.4	11.5	0.3	2.2	5.7
NEAG Tiba	17.3	33.0	51.0	8.7	16.5	25.5
NEAG Ext	30.0	47.5	70.9	15.0	23.8	35.4
AESW	98.0	190.3	227.9	49.0	95.2	113.9
Total	**519.1**	**970.9**	**1,327.6**	**259.6**	**485.4**	**663.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs herein do not represent GaffneyCline's opinion of the market value of the asset or any interest therein.

Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by Shell, Cairn, the Consortium, and/or obtained from other sources (e.g., public domain), the scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by Shell, Cairn, the Consortium and/or obtained from other sources (e.g., public domain), and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GaffneyCline has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 (see Appendix V).

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMBbl). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60°F.

Definition of Reserves and Resources

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any net present value (NPV) analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development" (per PRMS).

Reserves net to Shell's interest are quoted as Net Entitlement Reserves, reflecting the terms of the applicable contracts. Contingent Resources are presented at a gross field level and Shell working interest level.

GaffneyCline has not undertaken a site visit and inspection. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licences and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Use of Net Present Values

It should be clearly understood that the NPVs contained herein do not represent a GaffneyCline opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Proved and/or Probable and/or Possible Reserves may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the NPVs presented herein.

Qualifications

GaffneyCline is an independent international energy advisory group of more than 55 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with the Consortium. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

The team was led by Dr. Rand A. Mustafa, North Africa Advisor, who has over 12 years' industry experience. She holds a Ph.D. and Bachelors in Petroleum Engineering. She is a member of the Society of Petroleum Engineers.

The report was reviewed by Dr. John Barker, Technical Director, Reservoir Engineering, who has 35 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

Yours sincerely,

Gaffney, Cline & Associates Limited

Project Manager
Dr. Rand A. Mustafa, North Africa Advisor

John Barker

Reviewed by
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Appendix I
Glossary

GLOSSARY

Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
ACQ	Annual contract quantity
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus offset
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow out preventer
bopd	Barrels oil per day
bpd	Barrels per day
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
CBM	Coal bed methane
cf	Standard cubic feet
cfd	Standard cubic feet per day
CIIP	Condensate initially in place
CGR	Condensate to gas ratio
cm	Centimetres
CMM	Coal mine methane
CO_2	Carbon dioxide
cP	Centipoise (a measure of viscosity)
CSG	Coal seam gas
CT	Corporation tax
DCQ	Daily contract quantity
Dev	Developed
DHI	Direct hydrocarbon indicator
DST	Drill stem test
E&A	Exploration & appraisal
E&P	Exploration and production
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement interest
EIA	Environmental impact assessment
ELT	Economic limit test
EMV	Expected monetary value
EOR	Enhanced oil recovery
ESP	Electrical submersible pump

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EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FPSO	Floating production, storage and offloading vessel
FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GTL	Gas to liquids
GWC	Gas water contact
HIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)

Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Post stack depth migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved undeveloped
PVT	Pressure volume temperature
P10	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RUB	Russian Rouble
R_w	Resistivity of water

SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water saturation
t	Tonnes
TD	Total depth
te	Tonnes equivalent
THP	Tubing head pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical committee meeting
TOC	Total organic carbon
TOP	Take or pay
tpd	Tonnes per day
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)

Appendix II
Gross Field Production and Cost Profiles

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Table AII.1: Obaiyed

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.3	129.1	5.3	129.1	38.8	5.5	130.6	5.5	130.6	38.8	5.6	131.9	5.6	131.9	38.9	0.0
2021	4.1	108.1	8.6	158.5	33.5	4.4	111.9	12.0	174.4	34.8	4.5	115.3	15.0	189.7	35.9	25.0
2022	3.6	91.6	5.7	123.7	25.7	3.9	97.0	7.4	142.0	26.3	4.1	101.9	9.0	159.7	26.9	31.6
2023	3.1	77.9	5.7	118.6	25.5	3.4	84.4	7.6	139.5	26.2	3.7	90.3	9.4	158.9	26.8	43.5
2024	2.7	67.1	6.1	124.7	23.5	3.1	74.3	8.3	149.6	24.3	3.3	80.9	10.2	172.7	25.0	42.3
2025	2.3	58.1	4.3	98.7	23.3	2.7	65.8	5.4	118.3	23.8	3.0	72.9	6.5	137.9	24.2	1.9
2026	2.0	50.6	3.5	83.3	19.7	2.4	58.5	4.5	101.1	22.9	2.7	66.0	5.4	119.0	23.2	0.7
2027	1.7	44.3	3.0	71.3	19.1	2.2	52.2	3.9	87.9	22.2	2.5	59.9	4.8	104.6	22.5	0.0
2028	1.5	38.8	2.6	61.2	18.5	2.0	46.7	3.4	76.6	21.6	2.3	54.6	4.2	92.4	21.9	0.0
2029	1.3	23.2	2.0	35.9	17.5	1.8	28.4	2.6	45.7	20.3	2.1	33.6	3.2	55.5	20.6	0.0
Total to 2029	**10.1**	**251.7**	**17.1**	**367.1**	**245.0**	**11.4**	**273.9**	**22.2**	**425.7**	**261.1**	**12.3**	**294.9**	**26.8**	**483.0**	**265.9**	**144.9**
Total to economic limit	**10.1**	**251.7**	**17.1**	**367.1**	**245.0**	**11.4**	**273.9**	**22.2**	**425.7**	**261.1**	**12.3**	**294.9**	**26.8**	**483.0**	**265.9**	

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Table AII.2: NM

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.5
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.8
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43.8
2023	3.5	33.1	0	0	3.1	5.7	46	0	0	4.7	8.8	60.7	0	0	6.7	36.6
2024	5.3	50	0	0	4.7	9.3	74	0	0	7.6	15.4	104.6	0	0	11.6	46.1
2025	2.7	24.5	0	0	2.3	5.6	43	0	0	4.5	11.1	72.4	0	0	8.2	2.7
2026	1.3	11	0	0	1.1	3.2	23.4	0	0	2.5	7.6	47.3	0	0	5.5	0
2027	0.6	5	0	0	0.5	1.8	12.8	0	0	1.4	5.2	31.2	0	0	3.7	0
2028	0.3	2.3	0	0	0.2	1.1	7	0	0	0.8	3.6	20.6	0	0	2.5	0
2029	0.1	1.1	0	0	0.2	0.6	3.9	0	0	0.4	2.5	13.8	0	0	1.7	0
2030	0.1	0.5	0	0	0.2	0.3	2.2	0	0	0.3	1.7	9.2	0	0	1.1	0
2031	0	0.2	0	0	0.1	0.2	1.2	0	0	0.2	1.2	6.2	0	0	0.8	0
2032	0	0.1	0	0	0.1	0.1	0.7	0	0	0.2	0.8	4.2	0	0	0.5	0
2033	0	0.1	0	0	0.1	0.1	0.4	0	0	0.1	0.6	2.9	0	0	0.4	0
2034	0	0	0	0	0.1	0	0.2	0	0	0.1	0.4	1.9	0	0	0.3	0
2035	0	0	0	0	0.1	0	0.1	0	0	0.1	0.3	1.3	0	0	0.2	0
2036	0	0	0	0	0.1	0	0.1	0	0	0.1	0.2	0.9	0	0	0.1	0
2037	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.6	0	0	0.1	0
2038	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.4	0	0	0.1	0
2039	0	0	0	0	0.1	0	0	0	0	0.1	0.1	0.3	0	0	0.1	0
2040	0	0	0	0	0.1	0	0	0	0	0.1	0	0.2	0	0	0.1	0
2041	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2042	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2043	0	0	0	0	0.1	0	0	0	0	0.1	0	0.1	0	0	0.1	0
2044	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
2045	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
2046	0	0	0	0	0.1	0	0	0	0	0.1	0	0	0	0	0.1	0
Total to 2046	**5**	**46.7**	**0**	**0**	**14.5**	**10.3**	**78.6**	**0**	**0**	**24.3**	**21.8**	**138.5**	**0**	**0**	**44.1**	**139.4**
Total to economic limit	**5**	**46.4**	**0**	**0**	**12.2**	**10**	**76.8**	**0**	**0**	**21.9**	**19.8**	**128**	**0**	**0**	**39.7**	

Table AII.3: NUMB

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0.2	14.9	0.2	14.9	2.2	0.3	15.1	0.3	15.1	2.2	0.3	15.2	0.3	15.2	2.2	0.0
2021	0.2	11.0	0.2	11.0	1.2	0.2	11.3	0.2	11.3	1.2	0.2	11.6	0.2	11.6	1.2	0.0
2022	0.1	8.1	0.1	8.1	1.0	0.1	8.5	0.1	8.5	1.0	0.1	8.8	0.1	8.8	1.0	0.0
2023	0.1	5.9	0.1	5.9	1.0	0.1	6.3	0.1	6.3	1.0	0.1	6.7	0.1	6.7	1.0	0.0
2024	0.1	4.3	0.1	13.4	3.2	0.1	4.8	0.1	17.3	3.2	0.1	5.1	0.1	24.0	3.2	38.0
2025	0.1	3.2	0.1	10.5	3.2	0.1	3.6	0.1	14.4	3.2	0.1	3.9	0.1	20.6	3.2	0.0
2026	0.0	2.3	0.0	8.2	2.6	0.0	2.7	0.0	12.0	3.1	0.1	3.0	0.1	17.6	3.2	0.0
2027	0.0	1.7	0.0	6.4	2.5	0.0	2.0	0.0	10.1	3.1	0.0	2.3	0.0	15.2	3.1	0.0
2028	0.0	1.3	0.0	5.0	2.5	0.0	1.5	0.0	8.5	3.0	0.0	1.7	0.0	13.1	3.0	0.0
2029	0.0	0.9	0.0	4.0	2.4	0.0	1.1	0.0	7.2	2.9	0.0	1.3	0.0	11.3	3.0	0.0
2030	0.0	0.7	0.0	3.1	2.3	0.0	0.9	0.0	6.1	2.8	0.0	1.0	0.0	9.8	2.9	0.0
2031	0.0	0.5	0.0	2.5	2.3	0.0	0.6	0.0	5.1	2.8	0.0	0.8	0.0	8.5	2.8	0.0
2032	0.0	0.2	0.0	1.7	2.2	0.0	0.5	0.0	4.4	2.7	0.0	0.6	0.0	7.4	2.8	0.0
2033	0.0	0.0	0.0	1.3	2.1	0.0	0.1	0.0	3.5	2.6	0.0	0.4	0.0	6.4	2.7	0.0
2034	0.0	0.0	0.0	1.0	2.1	0.0	0.0	0.0	2.9	2.6	0.0	0.1	0.0	5.3	2.7	0.0
2035	0.0	0.0	0.0	0.8	2.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0	0.0	4.6	2.6	0.0
2036	0.0	0.0	0.0	0.7	2.0	0.0	0.0	0.0	2.2	2.5	0.0	0.0	0.0	4.1	2.6	0.0
2037	0.0	0.0	0.0	0.5	1.9	0.0	0.0	0.0	1.9	2.4	0.0	0.0	0.0	3.6	2.5	0.0
2038	0.0	0.0	0.0	0.4	1.9	0.0	0.0	0.0	1.6	2.4	0.0	0.0	0.0	3.2	2.5	0.0
2039	0.0	0.0	0.0	0.3	1.9	0.0	0.0	0.0	1.4	2.3	0.0	0.0	0.0	2.8	2.4	0.0
2040	0.0	0.0	0.0	0.3	1.8	0.0	0.0	0.0	1.2	2.3	0.0	0.0	0.0	2.4	2.4	0.0
2041	0.0	0.0	0.0	0.2	1.8	0.0	0.0	0.0	1.0	2.3	0.0	0.0	0.0	2.2	2.4	0.0
2042	0.0	0.0	0.0	0.2	1.8	0.0	0.0	0.0	0.9	2.2	0.0	0.0	0.0	1.9	2.3	0.0
2043	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.3	2.0	0.0	0.0	0.0	0.6	2.1	0.0
Total to 2043	**0.3**	**20.1**	**0.3**	**36.7**	**49.6**	**0.4**	**21.5**	**0.4**	**53.2**	**58.5**	**0.4**	**22.9**	**0.4**	**75.6**	**59.8**	**38.0**
Total to economic limit	**0.2**	**14.5**	**0.2**	**14.5**	**5.5**	**0.2**	**15.1**	**0.2**	**15.0**	**5.5**	**0.2**	**15.2**	**0.2**	**15.5**	**5.5**	

Gaffney Cline

Table AII.4: BED 2

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	1.0	14.3	5.4	14.3	16.7	1.0	14.7	5.6	14.7	16.8	1.1	15.0	5.9	15.0	16.9	12.0
2021	0.6	11.2	2.7	11.2	13.3	0.6	12.2	3.1	12.2	13.4	0.7	13.0	3.5	13.0	13.6	7.1
2022	0.4	8.8	1.7	9.9	13.4	0.5	10.2	2.4	14.1	13.7	0.5	11.2	3.0	17.1	13.9	8.7
2023	0.2	6.8	1.1	10.1	11.1	0.3	8.5	1.8	20.9	11.3	0.4	9.7	2.5	28.3	11.6	6.8
2024	0.2	5.4	0.7	7.6	9.8	0.2	7.1	1.3	17.4	10.1	0.3	8.4	1.9	25.0	10.3	0.2
2025	0.1	4.2	0.4	5.8	10.0	0.2	5.9	0.9	14.5	10.1	0.2	7.2	1.5	22.0	10.3	0.2
2026	0.1	3.3	0.3	4.4	9.4	0.1	4.9	0.7	12.1	9.7	0.2	6.3	1.2	19.5	9.9	0.0
2027	0.0	2.6	0.2	3.3	8.9	0.1	4.1	0.5	10.2	9.3	0.1	5.4	0.9	17.3	9.6	0.0
2028	0.0	2.0	0.1	2.6	8.5	0.1	3.4	0.4	8.5	8.9	0.1	4.7	0.8	15.4	9.3	0.0
2029	0.0	1.6	0.1	2.0	8.1	0.0	2.8	0.3	7.2	8.6	0.1	4.1	0.6	13.7	9.0	0.0
2030	0.0	1.2	0.1	1.5	7.8	0.0	2.4	0.3	6.0	8.3	0.1	3.5	0.5	12.2	8.8	0.0
2031	0.0	1.0	0.0	1.2	7.4	0.0	2.0	0.2	5.1	8.1	0.0	3.0	0.4	10.8	8.6	0.0
2032	0.0	0.8	0.0	0.9	7.1	0.0	1.7	0.2	4.3	7.8	0.0	2.6	0.4	9.7	8.4	0.0
2033	0.0	0.6	0.0	0.7	6.9	0.0	1.4	0.1	3.7	7.6	0.0	2.3	0.3	8.7	8.2	0.0
2034	0.0	0.1	0.0	0.1	6.1	0.0	0.4	0.0	1.0	6.7	0.0	0.7	0.1	2.6	7.2	0.0
Total to 2034	**0.9**	**23.3**	**4.6**	**27.6**	**144.5**	**1.1**	**29.8**	**6.5**	**55.5**	**150.6**	**1.4**	**35.4**	**8.6**	**84.0**	**155.5**	**35.0**
Total to economic limit	**0.5**	**9.3**	**2.9**	**9.3**	**30.0**	**1.0**	**24.7**	**6.0**	**42.4**	**94.4**	**1.4**	**33.4**	**8.3**	**76.4**	**131.8**	

Gaffney Cline

Table AII.5: BED 3

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.7	28.0	8.1	28.6	31.1	6.4	29.2	9.2	30.8	31.5	6.7	30.0	9.9	32.2	31.8	20.9
2021	3.1	19.5	7.9	22.1	22.5	3.6	21.5	11.7	28.7	23.9	3.9	22.9	15.6	35.2	25.4	39.6
2022	2.0	13.7	4.8	24.8	32.9	2.4	15.9	7.7	33.9	33.9	2.7	17.6	11.1	43.4	35.2	18.1
2023	1.4	9.6	3.9	23.7	18.5	1.7	11.8	6.0	31.4	19.2	1.9	13.5	8.6	39.7	20.2	12.9
2024	0.9	6.8	2.7	17.3	17.8	1.2	8.8	4.2	23.7	18.4	1.3	10.4	6.3	30.8	19.1	9.4
2025	0.6	4.8	1.9	12.7	17.9	0.8	6.5	3.1	18.0	18.4	1.0	8.1	4.8	24.0	19.0	3.9
2026	0.1	1.1	0.4	3.1	10.9	0.2	1.6	0.8	4.6	15.3	0.2	2.1	1.5	6.5	17.7	1.5
Total to 2026	**5.1**	**30.5**	**10.9**	**48.3**	**151.7**	**5.9**	**34.8**	**15.6**	**62.5**	**160.7**	**6.4**	**38.2**	**21.1**	**77.4**	**168.3**	**106.2**
Total to economic limit	**5.1**	**30.1**	**10.7**	**47.1**	**140.8**	**5.8**	**34.2**	**15.3**	**60.8**	**145.4**	**6.4**	**37.5**	**20.5**	**75.0**	**150.6**	

Gaffney Cline

Table AII.6: Sitra

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	4.5	23.4	4.9	24.9		4.8	24.4	5.5	27.5	35.2	4.9	25.2	5.8	29.9	35.3	7.3
2021	2.5	14.2	5.4	16.3	35.0	2.9	16.3	8.2	21.3	25.8	3.2	17.9	10.6	26.4	26.7	39.4
2022	1.6	8.8	4.4	10.6	24.8	2.1	11.0	7.7	15.7	21.5	2.4	12.9	11.3	21.9	22.8	21.2
2023	1.0	5.4	2.5	6.8	20.3	1.4	7.4	5.2	11.2	19.7	1.8	9.2	8.5	16.9	20.9	0.3
2024	0.6	3.3	1.4	4.1	18.7	1.0	5.0	3.6	7.5	18.9	1.4	6.6	6.4	12.3	19.9	0.3
2025	0.4	1.9	0.8	2.2	18.1	0.7	3.1	2.4	4.7	20.2	0.9	4.4	4.7	8.5	21.0	0.0
Total to 2030	**3.9**	**20.8**	**7.1**	**23.7**	19.6	**4.7**	**24.5**	**11.9**	**32.1**	**141.3**	**5.4**	**27.8**	**17.3**	**42.3**	**146.6**	**68.6**
Total to economic limit	**3.5**	**18.9**	**6.3**	**21.4**	**136.4**	**4.7**	**24.5**	**11.9**	**32.1**	**141.3**	**5.4**	**27.8**	**17.3**	**42.3**	**146.6**	

Gaffney Cline

Table AII.7: AESW

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	2.2	120.8	5.0	151.1	54.4	2.4	122.3	6.0	153.0	54.8	2.4	123.4	6.8	154.6	55.1	17.4
2021	1.1	89.0	6.0	190.7	49.4	1.3	92.6	8.1	202.8	50.2	1.4	95.4	9.9	220.1	50.8	52.5
2022	0.7	65.6	9.8	248.0	34.9	0.8	70.4	13.8	277.5	36.4	0.9	74.2	17.3	319.2	37.7	83.6
2023	0.4	48.1	8.5	220.4	34.2	0.5	53.5	14.1	260.8	36.2	0.6	57.8	19.5	313.8	38.2	67.7
2024	0.2	35.5	6.4	168.6	32.6	0.3	41.0	11.5	208.8	34.5	0.4	45.4	16.9	260.6	36.5	20.2
2025	0.1	26.2	4.3	121.3	32.6	0.2	31.5	8.5	159.1	34.1	0.3	36.0	13.4	207.1	35.9	3.8
2026	0.1	19.3	2.9	87.4	30.5	0.1	24.3	6.3	121.9	32.0	0.2	28.6	10.4	165.7	33.7	3.8
2027	0.0	14.2	2.0	63.0	28.8	0.1	18.8	4.7	94.1	30.3	0.1	22.9	8.1	133.5	31.9	2.8
2028	0.0	10.2	1.4	45.3	27.3	0.1	14.5	3.5	72.9	28.8	0.1	18.4	6.4	108.2	30.3	0.6
2029	0.0	7.5	1.0	32.8	26.0	0.0	11.0	2.6	56.6	27.4	0.1	14.6	5.1	88.1	29.0	0.6
2030	0.0	5.6	0.7	23.7	24.8	0.0	8.6	2.0	44.4	26.3	0.0	11.7	4.1	72.0	27.8	0.6
2031	0.0	4.1	0.5	17.2	23.8	0.0	6.8	1.5	35.0	25.3	0.0	9.5	3.3	59.4	26.8	0.6
2032	0.0	3.1	0.3	12.5	22.8	0.0	5.3	1.0	27.8	24.1	0.0	7.8	2.2	49.1	25.4	0.6
2033	0.0	0.8	0.1	3.0	20.4	0.0	1.4	0.2	7.5	21.4	0.0	2.1	0.5	13.6	22.1	0.0
Total to 2033	**1.8**	**164.4**	**17.9**	**505.9**	**442.6**	**2.1**	**183.4**	**30.6**	**629.1**	**461.8**	**2.4**	**200.1**	**45.3**	**790.8**	**481.2**	**254.8**
Total to economic limit	**1.8**	**156.7**	**16.9**	**473.3**	**324.9**	**2.1**	**180.9**	**30.2**	**616.2**	**416.3**	**2.4**	**199.3**	**45.1**	**785.8**	**459.1**	

Table AII.8: NAES

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	0.0	3.1	0.0	3.1	0.8	0.0	3.8	0.0	3.8	0.8	0.0	3.8	0.0	3.8	0.8	0.0
2021	0.0	1.0	0.0	1.0	0.8	0.0	1.8	0.0	1.8	0.8	0.0	2.2	0.0	2.2	0.8	0.0
2022	0.0	0.3	0.0	0.3	0.7	0.0	0.9	0.0	0.9	0.7	0.0	1.3	0.0	1.3	0.7	0.0
2023	0.0	0.1	0.0	0.1	0.7	0.0	0.4	0.0	0.4	0.7	0.0	0.7	0.0	0.7	0.7	0.0
2024	0.0	0.0	0.0	21.2	1.3	0.0	0.2	0.0	30.3	1.8	0.0	0.4	0.1	39.1	2.3	14.4
2025	0.0	0.0	0.0	8.2	0.5	0.0	0.1	0.0	16.5	1.0	0.0	0.2	0.0	25.3	1.5	0.0
2026	0.0	0.0	0.0	2.7	0.4	0.0	0.0	0.0	7.9	0.9	0.0	0.1	0.0	14.6	1.6	0.0
2027	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	3.8	0.8	0.0	0.1	0.0	8.5	1.7	0.0
2028	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	1.8	0.7	0.0	0.0	0.0	4.9	1.8	0.0
2029	0.0	0.0	0.0	0.1	0.3	0.0	0.0	0.0	0.9	0.6	0.0	0.0	0.0	2.8	1.7	0.0
2030	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.4	0.6	0.0	0.0	0.0	1.6	1.5	0.0
2031	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.5	0.0	0.0	0.0	0.9	1.4	0.0
2032	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.5	1.2	0.0
2033	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.3	1.1	0.0
2034	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.9	0.0
2035	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.1	0.8	0.0
2036	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.1	0.8	0.0
2037	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.7	0.0
2038	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.6	0.0
2039	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.5	0.0
2040	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.5	0.0
2041	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.5	0.0
2042	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.4	0.0
Total to 2042	**0.0**	**1.7**	**0.0**	**13.9**	**8.8**	**0.0**	**2.7**	**0.0**	**25.3**	**13.2**	**0.0**	**3.3**	**0.1**	**39.1**	**24.4**	**14.4**
Total to economic limit	**0.0**	**1.1**	**0.0**	**1.1**	**0.8**	**0.0**	**2.7**	**0.0**	**24.6**	**8.0**	**0.0**	**3.3**	**0.1**	**36.7**	**11.8**	

Table AII.9: NEAG EXT

	Low					Best					High					
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		CAPEX
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	5.9	0.0	5.9	0.0	31.4	6.2	0.0	6.2	0.0	31.5	6.4	0.0	6.4	0.0	31.6	0.8
2021	3.7	0.0	3.7	0.0	23.1	4.2	0.0	4.2	0.0	23.3	4.5	0.0	4.5	0.0	23.4	1.7
2022	2.4	0.0	6.2	0.0	21.3	2.9	0.0	8.9	0.0	22.3	3.3	0.0	12.2	0.0	23.5	33.9
2023	2.6	0.0	3.9	0.0	20.3	3.0	0.0	5.5	0.0	20.9	3.3	0.0	7.8	0.0	21.7	9.1
2024	1.9	0.0	2.6	0.0	21.8	2.3	0.0	3.7	0.0	22.2	2.6	0.0	5.3	0.0	22.8	1.8
2025	1.4	0.0	1.9	0.0	22.1	1.7	0.0	2.8	0.0	22.4	2.1	0.0	4.0	0.0	22.8	0.7
2026	1.0	0.0	1.4	0.0	20.9	1.3	0.0	2.2	0.0	21.3	1.6	0.0	3.1	0.0	21.7	0.0
2027	0.8	0.0	1.1	0.0	19.9	1.1	0.0	1.7	0.0	20.4	1.3	0.0	2.5	0.0	20.8	0.0
2028	0.6	0.0	0.8	0.0	19.0	0.8	0.0	1.4	0.0	19.7	1.1	0.0	2.1	0.0	20.0	0.0
2029	0.4	0.0	0.6	0.0	18.2	0.6	0.0	1.2	0.0	19.0	0.9	0.0	1.8	0.0	19.4	0.0
2030	0.3	0.0	0.5	0.0	17.5	0.5	0.0	1.0	0.0	18.4	0.7	0.0	1.5	0.0	18.8	0.0
2031	0.3	0.0	0.4	0.0	16.8	0.4	0.0	0.8	0.0	17.8	0.6	0.0	1.3	0.0	18.3	0.0
2032	0.2	0.0	0.3	0.0	16.1	0.3	0.0	0.6	0.0	17.1	0.5	0.0	1.0	0.0	17.6	0.0
2033	0.0	0.0	0.0	0.0	13.4	0.0	0.0	0.0	0.0	14.3	0.1	0.0	0.1	0.0	14.7	0.0
2034	0.0	0.0	0.0	0.0	11.6	0.0	0.0	0.0	0.0	12.9	0.0	0.0	0.0	0.0	13.2	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.6	0.0
Total to 2036	**7.9**	**0.0**	**10.7**	**0.0**	**293.6**	**9.3**	**0.0**	**14.7**	**0.0**	**303.4**	**10.6**	**0.0**	**19.6**	**0.0**	**333.8**	**47.9**
Total to economic limit	**6.6**	**0.0**	**8.8**	**0.0**	**140.4**	**8.3**	**0.0**	**12.8**	**0.0**	**184.3**	**10.2**	**0.0**	**18.7**	**0.0**	**246.4**	

Table AII.10: NEAG TIBA

	Low					Best					High					CAPEX
	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	NFA		NFA + Activities		OPEX	
	Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		Oil	Gas	Oil	Gas		
	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	Mbopd	MMscfd	Mbopd	MMscfd	US$ MM	US$ MM
2020	2.0	12.0	2.4	12.4	9.8	2.0	12.3	2.7	13.1	9.9	2.0	12.6	2.9	13.7	10.0	8.2
2021	1.3	8.0	2.8	9.7	10.2	1.4	8.8	4.0	12.2	10.6	1.4	9.3	5.2	15.1	11.0	17.2
2022	1.0	5.4	1.9	6.4	8.7	1.1	6.3	2.8	8.6	9.0	1.2	7.0	3.9	11.3	9.4	4.1
2023	0.7	3.6	2.6	5.4	8.9	0.8	4.5	3.8	8.2	9.3	0.9	5.3	5.4	11.7	9.9	19.7
2024	0.5	2.4	3.1	5.4	8.9	0.6	3.3	4.7	9.2	9.5	0.7	4.0	6.7	14.3	10.3	26.1
2025	0.4	1.6	2.2	3.7	8.8	0.5	2.4	3.6	6.9	9.3	0.6	3.1	5.5	11.5	10.0	1.4
2026	0.3	1.1	1.5	2.5	8.1	0.4	1.8	2.7	5.2	8.6	0.5	2.4	4.5	9.2	9.3	0.0
2027	0.0	0.1	0.2	0.3	6.3	0.1	0.2	0.4	0.7	6.5	0.1	0.3	0.7	1.4	6.7	0.0
2028	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.1	0.1	5.5	0.0
2029	0.0	0.0	0.0	0.0	4.4	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	4.8	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total to 2034	**2.2**	**12.5**	**6.1**	**16.8**	**79.2**	**2.5**	**14.5**	**9.0**	**23.3**	**82.7**	**2.7**	**16.1**	**12.7**	**32.3**	**87.0**	**76.7**
Total to economic limit	**2.2**	**12.4**	**6.0**	**16.7**	**63.3**	**2.5**	**14.4**	**8.9**	**23.1**	**66.3**	**2.7**	**16.1**	**12.7**	**32.2**	**76.7**	

Notes for all Appendix II Tables:

1. Production and costs are shown at gross field level, i.e. 100% of the production and costs.
2. The volumes shown are after deduction of fuel and shrinkage.
3. CAPEX is the same in all three cases (Low, Best and High).
4. Totals are in MMBbl for oil and Bscf for gas.

Appendix III
CAPEX Breakdowns

Table AIII.1: CAPEX Breakdown for Obaiyed (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Flank Horizontal Well	7				18.0	24.0			
Vertical Well	5		5.6	13.4					
Recompletion/WO	13		8.8	1.1	2.2	2.2			
Gas Well Hook-up	12		2.4	3.6	3.6	4.8			
LLP Compressor Phase 1 Project (NFA)			2.8	4.7	7.3	3.7			
Life Extension Project (NFA)			1.8	3.0	4.8	2.4			
Asset Integrity Project (NFA)			1.8	3.0	3.3	2.8	1.7	0.7	
Contamination + Well Integrity Project (NFA)			0.2	0.2	0.2	0.2	0.2		
LLP Compressor Phase 1 Project (Infill)			0.9	1.6	2.4	1.2			
LLP Compressor Phase 2 (Infill)			0.6	1.0	1.6	0.8			
Total (US$MM)			**24.9**	**31.5**	**43.5**	**42.3**	**1.9**	**0.7**	

Table AIII.2: CAPEX Breakdown for NM (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	13				21.1	33.8			
Gas Well Hook-up	16				9.7	9.7			
NM Development Project (FO)			8.8	43.8	5.8	2.7	2.7		
Exploration CAPEX		1.5							
Total (US$MM)		**1.5**	**8.8**	**43.8**	**36.6**	**46.1**	**2.7**		

Table AIII.3: CAPEX Breakdown for NUMB (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	7					29.5			
Gas Well Hook-up	7					8.5			
Total (US$MM)						**38.0**			

Table AIII.4: CAPEX Breakdown for BED2 (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	10	4.5		6.0	4.5				
Horizontal Well	1	3.5							
Injector									
Gas Well Hook-up									
Oil Well Hook-up	11	1.6		1.6	1.2				
Injector Hook-up									
LLP Compressor Project (NFA)		2.3	7.0						
Contamination + Well Integrity Project (NFA)			0.1	1.1	1.1	0.2	0.2		
Total (US$MM)		**12.0**	**7.1**	**8.7**	**6.8**	**0.2**	**0.2**		

Table AIII.5: CAPEX Breakdown for BED3 (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	17	3.0	19.4	3.0					
Injector	5	1.0	3.9						
Re-Perf	1		0.3						
Gas Well Hook-up									
Oil Well Hook-up	18	1.2	5.3	0.8					
Injector Hook-up	5	0.2	0.8						
Sitra PWRI at BED3 Project (NFA)		8.0							
LLP Compression Project (NFA)		3.0							
Asset Integrity (NFA)			3.8	6.4	7.1	6.1	3.6	1.5	
Contamination + Well Integrity (NFA)			0.2	1.3	1.3	0.3	0.3		
Mercury Removal Facility (NFA)		4.5							
Electrification Project (NFA)			2.5	3.7	3.7	2.5			
LP Oil AG LLP tie-in Project (Infill)			0.8						
2 x Separators BED3 Oil Project (Infill)			0.6	0.6					
Additional Export Pump Project (Infill)			1.5	1.5					
Electrification Project (Infill)			0.5	0.8	0.8	0.5			
Total (US$MM)		**20.9**	**39.6**	**18.1**	**12.9**	**9.4**	**3.9**	**1.5**	

Table AIII.6: CAPEX Breakdown for Sitra (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	19	5.3	14.1	14.1					
Horizontal Well	5		17.6						
Injector	5		1.9	2.9					
Gas Well Hook-up	1	1.2							
Oil Well Hook-up	23	0.8	5.3	3.3					
Injector Hook-up	5		0.4	0.6					
Contamination + Well Integrity Project (NFA)			0.1	0.3	0.3	0.3			
Total (US$MM)		**7.3**	**39.4**	**21.2**	**0.3**	**0.3**			

Table AIII.7: CAPEX Breakdown for AESW (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Karam Gas Well	14		36.0	48.0	28.0				
Vertical Well	41	12.0	6.0	13.5	19.4	10.5			
Injector	11			3.9	3.9	2.9			
Gas Well Hook-up	21	2.4	4.8	7.3	6.1				
Oil Well Hook-up	16	2.4	1.6	3.7	4.9	2.9			
Injector Hook-up	11			0.8	0.8	0.6			
Bahga Electrification Project (NFA)		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Baraq Electrification Project (NFA)		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Contamination + Well Integrity Project (NFA)			0.1	0.1	0.1	0.1			
AESW Electrification Project (NFA)						1.6	2.4	2.4	1.6
Barq Evaporation Pond Project (NFA)			0.5						
Barq-Sitra Water Pumps & Line Project (NFA)				1.0					
Bahga Evaporation Pond Project (NFA)			1.4						
Gas Debottlenecking Project (Infill)			1.5	1.5					
AESW Electrification Project (Infill)						0.6	0.9	0.9	0.6
Assil G/L Separator Project (Infill)				0.6					
Barq Leased Separator Project (Infill)						0.5			
Barq Export Line BED3 Looping Project (Infill)					1.4				
Barq G/L Separator Project (Infill)				0.6					
Bahga Separator G/L/FWKO Project (Infill)				1.7					
Bahga Leased Separator Project (Infill)				0.5					
Bahga Water Disposal Project (Infill)					2.6				
Total (US$MM)		**17.4**	**52.5**	**83.6**	**67.7**	**20.2**	**3.8**	**3.8**	**2.8**

Table AIII.8: CAPEX Breakdown for NAES (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	2					12.0			
Injector									
Gas Well Hook-up	2					2.4			
Total (US$MM)						**14.4**			

Table AIII.9: CAPEX Breakdown for NEAG-Ext (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	15			20.9	1.5				
Injector	6			2.9	2.9				
Oil Well Hook-up	15			5.7	0.4				
Injector Hook-up	6			0.6	0.6				
Accelerated WD Project (NFA)		0.8							
NEAG2 Electrification Project (NFA)			0.8	0.8					
Contamination + Well Integrity Project (NFA)			0.2	1.7	1.7	0.7	0.7		
Asset Integrity Project (NFA)			0.8	1.3	1.4	0.5			
NEAG1 WD Ph3 + NEAG2 WD Project (Infill)					0.6	0.6			
Total (US$MM)		**0.8**	**1.7**	**33.9**	**9.1**	**1.8**	**0.7**		

Table AIII.10: CAPEX Breakdown for NEAG-Tiba (US$ MM)

	Number	2020	2021	2022	2023	2024	2025	2026	2027
Vertical Well	6		9.5			4.8			
Horizontal Well	9	7.4	3.7		11.1	11.1			
Injector	8		1.0		1.9	4.8			
Oil Well Hook-up	15	0.8	2.0		1.2	2.0			
Injector Hook-up	8		0.2		0.4	1.0			
JG WD Ph2 + spare WD well Project (NFA)			1.7	1.7					
Additional Water Source Wells Project (NFA)			1.0	1.0					
JG Electrification Project (NFA)			0.4	0.4	0.4	0.4	0.4		
Contamination + Well Integrity Project (NFA)			0.1	0.7	1.7	1.7	0.7		
JG Electrification Project (Infill)			0.4	0.4	0.4	0.4	0.4		
Total (US$MM)		**8.2**	**17.2**	**4.1**	**19.7**	**26.1**	**1.4**		

Appendix IV
Reserves and NPVs as at 31st December 2020

As mentioned in the Introduction, given the time that has elapsed since the Effective Date of the estimates of Reserves and NPVs presented in the CPR, to meet the requirements of the FCA, GaffneyCline has included tables showing the Reserves that would remain as at 31st December 2020 and the corresponding NPVs at that date. For this purpose, GaffneyCline has only considered the cash flows after December 31st 2020, but has not made any other adjustment to the forecasts made for the Reserves cases as at 31st December 2019. This is considered a reasonable assumption given that actual production from January to December 2020 has been comparable, in the aggregate, with GaffneyCline's estimates made as at 31st December 2019.

An updated Brent crude oil price scenario has been used for the economic limit, NPV and entitlement calculations, namely GaffneyCline's own 1Q 2021 Brent Crude oil price scenario shown in Table AIV.1.

Table AIV.1: 1Q 2021 Brent Crude Oil Price Scenario

Year	Price (US$/Bbl)
2021	51.38
2022	54.00
2023	57.00
2024	60.00
2025+	+2% per annum

Resulting Reserves volumes are shown in Table AIV.2 and NPVs in Table AIV.3.

Since 31st December 2020, GaffneyCline has reviewed information regarding the performance of the Assets in 2020, and compared forecasts (including production and costs) against those set out in the CPR. GaffneyCline notes the deferral in the implementation of the drilling schedule planned by the Consortium. Based on the information available, GaffneyCline expects this deferral to defer some production, particularly in 2021, which could impact the NPVs but is unlikely to have a material impact on the Reserves. Additionally, the reduction in NPVs will be offset by the recovery in oil prices since the beginning of 2021, which makes the scenario shown in Table AIV.1 now appear conservative in the short term. GaffneyCline therefore believes that the Reserves and NPVs as at 31st December 2020 reported herein remain valid in the aggregate.

Table AIV.2: Summary of Reserves[3] as at 31st December 2020

(b) Oil and Condensate

Assets	Gross Field Reserves (MMBbl)			Shell WI (%)	Shell Net Entitlement (MMBbl)			50% Shell Net WI (%)	50% of Shell Net Entitlement (MMBbl)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	15.1	20.2	24.8	100.0	5.8	7.1	8.1	50.0	2.9	3.5	4.0
NUMB	0.1	0.2	0.2	100.0	0.1	0.1	0.1	50.0	0.0	0.0	0.0
NM	5.0	10.0	19.8	100.0	2.0	3.6	5.3	50.0	1.0	1.8	2.7
BED 2	1.0	3.8	6.0	100.0	0.4	1.7	2.4	50.0	0.2	0.8	1.2
BED 3	7.8	12.0	16.9	100.0	3.6	5.5	6.8	50.0	1.8	2.7	3.4
Sitra	0.0	9.9	15.2	100.0	0.0	4.6	6.5	50.0	0.0	2.3	3.2
NAES	0.0	0.0	0.1	100.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0
NEAG Tiba	5.1	7.9	11.7	52.0	1.4	1.8	2.3	26.0	0.7	0.9	1.1
NEAG Ext.	6.0	9.9	15.1	52.0	1.7	2.6	3.6	26.0	0.8	1.3	1.8
AESW	15.1	27.4	42.6	40.0	2.5	4.5	5.7	20.0	1.3	2.3	2.8
Total	**55.2**	**101.3**	**152.2**		**17.4**	**31.3**	**40.7**		**8.7**	**15.7**	**20.4**

(b) Natural Gas

Assets	Gross Field Reserves (Bscf)			Shell WI (%)	Shell Net Entitlement (Bscf)			50% Shell Net WI (%)	50% Shell Net Entitlement (Bscf)		
	Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible		Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	320.1	378.2	435.0	100.0	130.0	140.4	150.2	50.0	65.0	70.2	75.1
NUMB	9.1	9.6	9.9	100.0	4.2	4.4	4.6	50.0	2.1	2.2	2.3
NM	46.4	76.8	128.0	100.0	18.5	27.4	34.7	50.0	9.3	13.7	17.3
BED 2	4.1	33.4	67.0	100.0	1.8	15.1	27.6	50.0	0.9	7.5	13.8
BED 3	36.7	49.6	63.3	100.0	16.9	22.8	25.7	50.0	8.5	11.4	12.9
Sitra	0.0	22.1	31.4	100.0	0.0	10.2	13.5	50.0	0.0	5.1	6.7
NAES	0.0	23.2	35.3	100.0	0.0	10.2	15.5	50.0	0.0	5.1	7.8
NEAG Tiba	12.1	18.3	27.2	52.0	3.3	4.2	5.5	26.0	1.7	2.1	2.8
NEAG Ext.	0.0	0.0	0.0	52.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0
AESW	418.3	547.6	729.5	40.0	68.5	89.4	97.4	20.0	34.3	44.7	48.7
Total	**846.8**	**1,158.8**	**1,526.6**		**243.3**	**324.1**	**374.6**		**121.6**	**162.0**	**187.3**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Shell Net Entitlement Reserves are the net economic entitlement attributable to Shell's interest under the terms of the Contract that governs the asset.
3. Reserves are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

Table AIV.3: Summary of Post-Tax NPV10[2] of Future Cash Flow from Reserves, as at 31st December 2020

Assets	NPV10 Net to Shell's Interest (US$MM)			NPV10 Net to 50% of Shell's Interest (US$MM)		
	Proved	Proved+ Probable	Proved + Probable + Possible	Proved	Proved+ Probable	Proved + Probable + Possible
Obaiyed	216.5	276.0	332.8	108.2	138.0	166.4
NUMB	11.5	12.2	12.7	5.7	6.1	6.4
NM	-6.3	64.5	131.1	-3.2	32.2	65.6
BED 2	4.7	27.3	50.6	2.3	13.6	25.3
BED 3	26.3	119.8	178.3	13.2	59.9	89.1
Sitra	0.0	76.7	161.9	0.0	38.4	81.0
NAES	0.0	3.7	11.4	0.0	1.8	5.7
NEAG Tiba	12.9	29.2	47.7	6.5	14.6	23.9
NEAG Ext	14.0	33.4	57.0	7.0	16.7	28.5
AESW	89.4	188.8	228.1	44.7	94.4	114.1
Total	**368.9**	**831.4**	**1,211.7**	**184.5**	**415.7**	**605.8**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. NPVs are based on production and cost profiles estimated as at 31st December 2019, not on a full update to 31st December 2020.
3. The NPVs herein do not represent GaffneyCline's opinion of the market value of a property or any interest therein.

Appendix V
SPE PRMS Definitions

**Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers**

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

1 These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guideline s
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	**Guidelines**
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	**Guidelines**
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

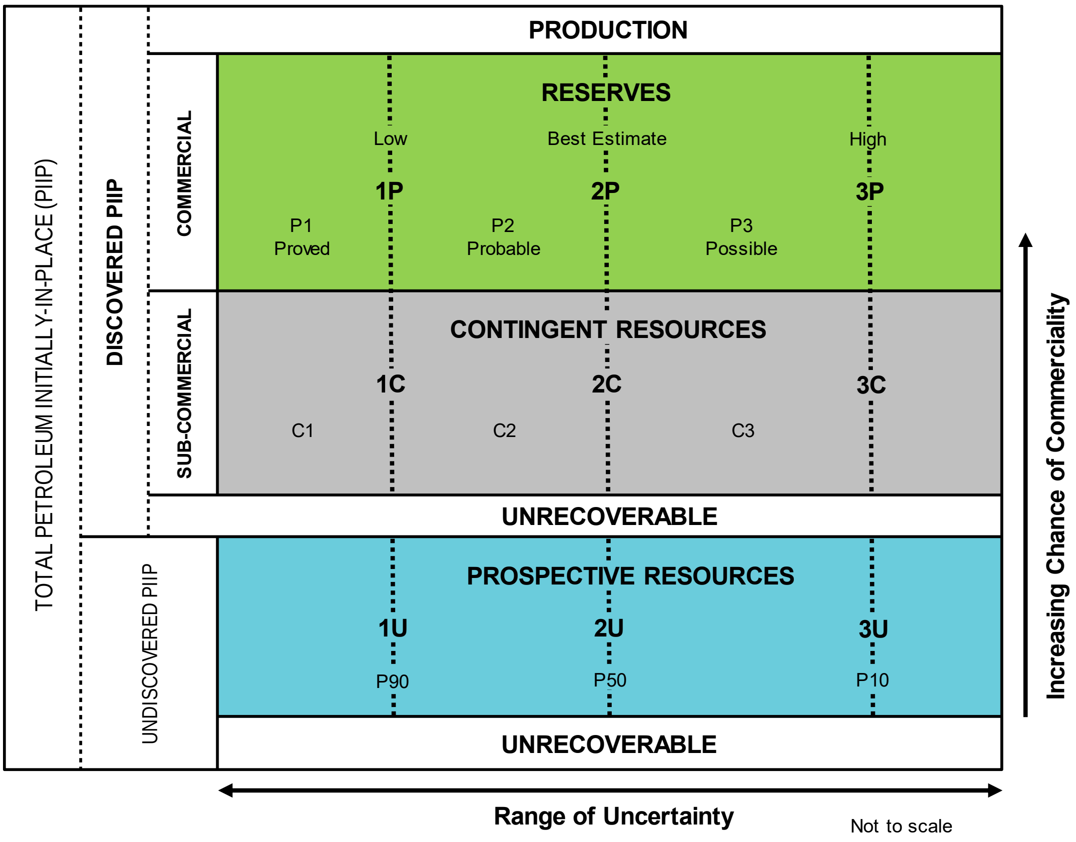
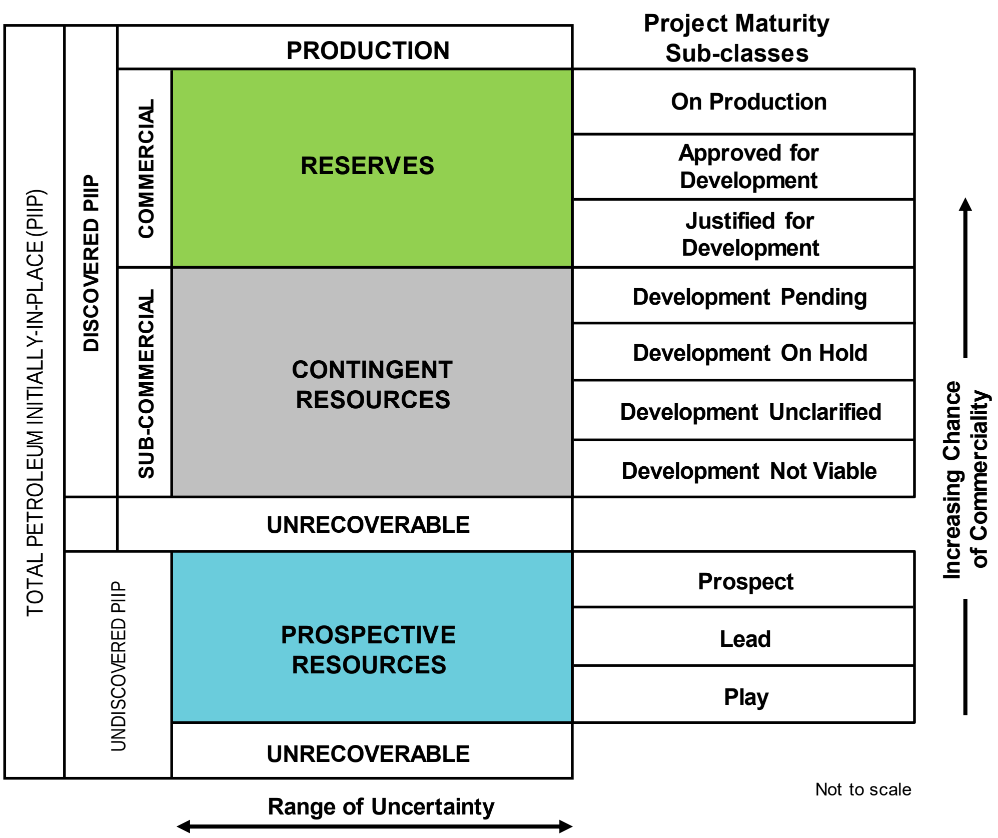


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



PART VII

ADDITIONAL INFORMATION

1. Responsibility

The Company and the Directors, whose names are set out in paragraph 3 of this Part VII below, accept responsibility for the information contained in this Circular. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this Circular is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. Cairn

The Company was incorporated and registered in Scotland on 7 January 2002 as a private company limited by shares with registered number SC226712 with the name of "Randotte (No. 507) Limited". On 5 December 2002 the Company was re-registered as a public limited company and changed its name to "New Cairn Energy PLC". The Company changed its registered name to "Cairn Energy PLC" on 19 February 2003.

The principal legislation under which the Company was formed and under which the Company operates is the Companies Act 1985 and the Companies Act 2006 respectively. The Company is domiciled in the United Kingdom.

The registered office of the Company is 50 Lothian Road, Edinburgh EH3 9BY and its telephone number is +44 (0)131 475 3000. The Company is the ultimate holding company of the Group, and its principal activity is the extraction of crude petroleum.

Capricorn Egypt was incorporated in England and Wales on 3 July 2020 as a private company limited by shares with registered number 12716481. The registered office of Capricorn Egypt is Wellington House 4th Floor, 125 The Strand, London WC2R 0AP and the principal legislation under which Capricorn Egypt was formed and under which it operates is the Companies Act 2006.

3. Directors and senior management

The names and principal functions of the Directors and the Company's senior management are as follows:

Directors	Position
Nicoletta Giadrossi	Non-Executive Chair
Keith Lough	Non-Executive Director
Peter Kallos	Non-Executive Director
Alison Wood	Non-Executive Director
Cathy Krajicek	Non-Executive Director
Erik Daugbjerg	Non-Executive Director
Simon Thomson	Chief Executive
James Smith	Chief Financial Officer

4. Directors' and senior management's shareholdings and stock options

4.1 Save as set out below, none of the Directors or other persons discharging managerial responsibilities ("**PDMRs**") has any interest in the share capital of the Company or any of its subsidiary undertakings.

4.2 The interests (all of which are beneficial) of the Directors, of their respective immediate families and (so far as is known or could with reasonable diligence be ascertained by the relevant Director) of any person connected with a Director in the share capital of the Company as at the Latest Practicable Date are as follows:

Director	Number of Shares	Percentage of issued ordinary share capital*
Nicoletta Giadrossi	0	0.000%
Keith Lough	0	0.000%
Peter Kallos	9,292	0.002%
Alison Wood	0	0.000%
Cathy Krajicek	0	0.000%
Erik Daugbjerg	0	0.000%
Simon Thomson(3)	1,150,319	0.230%
James Smith(3)	471,158	0.094%

* (rounded to the nearest third decimal place)

Notes:

(1) The table set out above assumes no dealings by the Directors or their connected persons and that no further Shares are issued, whether pursuant to the exercise of options or otherwise, in each case after the Latest Practicable Date.

(2) The interests of the Directors in Shares together represent 0.327 per cent. (rounded to the nearest third decimal place) of the issued ordinary share capital of the Company as at the Latest Practicable Date.

(3) The interests of the Executive Directors include Shares awarded to them under the SIP. These awards consist of "partnership shares" purchased using deductions from the relevant Director's salary and also "free shares" and free "matching shares" awarded by the Company. These shares are beneficially owned by the Director from the date of purchase/award and, as a consequence, are included in the numbers of Shares shown above.

4.3 The interests (all of which are beneficial) of the PDMRs (other than the Directors) in the share capital of the Company as at the Latest Practicable Date are as follows:

PDMR	Number of Shares	Percentage of issued ordinary share capital*
Eric Hathon, Director of Exploration(2)	47,496	0.01%
Paul Mayland, Chief Operating Officer(2)	551,464	0.11%

* (rounded to the nearest third decimal place)

Notes:

(1) The table set out above assumes no dealings by the PDMRs or their connected persons and that no further Shares are issued, whether pursuant to the exercise of options or otherwise, in each case after the Latest Practicable Date.

(2) The interests of these PDMRs include Shares awarded to them under the SIP. These awards consist of "partnership shares" purchased using deductions from the relevant PDMR's salary and also "free shares" and free "matching shares" awarded by the Company. These shares are beneficially owned by the PDMR from the date of purchase/award and, as a consequence, are included in the numbers of Shares shown above.

4.4 As at the Latest Practicable Date, the Directors and other PDMRs held the following outstanding rights to acquire Shares under the 2017 LTIP:

	Outstanding awards under the 2017 LTIP (Shares)	
	Unvested Awards still subject to performance conditions	Vested but unexercised Awards(1)
Executive/Director		
Simon Thomson	2,569,262	629,600
James Smith	1,671,063	409,496
PDMR		
Eric Hathon	1,376,551	337,324
Paul Mayland	1,427,817	352,055

(1) This column includes all outstanding Awards that have vested following the expiry of the applicable performance period, regardless of whether or not they are currently capable of being exercised under the rules of the 2017 LTIP.

4.5 As at the Latest Practicable Date the aggregate number of Shares in respect of which options or other rights to subscribe had been granted by the Company was 2,522,518 (representing approximately 0.51 per cent. of the issued ordinary share capital of the Company, excluding shares held in treasury at that date).

5. **Directors' service contracts**

5.1 **Executive directors' service agreements**

On 29 June 2011, Simon Thomson entered into an agreement with Cairn to act as an executive director and Chief Executive with effect from 1 July 2011. On 4 February 2014, James Smith entered into an agreement with Cairn to act as Director of Finance (a non-Board position). He was then appointed as Chief Financial Officer with effect from 15 May 2014.

The service agreements are permanent contracts but can be terminated by either the Director concerned or Cairn on giving 12 months' notice of termination. The service agreements do not specify a retirement age.

Under the service agreements, as amended, the current annual basic salary of Simon Thomson and James Smith is as follows:

Simon Thomson	£586,650
James Smith	£381,561

Salaries are reviewed on an annual basis by the Remuneration Committee. Bonus payments are at the sole discretion of the Remuneration Committee.

Each Executive Director is entitled to a company car up to a maximum value of £70,000 (or, as an alternative, an annual car allowance of up to £8,771), permanent health insurance, private health insurance and death in service benefit of up to 4 times annual basic salary at the date of death.

Each Executive Director is also entitled to be reimbursed for all reasonable out-of-pocket expenses properly incurred in the performance of his or her duties.

The Company operates a defined contribution group personal pension plan in the UK, called the Cairn Oil Group Pension Plan. The scheme is non-contributory and all UK permanent employees are eligible to participate. The Company contributes 15 per cent. in respect of the annual basic salaries of the current Executive Directors.

If an Executive Director's pension arrangements are fully funded or applicable statutory limits are reached, an amount equal to the Company's contribution (or the balance thereof) is paid in the form of additional salary.

On joining the Company, James Smith became a member of the Cairn Oil Group Pension Plan.

Simon Thomson's pension arrangements are fully funded. As a result, he receives an amount equal to 15 per cent. of his annual basic salary as additional salary.

The service agreements do not provide for any commission or profit-sharing arrangements.

On a change of control of the Company resulting in the termination of his employment, the current Chief Executive is entitled to compensation of a sum equal to his annual basic salary as at the date of termination of employment. The Board recognises that this provision is no longer in accordance with best practice. It was not included in the contract of the new Chief Financial Officer, and will not be included in the contracts of other future appointees to the Board; however, it continues to apply to the current Chief Executive.

Each Executive Director is subject to post-termination obligations for a period of 6 months from the date of termination of employment. The obligations relate to non-competition, non-soliciting of clients or employees, and non-interference with the existing suppliers of the Company.

5.2 **Non-executive directors' letters of appointment**

Letters of appointment have been entered into between the Company and each of the Non- Executive Directors, which set out their respective responsibilities. Those letters of appointment do not provide for any period of notice. Under the Articles of Association (and consistent with the UK Corporate Governance Code), at each AGM every director must retire and offer themselves for re-election. The following table sets out the date of appointment or last reappointment of each Non-Executive Director. No compensation is payable to any Non- Executive Director who retires at an AGM and is not re-elected or whose appointment is otherwise terminated by the Company. In addition to an annual fee, each Non-Executive Director is also entitled to be reimbursed for all reasonable out-of-pocket expenses properly incurred in the performance of his or her duties.

Director	Date of appointment or of last reappointment	Annual fee
Nicoletta Giadrossi	11 May 2021	£180,000
Keith Lough	11 May 2021	£ 85,500[(1)]
Peter Kallos	11 May 2021	£ 75,500
Alison Wood	11 May 2021	£ 85,500[(2)]
Cathy Krajicek	11 May 2021	£ 75,500
Erik Daugbjerg	11 May 2021	£ 75,500

Notes:

(1) Keith Lough is also entitled to an additional annual fee of £10,000 for chairing the Audit Committee.

(2) Alison Wood is also entitled to an additional annual fee of £10,000 for chairing the Remuneration Committee.

Save as disclosed in paragraphs 5.1 and 5.2 of this Part VII above, there are no existing or proposed service contracts or letters of appointment between any Director and any member of the Group.

6. Major Shareholders

6.1 Other than the interests of the Directors and members of the senior management disclosed in paragraph 5 of this Part VII, as at the Latest Practicable Date the Company had been notified of the following holdings in the Company's issued ordinary share capital pursuant to DTR 5 (each, a "**Notifiable Interest**"):

Shareholder	Number of Shares	Percentage of voting rights attached to the Shares as at the Latest Practicable Date[(1)]
MFS Investment Management	71,280,167	14.28
BlackRock	57,442,773	11.51
Standard Life Aberdeen	31,274,340	6.26
Vanguard Group	23,060,964	4.62
Franklin Templeton Investments	15,379,377	3.08
Aegon Asset Management UK	15,204,041	3.05

Notes:

(1) Calculated by reference to the issued share capital of the Company as at the Latest Practicable Date.

6.2 Save as set out above, the Company is not aware of any other Notifiable Interests.

7. Related party transactions

7.1 Save as set out below, no related party transactions have been entered into by members of the Group between 1 January 2018 and the Latest Practicable Date.

The related party transactions for the purposes of the standards adopted according to Commission Regulation (EC) No. 1606/2002 which the Company entered into during the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020 are included in this Circular through the incorporation by reference of the 2018 Annual Report and Accounts, the 2019 Annual Report and Accounts and the 2020 Annual Report and Accounts.

The information incorporated by reference for the period ended 31 December 2020 can be found on pages 94 to 121 (inclusive) and in note 8.8 on page 187 of the 2020 Annual Report and Accounts.

The information incorporated by reference for the period ended 31 December 2019 can be found on pages 94 to 123 (inclusive) and in note 8.7 on page 192 of the 2019 Annual Report and Accounts.

The information incorporated by reference for the period ended 31 December 2018 can be found on pages 87 to 113 (inclusive) and in note 7.9 on page 177 of the 2018 Annual Report and Accounts.

7.2 The Company entered the following related party transactions for the purposes of the standards adopted according to Commission Regulation (EC) No. 1606/2002 during the period from 1 January 2021 to the Latest Practicable Date:

(a) **Remuneration of key management personnel**

The remuneration of the Directors, who are the key management personnel of the Company, is set out below in aggregate:

	US$m
Short-term employee benefits	1.8
Pension contributions	—
Share-based payments	1.8
	3.6

(b) **Subsidiary Undertakings**

The following table provides the total amount of transactions which have been entered into by the Company with its subsidiary undertakings:

	US$m
Transactions during the period	
Amounts invoiced to subsidiaries	5.7
Amounts invoiced from subsidiaries	(2.7)
Finance income – dividends received	—

	US$m
Balances as at the Latest Practicable Date	
Amounts owed by subsidiary undertakings	—
Amounts owed to subsidiary undertakings	—

8. **Material contracts**

8.1 **The Group**

Other than the contracts set out below and the Sale and Purchase Agreement (the principal terms of which are summarised in Part III (*Principal Terms of the Sale and Purchase Agreement)* of this Circular), no member of the Group has entered into any contracts (not being contracts entered into in the ordinary course of business) either: (i) within the two years immediately preceding the publication of this Circular which are, or may be, material to the Group; or (ii) which contain any provision under which any member of the Group has any obligation or entitlement which is, or may be, material to the Group as at the date of this Circular.

(a) In December 2018, Cairn completed the extension of the maturity of the Group's US$575 million reserves based lending facility provided by BNP Paribas, DNB (UK) Limited, HSBC UK Bank PLC, Nedbank Limited London Branch, Société Générale London Branch and Standard Charter Bank to 2025, increasing the borrowing base to include the Nova development in Norway. Though the terms of the extended facility are consistent with that of the original, under IFRS 9 the extension is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability due to the extended period over which the facility is available. As at 31 December 2020, the Group had US$575 million undrawn in its reserves-based lending facility.

(b) On 5 August 2019 Cairn Norge, the Norwegian-incorporated wholly-owned subsidiary of Cairn holding all of the Group's oil and gas assets located in Norway, entered into a farm-out agreement (the "**Nova Farm-Out Agreement**") with ONE-Dyas Norge AS to sell a 10 per cent. participating interest in Norwegian Petroleum Licence (PL) 418 and 418B (incorporating the Nova development offshore Norway for which first oil is targeted in 2021) and a 12.12 per cent. participating interest in Norwegian PL 378. Under the Nova Farm-Out Agreement, Cairn Norge received a post-tax amount of US$59,500,000 at Completion, together with interest accruing from the effective economic date of the transaction of 1 January 2019 and subject to a customary interim period adjustment in relation to costs incurred from the effective economic date.

Completion under the Nova Farm-Out Agreement occurred in Q4 2019. Completion was conditional on, amongst other things: the consent of the Norwegian Ministry of Petroleum and Energy ("**MPE**"); submission of the required notification of the transaction to the Norwegian Ministry of Finance

("**MoF**"); the non-exercise of applicable pre-emption rights relating to the participating interests proposed to be transferred; and JV approval by the PL 378, PL 418 and PL 418B management committees, if required under the relevant joint operating agreements.

Cairn Norge also agreed under the Nova Farm-Out Agreement to:

(i) certain undertakings and obligations in relation to the conduct of the business relating to PL 378, PL 418 and PL 418B between signing and completion; and

(ii) certain representations, warranties and indemnities customary for a transaction of its type.

The Nova Farm-Out Agreement is governed by Norwegian law, with the District Court of Stavanger having jurisdiction under the Norwegian Arbitration Act (Act No. 25/2004) over any controversy or dispute that may arise in connection with or as a result of the Nova Farm-Out Agreement and which cannot be resolved by mutual agreement.

(c) On 26 November 2019, Capricorn Energy Limited, a member of the Group, entered into a share sale and purchase agreement (the "**Norge SPA**") with Solveig Gas Norway AS ("**Solveig**") in respect of the sale of the entire issued share capital of Capricorn Norge AS. Under the Norge SPA, Capricorn Energy Limited will receive a cash consideration of US$100 million at completion, on a cash free/ debt free basis at a financial effective date of 1 January 2020, subject to a net debt and working capital adjustment. In addition, interest accrued on the consideration payable under the Norge SPA from 1 January 2020 until completion, calculated on the basis of the average of three month LIBOR (in relation to US$ payments) or three month NIBOR (in relation to NOK payments).

Completion under the Norge SPA occurred in February 2020. Completion was conditional upon, amongst other things, approval of the transaction by the MPE, submission of the required notification of the transaction to the MoF and completion under the Nova Farm-Out Agreement referred to in paragraph 8.1(b) above. If completion under the Norge SPA did not occur by 1 July 2020 (or such later date as the parties agreed) either party was entitled to terminate the Norge SPA by written notice to the other. Capricorn Energy Limited also agreed under the Norge SPA to:

(i) certain undertakings and obligations in relation to the conduct of the business of Capricorn Norge AS between signing and completion;

(ii) a "locked box" indemnity in relation to leakage before completion (meaning certain payments or other obligations made, authorised or agreed to be made by Capricorn Norge AS between 31 December 2019 and completion, unless identified in the Norge SPA as permitted leakage);

(iii) certain representations, warranties and indemnities customary for a transaction of its type.

The Norge SPA is governed by, and construed in accordance with, Norwegian law, with the Norwegian courts having jurisdiction over any dispute, controversy or claim arising out of or in connection with the Norge SPA.

(d) On 4 September 2020 a sale and purchase agreement was entered into by and between Capricorn Senegal, Woodside Energy (Senegal) B.V. ("**Woodside**") and Cairn (the "**Senegal SPA**"), pursuant to which Capricorn Senegal conditionally agreed to sell to Woodside Capricorn Senegal's undivided legal and beneficial interest in the RSSD PSC and a corresponding proportion of the legal and beneficial right, title and interest in and under the RSSD JOA (the "**Senegal Sale Interest**") on the following key terms:

(i) the Group received base consideration of US$300 million in cash at completion for the Senegal Sale Interest, together with an interim period adjustment for expenditure related to the Senegal Sale Interest from the economic date of 1 January 2020;

(ii) in addition, after completion the Group may become entitled to an additional payment from Woodside depending on the timing of first oil from Sangomar development and the Average Brent Price during the 180 days after first oil. If first oil, as defined in the Senegal SPA, occurs:

(A) on or before 31 December 2023 Woodside will pay in cash to the Group:

(1) US$100 million if the Average Brent Price during the 180 days after First Oil is above US$60 per barrel; or

(2) US$50 million if the Average Brent Price during the 180 days after First Oil is above US$55 per barrel but less than or equal to US$60 per barrel; or

(B) in the first half of 2024 Woodside will pay in cash to the Group:

(1) US$50 million if the Average Brent Price during the 180 days after First Oil is above $60 per barrel; or

(2) US$25 million if the Average Brent Price during the 180 days after First Oil is above US$55 per barrel but less than or equal to US$60 per barrel.

In either case, no additional payment will be due from Woodside if the Average Brent Price during the 180 days after First Oil is less than or equal to US$55 per barrel.

Capricorn Senegal gave certain customary warranties in connection with the disposal of the Senegal Sale Interest. The Senegal SPA is governed by English law and completion took place on 17 December 2020.

(e) On 17 January 2020 Cairn and Cheiron Energy entered into a joint bidding agreement (as partially novated and amended pursuant to a novation and amendment agreement dated 28 January 2020 among (1) Cheiron Holdings Egypt Limited, (2) Pharos Energy Plc (not part of the Consortium), and (3) Capricorn Energy Limited) pursuant to which Cairn and Cheiron Energy formed the Consortium to bid to acquire the Assets (the "**JBA**"). The JBA governed the parties' relationship with respect to the submission of a binding offer and the negotiation thereof until signature of the SPA. Pursuant to the terms of the JBA, each of Cairn and Cheiron will acquire 50 per cent. of the Sellers' interests in the Concessions (and any related agreements) and the relevant operating company. The JBA terminated following signature of the SPA.

(f) On 8 March 2021, Capricorn Egypt, Capricorn Oil Limited and the Cheiron Energy Purchasers entered into a Joint Management Agreement (the **"JMA")** in connection with the Transaction. The JMA regulates the relationship between the Consortium members, including in relation to governance (including voting rights and decision-making power), day-to-day operational matters (including financial, operational and HSE decisions in respect of each of the Concessions) and other financial management matters required in respect of the Acquisition RBL Facility (including balancing and true-up mechanisms). The JMA includes cross-indemnification provisions in respect of any liability borne by a Party in excess of their 50 per cent. interest which is included pursuant to the SPA or the Acquisition RBL Facility. The JMA also includes provisions for the resolution of any deadlock in a form that is customary for this type of agreement. The JMA will terminate if: (a) a completion of the SPA does not occur; (b) where only one party holds 100 per cent. of the participating interests and shares in all operating companies originally held by the two parties; or (c) if agreed by both parties in writing. Pursuant to the JMA, the Consortium undertake to enter into joint operating agreements at Completion (the **"Egyptian Assets JOA"),** which will govern the relationship between the Consortium members at Concession level. The Egyptian Assets JOA shall be based on AIPN standard model, subject to certain amendments as agreed between the parties. The Egyptian Assets JOA will set out, amongst other things, that: (a) party will have equal representation on the operating committee, which will be chaired by the operator (no casting vote); (b) Cheiron to be appointed as operator of the producing Concessions and Capricorn Egypt will be operator of the exploration Concessions; and (c) all voting decisions require unanimity. The Egyptian Assets JOA will also include standard default provisions and pre-emption rights in respect of exploration assets.

(g) On 24 June 2021 Capricorn Egypt and Cheiron Oil & Gas (in capacity as original borrowers (the "**Borrowers**") and as original guarantors) entered into the Acquisition RBL Facility with, among others, Societe Generale, London Branch, Arab Petroleum Investments Corporation (APICORP) – Bahrain Banking Branch, Mashreqbank psc, Nedbank Limited, London Branch, Africa Export-Import Bank, Deutsche Bank AG, Amsterdam Branch, The Mauritius Commercial Bank Limited, BP Oil International Ltd and Trafigura Ventures V B.V. (together, the "**Acquisition RBL Lenders**") as initial lenders, Societe Generale, London Branch as facility agent, security agent, account bank, technical bank and modelling bank.

The Acquisition RBL Facility is divided into two separate tranches, pursuant to which the Acquisition RBL Lenders make available up to US$162.5 million to Capricorn Egypt and up to US$162.5 million available to Cheiron Oil & Gas.

The facility amount available to the Borrowers will reduce on a semi-annual basis (in accordance with the terms of a reduction schedule) following the first reduction date falling on 12 months after the Closing Date. The Acquisition RBL Facility also has an accordion mechanism that will allow each Borrower to borrow across each tranche up to US$200 million in aggregate (subject to the reduction mechanism described above). The accordion can only be utilised three times and has to be used within three years of entry into this facility agreement. The reduction schedule will be increased by the accordion commitments and reduced in line with the existing amortization schedule.

The Borrowers may request the addition of other oil and gas producing assets at a later stage subject to approval of majority lenders and customary conditions precedent, including approval of an updated projection. For any asset to be added as a borrowing base asset that is located outside of Egypt, the affirmative consent of at least 80 per cent. of the Acquisition RBL Lenders shall be required.

The Acquisition RBL Facility is secured by way of first priority security over the shares and assets (including offtake contracts, shareholder loans, bank accounts, intercompany loans, the petroleum lease and joint operating agreements and hedging agreements) of the Borrowers. The Borrowers' obligations are guaranteed on a joint and several basis by the original guarantors listed above.

The Acquisition RBL Facility is to be applied for the following purposes: (i) partial payment of the target Assets purchase price; (ii) payment of any ongoing capital and operating expenditures in respect of the borrowing base assets; (iii) payment of any finance costs under the RBL Facility; (iv) refinancing maturing loans under the Acquisition RBL Facility by way of rollover loans; and (v) for other lawful general corporate purposes.

The Acquisition RBL Facility matures on the earliest to occur of (a) the Reserve Tail Date, (b) the date falling five years from the date the Closing Date, being the date on which all conditions to first utilisation are satisfied and all of the conditions under the SPA are satisfied; (c) if the acquisition of certain specified Assets does not complete on or before the Cut-Off Date, the Cut-Off Date; or (d) if the Sale and Purchase Agreement terminates before the completion of the acquisition of certain specified Assets, the date of such termination. The Acquisition 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 Borrowers must deliver utilisation requests simultaneously and for an equal amount under each tranche. The Acquisition RBL Facility is structured as a revolving facility with one, three or six month repayment periods and with the facility amortising over the five year period. The availability of the Acquisition RBL Facility is subject to satisfaction of certain conditions which are expect to be satisfied around the time of Completion.

The Acquisition RBL Facility contains customary representations, undertakings, covenants and events of default with appropriate carve-outs and materiality thresholds, where relevant. The financial covenant is a liquidity test looking at the corporate cashflow projection for each Borrower (and its subsidiaries) on a twelve month look-forward basis to be submitted on each liquidity test date (being 30 June and 30 December each year; upon the adoption of each banking case; and the date on which an obligor acquires an interest in a petroleum asset). However, if any borrowing base asset is a development asset and contributes an amount equal to or greater than 40 per cent. of the borrowing base amount, the liquidity test shall extend beyond such twelve month period until the scheduled completion date of that development asset.

The Acquisition RBL Facility may be prepaid without premium or penalty but subject to breakage costs (if any) and accrued interest. Any voluntary prepayment must be in a minimum amount of US$5 million and only with at least three Business Days' notice. The Acquisition 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 claim from a lender in respect of increased costs, tax-gross up and tax indemnity; a change in the nominated operator; and a change of control of either Cairn or Cheiron. Any prepayment or cancellation of a tranche shall be made *pro rata* across each of the tranches.

The interest rate charged on the loans made under the Acquisition RBL Facility will be equal to the aggregate of the applicable margin and LIBOR (and if that rate is negative, LIBOR shall be deemed to be zero).

Certain fees are payable to the finance parties in connection with the Acquisition RBL Facility, such as upfront fees, commitment fees and ticking fees. The Acquisition RBL Facility is governed by English law.

(h) On 24 June 2021 Capricorn Egypt and Cheiron Energy (in capacity as borrowers (the **"Borrowers"**) and as joint and several guarantors) entered into a US$80 million subordinated term loan facility agreement (the **"Junior Debt Facility"**) with, among others, Deutsche Bank AG, Amsterdam Branch and Trafigura Ventures V B.V as lenders (the **"Junior Debt Lenders"**) and Deutsche Bank Luxembourg S.A. as junior agent and Societe Generale, London Branch as security agent, for the acquisition by the Borrowers of certain assets in the Western Desert in Egypt held by Shell Egypt and Shell Austria.

Each Junior Debt Lender makes available US$40 million to the Borrowers. The maximum available amount is the lower of: US$80 million and the borrowing base amount. The facility amount available to the Borrowers will reduce on an annual basis (in accordance with the terms of a reduction schedule and subject to cash sweep requirements) following a grace period of four years (subject to being limited by available distributions) from financial close. The facility is to be applied: (i) towards payment of the fees, costs and expenses associated with the intended acquisition; and (ii) to other agreed general corporate purposes.

The Junior Debt Facility is secured by way of a second ranking pledge over the security package pledged in favour of the Acquisition RBL Lenders. The Junior Debt Facility matures on the date falling seven years after financial close. The availability of the facility is subject to satisfaction of certain conditions which are expected to be satisfied at financial close.

The Junior Debt Facility contains customary representations, undertakings, covenants and events of default, substantially in line with the Acquisition RBL Facility. However, non- compliance by the Borrowers with its subordinated debt covenants triggers an immediate cash sweep of all cash flows available for distribution after the Acquisition RBL Facility debt amortization, rather than being an event of default.

The mandatory, voluntary prepayment and cancellation provisions are also customary for such transactions, including provisions in respect of illegality, breach of sanctions, change of control, increased costs, tax gross up and tax indemnity. If the Borrowers make a voluntary prepayment during the first three years of the Junior Debt Facility, the Borrowers shall pay a prepayment fee on such prepayment equal to: (i) 3% of the outstanding principal being prepaid if such prepayment occurs prior to the date of first anniversary of the Junior Debt Facility; (ii) on and from the first anniversary of the Junior Debt Facility, 2% of the outstanding principal being prepaid if such prepayment occurs prior to the date of the second anniversary of the Junior Debt Facility; and (iii) on and from the second anniversary of the Junior Debt Facility, 1% of the outstanding principal being prepaid if such prepayment occurs prior to the date of the third anniversary of the Junior Debt Facility. On and from the third anniversary, no prepayment fee shall be payable.

The interest rate charged is equal to the applicable margin and LIBOR (and if that rate is negative, LIBOR shall be deemed to be zero). The Borrowers have the option at the end of each semi-annual period to capitalize interest. The Borrowers are also required to pay an upfront fee to the Lenders.

The Junior Debt Facility is governed by the laws of England and Wales.

(i) On 11 March 2021, Nautical Petroleum and Capricorn North Sea entered into a hive down agreement, pursuant to which Nautical Petroleum agreed to transfer the Catcher/Kraken Interests to Capricorn North Sea (the "**Catcher/Kraken Hive Down Agreement**"). Completion under the Catcher/Kraken Hive Down Agreement is conditional upon the satisfaction or, where applicable, waiver of the following conditions:

  (i) the amendment of certain guarantees given by the Group in favour of the Oil and Gas Authority, the Kraken FPSO owner, the Catcher FPSO owner and Enquest Heather Limited, Enquest ENS Limited and First Oil and Gas Limited to guarantee the performance of Target;

  (ii) all necessary consents, approvals or waivers to the Catcher/Kraken Hive Down having been obtained from the parties to the documents entered by Nautical Petroleum in relation to the Catcher/Kraken Interests (including the other holders of the Kraken Licence and Catcher Licences and the Kraken and Catcher FPSO owners) having been obtained and such parties having entered into assignment or novation agreements in respect of those documents; and

  (iii) the consent of the Oil and Gas Authority to the transfer of the Catcher/Kraken Interests to Capricorn North Sea being obtained.

The consideration payable by Capricorn North Sea to Nautical Petroleum for the Catcher/Kraken Interests under the Catcher/Kraken SPA is US$460 million, which will be left outstanding as an intra-group loan repayable by Capricorn North Sea to Nautical Petroleum. Both parties have given warranties to the other in connection with the capacity of the parties to enter into the Catcher/Kraken Hive Down Agreement. These warranties will be repeated on the date of completion of the Catcher/Kraken Hive Down Agreement. The Catcher/Kraken Hive Down Agreement is governed by the law of England and Wales and the parties have irrevocably submitted to the exclusive jurisdiction of the English courts.

(i) Nautical Petroleum and Waldorf entered into a put and call option agreement on 8 March 2021 (the "**Put and Call Option Agreement**"), pursuant to which Nautical Petroleum has agreed to grant Waldorf the right to require Nautical Petroleum to enter into the Catcher/Kraken SPA (the "**Call Option**") and Waldorf has agreed to grant Nautical Petroleum the right to require Waldorf to enter into the Catcher/Kraken SPA (the "**Put Option**"). The exercise of the Put Option and Call Option is conditional upon the satisfaction or, where applicable, waiver of the following conditions:

(i) no material adverse change having occurred;

(ii) execution of the Catcher/Kraken Hive Down Agreement;

(iii) satisfaction of the conditions precedent contained in the Catcher/Kraken Hive Down Agreement; and

(iv) completion of the Catcher/Kraken Hive Down.

If any of the conditions have not been satisfied or, where applicable, waived on or before a long stop date of 29 October 2021 (or such later time as may be agreed between Nautical Petroleum and Waldorf), either party may terminate the Put and Call Option Agreement.

The Call Option is exercisable by Waldorf in the period of five business days following the satisfaction or, where applicable, waiver of the conditions set out above. If the Call Option is not exercised by Waldorf during the period, the Put Option is exercisable by Nautical Petroleum in the period of ten business days following the expiry of the period in which the Call Option is exercisable. Both parties have given warranties to the other in connection with title to the shares in Capricorn North Sea and the capacity of the parties to enter into the Put and Call Agreement. These warranties will be repeated on the date of completion of the Put and Call Option Agreement. The Put and Call Option Agreement is governed by the law of England and Wales and the parties have irrevocably submitted to the exclusive jurisdiction of the English courts.

(k) Nautical Petroleum and Waldorf will enter into the Catcher/Kraken SPA following exercise of the Put Option or the Call Option. Completion under the Catcher/Kraken SPA is conditional upon the satisfaction or, where applicable, waiver of the following conditions:

(i) the release of certain members of the Group from certain guarantees in favour the Oil and Gas Authority, Kraken FPSO owner, Catcher FPSO owner and Enquest Heather Limited, Enquest ENS Limited and First Oil and Gas Limited;

(ii) the unconditional and irrevocable release of the Catcher/Kraken Interests from the security interests over the Catcher/Kraken Interests in favour of DNB Bank ASA;

(iii) the completion of the Catcher/Kraken Hive Down;

(iv) no material adverse change having occurred;

(v) all necessary third party consents, approvals and waivers (including from the Catcher FPSO owner and the Kraken FPSO owner) having been obtained on terms reasonably acceptable to Nautical Petroleum and Waldorf;

(vi) the Oil and Gas Authority having confirmed that it does not intend to exercise its power to revoke or recommend the revocation of, any petroleum licences included in the Catcher/Kraken Interests, or to recommend a further change of control in respect of, any such petroleum licence; and

(vii) the Shareholders passing the appropriate resolution at a general meeting of the Company or, if required in certain circumstances, separate approval by Shareholders in relation to the completion of the transaction following exercise of the Put Option.

Nautical Petroleum and Waldorf have each undertaken to use reasonable endeavours to obtain fulfilment of the conditions set out above are satisfied as soon as practicable. If any of the conditions have not been satisfied or, where applicable, waived on or before a long stop date of 31 December 2021 (or such later time as may be agreed between Nautical Petroleum and Waldorf), either party may terminate the Catcher/Kraken SPA. The firm cash consideration of US$460 million will be payable by Waldorf to Nautical Petroleum, to be adjusted for interim period and working capital cashflows from the economic date of 1 January 2020. US$425 million of the US$460 million firm consideration will be payable in cash. The balance of US$35 million will be payable (together with interest thereon at 3 per cent per annum above the base rate of the Bank of England) out of

Waldorf's excess cash flow, not later than 48 months after completion of the transaction under the terms of the Catcher/Kraken Deferred Consideration Agreement (see below).

Both parties have given customary warranties to the other in connection with the transaction contemplated under the Catcher/Kraken SPA. Nautical Petroleum's liability under the warranties given by it under the Catcher/Kraken SPA is subject to certain customary limitations and exclusions. Nautical Petroleum and Waldorf have agreed to work together in good faith to agree a transitional services agreement in respect of the provision of certain services by Nautical Petroleum to Waldorf following completion. The charges for such services will be at cost plus 10 per cent. (plus VAT thereon). The Catcher/Kraken SPA is governed by the law of England and Wales and the parties have irrevocably submitted to the exclusive jurisdiction of the English courts.

(l) Nautical Petroleum and Waldorf will enter into a deferred consideration agreement at completion of the transaction contemplated under the Catcher/Kraken SPA (the "**Catcher/Kraken Deferred Consideration Agreement"),** pursuant to which the Catcher/Kraken Deferred Consideration will be payable. Interest will accrue on the Catcher/Kraken Deferred Consideration which is outstanding at 3 per cent. per annum above the base rate of the Bank of England from time to time. Interest accrued in each quarterly period ending 31 March, 30 June, 30 September and 31 December (a "**Quarterly Period")** will be capitalised and added to the amount of the Catcher/Kraken Deferred Consideration at the end of that Quarterly Period. Waldorf is required to pay Catcher/Kraken Deferred Consideration on the last day of each Quarterly Period. The amount payable on such date is 50% of Waldorf's excess cashflow in respect of the applicable Quarterly Period. Any Catcher/Kraken Deferred Consideration which is outstanding on the date which is 48 months after completion will be payable on that date. The Catcher/Kraken Deferred Consideration Agreement contains customary representations and undertakings from Waldorf in favour of Nautical Petroleum and events of default, the occurrence of which will (subject to certain conditions) permit Nautical Petroleum to accelerate payment of the Catcher/Kraken Deferred Consideration. The Catcher/Kraken Deferred Consideration will be unsecured until the date that Waldorf's senior debt facilities have been repaid. Following that date, Waldorf is required to provide security over the Catcher/Kraken Interests and the shares in Capricorn North Sea for the Catcher/Kraken Deferred Consideration in form and substance reasonably satisfactory to Nautical Petroleum. Such security will rank behind the security provided by Waldorf in respect of its mezzanine facilities. Nautical Petroleum may without notice or demand set off any matured obligation of Waldorf under the Catcher/Kraken Deferred Consideration Agreement against any matured obligation owed by Nautical Petroleum to Waldorf (including any credit balances on Nautical Petroleum's account) regardless of the place of payment, booking branch or currency of the obligation. The Catcher/Kraken Deferred Consideration Agreement is governed by the law of England and Wales and the parties have irrevocably submitted to the exclusive jurisdiction of the English courts.

8.2 The Assets

Other than the contracts set out below and the Sale and Purchase Agreement, no contracts (not being contracts entered into in the ordinary course of business) have been entered into in connection with the Assets either: (i) within the two years immediately preceding the publication of this Circular which are, or may be, material to the Assets; or (ii) which contain any provision under which there is any obligation or entitlement which is, or may be, material to the Assets as at the date of this Circular.

(a) Obaiyed Concession Agreement

The Obaiyed Onshore Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Winning N.V and Shella Austria Aktiengesellschaft on 17 January 1989 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 3 of 1989 (the "**Obaiyed Concession Agreement**"). Following the various assignments and mergers, the Obaiyed Concession Agreement is currently between ARE, EGPC and the Shell Contractors.

Under the Obaiyed Concession Agreement (i) the ARE has granted the Shell Contractors and EGPC exclusive rights to explore for and develop oil and gas in the Obaiyed concession area, and (ii) the Shell Contractors agree to bear all the costs and expenses required in carrying out operation under the Obaiyed Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the Obaiyed Concession Agreement).

The governing law of the Obaiyed 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 the Shell Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The exploration period granted to EGPC and the Shell Contractors under the Obaiyed Concession Agreement for the original Obaiyed concession area which has not been relinquished or converted to a development lease ended in 1997. During the exploration phase EGPC and the Shell Contractors made a commercial gas discovery in the Obaiyed concession area on 2 October 1994 and entered into a development lease details of which are set out in the table below. The terms of development under the Obaiyed Concession Agreement is 20 years from the date of first gas delivery under the gas sales agreement. The Shell Contractors will be granted a successive extension period of 10 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The Obaiyed Concession Agreement provides that the development lease period may not exceed 35 years from the date of the Minister's approval of the relevant development lease.

Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
Obaiyed Development Lease	1 November 1994	23 August 2019	23 August 2029

The Obaiyed 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.

Assignment

The Shell Contractors may not assign any of its rights duties or obligations under the Obaiyed Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government.

Fiscal Terms and Bonuses

Pursuant to the terms of the Obaiyed Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The Shell Contractors are entitled to receive quarterly all costs in respect of all operations under the Obaiyed Concession Agreement out of 30 per cent. of all petroleum produced from all development leases within the Obaiyed concession area. The remaining 70 per cent. in relation to natural gas produced is distributed as follows: (i) 80 per cent. to EGPC; and (ii) 20 per cent. to the Shell Contractors.

The Obaiyed Concession Agreement contains customary bonuses such as production bonuses. Any bonuses payable under the Obaiyed Concession Agreement are not cost recoverable.

Obaiyed Petroleum Company – the Joint Venture Company

Following a commercial discovery all development and production operations are undertaken by a joint venture operating company incorporated by EGPC and the Shell Contractors under the laws of Egypt called the Obaiyed Petroleum Company ("**Opetco**"). Opetco is owned equally by EGPC and the Shell Contractors, with the Shell Contractors holding 50 per cent. of the shares.

The joint venture operating company should carry out the operations as an agent on behalf of each of EGPC and the Shell Contractors. In practice all fields the subject to development lease to which the Shell Contractors have an interest are operated by Bapetco whereby it operates the assets on behalf of the other operating companies, including Opetco. 100 per cent. of the costs of Opetco (incurred through the operations of Bapetco) shall be covered by the Shell Contractors and recoverable as part of the Contractor's petroleum entitlement.

(b) **North Matruh Concession Agreement**

The North Matruh Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 30 October 2013 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 91 of 2013) (the "**NM Concession Agreement**").

Under the NM Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the NM concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the NM Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the NM Concession Agreement).

The governing law of the NM 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the NM Concession Agreement for the NAES concession area was a period of 3 years expiring on 30 October 2016. In May 2015, EGPC extended the initial exploration phase for a period of 15 months and the initial exploration phase accordingly expired on 29 January 2018. In February 2018, EGPC approved the entry into the second exploration phase of 3 years to expire on 29 January 2021. On 26 July 2020 this expiry date was extended by agreement with EGPC to 29 April 2021 and a further 6-month extension was exercised by Shell Egypt on 21 April 2021. The second exploration phase shall now expire on 29 October 2021.

During the exploration phase, one commercial gas discovery has been made which was mutually agreed between EGPC and Shell Egypt on 20 January 2020. Details of the development lease are set out in the table below. The terms of any development under the NM Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The NM Concession Agreement provides that the development lease period may not exceed 35 years from the date of the Minister's approval of the relevant development lease.

Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
North Matruh-1 Development Lease	20 January 2020	20 January 2040	20 January 2045

The NM 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.

Commitments

During the first exploration phase of the NM Concession Agreement, Shell Egypt have the obligations to spend a minimum of US$36,000,000 for exploration and related activities and drill 5 wells and cover 1200km2 3D seismic survey. During the second exploration period of 3 years, Shell Egypt has the obligation to spend US$10 million for exploration and related activities and drill one well. It was agreed in December 2017 that Shell Egypt would carry over two of its commitment wells from the initial exploration phase into the second exploration phase. The remaining commitment is one well which spudded in April 2021. Pursuant to the NM Concession Agreement, Shell Egypt's exploration obligations are backed by a production letter of guarantee for the sum of US$5 million in favour of EGPC. Upon completion of the current commitment well the obligations under the NM Concession Agreement and the guarantee shall be satisfied.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the NM Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the NM Concession Agreement, in which event EGPC will benefit from a pre-emption right under the NM Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or
- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the NM Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the NM Concession Agreement out of 25 per cent. of all petroleum produced from all development leases within the NM concession area. The remaining 75 per cent. is distributed as follows: (i) 80 per cent. to 82 per cent. to EGPC; and (ii) 18 per cent. to 20 per cent. to Shell Egypt calculated based on incremental production.

The NM Concession Agreement contains customary bonuses such as EGPC employees training bonus, an assignment bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the NM Concession Agreement are not cost recoverable.

(c) **North Um Baraka Concession Agreement**

The North Um Baraka Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 29 August 2017 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 199 of 2017) (the "**NUB Concession Agreement**").

Under the NUB Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the NUB concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the NUB Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the NUB Concession Agreement).

The governing law of the NUB 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the NUB Concession Agreement for the NEO concession area is a period of 4 years, with the option for a further 3 year extension by virtue of notice to EGPC. Upon the lapse of the initial 4 year exploration phase, EGPC and Shell Egypt shall relinquish 30 per cent. of the original NUB concession area.

On 19 April 2018, EGPC and Shell Egypt declared a commercial gas discovery. Details of the development lease are set out in the table below. The terms of any development under the NUB Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The NUB Concession Agreement provides that the development lease period may not exceed 30 years from the date of the Minister's approval of the relevant development lease.

Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
North Um Baraka – 1 Development Lease	26 April 2018	26 April 2038	26 April 2043

The NUB 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.

Commitments

During the first exploration phase of the NUB Concession Agreement, Shell Egypt have the following obligations:

- spend a minimum of US$28,000,000 for exploration and related activities; and
- drill 5 wells; and
- cover 50 km2 3D seismic survey.

One commitment well remains outstanding with plans to drill this in 2021.

Pursuant to the NUB Concession Agreement, Shell Egypt's exploration obligations are backed by a production letter of guarantee for the sum of US$28 million in favour of EGPC. The amounts covered by the guarantee reduce quarterly by the amounts spent by the Contractor and approved by EGPC.

During the three-year extension of the exploration phase, there is an obligation to spend US$7,500,000 for exploration and related activities and drill 2 wells.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the NUB Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the NUB Concession Agreement, in which event EGPC will benefit from a pre-emption right under the NUB Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or
- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the NUB Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the NUB Concession Agreement out of 30 per cent. of all petroleum produced from all development leases within the NUB Concession Area. The remaining 70 per cent. is distributed as follows:

- Crude Oil: (i) 77 per cent. to 82 per cent. to EGPC; and (ii) 18 per cent. to 20 per cent. to Shell Egypt, calculated based on incremental production; or
- LPG: (i) 77 per cent. to 86 per cent. to EGPC; and (ii) 14 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production.

The NUB Concession Agreement contains customary bonuses such as EGPC employees training bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the NUB Concession Agreement are not cost recoverable.

North Um Baraka Petroleum Company – the Joint Venture Company

Following a commercial discovery all development and production operations are undertaken by a joint venture operating company incorporated by EGPC and Shell Egypt under the laws of Egypt called the North Um Baraka Petroleum Company ("**NUB PetCo**"). NUB PetCo is owned equally by EGPC and Shell Egypt.

The joint venture operating company should carry out the operations as an agent on behalf of each of EGPC and Shell Egypt. In practice all fields the subject to development lease to which the Shell Contractors have an interest are operated by Bapetco whereby Bapetco operates the assets on behalf of the other operating companies, including NUB PetCo. 100 per cent. of the costs of NUB PetCo (incurred through the operations of Bapetco) shall be covered by Shell Egypt and recoverable as part of the Contractor's petroleum entitlement.

(d) **Sitra Concession Agreement**

The Sitra Development Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was entered into between the ARE, EGPC and the Shell Contractors on 8 January 2016 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 207 of 2014 (the "**Sitra Concession Agreement**"). The Sitra Concession Agreement indicates that its effective date is 1 December 2015.

Under the Sitra Concession Agreement (i) the ARE has granted the Shell Contractors and EGPC exclusive rights to explore for and develop oil and gas in the Sitra concession area, and (ii) the Shell Contractors agree to bear all the costs and expenses required in carrying out operation under the Sitra Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the Sitra Concession Agreement).

The governing law of the Sitra 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 the Shell Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

ARE previously allocated a concession by virtue of law no. 62 of 1979 (as amended) to Shell Winning N.V. in the Sitra concession area. Under this foregoing concession, the Contractor has made commercial discoveries which were converted to development leases in December 1985 which have been renewed several times before expiring on 1 December 2015. The Sitra Concession Agreement provides for a further 10 year period commencing on the effective date of 1 December 2015, to perform exploration and development operations in the Sitra development area. The terms of the Sitra development lease is embedded in the Sitra Concession Agreement.

The Sitra 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.

Commitments

During the 10-year term of the Sitra Concession Agreement, the Shell Contractors have the following obligations:

- spend a minimum of US$150,000,000 for exploration, development and related activities; and
- drill 22 wells; and
- Process debottlenecking and water reinjection projects, pipeline work and exploration maturation study in the Eastern area.

The Shell Contractors have fulfilled all of these obligations.

Assignment

The Shell Contractors may not assign any of their rights duties or obligations under the Sitra Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the Sitra Concession Agreement, in which event EGPC will benefit from a pre-emption right under the Sitra Concession Agreement and may elect to acquire the 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. An assignment bonus equal to 10 per cent. of the value of an assignment deal is payable to EGPC.

Fiscal Terms and Bonuses

Pursuant to the terms of the Sitra Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The Shell Contractors are entitled to receive quarterly all costs in respect of all operations under the Sitra Concession Agreement out of 35 per cent. of all petroleum produced from within the Sitra Concession Area. The remaining 65 per cent. of petroleum produced is distributed as follows: (i) 83 per cent. to EGPC; and (ii) 17 per cent. to the Shell Contractors.

The Sitra Concession Agreement contains customary bonuses such as EGPC employees training bonus, production bonuses and assignment bonus. Any bonuses payable under the Sitra Concession Agreement are not cost recoverable.

The Sitra Petroleum Company – the Joint Venture Company

The Sitra Petroleum Company ("**Sipetco**") is the joint venture operating company appointed pursuant to the Sitra Concession Agreement to carry out all of the operations under the Sitra Concession Agreement. Sipetco is owned equally by EGPC and the Shell Contractors, with the Shell Contractors holding 50 per cent. of the shares. The joint venture operating company should carry out the operations as an agent on behalf of each of EGPC and the Shell Contractors. In practice all fields the subject to development lease to which the Shell Contractors have an interest are operated by Bapetco whereby Bapetco operates the assets on behalf of the other operating companies, including Sipetco. 100 per cent. of the costs of Sipetco (incurred through the operations of Bapetco) shall be covered by the Shell Contractors and recoverable as part of the Contractor's petroleum entitlement.

(e) **Badr El Din Concession Agreement**

The Badr El Din Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Winning N.V (now Shell Egypt) on 5 June 1980 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 99 of 1980 and as amended by Laws no. 16 of 1984, No. 10 of 2001 and No. 68 of 2006) (the "**BED Concession Agreement**"). Following the various amendments, the BED Concession Agreement is currently between ARE, EGPC and the Shell Contractors.

Under the BED Concession Agreement (i) the ARE has granted the Shell Contractors and EGPC exclusive rights to explore for and develop oil and gas in the BED concession area, and (ii) the Shell Contractors agree to bear all the costs and expenses required in carrying out operation under the BED Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the BED Concession Agreement).

The governing law of the BED 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 Shell subject to settlement by arbitration in Stockholm in accordance with the Rules of Conciliation and Arbitration of the International Chamber of Commerce.

Term/Expiry and Remaining Duration

The exploration period granted to EGPC and the Shell Contractors under the BED Concession Agreement (as amended) for the original BED concession area which has not been relinquished or converted to a development lease ended in 2014. During the exploration phase of the BED Concession Agreement EGPC and the Shell Contractors made a number of commercial discoveries in the BED concession area, which have either now expired or have been extended pursuant to new standalone concession agreements. Details of the two remaining development leases under the original BED Concession Agreement are set out in the table below. The term of development under the BED Concession Agreement is 20 years from the date of a commercial discovery. The Shell Contractors will be granted a successive extension period of 10 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC.

Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
Badr El Din 1-19 Development Lease	15 October 2006	15 October 2026	15 October 2036
Badr El Din 20 Development Lease	1 April 2008	1 June 2034	1 June 2044

The BED 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.

Assignment

The Shell Contractors may not assign any of its rights duties or obligations under the BED Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government.

Fiscal Terms and Bonuses

Pursuant to the terms of the BED Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The Shell Contractors are entitled to receive quarterly all costs in respect of all operations under the BED Concession Agreement out of 40 per cent. of all petroleum produced from all development leases within the BED Concession Area. The remaining 60 per cent. in relation to natural gas produced is distributed as follows: (i) 80 per cent. to EGPC; and (ii) 20 per cent. to the Shell Contractors. This excludes natural gas from Abu Rawash and Bahariya which are wholly owned by EGPC.

The BED Concession Agreement contains customary bonuses such as EGPC employees training bonus and production bonuses. Any bonuses payable under the BED Concession Agreement are not cost recoverable.

The Badr Petroleum Company – the Joint Venture Company

As customary in Egypt and as set out in the BED Concession Agreement, following a commercial discovery EGPC and the Shell Contractors have incorporated a joint venture company under the laws of Egypt called The Badr Petroleum Company ("**Bapetco**"). Bapetco acts as operator of all the operations to be carried out under the BED Concession Agreement. 100 per cent. of the costs of Bapetco shall be covered by Shell and recoverable as part of the Contractor's petroleum entitlement.

The Shell Contractors hold 50 per cent. of the shares of Bapetco and have the right to nominate 4 directors to its board of directors. The chairman is appointed by EGPC and the General Manager by the Sellers.

(f) **Badr El Din-2 ("BED-2") and Badr El Din-17 ("BED-17") Concession Agreement**

The BED-2 and BED-17 Development Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was entered into between the ARE, EGPC and the Shell Contractors on 19 January 2020 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 117 of 2019 (the "**BED 2-17 Concession Agreement**").

Under the BED 2-17 Concession Agreement (i) the ARE has granted the Shell Contractors and EGPC exclusive rights to explore for and develop oil and gas in the BED-2 and BED-17 concession areas, and (ii) the Shell Contractors agree to bear all the costs and expenses required in carrying out operation under the BED 2-17 Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the BED 2-17 Concession Agreement).

The governing law of the BED 2-17 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 the Shell Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The BED-2 and BED-17 development areas were previously covered by 2 development leases in pace under the terms of the BED Concession Agreement. These development leases expired in 2019. The BED 2-17 Concession Agreement which contains the new development leases for BED-2 and BED-17 has an effective date of 10 April 2019 and provides for an initial period of 10 years expiring on 10 April 2029. The Shell Contractors will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister.

The BED 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.

Commitments

Prior to signature of the BED 2-17 Concession Agreement, a signature bonus of US$10 million was paid to EGPC.

During the 10-year term of the BED-2-17 Concession Agreement, the Shell Contractors have the following obligations:

- spend a minimum of US$60,000,000 for exploration, development and related activities; and
- drill 9 wells; and
- Install a LLP manifold compression at the BED-2 facility

To date, the Shell Contractors have spent $32.9 million and drilled 5 wells; all other commitments under the BED 2-17 Concession Agreement remain outstanding.

Pursuant to the BED 2-17 Concession Agreement, Shell Egypt's obligations are backed by a production letter of guarantee for the sum of US$60 million in favour of EGPC. The amounts covered by the guarantee reduce quarterly by the amounts spent by the Contractor and approved by EGPC.

Assignment

The Shell Contractors may not assign any of their rights duties or obligations under the BED 2- 17 Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the BED 2-17 Concession Agreement, in which event EGPC will benefit from a pre-emption right under the BED 2-17 Concession Agreement and may elect to acquire the 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. An assignment bonus equal to 10 per cent. of the value of an assignment deal is payable to EGPC.

Fiscal Terms and Bonuses

Pursuant to the terms of the BED Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The Shell Contractors are entitled to receive quarterly all costs in respect of all operations under the BED-3 Concession Agreement out of 35 per cent. of all petroleum produced from within the BED-3 Concession Area. The remaining 65 per cent. of petroleum produced is distributed as follows: (i) 83 per cent. to EGPC; and (ii) 17 per cent. to the Shell Contractors.

The BED-3 Concession Agreement contains customary bonuses such as EGPC employees training bonus, production bonuses and assignment bonus. Any bonuses payable under the BED-3 Concession Agreement are not cost recoverable.

The Badr Petroleum Company – the Joint Venture Company

Bapetco is the joint venture operating company appointed pursuant to the BED 2-17 Concession Agreement to carry out all of the operations under the BED 2-17 Concession Agreement. 100 per cent. of the costs of Bapetco shall be covered by the Shell Contractors and recoverable as part of the Contractor's petroleum entitlement.

(g) **Badr El Din – 3 Concession Agreement**

The Badr El Din – 3 Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was entered into between the ARE, EGPC and the Shell Contractors on 1 January 2015 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 206 of 2014) (the "**BED-3 Concession Agreement"**). The BED-3 Concession Agreement indicates that its effective date is 27 April 2016.

Under the BED-3 Concession Agreement (i) the ARE has granted the Shell Contractors and EGPC exclusive rights to explore for and develop oil and gas in the BED-3 concession area, and (ii) the Shell Contractors agree to bear all the costs and expenses required in carrying out operation under the BED-3 Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the BED-3 Concession Agreement).

The governing law of the BED-3 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 the Shell

Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

ARE previously allocated a concession by virtue of law no. 99 of 1980 (as amended) to Shell Winning N.V. in Badr El Din-3 area. Under this foregoing concession, the contractor has made commercial discoveries which were converted to development leases in April 1986 and has been renewed until 27 April 2016. The BED-3 Concession Agreement provides for a further 10 year period commencing on the effective date of 27 April 2016, to perform exploration and development operations in the BED-3 development area. The terms of the BED-3 development lease is embedded in the BED-3 Concession Agreement.

The BED 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.

Commitments

During the 10-year term of the BED-3 Concession Agreement, the Shell Contractors have the following obligations:

- spend a minimum of US$50,000,000 for exploration, development and related activities; and
- drill 8 wells and develop a central power plant to serve both the BED-3 and Sitra development leases.

All of the commitments under the BED-3 Concession Agreement have been fulfilled.

Assignment

The Shell Contractors may not assign any of their rights duties or obligations under the BED-3 Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the BED-3 Concession Agreement, in which event EGPC will benefit from a pre-emption right under the BED-3 Concession Agreement and may elect to acquire the 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. An assignment bonus equal to 10 per cent. of the value of an assignment deal is payable to EGPC.

Fiscal Terms and Bonuses

Pursuant to the terms of the BED Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The Shell Contractors are entitled to receive quarterly all costs in respect of all operations under the BED-3 Concession Agreement out of 35 per cent. of all petroleum produced from within the BED-3 Concession Area. The remaining 65 per cent. of petroleum produced is distributed as follows: (i) 83 per cent. to EGPC; and (ii) 17 per cent. to the Shell Contractors.

The BED-3 Concession Agreement contains customary bonuses such as EGPC employees training bonus, production bonuses and assignment bonus. Any bonuses payable under the BED-3 Concession Agreement are not cost recoverable.

The Badr Petroleum Company – the Joint Venture Company

Bapetco is the joint venture operating company appointed pursuant to the BED-3 Concession Agreement to carry out all of the operations under the BED-3 Concession Agreement. 100 per cent. of the costs of Bapetco shall be covered by the Shell Contractors and recoverable as part of the Contractor's petroleum entitlement.

(h) **North Alam el Shawish Concession Agreement**

The North Alam el Shawish Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 3 December 2013 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 90 of 2013) (the "**NAES Concession Agreement**").

Under the NAES Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the NAES concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the NAES Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the NAES Concession Agreement).

The governing law of the NAES 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the NAES Concession Agreement for the NAES concession area was a period of 3 years expiring on 3 December 2016. In December 2016, Shell Egypt entered into the second exploration phase of 3 years and carried over an obligation to drill 2 of the wells which were required under the initial exploration phase. In November 2019, EGPC agreed to extend the second exploration phase for a period of 6 months, and the second phase accordingly expired on 2 December 2019 in order to complete the drilling and testing of the BTE-4D well.

During the exploration phase EGPC and Shell Egypt made 2 commercial discoveries in the NAES concession area and to date has entered into 1 development lease details of which are set out in the table below. Shell Egypt sent a notice of commercial gas discovery to EGPC on 18 February 2020 for NAES-3 well (BTE-4D) and is in negotiation with EGPC for its conversion into a development lease. The terms of any development under the NAES Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The NAES Concession Agreement provides that the development lease period may not exceed 35 years from the date of the Minister's approval of the relevant development lease.

Development Lease	**Effective Date**	**End of Initial Development Phase**	**End of optional Extension Phase**
NAES-1 Development Lease	10 October 2017	10 October 2037	10 October 2042

The NAES 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.

Commitments

During the first exploration phase of the NAES Concession Agreement, Shell Egypt have the obligations to spend a minimum of US$17,000,000 for exploration and related activities and drill 3 wells. During the second exploration period of 3 years, Shell Egypt has the obligation to spend $12,000,000 for exploration and related activities, drill 1 well and cover 500 km2 3D seismic survey. As noted above, Shell Egypt also carried over 2 of its commitment wells from the initial exploration phase into the second exploration phase. All commitments have been fulfilled.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the NAES Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the NAES Concession Agreement, in which event EGPC will benefit from a pre-emption right under the NAES Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or

- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the NAES Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the NEO Concession Agreement out of 30 per cent. of all petroleum produced from all development leases within the NAES Concession Area. The remaining 70 per cent. is distributed as follows: (i) 80 per cent. to 82 per cent. to EGPC; and (ii) 18 per cent. to 20 per cent. to Shell Egypt calculated based on incremental production.

The NAES Concession Agreement contains customary bonuses such as EGPC employees training bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the NAES Concession Agreement are not cost recoverable.

North Alam El Shawish Petroleum Company – the Joint Venture Company

Following a commercial discovery all development and production operations are undertaken by a joint venture operating company incorporated by EGPC and Shell Egypt under the laws of Egypt called the North Alam El Shawish Petroleum Company ("**NAES PetCo**"). NAES PetCo is owned equally by EGPC and Shell Egypt.

The joint venture operating company should carry out the operations as an agent on behalf of each of EGPC and Shell Egypt. In practice all fields the subject to development lease to which the Shell Contractors have an interest are operated by Bapetco whereby Bapetco operates the assets on behalf of the other operating companies, including NAES PetCo. 100 per cent. of the costs of NAES PetCo (incurred through the operations of Bapetco) shall be covered by Shell Egypt and recoverable as part of the Contractor's petroleum entitlement.

(i) **North East Abu Gharadig ("NEAG") Concession Agreement**

The North East Abu Gharadig Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC, Shell and Pecten Egypt Ltd on 27 February 1996 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no.7 of 1996) (the "**NEAG Concession Agreement**"). In April 1996, Repsol Exploration Egypt S.A.("**Repsol**") and Mobile Exploration Egypt Inc. acquired a participating interest in the NEAG Concession Agreement. In January 1997, Apache Aby Gharadig LDC ("**Apache**") acquired Mobile Exploration Egypt Inc.'s interest in the NEAG Concession Agreement.

Following the various assignments, the current status of the NEAG Concession Agreement is as follows:

Shell Egypt	28%
Shell Austria	24%
Apache Egypt	48%

Shell Egypt, Shell Austria and Apache Egypt are the "**NEAG Contractors".**

In 2005, the NEAG Concession Agreement was amended pursuant to Egyptian Law no. 16 of 2005 and the NEAG Contractors were awarded an additional concession area in North Abu Gharadig (the "**NEAG Extension**")

Under the NEAG Concession Agreement (as amended), (i) the ARE has granted the NEAG Contractors and EGPC exclusive rights to explore for and develop oil and gas in the NEAG concession area, and (ii) the NEAG Contractors agree to bear all the costs and expenses required in carrying out operation under the NEAG Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the NEAG Concession Agreement).

The governing law of the NEAG 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 the NEAG Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The exploration period granted to EGPC and the NEAG Contractors under the NEAG Concession Agreement for the original AESW concession area which has not been relinquished or converted to a development lease ended in 2003 and in respect of the NEAG Extension, in 2011. During the exploration phase EGPC and the NEAG Contractors made 4 commercial discoveries in the original NEAG concession area and entered into 4 development leases and 5 commercial discoveries in the NEAG Extension area and entered into 5 development leases, details of which are set out in the table below. The terms of development under the NEAG Concession Agreement is 20 years from the date of a commercial discovery. The NEAG Contractors will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC.

*Original NEAG concession area ("**Tiba**")*

Tiba Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
JG Development Lease . .	20 February 2002	20 February 2022	20 February 2027
JD Development Lease . .	20 May 2004	20 May 2024	20 May 2029
Sheiba Development Lease	11 May 2004	11 May 2024	11 May 2029

Extension NEAG concession area

Tiba Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
NEAG-1 Development . . . Lease	18 November 2007	18 November 2027	18 November 2032
NEAG-2 Development . . . Lease	15 March 2009	15 March 2029	15 March 2034
NEAG-3 Development . . . Lease	15 March 2009	15 March 2029	15 March 2034
NEAG-4 Development . . . Lease	28 February 2011	28 February 2031	28 February 2036
NEAG-5 Development . . . Lease	3 November 2011	3 November 2031	3 November 2036

The NEAG 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.

Assignment

The NEAG Contractors may not assign any of its rights duties or obligations under the NEAG Concession Agreement (as amended) whether directly or indirectly without the prior written consent of the Egyptian Government.

Fiscal Terms and Bonuses

Pursuant to the terms of the NEAG Concession Agreement the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The NEAG Contractors are entitled to receive quarterly all costs in respect of all operations under the NEAG Concession Agreement out of 40 per cent. of all petroleum produced from all development leases within the NEAG concession area and NEAG Extension. The remaining 60 per cent. of petroleum produced is distributed as follows: (i) 77 per cent. to 86 per cent. to EGPC; and (ii) 14 per cent. to 23 per cent. to the NEAG Contractors calculated based on incremental production.

The NEAG Concession contains customary bonuses such as EGPC employees training bonus, and production bonuses. Any bonuses payable under the NEAG Concession are not cost recoverable.

(j) **NEAG Joint Operating Agreement**

On 7 April 1996, Shell Egypt, Shell Austria, Apache and Repsol entered into a Joint Operating Agreement for the operations of the NEAG Concession Agreement (the "**NEAG JOA**"). The NEAG JOA is based on standard industry terms for such an agreement and contains the customary provisions for an agreement of its type.

Pursuant to the terms of the NEAG JOA any transfer of a parties participating interest is subject to a pre-emption process and the approval of the other parties. The NEAG Contractors have a period of 30 days in order to exercise their pre-emption rights.

Pursuant to the NEAG JOA, Shell Egypt is designated as operator, however as is customary in Egypt and as set out in the NEAG Concession Agreement, following a commercial discovery all development and production operations are undertaken by a joint venture operating company incorporated by EGPC and the NEAG Contractors under the laws of Egypt called Tiba Petroleum Company ("**Tipetco**"). Tipetco is owned equally by EGPC and the NEAG Contractors, with Shell Egypt holding 26 per cent. of the shares. Pursuant to the NEAG Concession Agreement and the NEAG JOA, Bapetco is appointed to act as sub-contractor of Tipetco to carry out all development and exploration operations on behalf of each of EGPC and the NEAG Contractors. 100 per cent. of the costs of Tipetco (incurred through the operations of Bapetco) shall be covered by the NEAG Contractors and recoverable as part of the Contractor's petroleum entitlement.

(k) **Alam El Shawish West Concession Agreement**

The Alam El Shawish West Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the Arab Republic of Egypt ("**ARE**"), EGPC and Vegas Oil & Gas S.A ("**Vegas**") on 26 July 2005 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 157 of 2005) (the "**AESW Concession Agreement**"). The current status of the AESW Concession Agreement is as follows:

Shell Egypt	40%
North Petroleum Company S.A.	35%
Neptune Energy Alam El Shawish B.V.	25%

Shell Egypt, North Petroleum Company S.A. and Neptune Energy Alam El Shawish B.V. are the "**AESW Contractors**" and under the AESW Concession Agreement (i) the ARE has granted the AESW Contractors and EGPC exclusive rights to explore for and develop oil and gas in the AESW concession area, and (ii) the AESW Contractors agree to bear all the costs and expenses required in carrying out operation under the AESW Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the AESW Concession Agreement).

The governing law of the AESW 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 the AESW Contractors subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The exploration period granted to EGPC and the AESW Contractors under the AESW Concession Agreement for the original AESW concession area which has not been relinquished or converted to a development lease ended in 2012. During the exploration phase EGPC and the AESW Contractors made 4 commercial discoveries in the AESW concession area and entered into 4 development leases details of which are set out in the table below. The term of development under the AESW Concession Agreement is 20 years from the date of a commercial discovery. The AESW Contractors will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC.

Development Lease	Effective Date	End of Initial Development Phase	End of optional Extension Phase
Al-Assil Development Lease	1 April 2008	1 April 2028	1 April 2033
Al-Karam Development Lease	1 April 2008	1 April 2028	1 April 2033
Al-Magd Development Lease	1 April 2008	1 April 2028	1 April 2033
Al-Barq/Bahga Development Lease	28 May 2007	28 May 2027	28 May 2032

The AESW 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.

Assignment

The AESW Contractors may not assign any of their rights duties or obligations under the AESW Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian

Government. The Transaction will be a direct assignment under the AESW Concession Agreement, in which event EGPC will benefit from a pre-emption right under the AESW Concession Agreement and may elect to acquire the assigned interest on the same terms if it notifies the assignor of such election within 60 days of written notice from the assignor of the final terms (including value) of an assignment.

Fiscal Terms and Bonuses

Pursuant to the terms of the AESW Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

The AESW Contractors are entitled to receive quarterly all costs in respect of all operations under the AESW Concession Agreement out of 30 per cent. of all petroleum produced from all development leases within the AESW concession area. The remaining 70 per cent. of petroleum produced is distributed as follows: (i) 83 per cent. to 85 per cent. to EGPC; and (ii) 15 per cent. to 17 per cent. to the AESW Contractors calculated based on incremental production.

The ASEW Concession contains customary bonuses such as EGPC employees training bonus, production bonuses and development lease extension bonus. Any bonuses payable under the ASEW Concession are not cost recoverable.

(l) **Alam El Shawish West Joint Operating Agreement**

On 5 March 2008, Vegas and GDF entered into a Joint Operating Agreement for the operations of the AESW Concession Agreement (the "**AESW JOA**"). On 31 December 2009, Shell Egypt acceded to the AESW JOA pursuant to an accession and amendment agreement. The AESW JOA is based on standard industry terms for such an agreement and contains the customary provisions for an agreement of its type.

Pursuant to the terms of the AESW JOA (as amended) any transfer of a parties participating interest is subject to a pre-emption process and the approval of the other parties. The AESW Contractors have a period of 28 days in order to exercise their pre-emption rights.

Pursuant to the AESW JOA (as amended), Shell Egypt is designated as operator, however as is customary in Egypt and as set out in the AESW Concession Agreement, following a commercial discovery all development and production operations are undertaken by a joint venture operating company incorporated by EGPC and the AESW Contractors under the laws of Egypt called Petro Alam. Petro Alam is owned equally by EGPC and the AESW Contractors, with Shell Egypt holding 20 per cent. of the shares. Pursuant to the AESW JOA Bapetco can be appointed to carry out all development and exploration operations on behalf of Petro Alam and EGPC and the AESW Contractors. 100 per cent. of the costs of the Petro Alam (incurred through the operations of Bapetco) shall be covered by the AESW Contractors and recoverable as part of the Contractor's petroleum entitlement.

(m) **South Abu Sennan Concession Agreement**

The South Abu Sennan Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 19 January 2020 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 156 of 2019) (the "**SAS Concession Agreement**").

Under the SAS Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the SAS concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the SAS Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the SAS Concession Agreement).

The governing law of the SAS 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the SAS Concession Agreement for the SAS concession area ss a period of 3 years from the effective date, expiring on 19 January 2023. Shell Egypt will be granted one subsequent extension of 3 years by virtue of notice to EGPC. The SAS Concession Agreement shall expire upon lapse of the 6 year exploration phase in case no commercial discovery is achieved. At the end of the initial 3 year exploration period, 30 per cent. of the original SAS concession area that has not been converted into a development lease shall be relinquished. As an exception, Shell Egypt and EGPC may obtain an exception to maintain the relinquished are during the exploration phase extension upon approval of the Minister.

The terms of any development under the SAS Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The SAS Concession Agreement provides that the development lease period may not exceed 30 years from the date of the Minister's approval of the relevant development lease.

The SAS 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.

Commitments

During the first exploration phase of the SAS Concession Agreement, Shell Egypt have the obligations to spend a minimum of US$5,200,000 for exploration and related activities, drill 2 wells and acquire 3D existing seismic reprocessing. During the exploration phase extension of 3 years, Shell Egypt has the obligation to spend $2,600,000 for exploration and related activities and drill 1 well.

All commitments under the SAS Concession Agreement remain unfulfilled.

Pursuant to the SAS Concession Agreement, Shell Egypt's obligations are backed by a production letter of guarantee for the sum of US$5.2 million in favour of EGPC. The amounts covered by the guarantee reduce quarterly by the amounts spent by the Contractor and approved by EGPC.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the SAS Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the SAS Concession Agreement, in which event EGPC will benefit from a pre-emption right under the SAS Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or
- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the SAS Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the SAS Concession Agreement out of 27 per cent. of all petroleum produced from all development leases within the SAS concession area. The remaining 73 per cent. is distributed as follows:

- Crude Oil: (i) 77 per cent. to 80 per cent. to EGPC; and (ii) 20 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production; or
- Gas and LPG: (i) 77 per cent. to 81 per cent. to EGPC; and (ii) 19 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production.

The SAS Concession Agreement contains customary bonuses such as an EGPC employees training bonus, an assignment bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the SAS Concession Agreement are not cost recoverable.

(n) **South East Horus Concession Agreement**

The South East Horus Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 19 January 2020 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 156 of 2019) (the "**SEH Concession Agreement**").

Under the SEH Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the SEH concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the SEH Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the SEH Concession Agreement).

The governing law of the SEH 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the SEH Concession Agreement for the SEH concession area ss a period of 4 years from the effective date, expiring on 19 January 2024. Shell Egypt will be granted one subsequent extension of 3 years by virtue of notice to EGPC. The SEH Concession Agreement shall expire upon lapse of the 7 year exploration phase in case no commercial discovery is achieved. At the end of the initial 4 year exploration period, 30 per cent. of the original SEH concession area that has not been converted into a development lease shall be relinquished. As an exception, Shell Egypt and EGPC may obtain an exception to maintain the relinquished area during the exploration phase extension upon approval of the Minister.

The terms of any development under the SEH Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The SEH Concession Agreement provides that the development lease period may not exceed 30 years from the date of the Minister's approval of the relevant development lease.

The SEH 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.

Commitments

During the first exploration phase of the SEH Concession Agreement, Shell Egypt have the obligations to spend a minimum of US$16,400,000 for exploration and related activities, drill 3 wells and acquire 500 km2 3D seismic. During the exploration phase extension of 3 years, Shell Egypt has the obligation to spend $8,100,000 for exploration and related activities and drill 2 wells.

All of the commitments under the SHE Concession Agreement remain unfulfilled.

Pursuant to the SEH Concession Agreement, Shell Egypt's obligations are backed by a production letter of guarantee for the sum of UD$16.4 million in favour of EGPC. The amounts covered by the guarantee reduce quarterly by the amounts spent by the Contractor and approved by EGPC.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the SEH Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the SEH Concession Agreement, in which event EGPC will benefit from a pre-emption right under the SEH Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or
- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the SEH Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the SAS Concession Agreement out of 27 per cent. of all petroleum produced from all development leases within the SEH concession area. The remaining 73 per cent. is distributed as follows:

- Crude Oil: (i) 77 per cent. to 86 per cent. to EGPC; and (ii) 14 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production; or
- Gas and LPG: (i) 77 per cent. to 81 per cent. to EGPC; and (ii) 19 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production.

The SEH Concession Agreement contains customary bonuses such as an EGPC employees training bonus, an assignment bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the SEH Concession Agreement are not cost recoverable.

(o) **West El Fayium Concession Agreement**

The West El Fayium Area Western Desert Petroleum Exploration and Exploitation Concession Agreement was originally entered into between the ARE, EGPC and Shell Egypt on 19 January 2020 (following the enactment of the concession agreement terms into law pursuant to Egyptian Law no. 161 of 2019) (the "**WEF Concession Agreement**").

Under the WEF Concession Agreement (i) the ARE has granted Shell Egypt and EGPC exclusive rights to explore for and develop oil and gas in the WEF concession area, and (ii) Shell Egypt agrees to bear all the costs and expenses required in carrying out operation under the WEF Concession Agreement (subject to a deferred right to recover such costs in accordance with the terms of the WEF Concession Agreement).

The governing law of the WEF 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 Shell Egypt subject to settlement by arbitration in Cairo in accordance with the Arbitration Rules of the Cairo Regional Centre for International Commercial Arbitration.

Term/Expiry and Remaining Duration

The initial exploration period granted to EGPC and Shell Egypt under the WEF Concession Agreement for the WEF concession area is a period of 4 years from the effective date, expiring on 19 January 2024. Shell Egypt will be granted one subsequent extension of 3 years by virtue of notice to EGPC. The WEF Concession Agreement shall expire upon lapse of the 7 year exploration phase in case no commercial discovery is achieved. At the end of the initial 4 year exploration period, 30 per cent. of the original WEF concession area that has not been converted into a development lease shall be relinquished. As an exception, Shell Egypt and EGPC may obtain an exception to maintain the relinquished area during the exploration phase extension upon approval of the Minister.

The terms of any development under the WEF Concession Agreement is 20 years from the date on which the Minister ratifies the development lease. Shell Egypt will be granted a successive extension period of 5 years at its option upon written notice to EGPC of at least 6 months, subject to the approval of the Minister and EGPC. The WEF Concession Agreement provides that the development lease period may not exceed 30 years from the date of the Minister's approval of the relevant development lease.

The WEF 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.

Commitments

During the first exploration phase of the WEF Concession Agreement, Shell Egypt have the obligations to spend a minimum of US$17,900,000 for exploration and related activities, drill 4 wells and acquire 500 km2 3D seismic. During the exploration phase extension of 3 years, Shell Egypt has the obligation to spend $6,800,000 for exploration and related activities and drill 2 wells.

All of the commitments under the WEF Concession Agreement remain unfulfilled.

Pursuant to the WEF Concession Agreement, Shell Egypt's obligations are backed by a production letter of guarantee for the sum of US$17.9 million in favour of EGPC. The amounts covered by the guarantee reduce quarterly by the amounts spent by the Contractor and approved by EGPC.

Assignment

Shell Egypt may not assign any of its rights duties or obligations under the WEF Concession Agreement whether directly or indirectly without the prior written consent of the Egyptian Government. The Acquisition will be a direct assignment under the WEF Concession Agreement, in which event EGPC will benefit from a pre-emption right under the WEF Concession Agreement and may elect to acquire the 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. An assignment bonus is payable to EGPC calculated as follows:

- assignment during the exploration phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial obligations in the applicable exploration phase;
- assignment during the development phase (or its extension) – amount equivalent (calculated in US$) to 10 per cent. of total financial value to be paid by the assignee to assignor; or
- assignment during any exploration phase and after grant of a development lease – amount equivalent (calculated in US$) equivalent to the two items above.

Fiscal Terms and Bonuses

Pursuant to the terms of the WEF Concession Agreement, the ARE is entitled to a royalty of 10 per cent. of petroleum produced, which shall be borne and paid by EGPC.

Shell Egypt is entitled to receive quarterly all costs in respect of all operations under the SAS Concession Agreement out of 27 per cent. of all petroleum produced from all development leases within the SEH concession area. The remaining 73 per cent. is distributed as follows:

- Crude Oil: (i) 77 per cent. to 86 per cent. to EGPC; and (ii) 14 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production; or
- Gas and LPG: (i) 77 per cent. to 81 per cent. to EGPC; and (ii) 19 per cent. to 23 per cent. to Shell Egypt, calculated based on incremental production.

The WEF Concession Agreement contains customary bonuses such as an EGPC employees training bonus, an assignment bonus, a development lease bonus, a development lease extension and production bonuses. Any bonuses payable under the WEF Concession Agreement are not cost recoverable.

9. **Litigation**

9.1 *The Group*

Save as disclosed in paragraph 9.3 of this Part VII below, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) which may have, or have had during the 12 months preceding the date of this Circular, a significant effect on the Group's financial position or profitability.

9.2 *The Assets*

Save as set out below, 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 financial position or profitability of the Assets.

Apache Audit Dispute

Apache Khalda Corporation LDC ("**Apache**"), Shell and EGPC are a party to a gas processing and transportation agreement dated 24 February 2005 (the "**Apache Agreement**") pursuant to which Apache has rights to have a portion of the gas and condensate from the Qasr development lease in the Khalda concession area processed at the Obaiyed gas processing plant. Apache is the Contractor under the Khalda Area concession agreement.

The Obaiyed gas processing plant was built and has been operated under the terms of the Obaiyed Concession Agreement. Opetco is referenced in the Apache Agreement, but Bapetco operates the Obaiyed gas processing plant as agent for Opetco.

Pursuant to the terms of the Apache Agreement, Apache carried out an audit to verify that the allocations and associated activities for the period November 2016 to June 2019 were performed in accordance with the Apache Agreement and applicable amendment agreements between the parties. In a letter dated 25 June 2020, Apache raised a claim for under allocation in gas and condensate, as well as concerns regarding adjustments to cost recovery settlement under the NEAG JOA. Given this claim relates to the period Pre-Economic Date under the SPA, any liability will remain with the Sellers under the respective indemnity.

9.3 *Indian Income Tax Department and Arbitration under UK-India Bilateral Investment Treaty*

In January 2014 Cairn received notification from the Indian Income Tax Department (the "**ITD**").

In that notification, the ITD claimed to have identified unassessed taxable income resulting from certain intra-Group share transfers undertaken in 2006 (the "**2006 Transactions**"), such transactions having been undertaken in order to facilitate the initial public offering of CIL in 2007. The notification made reference to retrospective Indian tax legislation enacted in 2012, which the ITD was seeking to apply to the 2006 Transactions.

The assessment issued in February 2016 by the ITD of principal tax due on the 2006 Transactions is for INR 102 billion (currently US$1.36 billion), plus applicable interest and penalties. On 9 March 2017, the Income Tax Appellate Tribunal, Delhi ("**ITAT**") issued an order in which it was held that CUHL should not be required to pay interest under certain sections of the Indian Income Tax Act, 1961, on the basis that the tax payable had "arisen because of retrospective amendment" and that CUHL "could not have visualized" such liability when it carried out the transfers in 2006. Interest is currently being charged on the principal at a rate of 12 per cent. per annum from February 2016, although this is subject to the ITD's Indian high court appeal that interest should be back dated to 2007 and therefore amounts to INR 188 billion (currently US$2.51 billion). Penalties are currently assessed as 100 per cent. of the principal tax due, although this is subject to appeal by CUHL that penalties should not be charged. Cairn is contesting the tax proceedings in India.

In March 2015 Cairn filed a Notice of Dispute under the UK-India Bilateral Investment Treaty (the "**Treaty**") in order to protect its legal position and seek restitution of the value effectively seized by the ITD in and since January 2014.

The Treaty proceedings formally commenced in January 2016 following agreement between Cairn and the Republic of India on the appointment of a panel of three international arbitrators under the terms of the Treaty.

On 21 December 2020, the Tribunal issued its award in favour of Cairn, finding unanimously that the Republic of India had through its actions failed to accord Cairn's investments fair and equitable treatment in breach of Article 3(2) of the Treaty. The Tribunal ordered the Republic of India to pay damages to Cairn to compensate it for the breach, totalling approximately US$1.2 billion plus interest and costs, which sum is immediately due and payable.

On 30 March 2021, Cairn announced that it had received notice that the Government of India has petitioned the Dutch Court of Appeal to set aside the arbitration award dated 21 December 2020 issued pursuant to the UK-India Bilateral Investment Treaty which was granted unanimously in favour of Cairn.

10. Working capital

The Company is of the opinion that, taking into account available loan facilities, the Group, as enlarged by the Acquisition, has sufficient working capital for its present requirements, that is, for at least the next 12 months from the date of publication of this Circular.

11. Significant changes

11.1 *The Group*

Save as set out below, there has been no significant change in the financial position or the financial performance of the Group since 31 December 2020, being the end of the last financial period of the Group for which financial statements have been published.

- Cairn entered into an agreement on 8 March 2021 for the sale of its interests in the UK Catcher and Kraken fields to Waldorf for a cash consideration of US$460 million plus additional contingent consideration dependent principally on oil prices from 2021 to the end of 2025. Subject to regulatory and shareholder approval, the disposal is expected to complete in H2 2021.
- Cairn paid a special dividend of 32 pence per eligible ordinary share on 25 January 2021, amounting to a return of approximately US$250 million to shareholders.

11.2 *The Assets*

There has been no significant change in the financial position or the financial performance of the Assets since 31 December 2020, being the date to which the audited financial information on Assets presented in Part IV (*Financial Information Relating to the Assets*) of this Circular was prepared.

12. Consents

12.1 Rothschild & Co has given and not withdrawn its written consent to the inclusion of its name in this Circular in the form and context in which it is included.

12.2 Ernst & Young LLP has given and has not withdrawn its written consent to the inclusion in Section A of Part IV (*Financial Information Relating to the Assets*) of this Circular of its report on the historical financial information of the Assets and in Section 2 of Part V (*Unaudited Pro Forma Financial Information on the Group*) of this Circular of its report on the unaudited pro forma statement of net assets of the Group, in the form and context in which they are included.

12.3 GaffneyCline has given and has not withdrawn its written consent to the inclusion in Part VI (*Competent Person's Report in respect of the Assets*) of the GaffneyCline Report concerning the hydrocarbon reserves and resources of the Assets as of 31 December 2020 in the form and context in which it is included.

13. Documents available for inspection

Copies of the following documents may be inspected during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the registered office of the Company at 50 Lothian Road, Edinburgh EH3 9BY, United Kingdom up to and including the date of the General Meeting:

(a) the Sale and Purchase Agreement;

(b) the memorandum and articles of association of the Company;

(c) copies of the 2018 Annual Report and Accounts, the 2019 Annual Report and Accounts and the 2020 Annual Report and Accounts;

(d) this Circular and the Form of Proxy; and

(e) the written consents referred to in paragraph 12 of this Part VII.

The above documentation (other than document (a)) will also be available on the Company's website at www.cairnenergy.com, and also for inspection on the date and at the place of the General Meeting for at least 15 minutes before the General Meeting is held until its conclusion.

Dated: 29 June 2021

PART VIII

GLOSSARY OF TECHNICAL TERMS

The following technical terms are used in this Circular. Grammatical variations of these terms should be interpreted in the same way.

2D seismic	seismic data consisting of adjacent lines acquired individually, as opposed to the multiple closely spaced lines acquired together that constitute 3D seismic data
3D seismic	seismic data acquired as multiple, closely spaced traverses, typically providing a more detailed and accurate image of the subsurface than 2D seismic data
appraisal	the phase of petroleum operations immediately following a successful discovery to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells to reduce technical uncertainties and commercial contingencies
appraisal well	a well drilled as part of the appraisal of a discovery or field
bbl	barrel
Bcf	billion cubic feet
block	term commonly used to describe areas over which there is a petroleum or production licence or PSC
boepd	barrels of oil equivalent per day
bopd	barrels of oil per day
Brent	type of crude oil that originates from oil fields in the North Sea between the Shetland Islands and Norway
condensate	a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir but, when produced, are in the liquid phase at surface pressure and temperature conditions (when temperature or pressure is reduced relative to the reservoir)
contingent resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development project(s), but which are not currently considered to be commercially recoverable owing to one or more contingencies. Contingent resources have an associated chance of development. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status
cost recovery	a mechanism determined in a PSC by which the contractor parties to the PSC are enabled to recover present and past costs
discovery	an exploration well which has encountered oil and gas for the first time in a structure

exploration	the phase of operations which covers the search or prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies and exploratory drilling
exploration drilling	drilling carried out to determine whether oil and gas are present in a particular area or structure
exploration well	a well in an unproven area or prospect, sometimes also known as a "wildcat well"
farm-in	a term used to describe when an oil and gas company buys a portion of the acreage in a block from another company, usually in return for consideration and for taking on a portion of the selling company's work commitments
farm-out	a term used to describe when a company sells a portion of the acreage in a block to another company, usually in return for consideration and for the buying company taking on a portion of the selling company's work commitments
FID	final investment decision, a term used in the oil and gas industry to describe the decision to commence the development of a project, at which point material contract awards can commence, and each partner in the project is effectively committed to pay its share in accordance with its participating interest
field	a geographical area under which either a single reservoir or multiple reservoirs lie, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
FPSO	a floating production, storage and offloading unit, which is a vessel used for processing and storing hydrocarbons
hydrocarbon	a chemical compound consisting wholly of hydrogen and carbon molecules, which may exist as a solid, a liquid or a gas (for example, oil, gas or condensate)
infrastructure	oil and gas processing, transportation and off-take facilities
JOA	a joint operating agreement for the purpose of governing the relationship between the parties in relation to joint exploration, production and operation
km	kilometre(s) (and **km**2 means square kilometre(s))
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
m	metre
migration	the movement of hydrocarbons from source rocks into reservoir rocks, which can be local or can occur along distances of hundreds of kilometres in large sedimentary basins, and is critical to a viable petroleum system
MMbbl	million barrels
MMSCFD	million standard cubic feet per day

natural gas . . . . gas, predominantly methane, occurring naturally, and often found in association with crude petroleum

offshore . . . . that geographic area that lies seaward of the coastline

oil . . . . a mixture of liquid hydrocarbons of different molecular weights

oil field . . . . the mapped distribution of a proven oil-bearing reservoir or reservoirs

operator . . . . the company that has legal authority to drill wells and undertake production of petroleum, often acting on behalf of a consortium or JV

P10 . . . . in the context of quoted resource or reserve volumes, the probability of 10 per cent. that the quoted value would be larger than the reported and considered high value

P50 . . . . in the context of quoted resource or reserve volumes, the probability of 50 per cent. that the quoted value would be larger than the reported and considered best value

P90 . . . . in the context of quoted resource or reserve volumes, the probability of 90 per cent. that the quoted value would be larger than the reported and considered low value

participating interest . . . . the proportion of exploration and production costs each party will bear and the proportion of production each party will receive, typically set out in a JOA

petroleum . . . . a generic name for oil and gas, including crude oil, natural gas liquids, natural gas, condensate and their products

petroleum system . . . . geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal

play . . . . a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects

PRMS . . . . the SPE 2018 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers)

prospect . . . . an identified trap that may contain hydrocarbons. A potential hydrocarbon accumulation may be described as a lead or prospect depending on the degree of certainty in that accumulation. A prospect generally is mature enough to be considered for drilling.

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 geologic discovery and a chance of development. Prospective resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity

PSC . . . . production sharing agreement or contract, being a contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production and in return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms

reserves . . . . those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions and satisfying four criteria: discovered, recoverable, commercial and remaining (as of the evaluation's effective date) based on the development project(s) applied

reservoir . . . . a subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs)

resources . . . . contingent and prospective resources, unless otherwise specified

seal . . . . a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir, a critical component of a complete petroleum system

seismic survey . . . . a method by which an image of the earth's sub-surface is created through the generation of shockwaves and analysis of their reflection from rock strata

SPE . . . . The Society of Petroleum Engineers

STOIIP . . . . stock tank oil initially in place

trap . . . . a configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch outs and reefs). A trap is an essential component of a petroleum system

TRR . . . . technical recoverable resource

WI . . . . working interest

PART IX

DEFINITIONS

The following definitions apply throughout this Circular, unless stated otherwise:

2017 LTIP	the Cairn Energy PLC Long Term Incentive Plan (2017)
2018 Annual Report and Accounts	Cairn's annual report and accounts for the year ended 31 December 2018
2019 Annual Report and Accounts	Cairn's annual report and accounts for the year ended 31 December 2019
2020 Annual Report and Accounts	Cairn's annual report and accounts for the year ended 31 December 2020
Acquisition or Transaction	the proposed acquisition by the Buyers of the Assets pursuant to the terms of the Sale and Purchase Agreement
Acquisition RBL Facility	has the meaning given in paragraph 8.1(g) of Part VII *(Additional Information)* of this Circular
Acquisition RBL Lenders	has the meaning given in paragraph 8.1(g) of Part VII *(Additional Information)* of this Circular
AESW Concession	the Alam El Shawish West concession
AGM	annual general meeting of the Company
Articles of Association	the articles of association of the Company from time to time
Assets or **Target Group**	the SENV Transferred Interests and the SAG Transferred Interests
Average Brent Price	the average Brent price over the 180 days after First Oil at Sangomar development as determined by reference to the mid-prices of Dated Brent benchmark in US$/bbl as published by S&P Global Platts under the code "PCAAS00" for each of the publication days during that period
Bapetco	Badr El Din Petroleum Company, a company incorporated in the A.R.E. pursuant to the provisions of the Law No. 99 of 1980 (registered number 2925949) and having its registered office at 127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958, the A.R.E.
BED Concession	the Badr El Din concession
BED-3 Concession	the Badr El Din 3 concession
BED 2-17 Concession	the Badr El Din 2-17 concession
Board	the board of directors of the Company, comprising at the date of this Circular the Directors whose names appear on page 4 of this Circular
Business Day	a day, other than a Saturday or Sunday, on which banks are generally open for business in London or, where the term **Business Day** is used in Part III (*Principal Terms of the Sale and Purchase Agreement*) of

this Circular, a day, other than a Saturday or a Sunday, on which banks are open for normal banking business days in Cairo (A.R.E.), The Hague (NL), London (UK) and New York (U.S.A.)

Buyers .... means Capricorn Egypt and the Cheiron Energy Purchasers

Cairn Oil Group Pension Plan ...... a defined contribution group personal pension plan operated by the Company in the UK

Capricorn Egypt .... Capricorn Egypt Limited, a company incorporated in England and Wales (registered number 12716481) having its registered office at Wellington House, 4th Floor, 125, The Strand, London WC2R 0AP

Capricorn North Sea .... Capricorn North Sea Limited, incorporated in England and Wales with company number 13233288, a member of the Group and a wholly owned subsidiary of Nautical Petroleum

Capricorn Senegal .... Capricorn Senegal Limited, incorporated in Scotland with company number SC444808, an indirect wholly owned subsidiary of the Company

Catcher .... the Catcher area field development located in the UK Central North Sea

Catcher Licences .... the following licences:

(a) Licence P.2453 Block 28/9c (Bonneville);

(b) Licence P. 2550 Block 28/9f (Cougar and Rapide); and

(c) Licence P.1430 Block 28/9a, Licence P.2070 Block 28/4a and Licence P.2454 Block 28/9d (Greater Catcher)

Catcher/Kraken Deferred Consideration .... US$35 million plus capitalised interest accrued thereon in respect of the sale and purchase of the Catcher/Kraken Interests

Catcher/Kraken Deferred Consideration Agreement .... the deferred consideration agreement to be entered into between Nautical Petroleum and Waldorf at completion of the transaction contemplated under the Catcher/Kraken SPA, under which the Deferred Consideration is payable

Catcher/Kraken Hive Down .... the transfer of the Catcher/Kraken Interests from Nautical Petroleum to Target under the Hive Down Agreement

Catcher/Kraken Hive Down Agreement .... the hive down agreement dated 11 March 2021 between Nautical Petroleum and Capricorn North Sea

Catcher/Kraken Interests .... (a) an undivided interest in the Catcher Licences together with a 20 per cent. legal and beneficial interest in the JOAs in respect of the Catcher Licences; and

(b) an undivided interest in the Kraken Licence together with a 29.5 per cent. legal and beneficial interest in the JOA in respect of the Kraken Licence

Catcher/Kraken SPA .... the agreement for the sale and purchase of the Catcher/Kraken Interests which is required to be entered into between Nautical Petroleum and Waldorf following the exercise of a Put / Call Option

CCSS .... the CREST courier and sorting service operated by Euroclear to facilitate, *inter alia*, the deposit and withdrawal of securities

Cheiron	Cheiron Petroleum Corporation
Cheiron Energy	Cheiron Energy Limited, a company incorporated in England & Wales (registered number 07201627) having its registered office at 3rd Floor, 1 Ashley Road, Altrincham, Cheshire, WA14 2DT
Cheiron Energy Purchasers	Cheiron Oil & Gas and certain of Cheiron Energy's wholly owned affiliates that are party to the Sale and Purchase Agreement
Cheiron Holdings	Cheiron Holdings Egypt Limited, a company incorporated in the British Virgin Islands (registered number 1875391) having its registered office at Kingston House, PO Box 173, Road Town, Tortola, BVI
Cheiron Oil & Gas	Cheiron Oil & Gas Limited, a company incorporated in England and Wales (registered number 13207893) having its registered office at 3rd Floor, 1 Ashley Road, Altrincham, Cheshire WA14 2DT
Circular	this document, being a *class 1 circular* as such term is defined in the Listing Rules
Companies Act 1985	the Companies Act 1985 (as amended)
Companies Act 2006	the Companies Act 2006 (as amended)
Company or Cairn or Cairn Energy	Cairn Energy PLC
Completion	completion of the Acquisition in accordance with the Sale and Purchase Agreement
Conditions	the conditions to Completion under the Sale and Purchase Agreement, including those set out in paragraph 1 of Part III (*Principal Terms of the Sale and Purchase Agreement*) of this Circular
Concessions	together the AESW Concession, the BED Concession, the BED-3 Concession, the BED 2-17 Concession, the NAES Concession, the NEAG Concession, the NM Concession, the NUB Concession, the Obaiyed Concession, the SAS Concession, the SE Horus Concession, the Sitra Concession and the WEF Concession
Consortium	the consortium formed between Cairn and Cheiron Energy on 17 January 2020 for the purposes of the Transaction
Contractor	a relevant contract for each of the Concessions
CREST	the electronic, paperless transfer and settlement mechanism to facilitate the transfer of title of shares in uncertified form operated by Euroclear
CREST Manual	the rules governing the operation of CREST, consisting of the CREST Reference Manual, CREST International Manual, CREST Central Counterparty Service Manual, CREST Rules, Registrars Service Standards, Settlement Discipline Rules, CCSS Operations Manual, Daily Timetable, CREST Application Procedure and CREST Glossary of Terms (all as defined in the CREST Glossary of Terms promulgated by Euroclear on 15 July 1996 and as amended since)
CREST member	a person who has been admitted to CREST as a system member (as defined in the CREST Regulations)

CREST participant	a person who is, in relation to CREST, a system (as defined in the CREST Regulations)
CREST Proxy Instruction	a properly authenticated CREST message appointing and instructing a proxy to attend and vote in place of a Shareholder at the General Meeting and containing the information required to be contained in the CREST Manual
CREST Regulations	The Uncertificated Securities Regulations 2001 (SI 2001/3755)
CREST sponsor	a CREST participant admitted to CREST as a CREST sponsor
Cut-Off Date	means the later of the Long Stop Date and the date falling six (6) months after the Pre-Completion Date
Directors	the directors of the Company
DTR or **DTRs**	the Disclosure Guidance and Transparency Rules issued and maintained by the FCA under section 73A of FSMA
EGPC	the Egyptian General Petroleum Corporation, a company incorporated in the A.R.E. pursuant to the provisions of Law No. 167 of 1958 as amended and having its legal headquarters in 270 St., Part 4, New Maadi, Cairo, the A.R.E.
Encumbrance	any mortgage, charge, pledge, lien, assignment, option, restriction, claim, over-riding royalty interest or net profit arrangement, right of pre-emption, right of first refusal, third party right or interest, other encumbrance or security interest of any kind, or other type of preferential arrangement (including a title transfer or retention arrangement) having similar effect
Enlarged Group	Cairn as enlarged by the acquisition of the Assets
Equiniti	Equiniti Limited
Euroclear	Euroclear UK & Ireland Limited, the operator (as defined in the CREST Regulations) of CREST
Executive Directors	Simon Thomson and James Smith
FCA	the Financial Conduct Authority
Form of Proxy	the form of proxy accompanying this Circular for use by Shareholders in relation to the General Meeting
FSMA	the Financial Services and Markets Act 2000, as amended
GaffneyCline	Gaffney, Cline & Associates Limited
GaffneyCline Report or **Competent Person's Report**	the competent person's report prepared by GaffneyCline as set out in Part VI (*Competent Person's Report in respect of the Assets*)
General Meeting	the general meeting of the Company (or any adjournment thereof) to be held at 9.00 a.m. (BST) on 19 July 2021 at 50 Lothian Road, Edinburgh EH3 9BY, notice of which is set out at the end of this Circular

Group	the Company, its subsidiary undertakings and any other body corporate, legal entity, partnership or unincorporated joint venture in which the Company or any of its subsidiary undertakings holds a participating interest (as such term is defined by section 1162 of the Companies Act 2006) from time to time and references to a "member of the Group" shall be construed accordingly
H1	the first half of a calendar year, being January to June (inclusive)
H2	the second half of a calendar year, being July to December (inclusive)
HSE	health and safety
JV	joint venture
Junior Debt Facility	has the meaning given in paragraph 8.1(h) of Part VII (*Additional Information*) of this Circular
Junior Debt Lenders	has the meaning given in paragraph 8.1(h) of Part VII (*Additional Information*) of this Circular
Kraken	the Kraken Area which includes the Kraken and Kraken North heavy oil fields that are located close to the Mariner, Bentley and Bressay fields in the Northern North Sea
Kraken Licence	Licence P.1077 Block 9/2b
Latest Practicable Date	25 June 2021, being the latest practicable date prior to the publication of this Circular
LIBOR	the London Inter-Bank Offered Rate administered by ICE Benchmark Administration Limited giving an average rate at which a leading bank can obtain unsecured funding for a given period in a given currency in the London market
Listing Rules	the listing rules issued and maintained by the FCA under section 73A of FSMA
London Stock Exchange	London Stock Exchange plc or its successor
Long Stop Date	12 months from the date of signing the Sale and Purchase Agreement or such other date as may be agreed between the Sellers and the Buyers
MAR	Regulation (EU) No 596/2014 of the European Parliament and of the Council of 16 April 2014 on market abuse, as it forms part of retained EU law by virtue of the European Union (Withdrawal) Act 2018
Minister	the current minister of petroleum and metallurgical wealth in Egypt and his successors
NAES Concession	the North Alam El Shawish concession
Nautical Petroleum	Nautical Petroleum Limited, incorporated in England and Wales with company number 04362104, a member of the Group and a wholly owned subsidiary of Cairn
NEAG Concession	the North East Abu Ghadarig concession
NEO Concession	the North East Obaiyed concession
NM Concession	the North Matruh concession

Non-Executive Directors	Nicoletta Giadrossi, Keith Lough, Peter Kallos, Alison Wood, Catherine Krajicek and Erik Daugbjerg
Notice of General Meeting	the notice of the General Meeting set out at the end of this Circular
NUB Concession	the North Um Baraka concession
Official List	the Official List of the FCA
Operating Company	a company that operates a relevant Concession
Opetco	Obaiyed Petroleum Company
Put and Call Option Agreement	the put and call option agreement dated 8 March 2021 between Nautical Petroleum and Waldorf
Remuneration Committee	the remuneration committee of the Board from time to time
Reserve Tail Date	the date on which remaining economic reserves for all the borrowing base assets are projected to exceed 20 per cent. of initial economic reserves (being the aggregate oil, condensate, or oil equivalent gas and hydrocarbon reserves) that are forecast in the initial banking case to be derived from the initial borrowing base assets
Resolution	the ordinary resolution of the shareholders of Cairn Energy PLC which, among other things, approves the Transaction as a Class 1 transaction and any other matters arising out of the Sale and Purchase Agreement and related documents which will be voted on at the General Meeting set out in the Notice of General Meeting
Sale and Purchase Agreement or **SPA**	the agreement for the sale and purchase of the Assets dated 8 March 2021 between Capricorn Egypt, Capricorn Oil Limited, Cheiron Holdings, Cheiron Oil & Gas and the other Cheiron Energy Purchasers, Shell Egypt N.V. and Shell Austria Gesellschaft MBH
SAG Transferred Interests	means the undivided legal and beneficial interest of Shell Austria Gesellschaft MBH in: (i) the Concessions; (ii) the shares of the Operating Companies; (iii) the facilities, infrastructure and inventory; and (iv) specific amounts receivable in relation to petroleum sales and other costs
SAS Concession	the South Abu Senan concession
SE Horus Concession	the South East Horus concession
Sellers or Shell Contractors	Shell Egypt and Shell Austria
SENV Transferred Interests	means the undivided legal and beneficial interest of Shell Egypt N.V. in: (i) the Concessions; (ii) the shares of the Operating Companies; (iii) the facilities, infrastructure and inventory; and (iv) specific amounts receivable in relation to petroleum sales and other costs
Shareholders	the holders of the Shares
Shares	the ordinary shares of 21/13 pence each in the capital of the Company
Shell Egypt	Shell Egypt N.V.
Shell Austria	Shell Austria Gesellschaft MBH
SIP	the Cairn Energy PLC 2010 Share Incentive Plan
Sitra Concession	the Sitra concession
UK or **United Kingdom**	the United Kingdom of Great Britain and Northern Ireland

United States or **US** . . . . The United States of America, its territories and possessions, any State of the United States and the District of Columbia

Waldorf . . . . Waldorf Production UK Limited, a company incorporated in England and Wales with company number 12149322

WEF Concession . . . . the West El Fayium concession

Cairn Energy PLC

(Incorporated in Scotland with registered number SC226712)

NOTICE OF GENERAL MEETING

NOTICE IS HEREBY GIVEN that a GENERAL MEETING of Cairn Energy PLC (the "**Company**") will be held at 50 Lothian Road, Edinburgh EH3 9BY on 19 July 2021 at 9.00 a.m. (BST) to consider and, if thought fit, pass the following resolution, which will be proposed as an ordinary resolution. Capitalised terms not defined below are references to those terms as defined in the circular to shareholders dated 29 June 2021 of which this notice forms part.

Ordinary resolution

THAT the proposed Acquisition substantially on the terms and subject to the conditions set out in the circular to shareholders of the Company outlining the Acquisition dated 29 June 2021, of which this notice forms part (the "**Circular**") be and is hereby approved and the Directors (or a committee of the Directors) be and are hereby authorised to waive, amend, vary or extend any of the terms of the Sale and Purchase Agreement, as the case may be (provided that any such waivers, amendments, variations or extensions are not of a material nature), and to do all things as they may consider to be necessary or desirable to implement and give effect to, or otherwise in connection with, the Acquisition and any matters incidental to the Acquisition.

By order of the Board,

Anne McSherry
Secretary
29 June 2021

Registered office:

50 Lothian Road, Edinburgh EH3 9BY, United Kingdom

Shareholder Notes:

1. Please note that, in light of the ongoing COVID-19 pandemic and the UK and Scottish legislation and government guidance currently in force as a consequence of the pandemic, there remain in force significant restrictions on public gatherings. Unless there is a material change in circumstances between the date of this Notice of General Meeting and the date of the meeting itself, only a very limited number of Shareholders or their appointed proxies (unless the proxy is the chair of the General Meeting) will be allowed to attend the General Meeting. All of the notes to this notice of General Meeting and, in particular, any reference to attendance at the General Meeting, whether by a Shareholder, its proxy or its corporate representative, shall be construed accordingly. A member of the Company entitled to attend and vote at the General Meeting is entitled to appoint a proxy or proxies to attend, speak and vote instead of him or her. A proxy need not be a member of the Company, but must attend the General Meeting to represent you. As noted above, only a very limited number of Shareholders or their appointed proxies (unless the proxy is the chair of the General Meeting) will be allowed to attend the General Meeting. A form of proxy (the "**Form of Proxy**") accompanies this Notice of General Meeting and must be lodged with the Company at the office of its registrars, Equiniti Limited, Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA (the "**Registrars**") or received via the Sharevote service (see Note 2 below) or lodged using the CREST proxy voting service (see Note 3 below) not less than 48 hours before the time appointed for the General Meeting or any adjournment(s) thereof (excluding any part of any day that is not a working day). The appointment of a proxy or submission of an electronic voting direction will not preclude a member entitled to attend and vote at the General Meeting from doing so if he or she wishes. You can only appoint a proxy using the procedures set out in these notes and the notes to the Form of Proxy. If you wish to change or revoke your proxy appointment, please contact the Registrars on 0371 384 2660 (for calls from within the United Kingdom) and +44 (0) 121 415 7047 (for calls from outside the United Kingdom) between 8.30 a.m. and 5.30 p.m. (both BST) on any Business Day. Calls to +44 (0) 121 415 7047 from outside the United Kingdom are charged at applicable international rates.

2. Members may register their proxy appointments or voting directions electronically via the www.sharevote.co.uk website, where full details of the procedure are given. Members will need the Voting ID, Task ID and Shareholder Reference Number set out on the Form of Proxy which accompanies this Notice of General Meeting. Members are advised to read the terms and conditions of use carefully. Electronic communication facilities are available to all shareholders and those who use them will not be disadvantaged. The Company will not accept any communication that is found to contain a computer virus.

3. CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the General Meeting to be held on 19 July 2021 and any adjournment(s) thereof by using the procedures described in the CREST Manual. CREST personal members or other CREST sponsored members, and those CREST members who have appointed a voting service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

4. 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 UK & Ireland Limited's specifications and must contain the information required for such instructions, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or 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 Registrars (ID RA19) by no later than 9.00 a.m. (BST) on 15 July 2021, or, in the event that the General Meeting is adjourned, not less than 48 hours before the time appointed for the adjourned General Meeting (excluding any part of any day that is not a working day). No such message received through the CREST network after this time will be accepted. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST core processor) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time, any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

5. CREST members and, where applicable, their CREST sponsors or voting service provider(s) should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular messages. Normal system timings and limitations will therefore apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member or sponsored member or has appointed a voting service provider(s), to procure that his or her CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting service provider(s) are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings, which can be viewed at www.euroclear.com. 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.

6. You may appoint more than one proxy provided that each proxy is appointed to exercise rights attached to different Shares. You may not appoint more than one proxy to exercise rights attached to any one Share. To appoint more than one proxy, please contact the Registrars on 0371 384 2660 (for calls from within the United Kingdom) and +44 (0) 121 415 7047 (for calls from outside the United Kingdom) between 8.30 a.m. and 5.30 p.m. (both BST) on any Business Day. Please note that calls to these numbers may be monitored and recorded. Calls to +44 (0) 121 415 7047 from outside the United Kingdom are charged at applicable international rates.

7. The right to appoint a proxy does not apply to persons whose shares are held on their behalf by another person and who have been nominated to receive communications from the Company in accordance with section 146 of the Companies Act 2006 ("**Nominated Persons**"). Nominated Persons may have a right under an agreement with the registered shareholder who holds the shares on their behalf to be appointed (or to have someone else appointed) as a proxy. Alternatively, if Nominated Persons do not have such a right, or do not wish to exercise it, they may have a right under such an agreement to give instructions to the person holding the shares as to the exercise of voting rights.

8. Any corporation which is a shareholder can appoint one or more corporate representative(s) who may exercise on its behalf all of its powers as a shareholder provided that they do not do so in relation to the same Shares.

9. To be entitled to vote at the General 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 at 6.30 p.m. (BST) on 15 July 2021 (or, in the event of any adjournment, on the date which is two days (excluding

any part of a day that is not a working day) before the time of the adjourned meeting). Changes to the register of members after the relevant deadline shall be disregarded in determining the rights of any person to vote at the meeting.

10. As at 5.00 p.m. (BST) on 25 June 2021 (being the latest practicable time before printing this Notice of General Meeting), the Company's issued share capital comprised 499,267,656 ordinary shares of 21/13 pence each. Each such ordinary share carries the right to one vote at a general meeting of the Company. Therefore, the total number of voting rights in the Company as at 5.00 p.m. (BST) on 25 June 2021 was 499,267,656. It is proposed that all votes on the Resolution at the General Meeting will be taken by way of a poll rather than on a show of hands. The Company considers that a poll is more representative of Shareholders' voting intentions because (a) votes are counted according to the number of shares held and all votes tendered are taken into account, and (b) only a very limited number of Shareholders will be allowed to attend the General Meeting in person as a result of the laws and associated guidance introduced in response to the current COVID-19 pandemic. The results of the voting will be announced through a Regulatory Information Service and will be published on our website www.cairnenergy.com as soon as reasonably practicable thereafter.

11. In accordance with section 311A of the Companies Act 2006, the contents of this Notice of General Meeting, details of the total number of shares in respect of which members are entitled to exercise voting rights at the General Meeting and, if applicable, any members' statements, members' resolutions or members' matters of business received by the Company after the date of this Notice of General Meeting will be available on the Company's website at www.cairnenergy.com.

12. Pursuant to section 319A of the Companies Act 2006, the Company must cause to be answered at the General Meeting any question relating to the business being dealt with at the General Meeting which is put by a member attending the General Meeting, except in certain circumstances, including if it is undesirable in the interests of the Company or the good order of the General Meeting that the question be answered or if to do so would involve the disclosure of confidential information. As only a very limited number of Shareholders are expected to attend the General Meeting, the Board will also offer an opportunity for Shareholders to engage in advance of the meeting through a facility to submit questions by email. If Shareholders have any questions for the Board in relation to the Transaction before the General Meeting, these can be sent by email to IR.Mailbox@cairnenergy.com. The Board will endeavour to answer key themes of these questions on the Company's website as soon as practical.

13. Copies of the following documents may be inspected at the registered office of the Company during normal business hours, Monday to Friday (public holidays excepted) up to and including the day of the General Meeting, and at the venue for the General Meeting from 15 minutes before the time fixed for the General Meeting until the end of the General Meeting:

    - the current memorandum and articles of association of the Company;
    - the Sale and Purchase Agreement;
    - the Circular (including this Notice of General Meeting) and the Form of Proxy; and
    - copies of the 2018 Annual Report and Accounts, the 2019 Annual Report and Accounts and the 2020 Annual Report and Accounts.

14. A member may not use any electronic address provided either in this Notice of General Meeting or any related documents (including the Chair's letter and the Form of Proxy), to communicate with the Company for any purpose other than those expressly stated.