THIS DOCUMENT AND THE ACCOMPANYING FORM OF PROXY ARE IMPORTANT AND REQUIRE YOUR IMMEDIATE ATTENTION. If you are in any doubt as to the action you should take, you are recommended to seek your own financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other professional 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, please send this document (the "Circular"), together with the accompanying Form of Proxy, at once to the purchaser or transferee, or to the stockbroker, bank or other agent through whom the sale or transfer was effected for transmission to the purchaser or transferee, 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, please consult the bank, stockbroker or other agent through whom the sale or transfer was effected.

OPHIR ENERGY PLC

Incorporated under the Companies Act 1985 and registered in England and Wales with registered number 05047425

Proposed acquisition of certain Southeast Asian producing and exploration assets from Santos Limited

This Circular should be read as a whole. Your attention is drawn to the letter from the Chairman of Ophir which is set out in Part I of this Circular and which recommends you to vote in favour of the Resolutions 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 Resolutions to be proposed at the General Meeting. The whole of this Circular should be read in light of these risk factors.

Notice of a General Meeting of Ophir to be held at the offices of Linklaters LLP, One Silk Street, London EC2Y 8HQ at 12:00 p.m. on Monday 20 August 2018 is set out at the end of this Circular. A Form of Proxy for use at the General Meeting is enclosed with this Circular. The Form of Proxy, and any power of attorney or other authority under which it is executed (or a duly certified copy of any such power or authority), must be either: (i) received by post or (during normal business hours only) by hand at the offices of the Ophir's Registrars, Equiniti Limited, Aspect House, Spencer Road, Lancing BN99 6DA, United Kingdom; or (ii) Shareholders may submit their proxies electronically at www.sharevote.co.uk using the Voting ID, Task ID and Shareholder Reference Numbers set out in the Form of Proxy, in each case so as to be received by no later than 12:00 p.m. on Thursday 16 August 2018, being 48 hours before the time appointed for the holding of the General Meeting, excluding non-working days.

CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the General Meeting by following the procedures described in the CREST Manual (available at www.euroclear.com). CREST Personal Members or other CREST Sponsored Members, and those CREST members who have appointed a voting service provider, should refer to their CREST sponsor or voting service provider who will be able to take the appropriate action on their behalf. In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST proxy instruction must be transmitted in accordance with the procedures described in the CREST Manual so that it is received by the issuer's agent (ID: RA19) by no later than by the latest time for receipt of proxy appointments specified above.

Completing and returning a Form of Proxy or electronic proxy appointment or completing and transmitting a CREST proxy instruction will not prevent a member from subsequently attending and voting at the General Meeting in person if they so wish.

Barclays Bank PLC ("**Barclays**"), which is authorised by the Prudential Regulation Authority and regulated in the UK by the Financial Conduct Authority and the Prudential Regulation Authority, is acting exclusively for Ophir and no one else in connection with the Transaction and will not be responsible to anyone other than Ophir for providing the protections afforded to clients of Barclays nor for providing advice in relation to the Transaction or any other matter referred to in this Circular. Neither Barclays nor any of its subsidiaries, branches or affiliates owes or accepts any duty, liability or responsibility whatsoever (whether direct or indirect, whether in contract, in tort, under statute or otherwise) to any person who is not a client of Barclays in connection with this Circular, any statement contained herein or otherwise.

Merrill Lynch International ("**BofA Merrill Lynch**"), which is authorised in the UK by the Prudential Regulation Authority and regulated in the UK by the Financial Conduct Authority and the Prudential Regulation Authority, is acting exclusively for Ophir and no one else in connection with the matters described in this Circular, and will not be responsible for anyone other than Ophir for providing the protections afforded to clients of BofA Merrill Lynch nor for providing advice in relation to the matters referred to in this Circular. Neither BofA Merrill Lynch nor any of its subsidiaries, branches or affiliates owes or accepts any duty, liability or responsibility whatsoever (whether direct or indirect, whether in contract, in tort, under statute or otherwise) to any person who is not a client of BofA Merrill Lynch in connection with this Circular, any statement contained herein or otherwise.

Save for the responsibilities and liabilities, if any, of Barclays and BofA Merrill Lynch under the Financial Services and Markets Act 2000 or the regulatory regime established thereunder, Barclays and BofA Merrill Lynch assume no responsibility whatsoever and makes no 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 Ophir, or on Ophir's behalf, or by Barclays or BofA Merrill Lynch or on Barclays' or BofA Merrill Lynch's behalf and 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 Ophir or the Transaction. Barclays and BofA Merrill Lynch accordingly disclaim 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.

INFORMATION RELATING TO THE PRESENTATION AND SOURCE OF INFORMATION

Currencies

References to “Pounds Sterling”, “£” or “pence” are to the lawful currency of the United Kingdom.

References to “US Dollars”, “US$” or “US cents” are to the lawful currency of the United States of America.

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. 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 confirm 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 IX: “Glossary of Technical Terms” and Part X: “Definitions” of this Circular.

For the purposes of this Circular, “subsidiary” and “subsidiary undertaking” have the respective meanings given thereto by the Companies Act 2006.

All references to legislation in this Circular are to the legislation of England and Wales unless otherwise stated. Any reference to any provision of any legislation shall include any amendment, modification, re-enactment or extension thereof.

References to the singular include the plural and vice versa.

Forward Looking Statements

This Circular contains statements that are or may be forward looking statements. All statements other than statements of historical facts included in this Circular may be forward looking statements. Without limitation, any statements preceded or followed by or that include the words “targets”, “plans”, “believes”, “expects”, “aims”, “intends”, “will”, “may”, “anticipates”, “estimates”, “projects” or words or terms of similar substance or the negative thereof, are forward looking statements. Forward looking statements include statements relating to the following: (i) future capital expenditures, expenses, revenues, earnings, synergies, economic performance, indebtedness, financial condition, dividend policy, losses and future prospects; (ii) business and management strategies and the expansion and growth of Ophir’s or the Enlarged Group’s operations; and (iii) the effects of government regulation on Ophir’s or the Enlarged Group’s business.

Such forward looking statements involve risks and uncertainties that could significantly affect expected results and are based on certain key assumptions. Many factors could cause actual results, performance or achievements to differ materially from those projected or implied in any forward looking statements. The important factors that could cause Ophir’s or the Enlarged Group’s actual results, performance or

achievements to differ materially from those in the forward looking statements include, among others, economic and business cycles, the terms and conditions of Ophir's or the Enlarged Group's financing arrangements, foreign currency rate fluctuations, competition in Ophir's or the Enlarged Group's principal markets, acquisitions or disposals of businesses or assets and trends in Ophir's or the Enlarged Group's principal industries. Due to such uncertainties and risks, readers are cautioned not to place undue reliance on such forward looking statements, which speak only as of the date of this Circular. Ophir and each of its members, directors, officers, employees, advisers and any other persons acting on its behalf disclaims any obligation to update any forward looking or other statements contained herein, except as required by applicable law.

Shareholders should specifically consider the factors identified in this Circular which could cause actual results to differ before making an investment decision. Such risks, uncertainties and other factors are set out more fully in Part II: "Risk Factors" of this Circular. To the extent required by the Listing Rules, the Prospectus Rules, the Disclosure Guidance and Transparency Rules, the London Stock Exchange or applicable law, Ophir will update or revise the information in this Circular. Otherwise, Ophir expressly disclaims any obligations or undertakings to release publicly any updates or revisions to any forward looking statements contained in this Circular to reflect any change in the expectations of Ophir or the Enlarged Group with regard thereto or any change in events, conditions or circumstances on which any such statement is based.

No Profit Forecasts or Estimates

No statement in this Circular is intended as a profit forecast or estimate for any period and no statement in this Circular should be interpreted to mean that earnings or earnings per share for Ophir for the current or future financial years would necessarily match or exceed the historical published earnings or earnings per share for Ophir.

The estimated cost savings should not be construed as a profit forecast or interpreted to mean that the Group's earnings in the first full year following the Transaction, or in any subsequent period, would necessarily match or be greater than or be less than those of the Group for the relevant preceding year or any other period.

No Offer or Solicitation

This Circular is not a prospectus and it does not constitute or form part of any offer or invitation to purchase, acquire, subscribe for, sell, dispose of or issue, or any solicitation of any offer to sell, dispose of, purchase, acquire or subscribe for, any security.

Mineral Reserve and Mineral Resource Reporting

Unless otherwise indicated, all reserves and resources information presented in this Circular were prepared using the definitions and guidelines set out by the 2007 PRMS.

"Reserves" are defined by the 2007 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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further 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".

"Contingent resources" are defined by the 2007 PRMS as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not

yet considered mature enough for commercial development due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status".

"Prospective resources" are defined by the 2007 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 discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity".

Shareholders should not place undue reliance on the forward looking statements in this Circular or on the ability of Ophir 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. There can be no assurance that mineral reserve estimates will be accurate or that such reserves can be profitably exploited. 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.

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EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Latest time and date for receipt of Forms of Proxy or electronic proxy appointments or completion and transmission of CREST proxy instructions	12:00 p.m. on Thursday 16 August 2018
General Meeting	12:00 p.m. on Monday 20 August 2018
Expected date of Completion in respect of the Producing Assets	Friday 7 September 2018
Expected date of Completion in respect of the Exploration Assets	First half of 2019

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 in respect of the Producing Assets and the Exploration Assets are both conditional on Shareholder approval. Completion in respect of the Exploration Assets is also conditional upon, amongst other things, regulatory and certain partner consents, and their respective pre-emption regimes. There can be no certainty if or when such conditions will be fulfilled and therefore there is no certainty as at the date of this Circular regarding the date of Completion in respect of any or all of the Exploration Assets.

PART I
LETTER FROM THE CHAIRMAN OF OPHIR

(incorporated under the Companies Act 1985 and registered in England and Wales with registered number 05047425)

Level 4
123 Victoria Street
London
SW1E 6DE

3 August 2018

Dear Shareholder

Proposed acquisition of certain Southeast Asian producing and exploration assets from Santos Limited

1 Introduction

As part of Ophir's strategy to grow its production base further in order to self-fund its selective exploration, appraisal and development activities, on 3 May 2018, the Board announced that Ophir has agreed to acquire a package of Southeast Asian assets from Santos Limited, an Australian listed Oil & Gas company, for an aggregate cash consideration of US$205 million (pre-working capital adjustments), subject to certain approvals (the "**Transaction**"). The portfolio of assets includes (i) material producing assets in Vietnam and Indonesia and (ii) exploration and appraisal assets in Malaysia, Vietnam and Bangladesh.

Ophir's principal rationale for entering into the Transaction is to acquire the material producing assets in Vietnam and Indonesia, from which it expects to derive substantially all of the value of the Transaction. However, as part of the commercial negotiations to agree the Transaction, the Company has also agreed to acquire the exploration and appraisal assets in Malaysia, Vietnam and Bangladesh or to otherwise assume certain exploration liabilities and commitments in respect of them (as further described below).

The Producing Assets

The Transaction involves the acquisition by Ophir of interests in three producing assets: (i) a 31.875% non-operated interest in the Block 12W PSC in Vietnam; (ii) a 45% operated interest in the Sampang PSC in Indonesia; and (iii) a 67.5% operated interest in the Madura Offshore PSC in Indonesia, (together, the "**Producing Assets**").

Further details on each of these Producing Assets is set out in paragraph 3 below.

The Exploration Assets

The Transaction also involves the acquisition by Ophir of interests in the following exploration and appraisal assets: (i) a 20% non-operated interest in the Deepwater Block R PSC in Sabah, Malaysia; (ii) a 50% operated interest in the Block 123 PSC in the frontier Phu Khanh Basin, Vietnam; (iii) a 40% non-operated interest in the Block 124 PSC in the frontier Phu Khanh Basin, Vietnam; and (iv) a 45% operated interest in the Block SS-11 PSC, Bangladesh (together, the "**Exploration Assets**").

Further details on each of these Exploration Assets is set out in paragraph 3 below.

Transaction Structure

The Transaction is being structured as a series of acquisitions of each of the different assets. The acquisitions of the Producing Assets are inter-conditional, with the acquisitions being conditional upon the approval of Shareholders.

The acquisitions of the Exploration Assets are conditional, *inter alia*, on: (i) completion of Ophir's acquisitions of the Producing Assets; (ii) approval of Shareholders; (iii) regulatory consents; and (iv) the relevant pre-emption provisions applicable to the relevant Exploration Asset not being exercised, in each case by 2 May 2019 (or such other date as may be agreed between the parties). The acquisitions of the

Exploration Assets are not inter-conditional and if the conditions are satisfied for some but not all of the Exploration Assets, Ophir will acquire those, but not all of the Exploration Assets.

It is anticipated that the closing of the acquisitions of the Producing Assets will occur before the closing of the acquisitions of the Exploration Assets. However, the acquisitions have each been structured to have an effective economic date of 1 January 2018, with the base consideration (other than in respect of the Block SS-11 Asset) being subject to a locked box mechanism and customary contribution and leakage adjustments.

Further details on the conditions relating to each acquisition are set out in Part III: "Summary of the Transaction Agreements" of this Circular.

The Commitment Compensation Payment Arrangements

If the acquisitions of the Producing Assets complete, but the acquisitions of any or all of the Exploration Assets do not complete, in certain circumstances, in addition to the aggregate cash consideration of US$205 million (pre-working capital adjustments), Ophir has agreed to meet certain future work commitments and budgeted costs on these assets (totalling US$35.5 million) (the "**Commitment Compensation Payment Arrangements**") so that, in effect, if Santos has sold the Producing Assets, it does not retain the liabilities attached to the Exploration Assets that would otherwise have been assumed by Ophir. These arrangements are explained in further detail in Part III: "Summary of the Transaction Agreements" of this Circular.

Funding

The Transaction is being funded through existing financial resources and facilities and a new up to US$130 million acquisition bridge facility which is summarised in paragraph 9.1.2 of Part VI: "Additional Information" of this Circular. The Board expects that the bridge facility will be refinanced into Ophir's existing Reserve Based Lending facility in due course. The refinancing of the Group's outstanding US$105 million NOK bond continues to progress and is expected to be completed by June 2019.

Shareholder Approval

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 conditional upon the approval of Shareholders. The Commitment Compensation Payment Arrangements are also of sufficient size relative to the Group to be treated as a Class 1 transaction under the Listing Rules and these arrangements are therefore also conditional upon the approval of Shareholders.

Your approval of the Transaction (including the Commitment Compensation Payment Arrangements) is therefore being sought at a General Meeting of the Company to be held at 12:00 p.m. on Monday 20 August 2018 at the offices of Linklaters LLP, One Silk Street, London EC2Y 8HQ, United Kingdom. A notice of the General Meeting setting out the Resolutions to be considered at the General Meeting can be found at the end of this Circular. The Resolutions to be considered at the General Meeting permit the Transaction and payment of the Commitment Compensation Payment Arrangements. The Resolutions are inter-conditional so that both or neither will be passed. A summary of the action you should take is set out in paragraph 7 of this letter and on the Form of Proxy that accompanies this Circular.

The purpose of this Circular is to: (i) explain the background to and reasons for the Transaction; (ii) provide you with information about the Producing Assets and Exploration Assets being acquired pursuant to the Transaction; (iii) provide information about the Commitment Compensation Payment Arrangements; (iv) explain why the Directors unanimously consider the Transaction to be in the best interests of the Shareholders as a whole; and (v) recommend that you vote in favour of the Resolutions to be proposed at the General Meeting.

2 Background to and reasons for the Transaction

Ophir is a premium listed, full cycle, upstream oil and gas exploration and production company. Ophir's strategy is to create value by extracting maximum return from its producing assets and existing discoveries and investing selectively in exploration. The Group seeks to monetise success in the most efficient way for each investment, with the intention to reinvest excess cash flows in growth or return capital to Shareholders. Historically, Ophir has focused on deepwater exploration in Africa. Through the acquisition

of Salamander Energy plc in 2015, Ophir has built an efficient cash generative production base in Southeast Asia to complement its exploration assets and discoveries. The Group's short to medium term objective is to grow the production base further in order to self-fund its selective exploration, appraisal and development activities, as well as future value-enhancing acquisitions and potentially returning capital to Shareholders.

Over recent years, against a challenging backdrop for the sector, Ophir has taken a number of steps to deliver against its strategy including:

- increasing the focus on Ophir's cash generative production and development assets and maximising and expanding the cash flows from that portfolio;
- refocusing exploration into a smaller number of lower-risk near-field opportunities that tie back to existing infrastructure, where Ophir is most confident of being able to monetise discoveries in a shorter time frame (e.g. infield opportunities in the Bualuang field, Thailand and the Kerendan field, Indonesia), alongside the selective acquisition of new acreage in particularly attractive areas (e.g. underexplored world-class petroleum systems, offshore Mexico);
- pursuing opportunities to monetise contingent resources through asset development, farm-out or divestment;
- undertaking a significant cost reduction programme, including reductions to the London head office organisation and executive teams; and
- deploying capital and manpower in a disciplined manner where Ophir sees the greatest risk-adjusted opportunity for returns.

The Board believes that the Transaction represents an attractive next step in this strategy, adding a portfolio of high quality production and development assets that will further enhance the cash flow characteristics of the Group. Furthermore, the Board believes that the Transaction offers a number of opportunities to create significant value for Shareholders including:

- through the addition of a balanced and complementary portfolio of low cost, highly cash generative Producing Assets in Southeast Asia, a region where Ophir already has producing assets;
- through increased scale and stability of cashflows. The Transaction is forecast to increase the Group's 2P reserves by over 40% from 49.4 MMboe to 70.4 MMboe. Forecast production and funds flow for the Enlarged Group for the year ending 31 December 2018 on a full year pro forma basis (assuming the acquisition was effective from 1 January 2018) will increase to c.25,000 boepd (including c.13,500 boepd from the Producing Assets) and US$190 million, respectively;
- through significant near-term development opportunities (e.g. the Meliwis gas field development in Indonesia), alongside production life extensions utilising strategic infrastructure positions;
- through economies of scale in operating expenditures, general and administration expenses and greater financing efficiencies. The Board expects the Enlarged Group to benefit from material cost synergies arising as a result of the Transaction, principally through the combination of the Group's existing Indonesian assets with the Indonesian assets being acquired from Santos. In aggregate, synergies are estimated to be at least US$13 million per annum (pre-costs of realising the synergies); and
- through the deployment of its significant technical expertise and wide ranging regional experience, adding value to the assets via delivering on upside potential where the Group will be operator, or working with project partners where it will not be the operator to drive value creation.

Ophir remains focused on achieving its objectives for its existing assets, specifically FID of the Fortuna project in Equatorial Guinea, which, given the level of cash flows expected from the project once production starts, would also represent an important milestone in accelerating delivery of Ophir's ambition to be fully self-funded. Following the announcement by Ophir on 31 May 2018 regarding the dissolution of the OneLNG joint venture between Golar LNG and Schlumberger, Ophir and Golar remain actively engaged in discussions with new potential partners and financing parties regarding the Fortuna project. The Block

R licence is due to expire at the end of 2018 and, as highlighted in our operations and trading update on 12 July 2018, depending on how these discussions progress, the carrying value of the Block R licence (US$604 million as at 31 December 2017) may need to be reassessed as part of Ophir's interim reporting process. The Board has reaffirmed its current intention not to invest more than US$150 million into the project. Ophir's disciplined approach to capital allocation means that it is able to continue to pursue FID while still delivering the benefits to Shareholders as result of this Transaction.

Ophir will continue to pursue a strategy focused on maximising value of its production, monetising its existing contingent resource base, adding cash generative production assets in order to become self-funded, and investing selectively in growth assets (including selected exploration). Ophir will consider both organic and inorganic growth opportunities to deliver those goals.

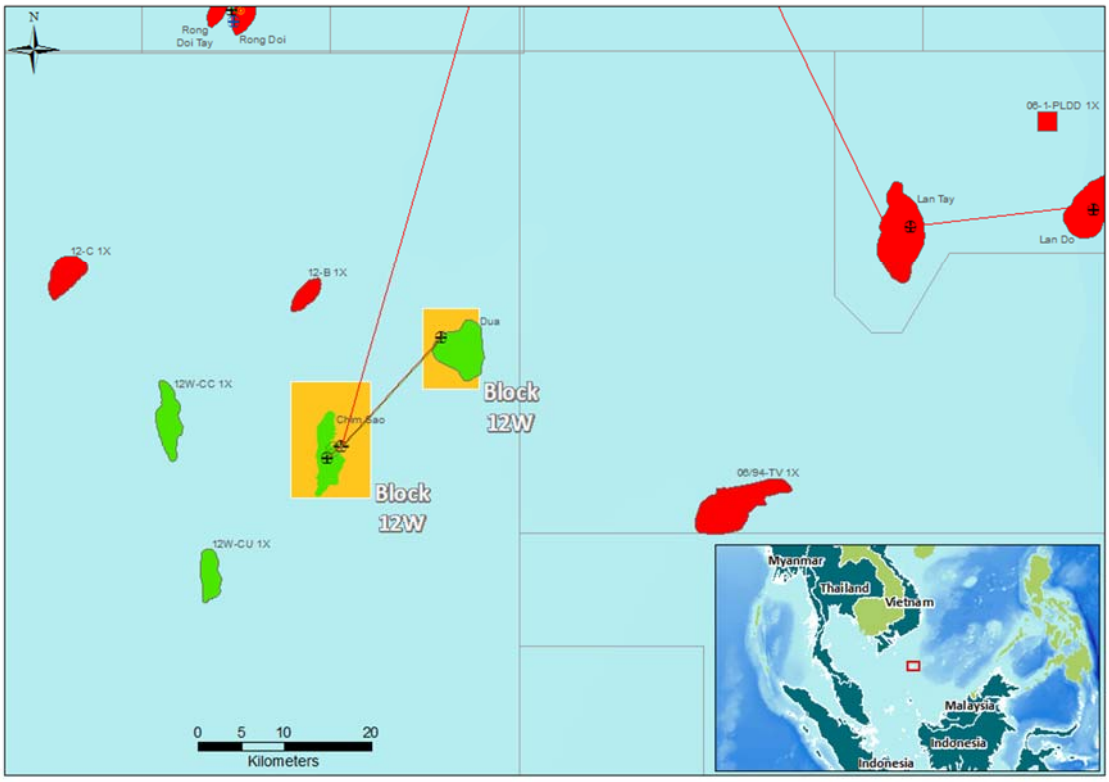
3 Information on the Assets

(i) The Producing Assets

(a) Block 12W, Vietnam

Location

The Block 12W PSC contract area is located in the Nam Con Son basin offshore Vietnam in water depths of approximately 95 metres, covers an area of 182.26 km^2 and contains the Chim Sáo and Dua producing fields. The following map shows the location of the block:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire Santos Petroleum Ventures B.V. which holds a 31.875% non-operated interest in the Block 12W PSC.

The remaining interests are held by Premier Oil (53.125% aggregated interest) (operator) and PetroVietnam (15% non-operated interest).

The Block 12W PSC was awarded in 2000 to Opeco Natural Gas, Ltd. and Samedan Vietnam Ltd. and following a series of transfers between 2000 and 2004, Premier Oil Vietnam Offshore B.V. acquired a 75% participating interest in the Block 12W PSC from Delek Energy (Vietnam) LLC and became operator.

Santos acquired Petroleum Ventures B.V. (now Santos Petroleum Ventures B.V.) from Premier Oil in 2006. At the time of the acquisition, Petroleum Ventures B.V. held a 37.5% interest in the Block 12W PSC.

In 2009, a subsidiary of the Vietnamese state owned oil and gas company, PetroVietnam, exercised a state participation right and acquired a 15% non-operated interest in the Block 12W PSC, which was transferred by the then current contractors to the Block 12W PSC and, as a result, Santos Petroleum Ventures B.V. holds a 31.875% non-operated interest in the Block 12W PSC, with Premier Oil holding a 53.125% interest (through two subsidiaries holding 28.125% operated interest and 25% non-operated interest) and PVEP holding the remaining 15% non-operated interest. PetroVietnam does not have any outstanding state participation rights in the Block 12W PSC.

The Block 12W PSC is scheduled to expire on 21 November 2030.

Santos Petroleum Ventures B.V. does not hold a right of veto over decisions of the Block 12W operating committee, other than those select decisions requiring unanimous approval, which include: waiving the notice requirements for a meeting of the operating committee, a surrender of all or part of the contract area and an assignment of intellectual property to the operator or a party.

Operatorship

In 2004, Premier Oil Vietnam Offshore B.V. was appointed as the operator under the Block 12W PSC.

Exploration and Appraisal

In 2006, Premier Oil Vietnam Offshore B.V. announced the Chim Sáo and Dua discoveries in Block 12W and first oil was achieved from the Chim Sáo field in 2011. A subsea tie-back of the Dua field to Chim Sáo was completed in 2014. Chim Sáo and Dua are now both producing.

Infrastructure

Oil is produced from both fields through the leased Lewek EMAS FPSO. Chim Sáo produces through thirteen production wells supported by seven water injection wells to a well head platform and then exported to the FPSO. Dua produces through three subsea production wells which are tied back to the FPSO through subsea flowlines which are approximately 17 kilometres in length.

Associated gas produced from the Chim Sáo and Dua fields is exported to shore through the Block 12W 96 kilometre 10” gas export pipeline. In 2010, the Block 12W contractors entered into an agreement with the owners of the Nam Con Son transportation system in Vietnam for the tie-in of the Block 12W gas export pipeline with the Nam Con Son pipeline, at which point Block 12W gas is sold to a subsidiary of PetroVietnam.

Production and Reserves

Cumulative gross production to the year end 31 December 2017 was 54.8 MMstb (Chim Sáo: 51.6 MMstb, Dua: 3.1 MMstb) with sales gas of 32.8 Bcf. Gross average 2017 production was approximately 27,000 stb of oil per day and 25 MMcf of associated gas per day.

RISC (UK) Limited has estimated that as of 1 January 2018 a further 40.3 MMstb of oil and 31 Bcf of gas remains to be produced. This represents 2P net reserves entitlement of 10.6 MMstb and 9 Bcf respectively for the interest being acquired (and 1P net reserves entitlement of 7 MMstb and 6 Bcf respectively).

A successful two well infill drilling programme was completed in December 2017, adding approximately 5,000 bbl per day to net production from Block 12W. In 2017, a series of well intervention activities were also completed. These include the addition of new perforations to both existing reservoirs intervals and intervals previously not on production. These activities have added 1,000 to 1,500 bbl per day.

RISC (UK) Limited has estimated that as of 1 January 2018, over 70% of the total value of the Producing Assets is attributable to the Chim Sáo and Dua oil fields.

The estimated gross and net oil and condensate and gas reserves for Block 12W, as well as, inter alia, more details in relation to the historic drilling activity, the subsurface description and the producing wells for Chim Sáo and Dua and production forecasts, are set out in the Competent Person's Report at Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular.

Forward Plan

Following the success of the 2017 infill drilling program, an additional infill well is expected to proceed in 2020. Further infill drilling may also be matured to target most of the 6.5 MMstb contingent resources that have currently been identified. A 2018 well intervention program is also in progress which targets further perforations in the existing well stock. It is anticipated that further activities will also be pursued by the joint venture.

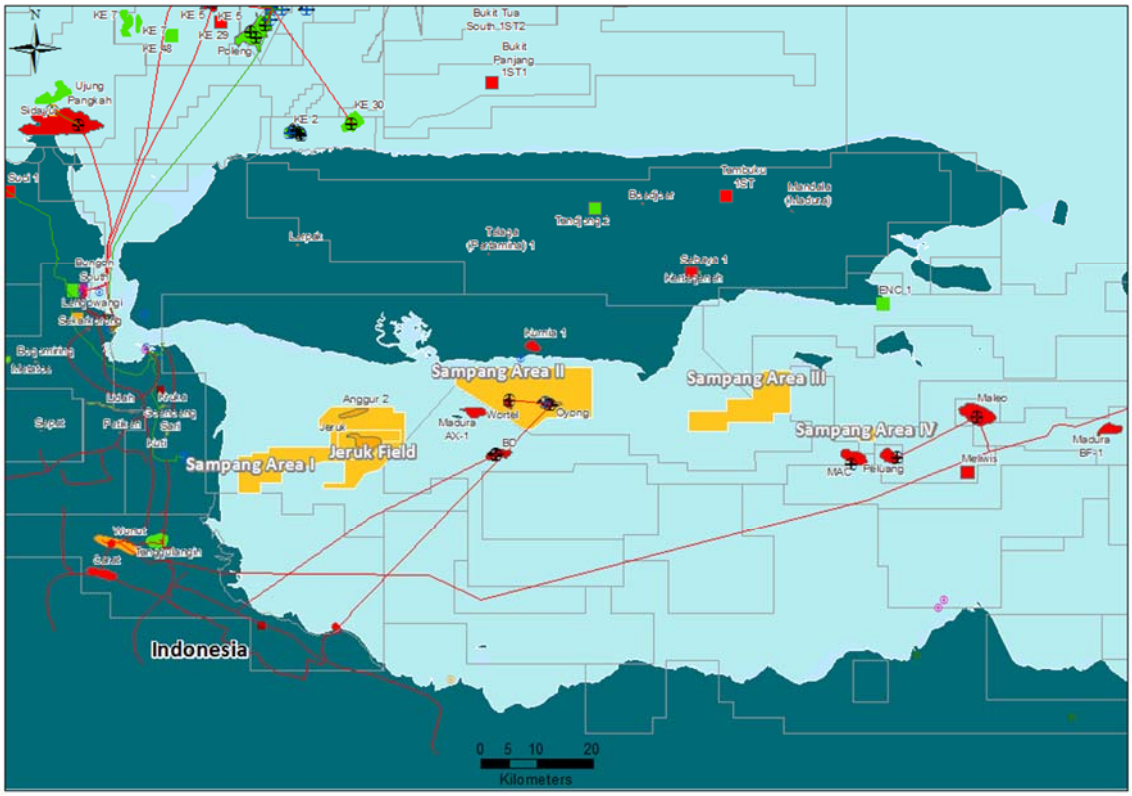
On completion of the acquisition of this asset, Ophir will focus on delineating potential incremental field volumes, and identifying investment opportunities to maximise hydrocarbon recovery, and will work with Premier Oil Vietnam Offshore B.V. to agree a forward work programme to realise that potential as appropriate.

Further information on the Block 12W PSC is set out in the Competent Person's Report in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular which should be read in addition to this asset summary.

(b) Sampang, Indonesia

Location

The Sampang PSC contract area, offshore Indonesia is located in the East Java Basin in water depths of 48 metres to 65 metres and covers an area of 534.30 km^2. The following map shows the location of the block:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire Santos Sampang which holds a 45% operated interested in the Sampang PSC.

The Sampang PSC was awarded to Santos Sampang, Coastal Indonesia Sampang Ltd (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty. Ltd. on 4 December 1997. Santos

Sampang has a 45% operated interest in the Sampang PSC, with Singapore Petroleum Sampang Ltd and Cue Sampang Pty. Ltd holding 40% and 15% non-operated interests, respectively.

The Sampang PSC is comprised of three separate blocks and contains the producing Wortel and Oyong gas fields. The Sampang PSC also contains the Jeruk field which is currently deemed to be a sub-commercial oil discovery.

The Sampang PSC is for a thirty year term and expires on 3 December 2027.

Santos Sampang has a blocking right for all the decisions of the Sampang operating committee and therefore any decisions of the operating committee cannot be passed without Santos Sampang's approval.

Operatorship

Santos Sampang has been the operator of the Sampang PSC since it was awarded on 4 December 1997.

Exploration and Appraisal

The Oyong field was discovered in 2001 and is located offshore Madura Island, Sampang District, approximately 70 kilometres from Surabaya, East Java.

The Wortel field was discovered in 2006 and is located offshore Madura Island, Sampang District, and is approximately 7 kilometres west of the Oyong field.

In 2018, the joint venture partners intend to drill the Paus Biru-1 exploration well located 27 kilometres east from the producing Oyong gas field. The Paus Biru prospect targets the Pliocene Mundu Formation which is analogous to the hydrocarbon producing zone in the Oyong field. The well is planned to be drilled in Q4 2018 to a depth of 650 metres using a jack up drilling rig.

Infrastructure

Gas from the Wortel and Oyong fields is currently being produced from two wells and four wells respectively through the Wortel and Oyong well head platforms. Produced gas from Wortel is exported to the Oyong well head platform and subsequently transported via a 56 kilometre subsea pipeline to a Santos Sampang onshore processing facility in Grati. After processing, gas is sold to PT Indonesia Power and the associated condensate is sold to PT Pertamina.

In 2017, Santos Sampang completed phase one of the Sampang Sustainability Project, which involved switching the Oyong and Wortel fields to an unmanned gas only production system, decommissioning the previously installed floating production storage offloading vessel and the floating storage offloading vessel, and ceasing the production of oil from the fields.

Production and Reserves

Oil production commenced from Oyong in 2007, followed by gas production in 2009. Oil production ceased in mid-2017. Wortel gas production commenced in 2012.

Cumulative gross production to year end 2017 is 190 Bcf of sales gas and 9.8 MMstb of oil and condensate (Oyong: 103 Bcf and 9.7 MMstb; Wortel: 86.8 Bcf and 0.1 MMstb). Gross average 2017 production was approximately 46 MMcf of sales gas per day.

The producing Oyong and Wortel fields are in late life and depleted with substantial production from high quality reservoirs. RISC (UK) Limited has estimated as of 1 January 2018 a further 30 Bcf of gross 2P gas reserves (gross contractor entitlement basis) from the Sampang PSC (and 21 Bcf of gross 1P gas reserves). This represents a 2P net reserves entitlement of 14 Bcf for the interest being acquired (and 1P net reserves entitlement of 9 Bcf).

The estimated gas reserves for Sampang PSC, as well as, inter alia, more details in relation to the historic drilling activity, the subsurface description and the producing wells for Oyong and Wortel and production forecasts, are set out in the Competent Person's Report at Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular.

Forward plan

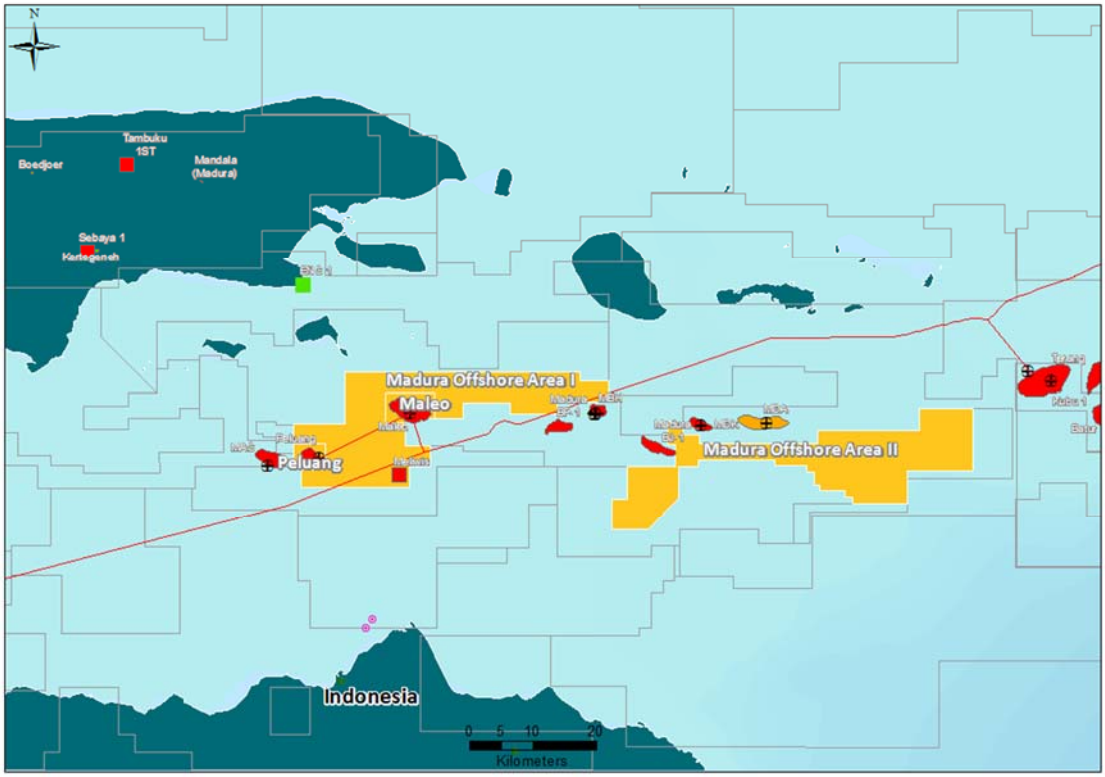
The Wortel and Oyong fields are fully developed. Upside is limited to pushing out field abandonment pressure through ultra-low compression and minor well intervention activity on Oyong. Phase two of the Sampang Sustainability Project ("**SSP2**") is a potential further capital project which would lower the operating pressure of the onshore processing facility at the Grati power plant to 10 psig and would allow for additional 8.5 Bcf of gas (gross 2C) to be recovered from Wortel and Oyong. The SSP2 project has not yet been approved by the joint venture partners and as such the additional gas recovered as a result of SSP2 is classified as contingent resources.

Further information on the Sampang PSC is set out in the Competent Person's Report in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular which should be read in addition to this asset summary.

(c) Madura, Indonesia

Location

The Madura Offshore PSC contract area, offshore Indonesia is located in the East Java Basin in water depths of 48 metres to 65 metres and covers an area of 849 km^2. The following map shows the location of the block:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire Santos Madura which holds a 67.5% operated interested in the Madura Offshore PSC.

The remaining interests are held by PC Madura Ltd. (22.5% non-operated interest) and PT Petrogas Pantai Madura (10% non-operated interest).

The Madura Offshore PSC was awarded to Talisman (Madura) Ltd. on 4 December 1997. In 2001, Santos Madura acquired a 75% operated interest in the Madura Offshore PSC from Talisman (Madura) Ltd.

In 2005, Petronas Carigali Oversees Sdn. Bhd. (now PC Madura Ltd.) acquired a 25% non-operated interest in the Madura Offshore PSC from Talisman (Madura) Ltd. In 2011, a 10% non-operated interest (7.5% from Santos Madura and 2.5% from PC Madura Ltd.) was assigned to PT Petrogas Pantai Madura, an East Java Province regional company, in satisfaction of Indonesian law local

participation requirements. PT Petrogas Pantai Madura does not have any outstanding state participation rights in the Madura Offshore PSC.

The Madura Offshore PSC is comprised of two blocks and includes the producing Peluang and Maleo gas fields and the undeveloped Meliwis gas field. Santos Madura and PC Madura Ltd. participated in the sole risk drilling of Merem-1 and Meliwis-1. PT Petrogas Pantai Madura did not participate and therefore the participating interests in the Meliwis gas field are: Santos Madura 77.5% operated interest and PC Madura Ltd. 22.5% non-operated interest (Santos Madura assumed all of PT Petrogas Pantai Madura's 10% non-operated interest).

The Madura Offshore PSC is for a thirty year term and expires on 3 December 2027.

Santos Madura has a blocking right for all the decisions of the Madura operating committee and therefore any decisions of the operating committee cannot be passed without Santos Madura's approval.

Operatorship

In 2001, Santos Madura was appointed the operator under the Madura Offshore PSC.

Exploration and Appraisal

The Maleo field was discovered in 2002 and is located offshore Madura Island, Sumenep District, approximately 145 kilometres from Surabaya, East Java, and approximately 7.4 kilometres from the East Java Gas Pipeline. The Peluang field was discovered in 2009 and is located offshore Madura Island, Sumenep District, and is approximately 17 kilometres Southwest of the Maleo field, as a tie-back to the existing Maleo facilities. The Meliwis field was discovered in 2016, some 11 kilometres south of the Maleo field.

Exploration opportunities in the Madura Offshore PSC include the Cangak-Berusaha-Molah ("**CBM**") prospects which target the proven Mundu formation on the Maleo and Peluang fields. The CBM and other exploration prospects in the Madura Offshore PSC are dependent on the joint venture partners obtaining an extension to the current term of the Madura Offshore PSC.

Infrastructure

The Peluang and Maleo fields are produced using one and four wells respectively. Gas from the Peluang wellhead platform is exported via an approximately 17 kilometre 10"-diameter pipeline, which is tied back to the leased Maleo production platform (MPP), which has gas compression. Gas from Maleo is also processed on the leased MPP. Maleo and Peluang gas is sold to separate buyers at the inlet to the East Java Gas Pipeline via a 7.4 kilometre spur-line.

Production and Reserves

Production commenced from Maleo in 2006 and Peluang in 2014. Cumulative gross production year end 2017 is 306 Bcf and 32 Bcf sales of gas respectively. Gross average 2017 production was approximately 54 MMcf of sales gas per day.

The Maleo field is in decline whilst the Peluang field is in plateau and provides backfill to the Maleo production. RISC (UK) Limited has estimated that as of 1 January 2018 a further 28 Bcf of gross 2P gas reserves (gross contractor entitlement basis) from the Madura Offshore PSC (and 11 Bcf of gross 1P gas reserves). This represents a 2P net reserves entitlement of 19 Bcf for the interest being acquired (and 1P net reserves entitlement of 7 Bcf).

The estimated gas reserves for Madura Offshore PSC, as well as, inter alia, more details in relation to the historic drilling activity, the subsurface description and the producing wells for Maleo and Peluang fields and production forecasts, are set out in the Competent Person's Report at Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular.

Forward plan

The Maleo and Peluang fields are fully developed. The potential Meliwis gas development presents the major potential upside in the Madura PSC.

The Meliwis development is planned as a single well wellhead platform tie-back to Maleo with a plateau rate of 25 MMcf per day. The development plan was submitted to the regulator during Q4 2017 and approved in January 2018. The Meliwis development plan envisages an unmanned well head platform in 74 metres of water tied back to the Maleo production platform (MPP). FID for Meliwis is expected to be taken in the coming months. Accordingly, Meliwis has been classified as a contingent resource which is assessed to produce 35.95 Bcf (gross 2C, technical recovery). On FID these resources would be reclassified as 2P reserves. A Meliwis project would also extend the economic field life of the Maleo and Peluang fields, resulting in an additional recovery of 8.3 Bcf (gross 2C) from these fields.

Further information on the Madura Offshore PSC is set out in the Competent Person's Report in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular which should be read in addition to this asset summary.

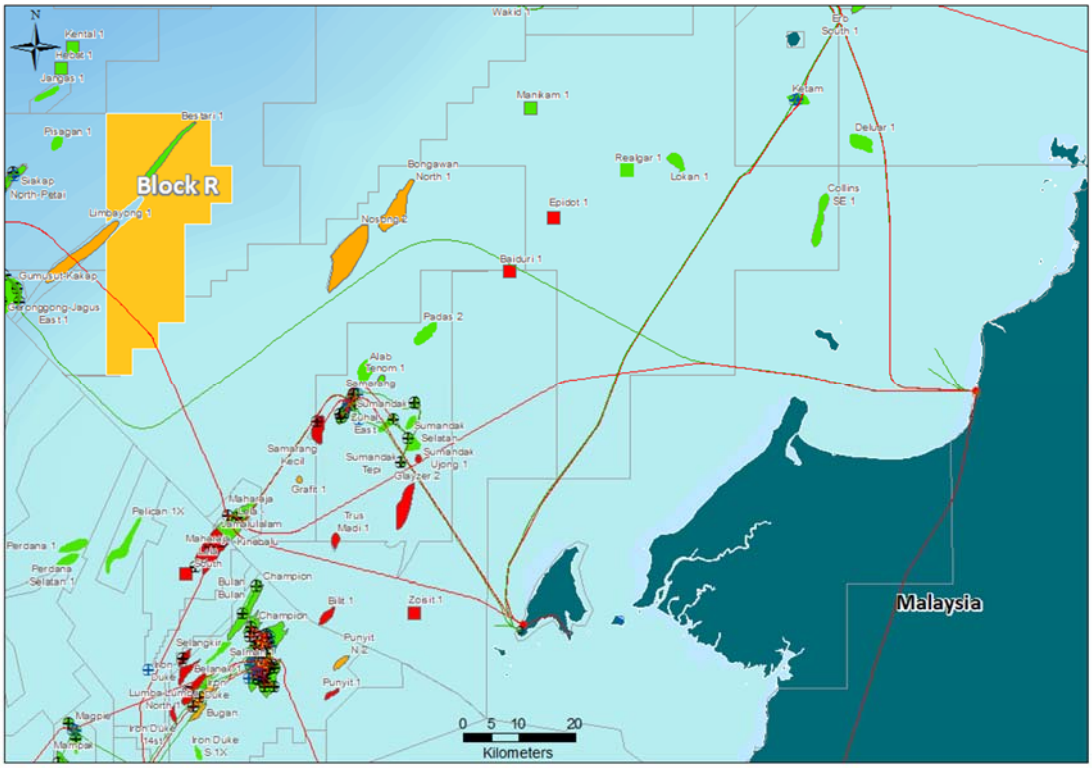
(ii) The Exploration Assets

As the Exploration Assets consist of early stage appraisal or exploration blocks, there is limited information pertaining to volumes and reserves. Following completion of the transfer of Santos's interests in the Exploration Assets, Ophir intends to undertake an integrated subsurface and commercial review of the respective exploration blocks and their prospectivity such that it can effectively rank the attractiveness of each asset against the assets in Ophir's current portfolio. Any subsequent investment decisions will be in line with Ophir's capital allocation framework. During the period prior to Completion, Santos cannot take a decision to withdraw from any of the Exploration Assets without Ophir's consent.

(a) Deepwater Block R PSC in Sabah, Malaysia

Location

The Deepwater Block R PSC contract area is located offshore Sabah, Malaysia and contains the oil discovery in the Bestari reservoir. The contract area is located in water depths of approximately 100 metres to 1,400 metres and covers an area of 672 km^2. The following map shows the location of the block:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire Santos Sabah which holds a 20% non-operated interest in the Deepwater Block R PSC.

The Deepwater Block R PSC was awarded to Inpex and JX Nippon in 2012. Pursuant to separate farm-in agreements, Inpex and JX Nippon each transferred a 10% non-operated interest in the Deepwater Block R PSC to Santos Sabah in 2015.

Santos Sabah therefore holds a 20% non-operated interest in the Deepwater Block R PSC, with Inpex and Petronas Carigali Sdn. Bhd. holding 27.5% and 25% non-operated interests, respectively. JX Nippon holds a 27.5% operated interest.

The current phase of the Deepwater Block R PSC is due to expire on 16 January 2019.

Santos Sabah does not have a blocking vote for the operating committee for the Deepwater Block R PSC, although Santos Sabah's approval is required for determination of a development plan to be submitted to Petronas for approval in its capacity as regulator.

Operator

JX Nippon was appointed operator under the Deepwater Block R PSC in 2012.

Exploration and Appraisal

The Bestari oil discovery was made in 2015, when the Deepwater Block R PSC contractors drilled the Bestari-1 well. An appraisal well, Bestari-2, was drilled in 2015 and did not encounter a hydrocarbon column. A further appraisal well, Bestari-3, was drilled at the end of 2017 and encountered oil. Bestari-3 was the final commitment well for the Deepwater Block R PSC.

Forward Plan

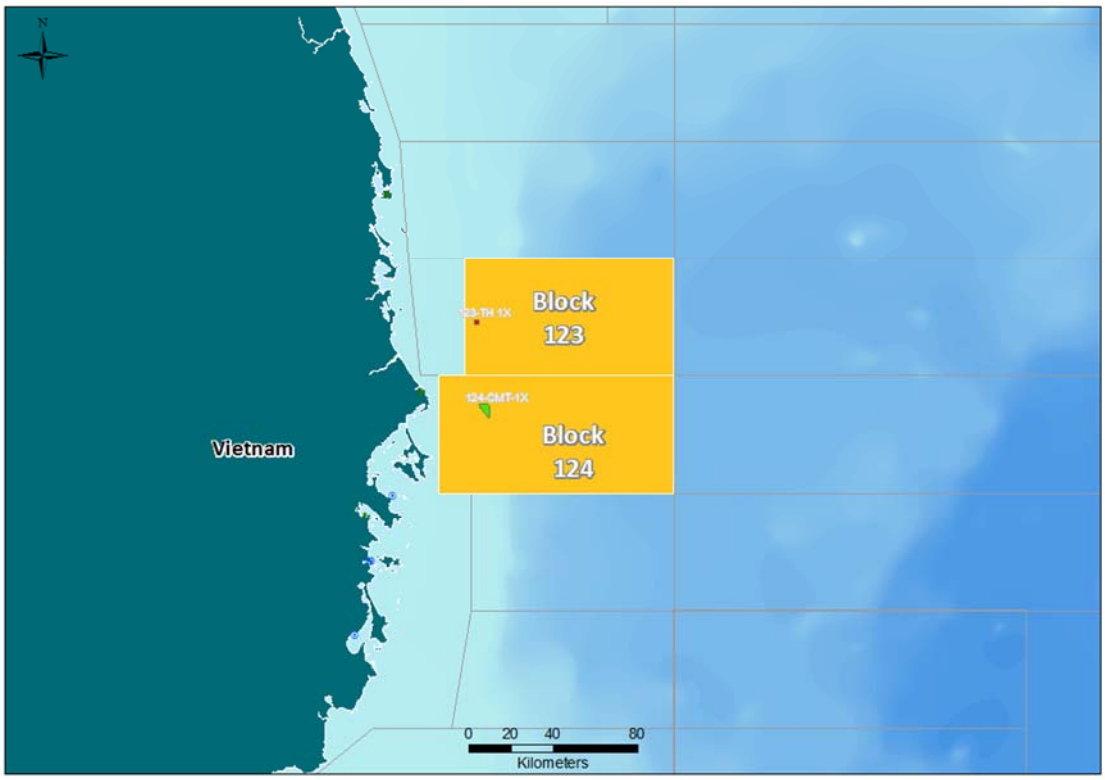
Pursuant to a letter dated 3 December 2015, Petronas acknowledged and accepted the completion of all the minimum work commitments under the Deepwater Block R PSC. The Deepwater Block R PSC was extended in 2015 and 2016 for the drilling of the two appraisal wells, Bestari-2 and Bestari-3. Petronas have recently provided another one-year extension to the Deepwater Block R PSC until January 2019 to allow for Bestari-3 post well-evaluation and future appraisal and development studies. All the minimum work commitments for the exploration period (including the extensions) under the Deepwater Block R PSC have been completed.

The joint venture is currently considering whether to proceed with the development of the Bestari prospect. The current phase of the Deepwater Block R PSC expires in January 2019 and a decision will need to be reached before this time as further described in paragraph 9.2.6(a) of Part VI: "Additional Information" of this Circular. The acquisition of Santos Sabah by Ophir is not conditional on the outcome of this decision and so if the conditions to their acquisition are satisfied but the licence expires or is relinquished, Ophir will still acquire Santos Sabah notwithstanding that it will no longer hold an interest in the Deepwater Block R PSC.

(b) Blocks 123 and 124, Vietnam

Location

The Block 123 PSC and Block 124 PSC contract areas are located in the Phu Khanh Basin offshore Vietnam in water depths of approximately 20 metres to 2,600 metres. Block 123 covers an area of 5,310 km^2 and Block 124 covers an area of 6006 km^2. The following map shows the location of the blocks:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire Santos Vietnam which holds a 50% operated interested in the Block 123 PSC and a 40% non-operated interest in the Block 124 PSC.

The Block 123 PSC was awarded to Santos Vietnam, SK Innovation Co. Ltd and PVEP in 2008. Santos Vietnam holds a 50% operated interest in the Block 123 PSC, with PVEP and SK Innovation Co. Ltd holding 30% and 20% non-operated interests, respectively. PVEP is carried by Santos Vietnam and SK Innovation Co. Ltd during the exploration period.

Block 124 PSC was awarded to Eni Vietnam B.V. ("**Eni**") and Santos Vietnam in 2014. Santos Vietnam holds a 40% non-operated interest in the Block 124 PSC, with Eni holding the remaining 60% operated interest. If there is a declaration of a commercial discovery under the Block 124 PSC, PetroVietnam will have the right to acquire a 30% non-operated interest in the Block 124 PSC which shall be transferred by Eni and Santos Vietnam in proportion to their respective interests.

The term of the Block 123 PSC and the Block 124 PSC is 30 years from the effective date (being 12 June 2008 and 30 October 2014 respectively). If, at the end of the exploration periods under the Block 123 PSC and the Block 124 PSC, no commercial discoveries are made, the PSCs automatically terminate. The exploration period for the Block 123 PSC is due to expire on 11 June 2019 and the exploration period for the Block 124 PSC expires on 29 October 2020.

Santos Vietnam has a blocking right for all the decisions of the Block 123 operating committee and therefore any decisions of the operating committee cannot be passed without Santos Vietnam's approval. Santos Vietnam also has a blocking right for all decisions of the Block 124 operating committee, subject to any votes in respect of the minimum work commitment for which Eni in its capacity as operator has a casting vote.

Operator

Santos Vietnam is the operator under the Block 123 PSC. Eni is the operator under the Block 124 PSC.

Exploration and Appraisal

During the first exploration phase of the Block 123 PSC, 2D and 3D seismic data was collected and one exploration well was drilled.

500km^2 of 3D seismic data was acquired in March 2018 which satisfies the minimum work commitment for the acquisition of seismic activity in relation to phase one of the Block 124 PSC Exploration Period, with outstanding requirements to process and interpret the data (currently ongoing). The processing of this acquired seismic data is currently ongoing, as further described in paragraph 9.2.5(c) of Part VI "Additional Information" of this Circular.

Forward Plan

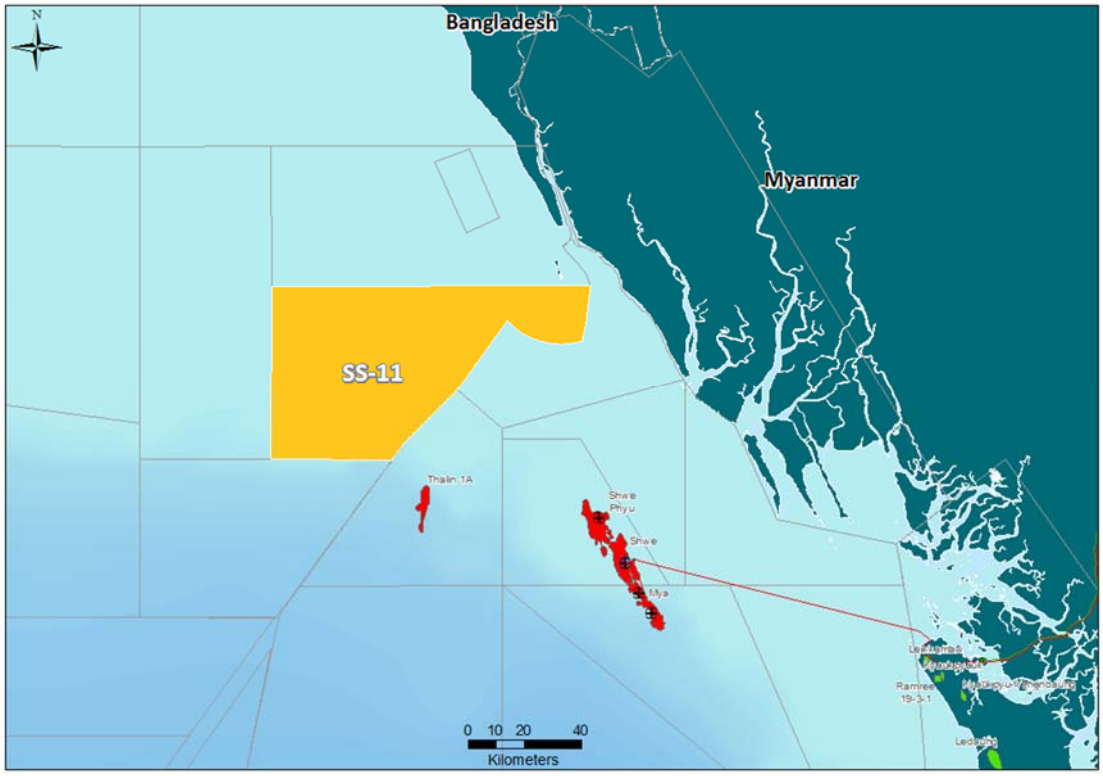
The Block 123 PSC contains a minimum work commitment to drill two exploration wells by the expiry of the current exploration phase, as further described in paragraph 9.2.5(a) of Part VI "Additional Information" of this Circular.

There is an outstanding minimum work commitment to drill one exploration well under the Block 124 PSC, as further described in paragraph 9.2.5(c) of Part VI: "Additional Information" of this Circular.

(c) Block SS-11, Bangladesh

Location

The Block SS-11 PSC contract area covers an area of 4,475 km^2 in the Bay of Bengal over the Bengal Fan. The majority of the block lies in shallow waters up to 200 metres with the furthest southwest portion extending into water depths up to 1,500 metres. Block SS-11 is adjacent to the Bangladesh/Myanmar maritime boundary and is north of the recently developed multi-Tcf Shwe gas field. The following map shows the location of the block:



Interest

Under the terms of the Transaction, Ophir has agreed to acquire the 45% operated interest in Block SS-11 currently held by Santos Sangu. In March 2014, Santos Sangu was awarded a 45% operated interest in the SS-11 PSC. KrisEnergy (Asia) Ltd and BAPEX were awarded a 45% and 10% non-operated interest respectively. BAPEX is carried by Santos Sangu and KrisEnergy during the exploration period of the SS-11 PSC.

The term of the SS-11 PSC is for a maximum of 33 years for oil and 38 years for gas. The current exploration period is due to expire on 11 March 2019. It is the current intention of the joint venture partners to apply for an extension to the initial exploration period after completing the 3D seismic, in order to allow further time to complete the well commitment. The acquisition of the 45% operated interest in Block SS-11 by Ophir is not conditional on the extension to the initial exploration period

and so, if the conditions to the acquisition are satisfied but the initial exploration period in the SS-11 PSC is not extended, Ophir will still acquire the 45% operated interest in Block SS-11 (including the liability to pay Petrobangla for not having fulfilled the minimum work commitment, as summarised at paragraph 9.2.7 of Part VI: "Additional Information" of this Circular.

Under the SS-11 PSC, Santos Sangu is not able to pass any operating committee resolution without KrisEnergy's approval.

Operator

Santos Sangu was awarded the operatorship of the SS-11 PSC in March 2014 and this will be transferred to Ophir when it acquires Santos Sangu's interest as described above (subject to the approval of Petrobangla and the written consent of KrisEnergy (Asia) Ltd).

Exploration Activities

In 2015, a 3,146 kilometre block-wide 2D seismic acquisition program was completed in SS-11 PSC. The 22-day program was conducted by CGG Services SA. In Q2 2018 a 300 km^2 3D marine seismic survey was acquired by COSL Oil-Tech (Singapore) Limited in SS-11 PSC.

Forward Plan

The 2018 acquired 3D seismic data is currently being processed and final seismic data volumes suitable for interpretation are anticipated before the end of 2018. Following completion of the transfer of Santos Sangu's interest, Ophir will undertake an integrated subsurface and commercial review which will incorporate the newly acquired 3D seismic data, with the block wide 2D seismic data and Ophir regional knowledge from its exploration activities in the Bay of Bengal, and in particular Myanmar.

The drilling of one exploration well is the remaining outstanding work commitment for the initial exploration phase of the SS-11 PSC, which is currently scheduled to end in March 2019.

4 Financial effects of the Transaction

Ophir management, having reviewed and analysed the benefits of the Transaction and based on their experience of operating in the sector and integrating Salamander Group plc and Dominion Petroleum Ltd into the Group, expect to deliver in excess of US$13 million per annum of cost synergies as a result of the Transaction, to be achieved progressively and reach run-rate by the second year post Completion.

The synergies are expected to be derived from a reduction in general and administrative costs, principally through, in order of significance:

- savings in manpower costs achieved via workforce reductions where there is duplication in a particular location;
- reductions in office and facilities costs, IT costs and general administration costs where both Ophir and Santos have existing office facilities and these can be combined into a single office location; and
- reductions in corporate overheads achieved by the consolidation of various corporate support functions such as corporate accounting and IT.

Achieving these synergies is expected to result in one-off costs of US$15 million to the Enlarged Group, with these costs expected to be incurred over the period Q4 2018 to end Q2 2019. These synergies are expected to arise as a direct result of the Transaction and could not be achieved independently, and reflect both the beneficial elements and relevant costs. Aside from these one-off costs, management does not anticipate any material dis-synergies to arise as a result of this transaction. In general, the level of synergy savings has been risk adjusted exercising a degree of prudence in the calculation of the estimated synergy benefits.

Management have a strong track record in delivering synergies from acquisitions, having delivered a 60% reduction in general and administrative costs in the three-year period following the acquisition of Salamander Energy plc in 2015.

The costs baseline used to generate the estimated synergies number reflects the cost base as included in the approved 2018 budgets for both organisations. In addition, Santos has provided sufficiently detailed information on organisational structure together with detailed budget breakdowns to allow a bottom up review to take place to arrive at the estimated level of run-rate savings that can be achieved. The review of the organisational information allowed decisions to be made on potential savings to be found from the combination of overlapping roles and functions. In addition, sufficient clarity was provided on office lease agreements and major contracts for facilities including IT services and transportation, to allow quantification of potential savings from eliminating duplicated services in these areas.

In making this estimate, management have focused purely on general and administrative activities with savings only being captured where overlap exists. By design, management have not attempted to make any changes to operational capability and no savings from operations are included. This is consistent with management's intention to maintain and grow the production base in the acquired production assets. In addition, management has assumed that there will be no material change to political, regulatory or legal conditions in the markets or regions in which the synergies are expected to be achieved that would materially impact on the ability to achieve or implement the synergy plans or the cost of doing so.

Looking forward, on a full year pro forma basis for the year ending 31 December 2018 (assuming the acquisition was effective from 1 January 2018), management expect the Transaction to:

- add 13,500 boepd of production, which would take the full year production to 25,000 boepd;
- increase operating cashflow to US$190 million (as against an expectation of $100 million for Ophir standalone); and
- increase capital expenditure, excluding the costs of the acquisition, to US$145 million, US$25 million of which relates to the Producing Assets (as against an expectation of US$120 million for Ophir standalone).

Should the Transaction complete, management expect net debt and gross liquidity (cash and undrawn debt facilities) as at 31 December 2018 to be circa US$135 million and circa US$280 million respectively.

An unaudited pro forma statement of consolidated net assets illustrating the effect of the Transaction on Ophir's consolidated net assets as at 31 December 2017, as if Completion had occurred at that date, is set out in Part V: "Pro Forma Statement of Net Assets of the Enlarged Group" of this Circular. This information has been prepared for illustrative purposes only. It shows that the Transaction would have led to a pro-forma movement in consolidated net assets from US$1,461 million to US$1,454 million as at 31 December 2017.

As at 31 December 2017, the value of the gross Assets totalled US$433.0 million. The profit before tax attributable to the Assets totalled US$101.3 million in 2017.

The future work commitments and budgeted costs across the Exploration Assets (which Ophir has agreed to pay as part of the Commitment Compensation Payment Arrangements), along with the historical capital expenditure for each asset for the previous three years, is shown below:

Capital Expenditure	**2015**	**2016**	**2017**	**Future work commitments**
		($m)		
20% non-operated interest in the Deepwater Block R PSC in Sabah, Malaysia	83.5	3.2	7.4	3.1
50% operated interest in the Block 123 PSC in the frontier Phu Khanh Basin, Vietnam	0.9	0.6	0.1	15.2
40% non-operated interest in the Block 124 PSC in the frontier Phu Khanh Basin, Vietnam	2.0	0.4	0.4	8.8
45% operated interest in Block SS-11 PSC, Bangladesh	2.1	0.4	0.4	8.4

Shareholders should read the whole of this Circular and should not rely solely on the summarised financial information set out above.

5 Terms of the Transaction

A summary of the Transaction Agreements is set out in Part III: "Summary of the Transaction Agreements" of this Circular.

6 General Meeting

Completion is conditional, amongst other things, upon Shareholders' approval being obtained at the General Meeting. Accordingly, you will find set out at the end of this Circular a notice convening a General Meeting to be held at the offices of Linklaters LLP at One Silk Street, London EC2Y 8HQ, United Kingdom at 12:00 p.m. on Monday 20 August 2018 at which the Resolutions will be proposed to approve the Transaction and the Commitment Compensation Payment Arrangements.

The Resolutions will be proposed as ordinary resolutions that will be passed if a simple majority of the votes cast are in favour of the Resolutions. **The Resolutions are also inter-conditional so that both or neither will be passed.**

7 Action to be Taken

You will find enclosed a Form of Proxy for use at the General Meeting. Whether or not you intend to be present at the General Meeting, you are requested to complete the Form of Proxy in accordance with the instructions printed on it and return it as soon as possible and in any case so as to be either: (i) received by the Company's Registrars, Equiniti Limited, Aspect House, Spencer Road, Lancing BN99 6DA, United Kingdom; or (ii) Shareholders may submit their proxies electronically at www.sharevote.co.uk using the Voting ID, Task ID and Shareholder Reference Numbers set out in the Form of Proxy, in each case so as to be received by no later than 12:00 p.m. on Thursday 16 August 2018, being 48 hours before the time appointed for the holding of the General Meeting excluding non-working days.

CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the General Meeting by following 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, should refer to their CREST sponsor or voting service provider who will be able to take the appropriate action on their behalf.

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 transmitted in accordance with the procedures described in the CREST Manual so that it is received by the issuer's agent (ID: RA19) by no later than by the latest time for receipt of proxy appointments specified above.

In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST Proxy Instruction must be properly authenticated in accordance with Euroclear U.K. & Ireland Limited's specifications and must contain the information required for such instruction, as described in the CREST Manual (available at www.euroclear.com). The message, regardless of whether it relates to the appointment of a proxy or to 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 issuer's agent (ID: RA19) by no later than 12:00 p.m. on Thursday 16 August 2018. No 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 Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST.

Completing and returning a Form of Proxy or electronic proxy appointment, or completing and transmitting a CREST Proxy Instruction, will not prevent a member from subsequently attending and voting at the General Meeting in person if they so wish.

8 Further information

Your attention is drawn to the further information contained in Part II: “Risk Factors” to Part X: “Definitions” of this Circular. Shareholders should read the whole of this Circular and not rely solely on information surmised in this letter.

9 Financial Advice

The Board has received financial advice from Barclays. In providing advice to the Board, Barclays has relied on the Board’s commercial assessment of the Transaction.

10 Recommendation

The Board considers the Transaction to be in the best interests of the Shareholders as a whole and unanimously recommends Shareholders to vote in favour of the Resolutions, as the Directors intend to do so in respect of their own beneficial holdings of 504,669 Shares, representing approximately 0.07 per cent of the Company’s existing issued ordinary share capital as at the Latest Practicable Date.

Yours faithfully

Bill Schrader
Chairman

PART II
RISK FACTORS

Prior to making any decision to vote in favour of the Resolutions, 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 Enlarged 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 and the Enlarged 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 or the Enlarged 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 and DTRs (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 and the Enlarged Group. If this occurs, the price of the Shares may decline and Shareholders could lose all or part of their investment.

1 Risks relating to the Transaction

Completion is subject to a number of conditions and Ophir will not realise the perceived benefits of the Transaction if it does not complete

The Transaction is subject to the satisfaction of a number of conditions (which are set out in more detail in Part III: “Summary of the Transaction Agreements” of this Circular).

Completion of the acquisition of the Producing Assets is conditional, *inter alia*, upon the approval of Shareholders at the General Meeting. Completion of the acquisition of the Exploration Assets is conditional upon the approval of Shareholders at the General Meeting, completion of the acquisition of the Producing Assets and the satisfaction of certain conditions precedent set out in the Transaction Agreements.

There can be no assurance that these conditions will be satisfied, or that Completion will be achieved by the long stop date of 2 November 2018 (for the Producing Assets) or 2 May 2019 (for the Exploration Assets) (or such later dates as Santos and the Group may agree in writing) or at all. The Board believes that the Transaction is in the best interests of Shareholders as a whole. If Completion does not occur, the Company will have incurred significant costs, including the loss of a US$4,000,000 non-refundable deposit, and management time in connection with the Transaction. It will also not realise the anticipated benefits of the Transaction and its ability to implement its stated strategy may be prejudiced.

Business growth opportunities, cost savings and synergies achieved from the Transaction may differ from those anticipated and the challenges and/or costs of integration may be higher than expected

While Ophir believes that the business growth opportunities, cost savings and synergies expected to arise from the Transaction have been reasonably estimated, unanticipated events or liabilities may arise which result in a delay or reduction in the benefits derived from the Transaction, 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 Target Group. The Transaction significantly increases

the Group's interests in production and development assets, including in countries in which 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 Enlarged Group. Additionally, the Transaction might affect the relationships that the Target Group has with suppliers, third party service providers, joint venture partners and governments, and adversely affect its performance and/or potential growth opportunities.

Under any of these circumstances, the business growth opportunities, cost savings and other synergies anticipated by Ophir to result from the Transaction may not be achieved as expected, or at all, or may be delayed materially. To the extent that the Enlarged Group incurs higher integration costs or achieves lower synergy benefits than expected, its and the Enlarged Group's results of operations, financial condition and/or prospects may be adversely affected.

The Transaction is being funded from existing cash resources and new debt which will reduce the Group's financial flexibility

The Transaction is being funded from Ophir's existing cash resources and a new up to US$130 million 18 month acquisition bridge facility which is described in more detail in Part VI: "Additional Information" of this Circular.

Consequently, the Transaction will reduce the Group's cash balances and increase the overall indebtedness and financial leverage of the Enlarged Group, which will result in increased repayment commitments and borrowing costs. This could limit the Enlarged Group's commercial and financial flexibility (including in relation to any changes to the possible funding of any development of the Fortuna project in Equatorial Guinea), causing Ophir to reprioritise its uses of capital to the potential detriment of its business prospects and the value of its assets. Therefore, depending on the level of the Enlarged Group's borrowings, prevailing interest rates and exchange rate fluctuations, this could result in reduced funds being available to fund future growth, dividend payments and other general corporate purposes, which could have a material adverse impact on the Enlarged Group's results of operations, financial condition and prospects.

The Group intends to refinance the aforementioned acquisition bridge facility and its outstanding US$105 million NOK bond, both of which are due to expire in Q1 2020, and the Transaction could impact the Group's ability to do this. A failure to refinance this facility and the NOK bond on commercially reasonable terms could have a material adverse impact on the Enlarged Group's results of operations, financial condition and prospects.

The oil and gas reserves and resources data are estimates and uncertain

The reserves and resources data contained in this Circular are estimates only and should not be construed as representing exact quantities. Reserves and resources estimates contained in this Circular are based on production data, prices, costs, ownership, geophysical, geological and engineering data, the interpretation of seismic data and other information assembled by Ophir and Santos (with assistance from other operators), including drilling results. Such interpretation and estimates of the amounts of oil and gas resources are subjective and the results of drilling, testing and production subsequent to the date of any particular estimate may result in substantial upward or downward revisions to the original interpretation and estimates. Furthermore, different reservoir engineers may make different estimates of reserves, resources and cash flows based on the same available data.

Estimating the value and quantity of economically recoverable crude oil and natural gas reserves and resources, and consequently the rates of production, net present value of future cash flows realised from those reserves and resources and the timing and amount of capital expenditure, necessarily depend upon a number of variables and assumptions, such as ultimate reserves recovery, interpretation of geological and geophysical data marketability of oil and gas, royalty rates, continuity of current fiscal policies and regulatory regimes, future oil and gas prices, operating costs, development and production costs and work over and remedial costs, all of which may vary from actual results. In addition, these factors are more

uncertain in areas where there has been limited historic hydrocarbon exploration, which is the case for certain of the Assets.

The estimates also assume that the future development of the Enlarged Group's fields and the future marketability of their crude oil, condensate and natural gas will be similar to past development and marketability, that the assumptions as to capital expenditure and operating costs are accurate and that the capital expenditure strategy of the Enlarged Group is successfully implemented by it.

Any production profiles and development plans are based on a number of assumptions which, together with the estimates, may prove to be materially incorrect. Unless otherwise indicated, the definitions and guidelines set out by the 2007 PRMS which defines prospective and contingent resources as undiscovered and/or undeveloped mineral resources, respectively have been used. 2007 PRMS recognises that contingent resources are by their nature uncertain in respect of the inferred volume range and may not be considered commercially recoverable for a variety of reasons, including the high costs involved in recovering contingent resources, the price of oil and gas at the time, the availability of personnel, equipment and funding, and other development plans that the Enlarged Group may have.

As a result, Shareholders should not place undue reliance on the forward-looking statements contained in this Circular concerning resources, reserves, production profiles and development plans. In addition, nothing in this Circular should be interpreted as assurances of the Enlarged Group's oil and gas resources, reserves, the production profiles of the Assets or the development plans of the Enlarged Group.

If the estimates of the oil and gas resources, reserves, production profiles and development plans of the Assets and the assumptions on which they have been based prove to be incorrect, the Enlarged Group may be unable to produce the estimated levels or quality of oil and gas set out in this Circular (or any oil and gas at all), actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material, and the Enlarged Group's business, prospects, financial condition and results of operations could be materially and adversely affected.

The acquisition of the Exploration Assets might not complete even if the Producing Assets are acquired

Completion of the acquisition of the Producing Assets is not conditional on completion of the Exploration Assets although completion of the acquisition of the Exploration Assets is, amongst other things, conditional on the completion of the Producing Assets. If completion of the acquisition of the Producing Assets occurs but the conditions to completion of the acquisition of some or all of the Exploration Assets are not satisfied or, where applicable, waived, Ophir will not acquire all of the Exploration Assets which could potentially reduce the benefits to Ophir of the Transaction and, in particular, Ophir would not receive any potential benefits associated with such Exploration Assets. In addition, as explained in Part III: “Summary of the Transaction Agreements” of this Circular, in certain circumstances, notwithstanding that Ophir will not have acquired all or some of the Exploration Assets, Ophir will be required to pay certain lump sum payments of up to US$35.5 million for work commitments and 2018 budgeted costs to Santos by way of compensation for not having acquired the Exploration Assets.

The value of the Exploration Assets is uncertain

The value of the Exploration Assets will depend on the Group’s willingness and ability to acquire, find, develop and/or commercially exploit resources and reserves. Exploration and development activities are capital intensive and their successful outcome cannot be assured. In particular, the Exploration Assets include the Bestari oil field in Malaysia, which has not yet had a declaration of commerciality. Following Completion, any exploration activities of the Enlarged Group in respect of the Exploration Assets would be undertaken with no guarantee that such expenditure would result in the discovery of commercially recoverable oil or gas with the risk that the Enlarged Group could have incurred substantial costs and the value of its assets could have decreased.

All the exploration periods of the Exploration Assets expire in 2019 or 2020. The relevant joint venture partners may be able to apply for an extension to allow further time to complete the outstanding work

commitments. However, there is no automatic right to such extension and any extension granted may be subject to increased work commitments. If the mandatory work commitments are not satisfied by the end of the relevant exploration periods, the relevant joint venture partners and/or the Enlarged Group may be liable to pay an equivalent amount to the applicable state oil and gas company and the relevant contract area may be relinquished and/or the relevant PSC may terminate. More details in relation to the outstanding liabilities and obligations in respect of each of the Exploration Assets is contained in Part VI: "Additional Information" of this Circular.

Although there are no outstanding work commitments under the Deepwater Block R PSC (Malaysia), its exploration period expires on 16 January 2019. At or before such time, some or all of the joint venture partners may decide to withdraw from the Deepwater Block R PSC, which may result in the Deepwater Block R PSC terminating (in which case Ophir will still acquire Santos Sabah notwithstanding that it will no longer hold an interest in the Deepwater Block R PSC) or Ophir's participating interest in the Deepwater Block R PSC increasing.

As explained in paragraph 3 of Part I: "Letter from the Chairman of Ophir" of this Circular, the current exploration periods of the Deepwater Block R PSC, the SS-11 PSC and the Block 123 PSC are due to expire on 16 January 2019, 11 March 2019 and 11 June 2019, respectively and the exploration period of the Block 124 PSC is due to expire on 29 October 2020. Although Santos and/or the Enlarged Group may withdraw from some or all of the relevant PSCs if it decides not to explore and develop further the Exploration Assets, any such withdrawals may be complicated and/or involve unforeseen difficulties and/or costs.

2 Risks relating to the Enlarged Group

The Group's business requires significant capital expenditure and the future expansion and development of the Enlarged Group's business could require further debt and equity financing. The future availability of such funding is not certain and immediately following Completion, the Enlarged Group's cash balances will be reduced

Ophir anticipates that in order to continue to implement its stated strategy it, and, following Completion, the Enlarged Group, will need to make substantial capital investments for its operations, exploration, appraisal, development and/or production plans, including in relation to any development of the Meliwis gas field, any development of the Group's interest in the Fortuna project in Equatorial Guinea and to continue to implement its short to medium term objective to grow production in order to self-fund the Group's activities.

The Group's business requires significant capital expenditure and future expansion and development of its business and capital expenditure beyond the Group's current committed capital expenditure for the next 12 months could require further debt or equity financing. The availability of any future funding, whether obtained through debt or equity financing, is not certain. Alternatively, the Group may in the future seek funds for such business activities or capital expenditure by selling part of its operations and/or by farming down its assets. If the Group and, following Completion, the Enlarged Group is unable to generate or obtain further additional funding (for expenditure beyond its current committed capital expenditure for the next 12 months), it is likely to be limited in its ability to undertake any additional operations, exploration, appraisal, development or appraisal plans.

Oil and gas prices are volatile and have fluctuated considerably in recent years, which has had, and may continue to have, a significant impact on the Group and, following Completion, the Enlarged Group

Oil and gas prices are subject to volatility due to a variety of factors beyond the Group's control. Factors affecting crude oil prices include supply and demand fundamentals, economic outlooks and production quotas set by the Organization of Petroleum Exporting Countries and political events. Over the past four years, as a result of factors, including weaker outlook for global demand growth combined with excess

supply, oil prices worldwide have been subject to significant volatility and there can be no assurance that the recent recovery in oil prices will continue. Lower oil prices may reduce the economic viability of the Group's and, following Completion, the Enlarged Group's operations and proposed operations and materially adversely affect their business prospects and financial condition.

Although the Group's hedging strategy involves the hedging of some but not all of its production revenues, the Group's and, following Completion, the Enlarged Group's ability to produce economically from a field (including from the Producing Assets) will be determined, in large part, by the difference between the revenue received for crude oil and/or natural gas produced by the Group or, following Completion, the Enlarged Group at fields in which it holds an interest and the Group's or, following Completion, the Enlarged Group's operating costs, taxation costs, royalties and costs incurred in transporting and selling its crude oil and/or natural gas. Therefore, lower crude oil and/or natural gas prices may reduce the amount of crude oil and/or natural gas that the Group or, following Completion, the Enlarged Group or operators of the fields where it holds an interest are able to produce economically or may reduce the economic viability of the production levels of specific wells or of projects planned or in development, to the extent that production costs exceed anticipated revenue from such production. This could, in turn, result in a reduction in the reserves and resources to the extent certain fields are no longer economically viable to develop. Any reduction in reserves and resources and/or any curtailment in the overall production volumes of the Group or, following Completion, the Enlarged Group or at fields in which the Group or, following Completion, the Enlarged Group holds an interest due to a decline in crude oil and/or natural gas prices could result in a reduction in the Group's or, following Completion, the Enlarged Group's net profit or increase in net losses, and impair its ability to make planned capital expenditures in the longer term and to incur costs that are necessary for the development of the Group's or, following Completion, the Enlarged Group's fields, any of which could materially adversely affect the Group's or, following Completion, the Enlarged Group's business financial condition and prospects.

The Producing Assets in Indonesia are in decline, FID has not yet been taken in respect of the development of the Meliwis gas field and the relevant licences are due to expire in the medium term. The offtake arrangements in respect of certain of the Indonesian Interests are also subject to regulatory approval

The Madura Offshore PSC and the Sampang PSC will expire in 2027 and production in the Indonesian Interests is in decline and further details on production forecasts for the Indonesian Interests which illustrate their decline, are set out in the Competent Person's Report in Part VII "Summary of Producing Assets Resources and Reserves Information" of this Circular. The development of the Meliwis gas field and other exploration prospects is key to extending economic production from the Indonesian Interests. FID for the Meliwis gas field development is expected to be taken in the coming months. If FID is not taken in respect of the Meliwis gas field development, production from the Maleo and Peluang fields may cease sooner than would otherwise be the case. In particular, the effectiveness of the gas sale and purchase agreement for Meliwis is dependent on the Meliwis FID and both that agreement and the replacement gas sale and purchase agreement for Maleo, which will result in increased prices from mid-2019, are agreed as between the parties although remain subject to regulatory approval. In addition, for the Sampang PSC, the Oyong gas sale and purchase agreement will expire in September 2019 and the Wortel gas sale and purchase agreement is expected to terminate in 2020. Neither of these agreements are anticipated to be extended with the current buyers due to forecast decline in 1P production by the end of the relevant GSAs although Ophir does not consider this to be a material risk for the Enlarged Group. The 2027 licence expiry increases the risk of the currently planned Paus Biru well in the Sampang PSC, even if it discovers hydrocarbons, not delivering attractive returns or even positive value due to a potentially insufficient remaining licence term.

The decline of production in the Indonesian Interests, a negative FID in respect of the Meliwis gas field, a failure to obtain regulatory approval in respect of the Maleo and Meliwis gas sale and purchase agreements and the 2027 licence expiry could each have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

The Producing Asset in Vietnam is not a growth asset and the infield opportunities for growing production are uncertain

The Chim Sáo field under the Block 12W PSC is a mid-life field at the early stages of production decline, and although there are material in-field opportunities that the Group intends to pursue, there is no certainty that these opportunities will enable the arrest of the production decline and extend the field life.

The Block 12W FPSO was designed with a 15-year design life ending on 14 October 2026. The joint venture partners in the Block 12W PSC may be liable to pay for repair and maintenance costs in relation to the Block 12W FPSO in order to allow production under the Block 12W PSC to continue and/or production may have to be suspended or terminated as a result of a failure of the FPSO or the production facilities.

Joint venture partner alignment, supply chain delivery and other contractual counterparties

Operations in the oil and gas industry are sometimes conducted in a joint venture environment. A number of the Group's and, following Completion, the Enlarged Group's major projects are operated by joint venture partners (including those being acquired pursuant to the Transaction such as the Block 12W PSC) or have joint venture partners with veto rights over certain decisions. Following the Transaction, a significant proportion of the Enlarged Group's interests in production assets will be in (and therefore its cashflow will be derived from) assets that it does not wholly own or control on its own. The Group's and, following Completion, the Enlarged Group's ability to influence these operating (and non-operating) partners is sometimes limited due to the Group's and, following Completion, the Enlarged Group's limited equity in such ventures. There is a risk that joint venture partners are not aligned in their objectives and drivers and this may lead to operational or production inefficiencies and/or delays, disagreements on or how to develop production assets further or a disruptive departure by one or more partners from the joint venture. Any mismanagement of these projects may result in increased costs to the Group and, following Completion, the Enlarged Group or an inability to explore or develop such assets further in a way and in a time of Ophir's choosing, or at all, which could adversely affect its business, results of operations, cash flow and prospects.

The Group and, following Completion, the Enlarged Group is heavily dependent on supply chain providers to deliver services and products to time, cost and quality criteria. There is a heightened risk during any extended period of downturn in the upstream services sector in relation to supply chain counterparties' ability to deliver. This could delay, restrict or lower the profitability and viability of the Group's and, following Completion, the Enlarged Group's projects and therefore have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group has entered into or is subject to agreements with a number of contractual counterparties in relation to the sale and supply of hydrocarbon production volumes. Therefore, the Group and, following Completion, the Enlarged Group is subject to the risk of delayed payment for delivered production volumes or counterparty default. Such delays or defaults could materially affect the Group's and, following Completion, the Enlarged Group's business, results of operations and cash flows.

The risk of joint venture partner misalignment may also apply to the Exploration Assets. For example, as noted at paragraph 9.2.5(c) of Part VI: "Additional Information" of this Circular, Eni Vietnam B.V. has a casting vote in respect of the minimum work commitments under the Block 124 JOA. Though the budgeted work commitments (which were used to calculate the Commitment Compensation Payments Arrangements in relation to Block 124) made allowances for certain spending, if Ophir is voted into a decision (through Eni Vietnam B.V.'s casting vote) in respect of incremental work in satisfaction of the minimum work commitment, for example a decision to drill an exploration well, then the costs incurred by Ophir may be higher than those budgeted work commitments.

Tax regimes in certain jurisdictions are subject to differing interpretations and are subject to change

Tax regimes in certain jurisdictions in which the Group and, following Completion, the Enlarged Group has a presence or enters as a result of the Transaction may be subject to differing interpretations and are often subject to legislative change and changes in administrative interpretation in those jurisdictions. Such changes can be prompted by, *inter alia*, transactions (including those that may require governmental consent) and may be implemented with retrospective effect. The interpretation by the Group and, following Completion, the Enlarged Group of relevant tax law as applied to transactions and activities in such jurisdictions (which could include this Transaction) may not coincide with that of the relevant tax authorities now or at a future date. As a result, transactions (including potentially this Transaction) may be challenged by tax authorities and any profits of the Group and, following Completion, the Enlarged Group from activities in those jurisdictions may be assessed to additional tax or additional transactional taxes (e.g. stamp duty or VAT), which, in each case, could result in significant additional taxes, penalties and interest, any of which could have a material adverse impact on the Group's and, following Completion, the Enlarged Group's business, prospects, financial condition or results of operations.

The Group and, following Completion, the Enlarged Group operates in jurisdictions that are subject to significant political, economic, legal, regulatory and social uncertainties

The Group's and, following Completion, the Enlarged Group's operations are exposed to significant political, social, economic, fiscal, legal, regulatory and social instability in the jurisdictions in which it operates (including expropriation of assets, unilateral amendments to PSCs, hostilities, civil unrest and piracy). The occurrence of any such factors could have a material and adverse effect on the Enlarged Group's business, prospects and results of operations. In particular, in several jurisdictions in which the Group and, following Completion, the Enlarged Group has assets, the less developed status of the legal systems may result in risks and uncertainties and regulatory requirements can be onerous and expensive. The laws in certain jurisdictions in which the Enlarged Group operates may also be subject to differing interpretations and are often subject to legislative change and changes in administrative interpretation which may be implemented with retrospective effect and which could result in transactions (which could include this Transaction) being challenged. Furthermore, in some of these jurisdictions there is little legislation regulating oil and gas exploration, development, production or other activities which the Enlarged Group may undertake. It may accordingly not be possible to establish, assert, protect or defend legal rights or title to assets in the jurisdictions in which the Enlarged Group operates or proposes to operate with any certainty and any contracts, PSCs, joint ventures or other legal agreements may not be enforceable under local laws. There can also be no assurance that the Enlarged Group's title to some of its PSC/licence interests or other assets will not be challenged or impugned. Any such challenge could have a material adverse effect on the Enlarged Group's business, prospects and results of operations. If the Transaction completes, the Enlarged Group's exposure to any such risks is likely to be increased in Southeast Asia including in countries in which Ophir has no previous experience of operating.

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

The Group currently conducts business in a number of jurisdictions that have been allocated low scores on Transparency International's "Corruption Perceptions Index". Doing business in developing countries brings with it inherent risks associated with enforcement of the Group's legal and contractual rights and third party obligations, fraud, bribery and corruption. Fraud, bribery and corruption are more common in some jurisdictions than in others. In addition, the oil and gas industries have historically been shown to be vulnerable to corrupt or unethical practices.

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

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

Oil and gas exploration, development and production can be dangerous and involve numerous risks and hazards, including health, safety and environmental risks, particularly in the case of deepwater operations, as was seen in the US Gulf of Mexico in 2010

Following Completion, the Enlarged Group's future success will depend, in part, on its ability to develop and extract natural gas reserves in a timely and cost-effective manner and achieve its production targets. Developing oil and gas resources and reserves into commercial production involves a high degree of risk. The Group's and, following Completion, the Enlarged Group's exploration, development and production operations will be subject to all the risks common in its industry. These hazards and risks include encountering unusual or unexpected rock formations or geological pressures, fires, explosions or power shortages, equipment failures or accidents, premature declines in reservoirs, blowouts, uncontrollable flows of natural gas or well fluids, or water cut levels, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and other equipment and transport and the delivery of equipment.

Consequent exploration, development and/or production delays and/or declines and deterioration in normal field operating conditions may adversely affect revenue and cash flow levels, result in significant additional costs to replace or repair the Group's and, following Completion, the Enlarged Group's assets, and result in expected production targets not being achieved.

Given the nature of some of its offshore, deepwater operations, the Group's and, following Completion, the Enlarged Group's exploration and drilling facilities, and in particular its rigs, will also be subject to the hazards inherent in marine operations, such as capsizing, sinking, grounding, damage from severe storms or other severe weather conditions, damage to pipelines, platforms, facilities and sub-sea facilities from trawlers, anchors and vessels, storms, strong currents, and risks and hazards resulting from navigational difficulties. The offshore drilling conducted by the Group and, following Completion, the Enlarged Group involves drilling risks, including high pressures and mechanical difficulties, which increase the risk of delays in drilling and of operational issues arising. Such dangers were evidenced by the blowout of the Macondo well in the Gulf of Mexico in 2010.

Such events may result in environmental damage, injury to persons and loss of life and a failure to produce oil or gas in commercial quantities. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to equipment owned by the Group or, following Completion, the Enlarged Group and equipment owned by third parties and personal injury or wrongful death claims being brought against Ophir or, following Completion, the Enlarged Group. These events can also put at risk some or all of the Enlarged Group's licences, gas or petroleum agreements which enable it to explore, and could result in the Group or, following Completion, the Enlarged Group incurring significant civil liability claims (as BP plc incurred following the Macondo well blowout), significant fines or penalties as well as criminal sanctions potentially being enforced against the Group or, following Completion, the Enlarged Group and/or its officers. The Group and, following Completion, the Enlarged Group may also be required to curtail or cancel any operations on the occurrence of such events.

Any of the above could materially and adversely affect the Group's and, following Completion, the Enlarged Group's business, prospects, financial condition and results of operations.

There will be decommissioning costs associated with the Producing Assets

The Producing Assets include a number of fields which Ophir will be the operator of and which are expected to cease production and require decommissioning in the medium-term. The Group has no experience of decommissioning assets and such processes involve a degree of risk and unforeseen challenges. The

Enlarged Group’s success in the future will, in part, depend on its ability to undertake decommissioning activities in a safe and cost-effective manner.

Decommissioning reserve funds have been established for the Producing Assets and are funded based on the anticipated costs of decommissioning the Producing Assets. Although such anticipated costs have been approved by the relevant governmental authorities and all funding obligations have been complied with to date, there is no guarantee that the actual decommissioning costs will not be in excess of those which are currently anticipated. The detailed plans in relation to the decommissioning of each individual asset will need to be agreed with the relevant authorities and stakeholders at the time of decommissioning. This is a relatively new area, with a limited number of these projects having been undertaken in the relevant countries to date. The risks associated with these projects relates to uncertainty in areas that impact the project costs, namely: stakeholder requirements; specific conditions related to individual assets; costs for major contracts; and rig and vessel rates. Such risks and their associated costs may materially and adversely affect the Enlarged Group's business, prospects, financial condition and results of operations.

PART III
SUMMARY OF THE TRANSACTION AGREEMENTS

The following is a summary of the principal terms of the Transaction Agreements for the Producing Assets and the Exploration Assets. The Transaction Agreements are available for inspection as described in Part VI: "Additional Information" of this Circular.

Part A: The Producing Assets

1 Overview

The Transaction Agreements for the Producing Assets consist of:

(a) a share sale and purchase agreement amongst Santos (UK) Limited (as seller), Santos International Holdings Pty Ltd (as seller guarantor), Jaguar 2 (as buyer) and Ophir (as buyer guarantor) dated 3 May 2018 and amended and restated for non-material amendments on 3 August 2018 for the entire issued share capital of Santos Petroleum Ventures B.V., which holds a 31.875% non-operated interest in the Block 12W PSC in Vietnam (the "**Block 12W SPA**"); and

(b) a share sale and purchase agreement amongst Santos Limited and Santos (BBF) Pty Ltd (as sellers), Santos International Holdings Pty Ltd (as seller guarantor and warrantor), Jaguar 2 (as buyer) and Ophir (as buyer guarantor) dated 3 May 2018 and amended and restated for non-material amendments on 3 August 2018 for: (i) the entire issued share capital of Santos SPV Pty Ltd which indirectly holds a 67.5% operated interest in the Madura Offshore PSC and a 77.5% operated interest in the Meliwis gas discovery; and (ii) the entire issued share capital of Santos Asia Pacific Pty Ltd which indirectly holds a 45% operated interest in the Sampang PSC, each in Indonesia (the "**Indonesian Interests**", the "**Madura / Sampang SPA**").

2 The Block 12W SPA

2.1 Consideration

The base consideration payable under the Block 12W SPA is US$152,255,846. This amount includes a negative US$2,744,150 in respect of net working capital liabilities. The base consideration is subject to a locked box mechanism and customary contribution and leakage adjustments in the period from 31 December 2017 (the economic date) to completion. Given that the asset is expected to generate free cash in the period pre-completion, a net leakage is anticipated, which would result in a corresponding reduction in the purchase price.

A deposit of US$4,000,000 was paid to the seller following the signing of the Block 12W SPA. The seller is only entitled to retain this deposit if the Resolutions are not approved or if the buyer fails to satisfy the completion conditions (described below).

2.2 Pre-Completion Obligations

In the period to completion, the seller has undertaken to, and shall procure that the target conducts its business in the ordinary and usual course and in accordance with good international oil and gas industry practice. It has also given a number of specific undertakings in relation to the actions it shall and shall not take regarding the 12W PSC and related agreements during such period.

At completion, the parties have undertaken to settle, repay or satisfy all intra-group balances pursuant to Santos intercompany facilities to which the target is party.

2.3 Conditions to Completion

Completion is subject to the passing of the Resolutions and the satisfaction or waiver of the conditions precedent under the Madura / Sampang SPA. The Block 12W SPA and the Madura / Sampang SPA are thereby inter-conditional so that both or neither of the Block 12W SPA and the Madura / Sampang SPA will complete.

The parties are each obliged to use reasonable endeavours to procure the fulfilment of the conditions precedent by 2 November 2018. Each party has a right to terminate the Block 12W SPA if any of the conditions precedent are not satisfied or waived by that date.

2.4 Warranties and Indemnities

The seller has provided customary warranties to the buyer in respect of itself, the target company and the Block 12W PSC, including *inter alia* with respect to title, capacity, authority, environment, tax, insurance, compliance, litigation, and anti-bribery and corruption.

The seller has indemnified the buyer against all environmental liabilities that are attributable to the acts or omissions of the Block 12W PSC operator in the period prior to completion that were negligent or failed to meet the standards of a reasonable and prudent operator. The indemnity is subject to the seller's limitations of liability described below. Subject to this indemnity, the buyer is liable for all decommissioning liabilities and environmental liabilities that are attributable to the Block 12W PSC whether arising before, on or after completion and the buyer provides an indemnity to the sellers in respect of its decommissioning liabilities and environmental liabilities. As is customary in such transactions, the indemnity is not subject to any limitations of liability and the buyer's decommissioning and environmental liabilities will be as prescribed by applicable law.

The seller is liable for (and has provided an indemnity in respect of such liability to the buyer) certain taxes on gains payable in Vietnam by the target company (on behalf of the seller) in connection with the transaction. The indemnity is subject to the seller's limitations of liability in respect of tax described below. There are further protections in respect of tax which relates to the pre-completion period, subject to certain carve-outs.

The buyer is liable for (and has provided an indemnity in respect of such liability to the seller) any stamp duties or similar taxes, and any notary and registration fees payable in relation to the Block 12W SPA and any other transaction agreement.

The seller's liability for claims under the warranties and indemnities is subject to a number of contractual limitations, in particular:

(a) any claims under the warranties and indemnities must be notified to the seller within 30 days after the buyer becomes aware of such claim and in any event within six years of completion for tax claims (unless there are open items outstanding in respect of assessments, filings or audits with the relevant tax authority in respect of the period prior to completion) and 24 months of completion for all other claims;

(b) the maximum aggregate liability of the seller for all claims relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$100,000,000;

(c) the maximum aggregate liability of the seller for all claims relating to a breach of the environmental warranties and environmental indemnity shall not exceed US$50,000,000;

(d) the maximum aggregate liability of the seller for all other claims shall not exceed US$25,000,000;

(e) the maximum aggregate liability of the seller for all claims shall not exceed the purchase price;

(f) the seller shall not be liable for any claim under the warranties unless each individual claim is in excess of US$250,000 and all claims in aggregate are in excess of US$1,000,000.

2.5 Parent Company Guarantees

The Company and Santos have each given an irrevocable and unconditional guarantee in respect of the buyer's and seller's obligations (respectively) under the Block 12W SPA.

Under the Block 12W SPA, the buyer has agreed to provide a guarantee in favour of PV Keez Pte. Ltd, as a replacement of the guarantee given by Santos to PV Keez Pte. Ltd. (the owner of the Block 12W FPSO), to cover for the target's participating interest share of amounts due under the Block 12W FPSO Charter in case the Block 12W operator fails to pay such amounts to PV Keez Pte. Ltd. when due. The replacement guarantee does not contain a financial cap but covers underlying obligations of approximately US$40 million. More information is provided at paragraph 9.2.2(c) of Part VI: "Additional Information" of this Circular. Until a replacement guarantee has been agreed with PV Keez Pte, Ltd., the buyer has agreed to provide an indemnity to Santos in respect of the existing guarantee.

3 MADURA / SAMPANG SPA

3.1 Consideration

The base consideration payable under the Madura / Sampang SPA is US$55,948,300, comprising US$28,502,150 for the share capital of Santos SPV Pty Ltd (which indirectly holds a 67.5% operated interest in the Madura Offshore PSC and a 77.5% operated interest in the Meliwis gas discovery) and US$27,446,150 for the share capital of Santos Asia Pacific Pty Ltd (which indirectly holds a 45% operated interest in the Sampang PSC). These amounts include an aggregate payment of US$5,948,300 in respect of working capital. The base consideration is subject to a locked box mechanism and customary contribution and leakage adjustments (including for working capital) in the period from 31 December 2017 (the economic date) to completion.

The base consideration includes payment for trade receivables amounting to US$1,400,000 and a VAT receivable amounting to US$351,500. The sellers have agreed to reimburse the buyer to the extent that any such amounts are not received by 31 December 2018.

3.2 Pre-Completion Obligations

In the period to completion, the sellers have undertaken to, and shall procure that Santos SPV Pty Ltd and Santos Asia Pacific Pty Ltd and their respective subsidiaries each, conduct their business in the ordinary and usual course and in accordance with good international oil and gas industry practice. They have also given a number of specific undertakings in relation to the actions they shall and shall not take regarding the Indonesian Interests and related agreements during such period.

There is currently a pending FID in respect of the development of the Meliwis gas discovery. The parties have therefore agreed an extensive voting protocol pursuant to which FID cannot be taken by the sellers if the commercial terms do not meet the minimum thresholds set forth in the voting protocol.

At completion, the parties have undertaken to settle, repay or satisfy all intra-group balances pursuant to Santos intercompany facilities to which the target is party.

3.3 Conditions to Completion

Completion is subject to the passing of the Resolutions and the satisfaction or waiver of the conditions precedent under the Block 12W SPA. The Block 12W SPA and the Madura / Sampang

SPA are thereby inter-conditional so that both or neither of the Block 12W SPA and the Madura / Sampang SPA will complete.

The parties are each obliged to use reasonable endeavours to procure the fulfilment of the conditions precedent by 2 November 2018. Each party has a right to terminate the Madura / Sampang SPA if any of the conditions precedent are not satisfied or waived by that date.

3.4 Warranties and Indemnities

The sellers and Santos International Holdings Pty Ltd have each provided customary warranties to the buyer with respect to title, capacity and authority. Santos International Holdings Pty Ltd, in its capacity as warrantor, has provided warranties in respect of Santos (BBF) Pty Ltd's and its own subsidiaries and the Indonesian Interests, including *inter alia* with respect to environment, tax, insurance, compliance, litigation, employees and anti-bribery and corruption.

Santos International Holdings Pty Ltd has indemnified the buyer against all environmental liabilities that are attributable to the acts or omissions of the operator of the Indonesian Interests in the period prior to completion that were negligent or failed to meet the standards of a reasonable and prudent operator. The indemnity is subject to the sellers' limitations of liability described below. Subject to this indemnity, the buyer is liable for all decommissioning liabilities and environmental liabilities that are attributable to the Indonesian Interests whether arising before, on or after completion and the buyer provides an indemnity to the sellers in respect of its decommissioning liabilities and environmental liabilities. As is customary in such transactions, the indemnity is not subject to any limitations of liability and the buyer's decommissioning and environmental liabilities will be as prescribed by applicable law.

Santos Asia Pacific Pty Ltd further indemnifies the buyer from and against all claims and losses incurred in relation to a named subsidiary that was de-registered on 6 June 2018. This indemnity is uncapped and has no time limit.

Santos International Holdings Pty Ltd is liable for (and has provided an indemnity in respect of such liability to the buyer) all taxes payable on gains made by the target companies and each of the target's subsidiaries arising in connection with the Transaction. The indemnity is subject to the sellers' limitations of liability in respect to tax described below. There are further protections in respect of tax which relates to the pre-completion period, subject to certain carve-outs.

The buyer is liable for (and has provided an indemnity in respect of such liability to the sellers) any registration, stamp duty or similar taxes, and any notary and registration fees payable in relation to the Madura / Sampang SPA and any other transaction agreement.

The sellers' and Santos International Holdings Pty Ltd's liability for claims under the warranties and indemnities is subject to a number of contractual limitations, in particular:

(a) any claims under the warranties and indemnities must be notified to the seller within 30 days after the buyer becomes aware of such claim and in any event within six years of completion for tax claims (unless there are open items outstanding in respect of assessments, filings or audits with the relevant tax authority in respect of the period prior to completion) and 24 months of completion for all other claims;

(b) the maximum aggregate liability of the sellers and Santos International Holdings Pty Ltd for all claims collectively under the warranties shall not exceed US$65,000,000;

(c) the maximum aggregate liability of Santos Limited and Santos International Holdings Pty Ltd relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$35,000,000 and for all other claims shall not exceed US$8,750,000, subject to an overall cap in respect of all such claims of US$35,000,000;

(d) the maximum aggregate liability of Santos (BBF) Pty Ltd and Santos International Holdings Pty Ltd relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$30,000,000 and for all other claims shall not exceed US$7,500,000, subject to an overall cap in respect of all such claims of US$30,000,000; and

(e) the sellers and Santos International Holdings Pty Ltd shall not be liable for any claim under the warranties unless each individual claim is in excess of US$250,000 and all claims in the aggregate are in excess of US$1,000,000.

3.5 Parent Company Guarantee

The Company and Santos International Holdings Pty Ltd have each given an irrevocable and unconditional guarantee in respect of the buyer's and Santos (BBF) Pty Ltd's obligations (respectively) under the Madura / Sampang SPA.

4 Governing Law and Dispute Resolution

Each of the Transaction Agreements for the Producing Assets is governed by the laws of England and Wales. Any dispute arising in respect of the Transaction Agreements shall be referred to and finally resolved by arbitration administered by the Singapore International Arbitration Centre in accordance with their rules of arbitration.

Part B: The Exploration Assets

1 Overview

1.1 The Transaction Agreements for the Exploration Assets consist of:

(a) a share sale and purchase agreement amongst Santos International Holdings Pty Ltd (as seller), Jaguar 1 (as buyer) and Ophir (as buyer guarantor) dated 3 May 2018 and amended and restated for non-material amendments on 14 May 2018 for the entire issued share capital of Santos Sabah Block R Limited, which holds a 20% non-operated interest in the Deepwater Block R PSC in Sabah, Malaysia (the "**Deepwater Block R SPA**");

(b) a share sale and purchase agreement amongst Santos International Holdings Pty Ltd (as seller), Jaguar 1 (as buyer) and Ophir (as buyer guarantor) dated 3 May 2018 and amended and restated for non-material amendments on 3 August 2018 for the entire issued share capital of Santos Vietnam, which holds a 50% operated interest in the Block 123 PSC and 40% non-operated interest in the Block 124 PSC, each in the frontier Phu Khanh Basin, Vietnam (the "**Blocks 123 / 124 SPA**"); and

(c) an asset sale and purchase agreement amongst Santos Sangu Field Limited (as seller), Santos International Holdings Pty Ltd (as seller guarantor), Jaguar 1 (as buyer) and Ophir (as buyer guarantor) dated 3 May 2018 and amended and restated for non-material amendments on 3 August 2018 for a 45% operated interest in Block SS-11 PSC in Bangladesh (the "**SS-11 ATA**").

1.2 If completion of the Block 12W SPA and the Madura / Sampang SPA occurs but acquisition of the Exploration Assets is terminated prior to their completion (other than as a result of a seller's insolvency or default of its obligations under the relevant agreement), the buyer has agreed to pay the relevant seller compensatory payments in recognition of the ongoing commitments that the seller will indirectly retain as a result of such termination. These payments are US$3,100,000 in respect of the Deepwater Block R SPA, US$24,000,000 in respect of the Blocks 123 / 124 SPA and US$8,400,000 in respect of the SS-11 ATA, each as further described below.

2 DEEPWATER BLOCK R SPA

2.1 Consideration

The base consideration payable under the Deepwater Block R SPA is negative US$4,121,699. This figure takes into account a net negative working capital amount of US$9,715,303.84 and a capital contribution of US$5,593,603.84 which was undertaken by the seller with effect from 9 April 2018. The base consideration is subject to a locked box mechanism and customary contribution and leakage adjustments (including for working capital) in the period from 31 December 2017 (the economic date) to Completion.

The consideration includes payment for tax receivables amounting to US$1,354,000. The seller has agreed to reimburse the buyer to the extent that any such amounts are not received by 31 December 2018.

2.2 Pre-Completion Obligations

In the period to Completion, the seller has undertaken to, and shall procure that the target conducts its business in the ordinary and usual course and in accordance with good international oil and gas industry practice. It has also given a number of specific undertakings in relation to the actions it shall and shall not take regarding the Deepwater Block R PSC and related agreements during such period.

The seller is also required to act in accordance with the buyer's instructions when responding to any withdrawal notices received from the other participants in the Deepwater Block R PSC.

At completion, the parties have undertaken to settle, repay or satisfy all intragroup balances pursuant to Santos intercompany facilities to which the target is party.

2.3 Conditions to Completion

Completion is subject to the passing of the Resolutions and the satisfaction or waiver (if applicable) of the following conditions:

(a) the other joint venture partners to the Deepwater Block R PSC waiving their pre-emption rights or not exercising such rights within thirty days of notice;

(b) receipt of consent for the transfer from Petroliam Nasional Berhad; and

(c) completion of the Block 12W SPA and Madura / Sampang SPA having occurred.

The parties are each obliged to use reasonable endeavours to procure the fulfilment of the conditions precedent by 2 May 2019 (or such other date as may be agreed between the parties). Each party has a right to terminate the agreement if any of the conditions precedent are not satisfied or waived by that date.

The Deepwater Block R SPA is not conditional on completion of the Blocks 123 / 124 SPA or completion of the SS-11 ATA.

If completion of the Block 12W SPA and the Madura / Sampang SPA occurs but the Deepwater Block R SPA is terminated prior to completion (other than as a result of non-satisfaction of the pre-emption condition or the seller's insolvency or default of its obligations under the Deepwater Block R SPA) the buyer has agreed to pay the seller US$3,100,000 in recognition of the ongoing commitments in respect of the Deepwater Block R PSC that the seller will indirectly retain as a result of such termination (the "**Deepwater Block R CCP**"), notwithstanding that the minimum work commitments under the Deepwater Block R PSC have been fulfilled.

If the buyer becomes liable to pay the Deepwater Block R CCP and the target incurs or becomes liable to pay a commitment under the Deepwater Block R PSC relating to a work programme and budget for 2019 directly as a result of the buyer having refused, during the interim period, to approve a matter which would have allowed the target to avoid incurring or becoming liable for such commitment, the buyer shall pay to the seller an additional amount equal to the target's participating interest of such commitment.

2.4 Warranties and Indemnities

The seller has provided customary warranties to the buyer in respect of itself, the target company and the Deepwater Block R PSC, including *inter alia* with respect to title, capacity, authority, environment, tax, insurance, compliance, litigation, employees and anti-bribery and corruption.

The seller has indemnified the buyer against all environmental liabilities that are attributable to the acts or omissions of the Deepwater Block R PSC operator in the period prior to completion that were negligent or failed to meet the standards of a reasonable and prudent operator. The indemnity is not subject to a financial cap on liability. Subject to this indemnity, the buyer is liable for all decommissioning liabilities and environmental liabilities that are attributable to the Deepwater Block R PSC whether arising before, on or after completion the buyer provides an indemnity to the seller in respect of its decommissioning liabilities and environmental liabilities. As is customary in such transactions, the indemnity is not subject to any limitations of liability and the buyer's decommissioning and environmental liabilities will be as prescribed by applicable law.

The seller is liable for any tax due in respect of revenue or actual or deemed gains in connection with the transaction. The indemnity is subject to the seller's limitations of liability in respect to tax described below. There are further protections in respect of tax which relates to the pre-completion period, subject to certain carve-outs.

The buyer is liable for (and has provided an indemnity in respect of such liability to the seller) any stamp duty, stamp duty reserve tax or their equivalents, and any notary and registration fees payable in relation to the Deepwater Block R SPA and any other transaction agreement.

The seller's liability for claims under the warranties and the indemnities is subject to a number of contractual limitations, in particular:

(a) any claims under the warranties and indemnities must be notified to the seller within 30 days after the buyer becomes aware of such claim and in any event within six years of completion for tax claims (unless there are open items outstanding in respect of assessments, filings or audits with the relevant tax authority in respect of the period prior to completion) and 24 months of completion for all other claims;

(b) the maximum aggregate liability of the seller for all claims relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$10,000,000;

(c) the maximum aggregate liability of the seller for all other claims for a breach of seller warranty shall not exceed US$2,500,000;

(d) the seller shall not be liable for any claim under the warranties unless each individual claim is in excess of US$50,000 and all claims in aggregate are in excess of US$250,000.

2.5 Parent Company Guarantee

The Company has given an irrevocable and unconditional guarantee in respect of the buyer's obligations under the Deepwater Block R SPA.

3 BLOCKS 123 / 124 SPA

3.1 Consideration

The base consideration payable under the Blocks 123 / 124 SPA is US$419,851. This amount includes a payment of US$419,850 in respect of working capital. The base consideration is subject to a locked-box mechanism and customary contribution and leakage adjustments in the period from the 31 December 2017 (the economic date) to completion.

The consideration includes payment for tax receivables amounting to US$116,000. The seller has agreed to reimburse the buyer to the extent that any such amounts are not received by 31 December 2018.

3.2 Pre-Completion Obligations

In the period to completion, the seller has undertaken to, and shall procure that the target conducts its business in the ordinary and usual course and in accordance with good international oil and gas industry practice. It has also given a number of specific undertakings in relation to the actions it shall and shall not take regarding the Block 123 PSC and the Block 124 PSC and related agreements during such period.

At completion, the parties have undertaken to settle, repay or satisfy all intragroup balances pursuant to Santos intercompany facilities to which the target is party.

3.3 Conditions to Completion

Completion is subject to the passing of the Resolutions and the satisfaction or waiver (if applicable) of the following conditions:

(a) the satisfaction of certain conditions in relation to pre-emption rights of PetroVietnam and the other Block 124 participants in relation to the Block 124 PSC; This is an unusual pre-emption condition because if such pre-emption rights are exercised and completion of the transfer to the pre-empting party completes, the condition is satisfied and the buyer is obliged to continue with the acquisition of the target in any case (for the avoidance of doubt, the parties to the Block 123 JOA have a pre-emption right over another party's participating interest in the Block 123 JOA in the event of a proposed change in control of such other party, however, the acquisition of the target by Ophir is not conditional upon such pre-emption rights being waived or fulfilled and the acquisition of the target is to proceed irrespective of whether any such pre-emption rights are exercised).

(b) receipt of an approval from the Ministry of Industry and Trade of Vietnam and the Prime Minister of Vietnam as required pursuant to the Block 124 PSC;

(c) the receipt of the written consent for the transfer from each participant in the Block 124 PSC;

(d) the provision by the buyer of two replacement guarantees, in a form acceptable to PetroVietnam, in relation to the obligations under Block 123 PSC and Block 124 PSC guaranteed by the seller to PetroVietnam (further information relating to such guarantees is included at paragraphs 9.2.5(a) and 9.2.5(c) of Part VI: "Additional Information" of this Circular); and

(e) completion of the Block 12W SPA and the Madura / Sampang SPA having occurred.

The Blocks 123 / 124 SPA is not conditional on completion of the Deepwater Block R SPA or completion of the SS-11 ATA.

The parties are each obliged to use reasonable endeavours to procure the fulfilment of the conditions precedent by 2 May 2019 (or such other date as may be agreed between the parties). Each party has a right to terminate the Blocks 123 / 124 SPA if any of the conditions precedent are not satisfied or waived by that date.

If completion of the Block 12W SPA and the Madura / Sampang SPA occurs but the Blocks 123 / 124 SPA is terminated prior to completion (other than as a result of the seller's insolvency or default of its obligations under the Blocks 123 / 124 SPA), the buyer has agreed to pay the seller US$24,000,000 in recognition of the ongoing commitments that the seller will indirectly retain as a result of such termination (the "**Blocks 123 / 124 CCP**").

If the buyer becomes liable to pay the Blocks 123 / 124 CCP and the target incurs or becomes liable to pay a commitment under the Block 123 PSC or the Block 124 PSC relating to a work programme and budget for 2019 directly as a result of the buyer having refused, during the interim period, to approve a matter which would have allowed the target to avoid incurring or becoming liable for such commitment, the buyer shall pay to the seller an additional amount equal to the target's participating interest of such commitment (to the extent that such amounts do not contribute to fulfilling any outstanding minimum work commitment under Block 123 PSC or Block 124 PSC).

3.4 Warranties and Indemnities

The seller has provided customary warranties to the buyer in respect of itself, the target company and the Block 123 PSC and Block 124 PSC, including *inter alia* with respect to title, capacity, authority, environment, tax, insurance, compliance, litigation, employees and anti-bribery and corruption.

The seller has indemnified the buyer against all environmental liabilities that are attributable to the acts or omissions of the operator (as applicable under each of the Block 123 PSC and Block 124 PSC) in the period prior to completion that were negligent or failed to meet the standards of a reasonable and prudent operator. The indemnity is not subject to a financial cap on liability. Subject to this indemnity, the buyer is liable for all decommissioning liabilities and environmental liabilities that are attributable to the Block 123 PSC and Block 124 PSC whether arising before, on or after completion and the buyer provides an indemnity to the seller in respect of its decommissioning liabilities and environmental liabilities. As is customary in such transactions, the indemnity is not subject to any limitations of liability and the buyer's decommissioning and environmental liabilities will be as prescribed by applicable law.

The seller is liable for (and provides an indemnity in respect of such liability to the buyer) against certain taxes on gains payable in Vietnam by the target in connection with the transaction. The indemnity is subject to the seller's limitations of liability in respect of tax described below.

The buyer is liable for (and provides an indemnity in respect of such liability to the seller) against any registration, stamp duty, stamp duty reserve tax or their equivalents, and any notary and registration fees payable in relation to the Blocks 123 / 124 SPA and any other transaction agreement. There are further protections in respect of tax which relates to the pre-completion period, subject to certain carve-outs.

The seller's liability for claims under the warranties and indemnities is subject to a number of contractual limitations, in particular:

(a) any claims under the warranties and indemnities must be notified to the seller within 30 days after the buyer becomes aware of such claim and in any event within six years of completion for tax claims (unless there are open items outstanding in respect of assessments, filings or audits with the relevant tax authority in respect of the period prior to completion) and 24 months of completion for all other claims;

(b) the maximum aggregate liability for all claims relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$20,000,000

(c) the maximum aggregate liability for all other claims for a breach of the seller's warranties shall not exceed US$5,000,000;

(d) the seller shall not be liable for any claim under the warranties unless each individual claim is in excess of US$50,000 and all claims in aggregate are in excess of US$250,000.

3.5 Parent Company Guarantee

The Company has given an irrevocable and unconditional guarantee in respect of the buyer's obligations under the Blocks 123 / 124 SPA.

4 SS-11 ATA

4.1 Structure

Following completion, the buyer will hold a 45% participating interest in the SS-11 PSC. The other participants in the SS-11 PSC, as of the date hereof, are KrisEnergy (Asia) Ltd. with a 45% interest and BABEX with a 10% interest (such 10% interest being carried during the exploration period by the other joint venture partners).

4.2 Consideration

The base consideration payable by the buyer under the SS-11 ATA is US$1. It is subject to the following customary adjustments in the period from 1 January 2018 (the effective date) to completion:

(a) the aggregate amount of all payments or cash distributions paid by or on behalf of the seller (increasing the base consideration);

(b) the aggregate amount of any payments received by the seller in connection with petroleum operations conducted in respect of the SS-11 PSC (excluding the amounts received from the other joint venture partners to the seller in its capacity as operator) (decreasing the base consideration); and

(c) the working capital at completion (increasing the base consideration if positive and decreasing if negative).

4.3 Pre-Completion Obligations

In the period to completion, the seller has undertaken to conducts its business in the ordinary and usual course and in accordance with good international oil and gas industry practice. It has also given a number of specific undertakings in relation to the actions it shall and shall not take regarding the SS-11 PSC and related agreements during such period.

The initial exploration period of the SS-11 PSC expires on 11 March 2019. It is therefore the current intention of the joint venture partners to apply for an extension to the initial exploration period after completing the 3D seismic, in order to allow further time to complete the well commitment, which, subject to the extension of the exploration period, is currently planned for 2020 or 2021. In the period to completion, the seller has undertaken not to propose or vote in favour of an extension of the exploration period where such extension involves additional work commitments.

The buyer is obliged to make offers of employment to each of the seven employees of the seller on terms and conditions not less favourable than their current employment terms and conditions. The

employment offered must commence on completion, but shall honour the relevant employee's previous years of service in respect of entitled employee benefits.

4.4 Conditions to Completion

Completion is subject to the passing of the Resolutions and the satisfaction or waiver (if applicable) of the following conditions:

(a) written approval from the Ministry of Power, Energy and Mineral Resources, Bangladesh and the Government of Bangladesh to the Transaction;

(b) written approval from Petrobangla to the transfer of operatorship to the buyer;

(c) written consent from the other joint venture partners to the SS-11 PSC to the Transaction or the lapse of 30 days from the later of: (i) the date the joint venture partners receive notice of the Transaction; or (ii) the date additional information on the financial and technical capabilities of the buyer is provided to the other joint venture partners;

(d) written consent of the joint venture partners for the transfer of operatorship to the buyer;

(e) provision by the buyer of a replacement bank guarantee in the form set forth in the SS-11 PSC, for an amount equal to US$7,500,000 in respect of the guarantee given by HSBC on behalf of the seller (further information in relation to this guarantee is provided at paragraph 9.2.7(a) of Part VI: "Additional Information" of this Circular);

(f) provision by the buyer of a replacement financial and performance guarantee in the form set forth in the SS-11 PSC, in respect of the guarantee given by Santos International Holdings Pty Ltd to Petrobangla (further information in relation to this guarantee is provided at paragraph 9.2.7(a) of Part VI: "Additional Information" of this Circular); and

(g) completion of the Block 12W SPA and the Madura / Sampang SPA having occurred.

The SS-11 ATA is not conditional on completion of the Deepwater Block R SPA or completion of the Blocks 123 / 124 SPA.

The parties are each obliged to use reasonable endeavours to procure the fulfilment of the conditions precedent by 2 May 2019 (or such other date as may be agreed between the parties). Each party has a right to terminate the SS-11 ATA if any of the conditions precedent are not satisfied or waived by that date.

If Petrobangla or the other joint venture partners to the SS-11 PSC have not approved the transfer of operatorship to the buyer by 2 November 2018, the parties shall enter into good faith negotiations to agree a sale and purchase agreement for the entire issued share capital of Santos Sangu on commercial terms substantially similar to the SS-11 ATA.

If completion of the Block 12W SPA and the Madura / Sampang SPA occurs but the SS-11 ATA is terminated prior to completion (other than as a result of the seller's insolvency or default of its obligations under the SS-11 ATA), the buyer has agreed to pay the seller US$8,400,000 in recognition of the ongoing commitments that the seller will retain as a result of such termination (the "**SS-11 CCP**").

If the buyer becomes liable to pay the SS-11 CCP and the target incurs or becomes liable to pay a commitment under the SS-11 PSC relating to a work programme and budget for 2019 directly as a result of the buyer having refused, during the interim period, to approve a matter which would have allowed the target to avoid incurring or becoming liable for such commitment, the buyer shall pay to the seller an additional amount equal to the target's participating interest of such commitment (to the extent that such amounts do not contribute to fulfilling any outstanding minimum work commitment under the SS-11 PSC).

4.5 Completion Deliverables

At completion the seller and the buyer are obliged to execute and deliver (or procure the execution and delivery of) certain documents required to give effect to the transfer, including the buyer accession to the joint operating agreement.

The seller is obliged to transfer and deliver to the buyer all joint property, books of accounts, records and other documents maintained by the seller in its capacity as operator and shall use reasonable endeavours to ensure that the buyer has at completion, full control over the operator's bank account. The seller shall also use reasonable endeavours to cooperate with the buyer to ensure that all pertinent operators, non-operators, oil and gas purchasers and government agencies have been notified of the transaction.

4.6 Warranties and Indemnities

The seller has provided customary warranties to the buyer in respect of itself and the SS-11 PSC, including *inter alia* with respect to title, capacity, authority, environment, tax, insurance, compliance, litigation, employees and anti-bribery and corruption.

The seller has indemnified the buyer against all environmental liabilities that are attributable to the acts or omissions of the operator of the SS-11 PSC in the period prior to completion that were negligent or failed to meet the standards of a reasonable and prudent operator. The indemnity is subject to the seller's limitations of liability described below. Subject to this indemnity, the buyer is liable for all decommissioning liabilities and environmental liabilities that are attributable to the SS-11 whether arising before, on or after completion and the buyer provides an indemnity to the sellers in respect of its decommissioning liabilities and environmental liabilities. As is customary in such transactions, the indemnity is not subject to any limitations of liability and the buyer's decommissioning and environmental liabilities will be as prescribed by applicable law.

The seller is liable for (and has provided an indemnity in respect of such liability to the buyer) all taxes payable on gains in relation to the sale of the 45% participating interest in the SS-11 PSC by the seller to the buyer. The seller is further liable for (and has provided an indemnity in respect of such liability to the buyer) for any tax attributable to the seller in respect of the 45% participating interest in the SS-11 PSC for the period up to and including completion. Both indemnities are subject to the seller's limitations of liability in respect of tax described below.

The buyer is liable for (and has provided an indemnity in respect of such liability to the seller) any registration, stamp duty or similar taxes, and any notary and registration fees payable in relation to the SS-11 ATA and any other transaction agreement.

The seller's liability for claims under the warranties and indemnities is subject to a number of contractual limitations, in particular:

(a) any claims under the warranties and indemnities must be notified to the seller within six years of completion for tax claims (unless there are open items outstanding in respect of assessments, filings or audits with the relevant tax authority in respect of the period prior to completion) and 24 months of completion for all other claims;

(b) the maximum aggregate liability for all claims relating to a breach of the fundamental warranties or in respect of tax collectively shall not exceed US$10,000,000 and for all other claims shall not exceed US$2,500,000; and

(c) the seller shall not be liable for any claim under the warranties unless each individual claim is in excess of US$50,000 and all claims in the aggregate are in excess of US$250,000.

4.7 Parent Company Guarantees

The Company and Santos International Holding Pty Ltd have each given an irrevocable and unconditional guarantee in respect of the buyer's and the seller's obligations (respectively) under the SS-11 ATA.

5 Governing Law and Dispute Resolution

Each of the Transaction Agreements for the Exploration Assets is governed by the laws of England and Wales. Any dispute arising in respect of the Transaction Agreements shall be referred to and finally resolved by arbitration administered by the Singapore International Arbitration Centre in accordance with their rules of arbitration.

Part C: Transitional Services Agreements

Pursuant to a transitional services agreement dated 3 August 2018, following completion of the Madura / Sampang SPA, Santos has agreed to provide certain IT infrastructure, staff and business application services to Santos Madura and Santos Sampang for a period of six months from the date of completion of the Madura / Sampang SPA. Pursuant to this agreement, Santos Madura and Santos Sampang (as subsidiaries of Ophir) shall pay a monthly service charge to Santos in consideration of the services received.

Following completion of each of the Madura / Sampang SPA and the SS-11 ATA, Ophir has also agreed to provide certain transitional support services to Santos in order to assist certain members of the Santos Group with their remaining petroleum operations in Bangladesh and Indonesia. Such services shall be provided for a fixed period and Ophir shall receive a service charge (on a cost reimbursement basis) in consideration of the provision of such services.

PART IV
HISTORICAL FINANCIAL INFORMATION OF THE TARGET GROUP

Combined Income Statement and Statement of Other Comprehensive Income

		Years ended 31 December		
	Note	**2015**	**2016**	**2017**
			($000)	
Revenue	4	286,058	260,676	255,845
Cost of sales	5a	(208,676)	(159,713)	(149,092)
Gross profit		77,382	100,963	106,753
(Impairment)/reversal of impairment oil and gas properties	9	(77,000)	59,758	-
Exploration expenses	5b	(30,980)	(14,454)	(3,386)
Other operating (expenses)/gains	5c	(174)	2,546	(274)
General and administration expenses	5c	(806)	(713)	(508)
Operating (loss)/profit		(31,578)	148,100	102,585
Net finance expense	6	(8,717)	(3,394)	(1,298)
(Loss)/from operations before taxation		(40,295)	144,706	101,287
Taxation expense	7	(4,682)	(60,167)	(45,719)
(Loss)/profit from operations for the year		(44,977)	84,539	55,568
Other comprehensive income				
Items that will not be classified to profit or loss in subsequent periods:				
Actuarial gain/(loss) on retirement plan	15	398	546	(1,593)
		398	546	(1,593)
Tax relating to components of other comprehensive income	7	(175)	(240)	701
Other comprehensive income/(loss) for the year, net of tax		223	306	(892)
Total comprehensive (loss)/income for the period		(44,754)	84,845	54,676

The results relate entirely to continuing operations.

All comprehensive (loss)/income is attributable to the equity holders of the Target Group.

Combined Statement of Financial Position

	Note	2015	31 December 2016	2017
			($000)	
Non-current assets:				
Exploration and evaluation assets	8	112,168	121,277	126,543
Oil and gas properties	9	204,229	189,212	129,845
Long-term receivables	10	51,314	61,522	71,172
Deferred tax asset	7	6,979	-	-
Amounts owing from related entities	22	18,471	66,706	38,517
		393,161	438,717	366,077
Current assets:				
Inventory	11	11,616	10,311	7,904
Taxation receivable		2,214	2,062	1,838
Trade and other receivables	12	44,518	44,375	40,483
Cash and cash equivalents	13	27,454	31,540	16,575
Amounts owing from related entities	22	7,263	-	115
Total assets		486,226	527,005	432,992
Current liabilities:				
Trade and other payables	14	(50,912)	(38,515)	(34,827)
Taxation payable		(5,200)	(8,683)	(13,555)
		(56,112)	(47,198)	(48,382)
Non-current liabilities:				
Defined benefit provision	15	(8,142)	(2,563)	(389)
Other provisions	16	(91,942)	(94,670)	(89,354)
Deferred tax liability	7	(38,234)	(48,067)	(43,172)
Related party borrowings	17	(13,673)	(7,761)	(10,132)
Total liabilities		(208,103)	(200,259)	(191,429)
Net assets		278,123	326,746	241,563
Capital and reserves:				
Invested capital		278,123	326,746	241,563
Total equity attributable to equity holders of the Target Group		278,123	326,746	241,563

Combined Statement of Changes in Equity

	Invested Capital
	($000)
As at 1 January 2015	349,031
Loss for the period, net of tax	(44,977)
Other comprehensive income, net of tax	223
Total comprehensive loss, net of tax	(44,754)
Capital contribution	129,846
Capital distribution	(156,000)
As at 31 December 2015	278,123
Profit for the period, net of tax	84,539
Other comprehensive income, net of tax	306
Total comprehensive income, net of tax	84,845
Capital contribution	7,428
Capital distribution	(43,650)
As at 31 December 2016	326,746
Profit for the period, net of tax	55,568
Other comprehensive income, net of tax	(892)
Total comprehensive income, net of tax	54,676
Capital contribution	9,141
Capital distribution	(149,000)
As at 31 December 2017	241,563

Combined Cash Flow Statement

		Years ended 31 December		
	Note	**2015**	**2016**	**2017**
		($000)		
Operating activities:				
(Loss)/profit before taxation		(40,295)	144,706	101,287
Adjustments to reconcile loss before taxation to net cash provided by operating activities				
Exploration expenses	5b	30,666	12,195	1,833
Depreciation and amortisation	9	105,142	74,985	68,830
Net impairment/(reversal)		77,000	(59,758)	-
Net finance expenses and other financial gains	6	1,948	1,334	1,954
Net foreign currency loss		508	979	452
Other non-cash items (1)		6,735	(465)	(2,356)

	Note	Years ended 31 December 2015	2016	2017
		($000)		
Increase/(decrease) in provisions	15	2,063	(1,134)	(2,173)
Cash flow from operations before working capital adjustments		183,767	172,842	169,827
(Increase)/decrease in inventories	11	(2,420)	1,305	2,407
Increase/(decrease) in other current and non-current payables		4,056	(5,891)	(8,367)
Decrease/(increase) in other current and non-current assets		7,415	(2,488)	4,319
Cash generated from operations		192,818	165,768	168,186
Interest received		93	98	121
Income taxes paid		(49,802)	(39,958)	(44,827)
Net cash flows generated from operating activities		143,109	125,908	123,480
Investing activities:				
Purchases of Exploration and Evaluation assets		(104,556)	(24,434)	(4,928)
Purchases of oil and gas assets and other property, plant and equipment		(53,223)	(13,422)	(25,001)
Proceeds from disposals of assets		(6,857)	(33,699)	(3,218)
Cash advances to related parties		214,299	43,669	73
Cash receipts from the repayment of advances to related parties		10,308	436	50
Net cash flows used in/(from) investing activities		59,971	(27,450)	(33,024)
Financing activities:				
Interest paid		(38)	(31)	(24)
Cash proceeds from related party borrowings	18	-	7,150	1,382
Repayment of related party of borrowings	18	(324,605)	(101,589)	(113,848)
Capital contributions		125,674	365	7,889
Net cash flows used in financing activities		(198,969)	(94,105)	(104,601)
Effect of exchange rates on cash and cash equivalents		(793)	(267)	(820)
Net increase/(decrease) in cash and cash equivalents		3,318	4,086	(14,965)
Cash and cash equivalents at the beginning of the year		24,136	27,454	31,540
Cash and cash equivalents at the end of the year	13	27,454	31,540	16,575

Note:

(1) Within Other non-cash items in 2015 is $5.7m relating to interest charges on related party borrowings.

Notes to the Historical Financial Information

1 General information

The combined historical financial information comprises the assets and liabilities, income and expenses and cash flows of the Target Group for the three years ended 31 December 2017.

The principal activity of the Target Group is the continuation of oil and gas production and marketing activities, and the development of offshore oil and gas exploration assets in Asia.

The historical financial information of the Target Group for the three years ended 31 December 2017 has been prepared in accordance with the basis of preparation as set out below. This historical financial information is presented in US Dollars and all values are rounded to the nearest thousand US Dollars ($000) except when otherwise indicated.

2 Basis of preparation

Whilst the entities and assets 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.

This combined historical financial information does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006.

The basis of preparation describes how 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**") for the three years ended 31 December 2017, except as noted below. The application of these conventions results in the following material departure from IFRS; in all other respects, IFRS has been applied.

As explained above, the combined historical financial information is not prepared on a consolidated basis and therefore does not comply with the requirements of IFRS 10 'Consolidated Financial Statements'. However, the combined historical financial information has been prepared on a combined basis applying the principles underlying the consolidations procedures of IFRS 10.

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**"), have been applied where IFRS does not provide specific accounting treatments.

The combined historical financial information for the Target Group has been prepared for three years ended 31 December 2017 on an aggregated basis, in accordance with the Annexure. The aggregation process was as follows:

- The Target Group does not comprise a separate legal entity or group of entities during the three years ended 31 December 2017. Therefore, it is not meaningful to present share capital or an analysis of reserves. The Invested Capital represents a combination of the funding balances with the equity holders.
- The assets and liabilities, income and expenses, equity and reserves and cash flows of Santos (SPV) Pty Ltd and its subsidiary Santos Madura Offshore (together the "**Santos (SPV) Pty Ltd Group**") have been consolidated in accordance with IFRS 10 *Consolidated Financial Statements*;
- The assets and liabilities, income and expenses, equity and reserves and cash flows of Santos Asia Pacific Pty Ltd and its subsidiary Santos Sampang (together the "**Santos Asia Pacific Pty Ltd Group**") have been consolidated in accordance with IFRS 10 *Consolidated Financial Statements;*

- The assets and liabilities, income and expenses, equity and reserves and cash flows of Santos Sabah, Santos Petroleum Ventures B.V., Santos Vietnam, the Santos (SPV) Pty Ltd Group, the Santos Asia Pacific Pty Ltd Group and asset Block SS-11 have been aggregated in accordance with paragraph 26 of the Annexure; and
- Intercompany transactions and balances between the Target Group entities and assets have been eliminated.

The historical financial information is prepared on a combined basis and has been prepared by applying the relevant principles underlying the consolidation procedures of IFRS and applies the accounting policies adopted by Ophir in its last audited annual financial statements.

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.

The Directors have a reasonable expectation that the Target Group has adequate resources to continue in operational existence for the foreseeable future. The Directors have considered the Target Group's and Enlarged Group's working capital forecasts and projections, taking account of reasonably possible changes in trading performance and the current state of its operating market, and are satisfied that the Target Group and the Enlarged Group should be able to operate within the level of its current facilities. Accordingly, they have adopted the going concern basis in preparing combined historical financial information.

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.

- Amendments to IAS 7 Statement of Cash Flows: Disclosure Initiative
- Amendments to IAS 12 Income Taxes: Recognition of Deferred Tax Assets for Unrealised Losses
- Annual Improvements Cycle – 2014-2016

At the date of approval of the historical financial information, the following standards and interpretations which have not been applied in these financial statements were in issue but not yet effective (and in some cases had not yet been adopted by the European Union):

- IFRS 16 'Leases' (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);
- Amendments to IAS 28: Long-term interests in associates and joint ventures (effective for annual periods commencing on or after 1 January 2019);
- Annual Improvements 2015-2017 Cycle (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);
- IFRS 15 'Revenue from Contracts with Customers' (effective for annual periods commencing on or after 1 January 2018);

- IFRIC 22 ‘Foreign currency transactions and advanced consideration’ (effective for annual periods commencing on or after 1 January 2018); and
- Clarifications to IFRS 15: ‘Revenue from contracts with customers’ (effective for annual periods commencing on or after 1 January 2018).

For new standards with an effective date of 1 January 2018, the Directors have performed a preliminary assessment of the impact of these standards on the Target Group, as outlined below.

IFRS 9 ‘Financial Instruments’

In July 2014, the IASB issued the final version of IFRS 9 Financial Instruments that replaces IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. IFRS 9 brings together all three aspects of the accounting for financial instruments project: classification and measurement, impairment and hedge accounting. IFRS 9 is effective for annual periods beginning on or after 1 January 2018.

(a) Classification and measurement

The Directors do not expect a significant impact on its balance sheet or equity on applying the classification and measurement requirements of IFRS 9. Trade receivables are held to collect contractual cash flows and are expected to give rise to cash flows representing solely payments of principal and interest. Thus, the Directors expect that these will continue to be measured at amortised cost under IFRS 9.

(b) Impairment

IFRS 9 requires recording of expected credit losses on all debt securities, loans and trade receivables, either on a 12-month or lifetime basis. The Directors do not expect a significant impact on its equity due to the short-term nature and high quality of the financial assets.

IFRS 15 ‘Revenue from Contracts with Customers’

IFRS 15 Revenue from Contracts with Customers was issued in May 2014, and amended in April 2016, and establishes a five-step model to account for revenue arising from contracts with customers. Under IFRS 15, revenue is recognised at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer. The new revenue standard will supersede all current revenue recognition requirements under IFRS.

The Target Group generates revenue through the sale of oil and petroleum products. The impact of IFRS 15 on contracts with customers in which the sale of oil and petroleum products is generally expected to be the only performance obligation, is not expected to have any impact on the Target Group’s profit or loss for such transactions. The Directors expect revenue recognition to occur at a point in time when control of the asset is transferred to the customer, generally on delivery of the products.

The Target Group enters into take-or-pay arrangements where customers have a right to take makeup product in the future. The Target Group recognises deferred revenue equal to the amount paid for the ‘undertake’ as it represents an obligation to provide the product in the future. The Target Group only recognises revenue once the product has been taken by the customer. Only once the makeup period has expired or it is clear that the purchaser has been unable to take the product, would the liability be eliminated and revenue recognised.

Under IFRS 15, the Target Group will be required to perform an assessment of each take-or-pay arrangement to determine the extent to which makeup product is expected to be taken by the customer under the contract. If the Target Group expects the customer to exercise its full contractual rights it should recognise the amount paid for the ‘undertake’ over the contract term based on the proportion of product delivered to date compared to the total contracted volumes. Otherwise, the

full amount paid for the 'undertake' should be recognised as revenue once the likelihood of the customer exercising its remaining rights becomes remote.

Given the pattern of rights exercised by the customer, who has always taken the maximum amount of makeup product available, the Directors do not expect the adoption of IFRS 15 to have any effect on revenue recognised from contracts with take or pay arrangements.

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which all leases, other than low value or short-term leases, will be accounted for by the recognition on the balance sheet of a right to-use asset and a lease liability, and the subsequent amortisation of the right-to-use asset over the lease term. IFRS 16 will be effective for annual periods beginning on or after 1 January 2019. The Directors' evaluation of the effect of adoption of the standard is ongoing but it is expected that it will have a material effect on the Target Group's financial statements, significantly increasing the Target Group's recognised assets and liabilities. It is expected that the presentation and timing of recognition of charges in the income statement will also change as the operating lease expense currently reported under IAS 17, typically on a straight-line basis, will be replaced by depreciation of the right-to-use asset and interest on the lease liability.

3.2 Summary of significant accounting policies

(a) Commercial reserves

Commercial reserves are proved and probable oil and gas reserves, which are defined as the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially viable. Proved and probable reserve estimates are based on a number of underlying assumptions including oil and gas prices, future costs, oil and gas in place and reservoir performance, which are inherently uncertain. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable reserves and a 50% statistical probability that it will be less. However, the amount of reserves that will be ultimately recovered from any field cannot be known with certainty until the end of the field's life.

(b) Intangible exploration and evaluation expenditure

Exploration and evaluation ("**E&E**") expenditure relates to costs incurred on the exploration for and evaluation of potential mineral reserves and resources. The Target Group applies the successful efforts method of accounting for E&E costs as permitted by IFRS 6 'Exploration for and Evaluation of Mineral Resources'.

Under the successful efforts method of accounting, all licence acquisition, exploration and appraisal costs (such as geological, geochemical and geophysical costs, exploratory drilling and other direct costs associated with finding mineral resources) are initially capitalised in well, field or specific exploration cost centres as appropriate, pending determination. Costs (other than payments for the acquisition of rights to explore) incurred prior to acquiring legal rights to explore an area and general exploration costs not specific to any particular licence or prospect are charged directly to the income statement.

E&E assets are not amortised prior to the determination of the results of exploration activity.

Treatment of E&E assets at conclusion of appraisal activities

Intangible E&E assets related to each exploration licence/block are carried forward, until the existence (or otherwise) of commercial reserves has been determined, subject to certain limitations including review for indicators of impairment. If, at completion of evaluation

activities, technical and commercial feasibility is demonstrated, then, following recognition of commercial reserves, the carrying value of the relevant E&E asset is then reclassified as a development and production asset (subject to an impairment assessment before reclassification).

If, on completion of evaluation activities, it is not possible to determine technical feasibility and commercial viability or if the legal right to explore expires or if the Target Group decides not to continue E&E activity, then the costs of such unsuccessful E&E are written off to the income statement in the period of that determination.

Impairment

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount. The cash generating unit ("**CGU**") applied for impairment test purposes is generally a well, block or number of blocks when cash flows are considered to be interdependent, as appropriate.

Where an indicator of impairment exists, management will assess the recoverability of the carrying value of the asset or CGU. This review includes a status report confirming that E&E drilling is still underway or firmly planned, or that it has been determined, or work is underway to determine that the discovery is economically viable. This assessment is based on a range of technical and commercial considerations and confirming that sufficient progress is being made to establish development plans and timing. If no future activity is planned, or the value of the asset cannot be recovered via successful development or sale, and the success of a well result or geological or geophysical survey, the balance of the E&E costs are written off in the income statement and statement of other comprehensive income.

Farm-in/farm-out arrangements

The Target Group may enter into farm-in or farm-out arrangements, where it may introduce partners to share in the development of an asset. For transactions involving assets at the exploration and evaluation phase, the Target Group adopts an accounting policy as permitted by IFRS 6 such that the Target Group does not record any expenditure made on its behalf under a 'carried interest' by a farm-in partner (the 'farmee').

Where applicable past costs are reimbursed, any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal. Farmed-out oil and gas properties are accounted for in accordance with IAS 16 'Property, Plant and Equipment'.

(c) Property, plant and equipment

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

Oil and gas properties – cost

Development and production assets are generally accumulated on a block-by-block basis and represent the cost of developing the commercial reserves discovered and bringing them into production. The initial cost of a development and production asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation and, for qualifying assets (where relevant), borrowing costs. When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases, and costs are either regarded as part of the cost of inventory or expensed, except for costs which qualify for capitalisation relating to oil and gas property asset additions, improvements or new developments. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Oil and gas properties – depreciation

Oil and gas properties are depreciated/amortised from the commencement of production, on a unit-of-production basis, which is the ratio of oil and gas production in the period to the estimated quantities of commercial reserves at the end of the period plus the production in the period, on a field-by-field basis. Costs used in the unit of production calculation comprise the net carrying amount of capitalised costs plus the estimated future field development costs. The production and reserve estimates used in the calculation are on an entitlements basis. Changes in the estimates of commercial reserves or future field development costs are dealt with prospectively.

Producing assets are generally grouped with other assets that are dedicated to serving the same reserves for depreciation purposes, but are depreciated separately from producing assets that serve other reserves.

Other fixed assets

Property, plant and equipment other than oil and gas properties, is depreciated at rates calculated to write off the cost less estimated residual value of each asset on a straight-line basis over its expected useful economic life of between three and ten years.

Impairment

The Target Group assesses at each reporting date whether there is an indication that an asset (or CGU) may be impaired. Management has assessed its CGUs as being an individual block, which is the lowest level for which cash flows are largely independent of those of other assets. If any indication exists, or when annual impairment testing for an asset is required, the Target Group estimates the asset's (or CGU's) recoverable amount. The recoverable amount is the higher of an asset's (or CGU's) fair value less costs of disposal (FVLCD) and value in use (VIU). The recoverable amount is then determined for an individual asset, unless the asset does not generate cash flows that are largely independent of those from other assets or groups of assets, in which case the asset is tested as part of a larger CGU to which it belongs. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset (or CGU) is considered impaired and written down to its recoverable amount. Impairment losses of continuing operations are recognised in the income statement and statement of other comprehensive income.

Where conditions giving rise to an impairment subsequently reverse, the effect of the impairment charge is also reversed as a credit to the income statement and statement of other comprehensive income, net of any depreciation that would have been charged since the impairment.

(d) Borrowing costs

Borrowing costs directly attributable to the acquisition or development of qualifying oil and gas assets, which are assets that necessarily take a substantial period of time to prepare for their intended use or sale, are capitalised as a component of the cost of development, until such time as the assets are substantially ready for their intended use or sale. All other borrowing costs are recognised in profit and loss in the period in which they are incurred.

(e) Financial Instruments

Financial assets and financial liabilities are recognised in the Target Group's statement of financial position when the Target Group becomes a party to the contractual provisions of the instrument.

(i) Financial Assets

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and liabilities (other than financial assets and financial liabilities through profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognised immediately in profit or loss.

All financial assets are recognised and derecognised on a trade date where the purchase or sale of an investment is under a contract whose terms require delivery of the investment within the timeframe established by the market concerned, and are initially measured at fair value, plus transaction costs, except for those financial assets classified as at fair value through profit and loss, which are initially measured at fair value.

Financial assets are classified into the following specified categories: financial assets 'at fair value through profit and loss' (FVTPL), 'held-to-maturity' investments, 'available-for-sale' (AFS) financial assets and 'loans and receivables'. The classification depends on the nature and purpose of the financial assets and is determined at the time of initial recognition.

Loans and receivables

Trade receivables, loans and other receivables that have fixed or determinable payments that are not quoted in an active market are classified as loans and receivables. Loans and receivables are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate, except for short-term receivables when the recognition of interest would be immaterial.

Effective interest method

The effective interest method is a method of calculating the amortised cost of a financial asset and of allocating interest income over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts (including all fees paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial asset.

Income is recognised on an effective interest basis for debt instruments other than those financial assets classified as at FVTPL.

Financial assets at FVTPL

Financial assets are classified as financial assets at FVTPL where the Target Group acquires the financial asset principally for the purpose of selling in the near term, is a part of an identified portfolio of financial instruments that the Target Group manages together and has a recent actual pattern of short-term profit taking as well as all derivatives that are not designated and effective as hedging instruments. Financial assets at fair value through profit or loss are stated at fair value, with any resultant gain or loss recognised in profit or loss. The net gain or loss recognised in profit or loss incorporates any dividend or interest earned on the financial asset and is included in the 'other financial gains' in the income statement and statement of other comprehensive income.

Impairment of financial assets

Financial assets, other than those at FVTPL, are assessed for indicators of impairment at each balance sheet date. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the investment have been impacted. All impairment losses are taken to the income statement and statement of other comprehensive income.

Trade receivables are assessed for impairment based on the number of days outstanding on individual invoices. Any trade receivable that is deemed uncollectible is immediately written off to the income statement and statement of other comprehensive income, any subsequent recoveries are also taken directly to the income statement and statement of other comprehensive income upon receipt of cash collected.

Derecognition of financial assets

The Target Group derecognises a financial asset only when the contractual rights to the cash flows from the asset expire; or it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity.

(ii) Financial liabilities

Financial liabilities are classified as either financial liabilities at FVTPL or other financial liabilities.

Financial liabilities at FVTPL

Financial liabilities are classified at FVTPL where the financial liability is either held for trading or it is designated at FVTPL. Financial liabilities at FVTPL are stated at fair value, with any resultant gain or loss recognised in profit or loss. The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in the 'other financial gains' in the income statement and statement of other comprehensive income.

Other financial liabilities

Other financial liabilities, including borrowings, are initially measured at fair value, net of transaction costs. Other financial liabilities are subsequently measured at amortised cost using the effective interest method, with interest expense recognised on an effective yield basis. The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments through the expected life of the financial liability, or, where appropriate, a shorter period.

Derecognition of financial liabilities

The Target Group derecognises financial liabilities when, and only when, the Target Group's obligations are discharged, cancelled or they expire.

Cash and short-term deposits

Cash and cash equivalents in the statement of financial position comprise cash at banks and in hand, short-term deposits and restricted cash.

For the purpose of the statement of cash flows, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts.

(f) Inventories

Inventories of oil and gas, materials and drilling consumables are stated at the lower of cost and net realisable value. Cost is determined by using the weighted average cost method and comprises direct purchase costs, cost of transportation and other related expenses.

(g) Provisions

A provision is recognised when the Target Group has a legal or constructive obligation as a result of a past event and it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate can be made of the obligation. If the effect of the time value of money is material, expected future cash flows are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to unwinding the discount is recognised as a finance cost.

Decommissioning liability

The Target Group recognises a decommissioning liability where it has a present legal or constructive obligation as a result of past events, and it is probable than an outflow of economic benefits will be required to settle the obligation and a reliable estimate can be made of the obligation.

The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/construction of the field.

Changes in the estimated timing or cost of decommissioning are dealt with prospectively by recording an adjustment to the provision and a corresponding adjustment to oil and gas assets. Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to the income statement and statement of other comprehensive income.

If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Target Group considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment. If, for mature fields, the estimate for the revised value of oil and gas assets net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense. Over time, the discounted liability is increased for the change in present value based on the discount rate that reflects current market assessments and risks specific to the liability. The periodic unwinding of the discount is recognised in the income statement and statement of other comprehensive income as a finance cost.

(h) Post-employment benefits

For defined benefit schemes the amounts charged to operating profit are the costs arising from employee services rendered during the period and the cost of plan introductions, benefit changes, settlements and curtailments. The net interest cost on the net defined benefit liability is charged to profit or loss and included within finance costs. Remeasurement comprising actuarial gains and losses and the return on scheme assets (excluding amounts included in net interest on the net defined benefit liability) are recognised immediately in other comprehensive income.

Pension scheme assets are measured at fair value and liabilities are measured on an actuarial basis using the projected unit credit method. The actuarial valuations are obtained annually.

(i) Employee benefits

Salaries, wages, annual leave and sick leave

Liabilities for salaries and wages, including non-monetary benefits, annual leave and accumulating sick leave expected to be settled within 12 months of the reporting date are recognised in respect of employees' services up to the reporting date. They are measured at the amounts expected to be paid when the liabilities are settled. Liabilities for non-accumulating sick leave are recognised when the leave is taken and are measured at the rates paid or payable.

(j) Equity Instruments

Equity instruments issued by the Target Group are recorded at the proceeds received, net of direct issue costs.

(k) Interests in joint operations

A joint operation is a type of 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 relation to its interests in joint operations, the Target Group recognises its:

- assets, including its share of any assets held jointly;
- liabilities, including its share of any liabilities incurred jointly;
- revenue from the sale of its share of the output arising from the joint operation;
- share of the revenue from the sale of the output by the joint operation; and
- expenses, including its share of any expenses incurred jointly.

(l) Revenue recognition

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the Target Group and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received and receivable, excluding discounts, sales taxes, excise duties and similar levies.

Revenue from the sale of oil and petroleum products is recognised on an entitlement basis when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil, in which the Target Group has an interest with other producers, is recognised based on the Target Group's working interest and the terms of the relevant production sharing contracts.

(m) Cost of sales

Underlift and overlift

Lifting or offtake arrangements for oil and gas produced in certain entities of the Target Group's jointly owned operations are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production is 'underlift' or 'overlift'. Underlift and overlift are valued at market value and included within receivables and payables respectively.

Movements during an accounting period are adjusted through cost of sales such that gross profit is recognised on an entitlements basis.

(n) Interest Income

Interest income is recognised as it accrues using the effective interest rate method, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset. Interest income is included in net finance expense in the income statement and statement of other comprehensive income.

(o) Foreign currency translation

The Target Group's financial statements are presented in US Dollars. The functional currency for each entity in the Target Group is USD, determined on an individual basis according to the primary economic environment in which they operate.

Transactions in foreign currencies are initially recorded in the functional currency by applying the spot exchange rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the statement of financial position date. All exchange differences are taken to the income statement and statement of other comprehensive income. Non-monetary items that are measured at historical cost in a foreign currency are translated using the spot exchange rate ruling as at the date of the initial transaction. Non-monetary items measured at a revalued amount in a foreign currency are translated using the spot exchange rate ruling at the date when the fair value was determined.

(p) Income taxes

Current tax

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the statement of financial position date.

Current income tax is charged or credited directly to equity if it relates to items that are credited or charged to equity. Otherwise income tax is recognised in the income statement and statement of other comprehensive income.

Deferred tax

Deferred income tax is recognised on all temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements, with the following exceptions:

- where the temporary difference arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction affects neither accounting nor taxable profit or loss;
- in respect of taxable temporary differences associated with investments in subsidiaries, associates and joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future; and
- deferred income tax assets are recognised only to the extent that it is probable that taxable profit will be available against which the deductible temporary differences, carried forward tax credits or tax losses can be utilised.

Deferred tax is provided on temporary differences arising on acquisitions that are categorised as business combinations. Deferred tax is recognised at acquisition as part of the assessment of the fair value of assets and liabilities acquired. Any deferred tax is charged and credited in the income statement and statement of other comprehensive income as the

underlying temporary difference is reversed. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised. Unrecognised deferred tax assets are reassessed at the end of each reporting period and are recognised to the extent that it has become probable that future taxable profit will be available to allow the deferred tax asset to be recovered.

Deferred income tax assets and liabilities are measured on an undiscounted basis at the tax rates that are expected to apply when the related asset is realised or liability is settled, based on tax rates and laws enacted or substantively enacted at the statement of financial position date.

Deferred income tax is charged or credited directly to equity if it relates to items that are credited or charged to equity. Otherwise deferred income tax is recognised in the income statement and statement of other comprehensive income.

In order to account for uncertain tax positions, management has formed an accounting policy, in accordance with IAS 8, whereby the ultimate outcome of legal proceedings is viewed as a single unit of account. The results of separate hearings in relation to the same matter, such as local tribunals and international arbitration, are not viewed separately and only the final outcome is assessed by management to determine the best estimate of any potential outcome. If management viewed the results of individual hearings separately an income statement charge could arise due to the differing recognition criteria of assets and liabilities.

(q) Royalties, resource rent tax and revenue-based taxes

In addition to corporate taxes, the Target Group's financial statements also include and recognise as taxes on income, other types of taxes on net income such as certain royalties, resource rent taxes and revenue-based taxes.

Royalties, resource rent taxes and revenue-based taxes are accounted for under IAS 12 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government tax authority and the amount payable is based on taxable income – rather than physical quantities produced or as a percentage of revenue – after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are accrued and included in cost of sales.

(r) Impairment

The accounting policies for the impairment of intangible exploration and evaluation assets and oil and gas properties are described in more detail in 3.3(i) and 3.3(ii).

The Target Group assesses at each reporting date whether there is an indication that an intangible asset or item of property, plant and equipment may be impaired. If any indication exists, the Target Group estimates the asset's recoverable amount. The recoverable amount is the higher of an asset's or (CGU's) fair value less costs of disposal and its value in use. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. When the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs of disposal,

recent market transactions are taken into account, if available. If no such transactions can be identified, an appropriate valuation model is used.

These calculations are corroborated by valuation multiples, quoted share prices for publicly traded subsidiaries or other available fair value indicators.

The Target Group bases its impairment calculation on detailed budgets and forecast calculations, which are prepared separately for each of the Target Group's CGU's to which the individual assets are allocated. These budgets and forecast calculations generally cover a period of five years.

Impairment losses of continuing operations (including impairment on inventories) are recognised in the income statement and statement of other comprehensive income in expense categories consistent with the function of the impaired asset. Where conditions giving rise to the impairment subsequently reverse, the effect of the impairment charge is also reversed, net of any depreciation that would have been charged since the impairment.

3.3 Key accounting judgements and sources of estimation uncertainty

The preparation of the Target Group's financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities at the date of the financial statements. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The Target Group has identified the following areas where significant judgements, estimates and assumptions are required. Further information on each of these areas and how they impact the various accounting policies are described below and also in the relevant notes to the financial statements.

(i) Judgements

Exploration and evaluation expenditure – accounting judgements

The application of the Target Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from either future exploration, development or asset sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves.

Management is also required to assess impairment in respect of exploration and evaluation assets. Note 8 discloses the carrying value of such assets. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the asset. Where this is no longer the case, the costs are immediately expensed. The triggering events for impairment are defined in IFRS 6. In making the assessment, management is required to make judgements on the status of each project and assumptions about future events and circumstances, in particular, whether an economically viable extraction operation can be established.

(ii) Estimates

Oil and gas properties – estimation of oil and gas reserves

The determination of the Target Group's estimated oil and natural gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir

performance data, acquisition and divestment activity, drilling of new wells, and commodity prices all impact on the determination of the Target Group's estimates of its oil and natural gas reserves. The Target Group employs independent reserves specialists who periodically report on the Target Group's level of commercial reserves by evaluating the estimates of the Target Group's in-house reserves specialists and where necessary referencing geological, geophysical and engineering data together with reports, presentation and financial information pertaining to the contractual and fiscal terms applicable to the Target Group's assets. In addition, the Target Group undertakes its own assessment of commercial reserves, using standard evaluation techniques and related future capital expenditure by reference to the same datasets using its own internal expertise.

The estimates adopted by the Target Group may differ from the independent reserves specialists' estimates where management considers that adjustments are appropriate in the circumstances.

Estimates of oil and natural gas reserves are used to calculate depreciation, depletion and amortisation charges for the Target Group's oil and gas properties. The impact of changes in reserves is dealt with prospectively by amortising the remaining carrying value of the asset over the expected future production. Oil and natural gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. If reserves estimates are revised downwards, earnings could be affected by changes in depreciation expense or an immediate write-down of the property's carrying value. Information on the carrying amounts of the Target Group's oil and natural gas properties, together with the amounts recognised in the income statement as depreciation, depletion and amortisation is contained in Note 9 and 5a respectively.

Impairment of oil and gas properties – estimation on the recoverability of asset carrying values

Determination as to whether, and by how much, an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional market supply-and-demand conditions for crude oil and natural gas. For oil and natural gas properties, the expected future cash flows are estimated using management's best estimate of future oil and natural gas prices and production and reserves' volumes. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

For value-in-use calculations, future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate.

The recoverability of exploration and evaluation assets is covered under exploration and evaluation expenditure – accounting judgements above.

Details of impairment charges and reversals recognised in the income statement and details on the carrying amounts of assets and key assumptions used in determining recoverable amounts are shown in Note 8 and Note 9.

Decommissioning – estimation of provisions

Decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new technology or experience at other production sites. The expected timing, extent and amount of expenditure may also change. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

The estimated decommissioning costs are reviewed annually by management and the results of this review are then used for the purposes of the Target Group's financial statements.

Provision for environmental clean-up and remediation costs is based on current legal and contractual requirements, technology and price levels.

The key assumptions used to determine the balance sheet obligations at the end of 2017 are presented in Note 16.

4 Revenue

	Note	2015	2016	2017
			($000)	
Sale of crude oil		149,727	124,422	136,658
Sale of gas		136,331	136,254	119,187
		286,058	260,676	255,845

5 Operating (loss)/profit before taxation

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

	Note	2015	2016	2017
			($000)	
(a) Cost of sales:				
Operating costs[1]		(92,828)	(73,370)	(66,425)
Royalty payable		(11,114)	(10,371)	(12,061)
Depreciation and amortisation of oil and gas properties		(105,142)	(74,985)	(68,830)
Movement in inventories of oil		408	(987)	(1,776)
		(208,676)	(159,713)	(149,092)
(b) Exploration (expenses)/gains:				
Exploration costs		(314)	(2,259)	(1,553)
Exploration expenditure written off	8	(30,666)	(12,195)	(2,989)
Exploration expenditure reversal		—	—	1,156[2]
		(30,980)	(14,454)	(3,386)
(c) Other operating (expenses)/gains				
Other operating (expenses)/gains		(174)	2,546[3]	(274)
General and administration expenses		(806)	(713)	(508)
		(980)	1,833	(782)

Notes:

(1) Included within operating costs in 2017 is $36.8m (2016: $37.9m) (2015: $48.9m) of operating lease expenses.

(2) Relates to a change in estimate for E&E expenditure at Madura, Indonesia.

(3) Included within other gains in 2016 is a $2.3m reimbursement for an underwater inspection at Madura, Indonesia, undertaken in 2011.

6 Net finance expense

	Note	2015	2016	2017
			($000)	
Net foreign currency exchange losses..		(256)	(1,576)	(485)
Unwinding of discount	16	(1,948)	(1,334)	(1,954)
Related party debt interest income		225	234	1,078
Related party debt interest expense		(6,083)	(270)	(7)
Other Interest (expense)/income		(655)	(448)	70
		(8,717)	(3,394)	(1,298)

7 Taxation

(a) Taxation (charge)/credit:

	Note	2015	2016	2017
			($000)	
Current Tax.....		(45,908)	(39,745)	(49,913)
Deferred tax:				
Origination and reversal of temporary differences.....		41,226	(20,422)	4,194
Total deferred income tax in the income statement.....		41,226	(20,422)	4,194
Tax charge in the income statement.....		(4,682)	(60,167)	(45,719)
Items that will not be classified to profit or loss in subsequent periods:				
Deferred tax on the actuarial (gain)/loss		(175)	(240)	701
Total deferred tax charge in the statement of other comprehensive income.....		(175)	(240)	701
Total tax charge in the income statement and statement of other comprehensive income.....		(4,857)	(60,407)	(45,018)

(b) Reconciliation of the total tax (credit)/charge

The tax benefit not recognised in the income statement and statement of other comprehensive income is reconciled to the Target Group's weighted average tax rate of 38.9% (2016: 36.7%) (2015: 8.5%). The differences are reconciled below:

	Note	2015	2016	2017
			($000)	
Loss/(profit) on operations before taxation		40,295	(144,706)	(101,287)
(Loss)/profit on operations before taxation multiplied by the weighted average corporate tax rate for the Target Group of 38.8% (2016: 37%) (2015: 8.5%)		3,422	(53,573)	(39,260)
Non-deductible expenditure		(984)	(2,440)	(4,591)
Movement in unrecognised deferred tax assets		(6,916)	(1,744)	(568)
Other adjustments		(1,341)	(2,418)	(1,300)
Foreign exchange gains and other translation adjustments		1	8	-
Adjustments in respect of prior periods		10	-	-
Non assessable income		1,126	-	-
Total tax charge in the income statement		(4,682)	(60,167)	(45,719)

(c) Deferred tax

	Note	2015	2016	2017
			($000)	
Deferred tax balances relate to the following:				
Corporation tax on fixed asset temporary differences		30,160	47,010	42,545
Other short term temporary differences		1,095	1,057	627
Total deferred tax		31,255	48,067	43,172

8 Exploration and evaluation

	Note	2015(1)	2016(2)	2017(3)
			($000)	
Balance at the beginning of the year		26,733	112,168	121,277
Acquisitions		24,707	—	—
Additions.....		91,394	21,304	8,255
Expenditure written off.....		(30,666)	(12,195)	(2,989)
Balance at the end of the year.....		112,168	121,277	126,543

Notes:

(1) The $24.7m acquisition and $83.5m of the additions relate to the farm-in and subsequent investment in exploration asset Block R. The remaining additions related to exploration activities at Madura in Indonesia ($2.9m), Block SS-11 in Bangladesh ($2.1m), Block 124 in Vietnam ($2.1m) and Block 123 in Vietnam ($0.9m). $29.9m of expenditure written off relates to dry wells at Block R in Malaysia. The remainder of the write off expense relates to Madura in Malaysia.

(2) Additions predominantly relate to exploration activities at Madura ($16.7m) and Block R ($3.2m). The remainder relates to Block 123, Block 124 and Block SS-11. Expenditure written off relates to a $6.9m dry well expense at Madura, a $3.0m write-off at Block R and $2.3m abandoned well costs in Block 123 in Vietnam.

(3) Additions predominately relate to exploration activities at Block R ($7.4m). Expenditure written off mainly relates to Block R ($2.6m).

The carrying amount at 31 December 2017 of $126.5m relates to Block R, Madura, Block 123, Block 124 and Block SS-11.

9 Oil and gas properties

	Note	2015	2016	2017
			($000)	
Cost:				
Balance at the beginning of the year		992,883	982,839	980,557
Additions.....		7,600	1,055	16,759
Disposals.....		(2,919)	(4,826)	-
Changes in estimates relating to restoration provision		(14,725)	1,489	(7,296)
Balance at the end of the year.....		982,839	980,557	990,020
Depreciation and amortisation:				
Balance at the beginning of the year		(596,468)	(778,610)	(791,345)
Charge for the year.....		(105,142)	(74,985)	(68,830)
Disposal.....		-	2,492	-
(Impairment)/reversal		(77,000)	59,758	-
Balance at the end of the year.....		(778,610)	(791,345)	(860,175)
Net book value:				
Balance at the beginning of the year		396,415	204,229	189,212
Balance at the end of the year.....		204,229	189,212	129,845

The impairments and reversals recognised were as follows:

CGU - Producing assets	Activity	Pre-tax discount rate assumption			(Impairment)/reversal		
		2017	2016	2015	2017	2016	2015
						($000)	
Vietnam Chim Sáo/Dua .	Oil and gas production	12.9%	11.5%	13.3%	—	55,000	(77,000)
Madura (Maleo & Peluang).....	Gas production	11.2%	10.4%	12.4%	—	—	—
Sampang (Oyong/Wortel)	Oil and gas production	11.2%	10.4%	12.4%	—	4,758	—
(Impairment)/reversal.....						59,758	(77,000)

The discount rates applied to the future forecast cash flows are based on the weighted average cost of capital, adjusted for risks where appropriate, including functional currency of the asset, and risk profile of the countries in which the asset operates.

The 2015 impairment charge recorded in respect of the Target Group's oil and gas properties primarily resulted from the lower oil price environment and a consequential reduction or delay in future capital expenditure that diminishes or removes the path to commercialisation.

The 2016 impairment reversals were driven by:

(i) Sampang – Reduction in forecasted operating costs due to the date of cessation of oil production being brought forward to mid-2017.

(ii) Chim Sáo/Dua - Successful execution of a new FPSO lease resulting in lower daily hire rates and higher revenues being realised from re-phasing of the production profile.

The Target Group applied the following oil and gas price assumptions for impairment assessments:

2015

	2016	2017	2018	2019	2020 onwards
Oil price, US$/bbl	40	60	70	80.77	US$75/bbl (2015 real) escalated at 2.5% p.a.
Gas price, US$/mmbtu.....	6.31	6.49	6.68	6.86	n/a

2016

	2017	2018	2019	2020	2021 onwards
Oil price, US$/bbl	60	70	80.77	82.79	US$75/bbl (2016 real) escalated at 2.5% p.a.
Gas price, US$/mmbtu.....	6.49	6.69	6.89	7.03	n/a

2017

	2018	2019	2020	2021	2022 onwards
Oil price, US$/bbl	55	60	65	70	US$70/bbl (2017 real) escalated at 2.0% p.a.
Gas price US$/mmbtu.....	6.67	6.84	6.69	7.11	n/a

Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a value-in-use basis using discounted future cash flows based on 2P reserves profiles.

10 Long-term receivables

	Note	2015	2016	2017
			($000)	
Security deposits		222	200	205
Amounts held in Escrow		51,092	61,322	70,967
		51,314	61,522	71,172

Amounts held in Escrow relate to funds held in joint operations' bank accounts for decommissioning activities.

11 Inventory

	Note	2015	2016	2017
			($000)	
Oil and condensate		4,944	3,760	1,985
Materials and consumables		6,672	6,551	5,919
		11,616	10,311	7,904

There is no material difference between the carrying value of inventories and their net realisable value.

12 Trade and other receivables

	Note	2015	2016	2017
			($000)	
Trade and other debtors		41,257	40,756	36,569
Prepayments		3,261	3,619	3,914
		44,518	44,375	40,483

All debtors are current. There are no receivables that are past due or impaired and as such there is no allowance for doubtful debts. Due to the short-term nature of these receivables, their carrying value is assumed to approximate to their fair value and credit risk is deemed to be low. Trade and other receivables primarily relate to receivables from operating partners or end customers.

13 Cash and cash equivalents

	Note	2015	2016	2017
			($000)	
Cash at bank and in hand		27,454	31,540	16,575
		27,454	31,540	16,575

14 Trade and other payables

	Note	2015	2016	2017
			($000)	
Trade payables		(2,985)	(12,469)	(10,000)
Accrued expenses		(47,927)	(26,046)	(24,827)
		(50,912)	(38,515)	(34,827)

Trade payables are unsecured and carrying value equals their fair value.

15 Defined benefit provision

Defined benefit schemes

Santos Sampang operates a post-employment defined benefit arrangement, as regulated under the Indonesian Law No. 13/2003, for the Sampang PSC. The arrangement covers retirement, death, disability and voluntary resignation benefits, which are based on final wages. While the legal obligation for the scheme sits with Santos Sampang, 55% of the obligation is recharged to the Sampang PSC joint operators. The portion of the obligation which is recharged to entities outside of the Target Group has been recorded as a receivable at 31 December 2015, 2016 and 2017, with the corresponding entry included in operating costs. The Statement of Financial Position, Income statement and Statement of Other Comprehensive income balances relating to the arrangement, as presented below, and the recharges, are recorded gross.

The actuarial valuations of scheme assets and the present value of the defined benefit obligation have been carried out at 31 December 2015, 2016 and 2017. Santos Sampang initiated a funding mechanism in September 2016 for post-employment benefit via DPLK (Financial Institution Pension Fund) using the PPUKP (Program Pensiun untuk Kompensasi Pesangon) programme, as such, there were no plan assets at 31 December 2015.

The key actuarial assumptions applied in determining the present value of the defined benefit obligations, the related current service cost and past service cost, which are measured using the projected unit credit method, are as follows:

Key economic assumptions used:

	2015	2016	2017
Discount rate	8%	7.5%	5.75%
Wage increase	9%	8.5%	5%
Expected Long-Term Inflation	4.5%	4%	4%
End of Contract	2019	2021	2020

Key employee assumptions used:

Early retirement rate

Management have considered the expected date of employees claiming their pension up to the end of employee's contracts. The assumed percentage of employees claiming their pension prior to 58 years of age, the normal retirement age, are as follows:

	2015	2016	2017
Retire in 2016	25%	—	—
Retire in 2017	25%	15%	—
Retire in 2018	25%	—	55%
Retire in 2019	25%	—	25%
Retire in 2020	—	80%	20%
Retire in 2021	—	5%	—

Resignation rate

The assumed rate of employees resigning prior to the end of their employment contract:

	2015	2016	2017
Age < 25 years	0%	5%	5%
25 years < Age < 30 years	0%	2%	2%
30 years < Age < 35 years	0%	5%	5%
Age > 35 years	0%	2%	2%

Amounts recognised in the profit and loss account in respect of these defined benefit schemes are as follows:

	2015	2016	2017
		($000)	
Current Service Cost	(930)	(1,193)	(1,321)
Past Service Cost	(2,293)	—	—
Interest Income	—	139	658
Interest Expense	(430)	(668)	(660)
Foreign Exchange	696	(262)	(33)
	(2,957)	(1,984)	(1,356)

Mortality and disability rates

The mortality rates for 2015, 2015 and 2017 follow the Indonesia Mortality Table 2011 (TMI III). The disability rate is set at 5% of the mortality rate for each year.

Financial disclosures:

Recognised in other comprehensive income:

	2015	2016	2017
		($000)	
Actuarial Gain/(Loss)	398	520	(1,456)
Return on Plan Assets o/t Net Income	—	26	(137)
	398	546	(1,593)

The amount included in the balance sheet arising from the Target Group's obligations in respect of its defined benefit schemes is as follows:

	2015	2016	2017
		($000)	
Present value of defined benefit obligations	(8,142)	(9,473)	(11,358)
Fair value of scheme assets	—	6,910	10,969
Net liability recognised in the balance sheet	(8,142)	(2,563)	(389)

Movements in the present value of defined benefit obligations were as follows:

	2015	2016	2017
		($000)	
At 1 January	(6,079)	(8,142)	(9,473)
Service cost	(3,223)	(1,193)	(1,321)
Interest cost	(430)	(668)	(660)
Foreign exchange gains and (losses)	696	(174)	72
Actuarial gains and (losses)	398	520	(1,456)
Benefits paid	496	184	1,480
	(8,142)	(9,473)	(11,358)

Movements in the fair value of scheme assets[1] were as follows:

	2015	2016	2017
		($000)	
At 1 January	—	—	6,910
Interest income	—	139	658
Foreign exchange gains and (losses)	—	(87)	(105)
Return on plan assets (excluding amounts included in net interest cost)	—	26	(137)
Contributions from the employer	—	6,942	5,123
Benefits paid	—	(110)	(1,480)
	—	6,910	10,969

Note:

(1) All plan assets are money market instruments

16 Other provisions

	Note	Decommissioning and restoration of oil and gas	Total
		($000)	
At 1 January 2015		(104,719)	(104,719)
Unwinding of discount	6	(1,948)	(1,948)
Remeasurement		14,725	14,725
At 31 December 2015		(91,942)	(91,942)
Unwinding of discount	6	(1,334)	(1,334)
Amounts released		95	95
Remeasurement		(1,489)	(1,489)
At 31 December 2016		(94,670)	(94,670)
Unwinding of discount	6	(1,954)	(1,954)
Remeasurement		7,296	7,296
Additions		(26)	(26)
At 31 December 2017		(89,354)	(89,354)

The decommissioning and restoration of oil and gas assets provision represents the present value of decommissioning costs relating to the Target Group's oil and gas properties. The Target Group applied the following assumptions:

2015

	Inflation assumption	Discount rate assumption	Assumed cessation of production	2015
				($000)
Oyong	1.9%	2.2%	2017	7,969
Maleo	2.1%	2.2%	2018	10,587
Peluang	2.1%	2.2%	2018	6,542
Vietnam Chim Sáo	2.1%	2.2%	2023	47,552
Vietnam Dua	2.1%	2.2%	2023	16,188
Wortel	1.9%	2.2%	2018	3,104
				91,942

2016

	Inflation assumption	Discount rate assumption	Assumed cessation of production	2016
				($000)
Oyong	2.5%	1.6%	2020	8,676
Maleo	2.5%	1.6%	2019	11,231
Peluang	2.5%	1.6%	2019	6,940
Vietnam Chim Sáo	2.5%	2.2%	2023	48,069
Vietnam Dua	2.5%	2.2%	2023	16,364
Wortel	2.5%	1.6%	2020	3,390
				94,670

2017

	Inflation assumption	Discount rate assumption	Assumed cessation of production	2017
				($000)
Oyong	2.0%	2.0%	2020	8,375
Maleo	2.0%	2.0%	2020	10,991
Peluang	2.0%	2.0%	2020	6,792
Vietnam Chim Sáo	2.0%	2.3%	2028	44,881
Vietnam Dua	2.0%	2.3%	2028	15,044
Wortel	2.0%	2.0%	2020	3,271
				89,354

17 Related party borrowings

	Note	2015	2016	2017
			($000)	
After five years		(13,673)	(7,761)	(10,132)
Total principal payable on maturity		(13,673)	(7,761)	(10,132)

The balance entirely relates to loans from members of the Santos group of companies (excluding the Target Group) (the "**Santos Group**"), which are repayable in 2024, are unsecured, and carry an interest rate of 6 month LIBOR plus a margin of 5.2%.

Related party borrowings will be settled as part of the transaction. There are no external borrowings within the Target Group.

18 Net debt

Net debt is defined as related party borrowings less cash and cash equivalents.

	Note	2015	2016	2017
			($000)	
Amounts due on maturity:				
Related party borrowings	17	(13,673)	(7,761)	(10,132)
Less cash and cash equivalents	13	27,454	31,540	16,575
Total net cash		13,781	23,779	6,443

The movement in net debt is as follows:

2015	At 1 January 2015	Cash flow movements	Foreign exchange, interest and other non-cash movements(1)	At 31 December 2015
Net cash and cash equivalents	24,136	4,110	(792)	27,454
Related party borrowings	(400,464)	324,605	62,186	(13,673)
Net (debt)/cash	(376,328)	328,715	61,394	13,781

Note:

(1) The following non-cash items are included in this column: FX movements, interest accrued, dividends settled through creation of related party borrowings, capital contributions through related party borrowings forgiveness and contracts with related party assets.

2016	At 1 January 2016	Cash flow movements	Foreign exchange, interest and other non-cash movements(1)	At 31 December 2016
Net cash and cash equivalents	27,454	4,354	(268)	31,540
Related party borrowings	(13,673)	94,439	(88,527)	(7,761)
Net cash	13,781	98,793	(88,795)	23,779

Note:

(1) The following non-cash items are included in this column: FX movements, interest accrued, dividends settled through creation of related party borrowings, capital contributions through related party borrowings forgiveness and contracts with related party assets.

2017	At 1 January 2017	Cash flow movements	Foreign exchange, interest and other non-cash movements(1)	At 31 December 2017
Net cash and cash equivalents.....	31,540	(14,145)	(820)	16,575
Related party borrowings.....	(7,761)	112,466	(114,837)	(10,132)
Net cash	23,779	98,321	(115,657)	6,443

Note:

(1) The following non-cash items are included in this column: FX movements, interest accrued, dividends settled through creation of related party borrowings, capital contributions through related party borrowings forgiveness and contracts with related party assets.

19 Financial instruments

Financial risk management objectives and policies

Capital risk

The capital structure consists of related party debt, which includes current and non-current interest bearing loans as disclosed in Note 17, cash and cash equivalents as disclosed in Note 13 and equity attributable to equity holders of the entities within the Target Group. Funding requirements were managed, through the issue or repayment of related party debt by the Santos Group.

Foreign currency risk

The Target Group is not materially exposed to foreign currency risk as it principally trades in US dollars through the sale of oil denominated in US dollars, incurs expenditure primarily in US dollars and has United States dollar borrowings from related entities.

Interest rate risk

The Target Group has historically held interest-bearing related party liabilities priced at LIBOR plus a margin of 5.2%. As such there has been some exposure to changes in market interest rates on borrowings. Interest rate risk was managed, through the issue, waiving or repayment of related party debt as directed by the Santos Group.

The sensitivity analysis below has been determined based on the exposure to LIBOR at the balance sheet date. The sensitivity assumes that the amount outstanding at 31 December in each period was outstanding for the full year. If LIBOR had been 1% higher and all other variables were held constant, the Target Group's profit for the year ended 31 December 2017, 2016 and 2015 would decrease by $0.1m, $0.1m and $0.1m respectively. A corresponding decrease of the same amount in each period would be recognised if the interest rate was decreased by 1%.

Commodity price risk

The Target Group may be exposed to commodity price fluctuations through the sale of petroleum products. Commodity price risk was managed at the Santos Group level and was not pushed down to the entities within the Target Group. As such the results of the entities within the Target Group reflect 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 on financial instruments.

Credit risk

Credit risk arises from cash and cash equivalents as well as credit exposures to customers, including outstanding receivables and committed transactions, and represents the potential financial loss if counterparties fail to perform as contracted. The Target Group applied the Santos Group credit policy and the exposure to credit risk was monitored on an ongoing basis.

The receivables balances were monitored on an ongoing basis and amounts outstanding are all current (being not more than 90 days), therefore, the Target Group's exposure to bad debts at reporting date is not significant. The Target Group does not hold collateral, nor does it securitise its trade and other receivables.

The Target Group's maximum exposure to credit risk is represented by the carrying amount of trade and other receivables recognised in the statement of financial position. At the reporting date there were no long overdue balances and therefore, there are no significant concentrations of credit risk.

Liquidity risk

The Target Group mitigates liquidity risk by maintaining sufficient cash balances to meet ongoing operational requirements and exploration activities. Historically the Target Group entities and assets have been funded, predominantly, through related party capital from parent undertakings.

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. Tables for periods ending December 2016 and December 2015 have not been shown given non-cash movements (dividends, related party debt forgiveness and contras) materially changed the interest profile for the period following the 31 December 2016 and 31 December 2015 reporting dates. The table below shows the cash-flow maturity profile for financial instruments outstanding at 31 December 2017.

	Within 1 year	1-2 years	2-5 years	5+ years	Total
31 December 2017					
Non-interest bearing	(34,827)	—	—	—	(34,827)
Variable interest rate instruments – related party borrowings	(713)	(713)	(2,139)	(10,132)	(13,697)

The weighted average interest rate for the related party borrowings is 5.2% plus 6M LIBOR.

Gearing ratio

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

Significant accounting policies

Details of significant accounting policies and methods adopted, including the criteria for recognition, the basis of measurement and the basis on which the income and expenses are recognised, in respect of each class of financial asset, financial liability and equity instrument are disclosed in the statement of accounting policies.

Categories of financial instruments

	2015	2016	2017
		($000)	
Financial assets			
Loans and receivables:			
Cash and cash equivalents	27,454	31,540	16,575
Trade and other receivables	41,257	40,756	36,569
Amounts owing from related entities	25,734	66,706	38,632
Long-term receivables	51,314	61,522	71,172
	145,759	200,524	162,948
Financial liabilities			
Amortised cost:			
Trade and other payables	(50,912)	(38,515)	(34,827)
Related party borrowings	(13,673)	(7,761)	(10,132)
	(64,585)	(46,276)	(44,959)

Trade and other payables above excludes deferred income. The carrying value of the financial liabilities, held at amortised cost, approximate to their fair value.

20 Commitments

Operating lease commitments

Non-cancellable operating lease payments are payable as follows:

	2015	2016	2017
		($000)	
Due within one year	37,729	34,901	30,228
Due later than one year but within five years	30,783	49,832	47,259
	68,512	84,733	77,487

Capital commitments

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

	2015	2016	2017
		($000)	
Due within one year	4,086	19,489	5,554
Due later than one year but within five years	61	170	1,535
	4,147	19,659	7,089

Exploration commitments

In acquiring its oil and gas interests, the Target Group has pledged that various certain minimum work commitment (MWC) work programmes as stated in the underlying agreements will be undertaken on each permit/interest prior to the end of licenses' exploration periods. In the event that these work programmes are not undertaken, the Target Group is required to pay the MWC value as a penalty. MWC exploration commitments at 31 December 2015, 2016 and 2017 were $31.5m. The timing of these work programme activities, and therefore the related expenditure including payment of penalty in lieu of the actual work programme, are not prescribed by the underlying agreements. The commitment value as at 31 December 2017 and the applicable exploration license expiry dates, by which time the costs will either have been incurred, or become payable, unless an extension is agreed, are as follows:

Exploration asset	Commitment	Permit expiry
	($000)	
Block 123	14,314	11 June 2019
Block 124	8,800	29 October 2020[1]
Block SS-11	8,400	11 March 2019

Note:

(1) On 20 June 2018, PetroVietnam confirmed that the Block 124 PSC exploration period had been extended from 29 October 2018 to 29 October 2020.

Excluded from the above table are 2018 Joint Venture approved budget commitments of $0.9m for Block 123 and $3.1m for Malaysia Block R, since these are not related to MWC's under the respective PSCs.

21 Material joint operations

The following joint operations are considered individually material to the Target Group as at 31 December 2017.

Asset	Principal place of business	Activity
Chim Sáo / Dua[1]	Vietnam	Oil and gas production
Sampang[2]	Indonesia	Oil and gas production
Madura Offshore[3]	Indonesia	Gas production
Block R[4]	Malaysia	Oil and gas exploration
Block 123 and 124[5]	Vietnam	Oil and gas exploration
Block SS-11[6]	Bangladesh	Oil and gas exploration

Notes:

(1) 31.875% non-operated interest in the Block 12W PSC (Chim Sáo /Dua).

(2) 45% operated interest in the Sampang PSC.

(3) 67.5% operated interest in the Madura Offshore PSC.

(4) 20% non-operated interest in the Deepwater Block R PSC.

(5) 50% operated interest in the Block 123 PSC and a 40% non-operated interest in the Block 124 PSC.

(6) 45% operated interest in the Block SS-11 PSC.

22 Related party transactions

Balances and transactions between the companies within the Target Group have been eliminated upon aggregation and are not disclosed within this Note. Furthermore, the entities within the Target Group contain no key management personnel as defined by IAS 24 *Related Party Transactions*. The key activities of the Target Group were managed by key management personnel within the Santos Group.

The Target Group has been funded by the Santos Group. Outstanding balances owed to Santos Finance Limited, Santos BBP P/L and Santos Limited have been disclosed in Note 17. The cash and non-cash movements have been disclosed in Note 18.

Amounts owing from related entities within non-current assets of $38.5m, $66.7m and $18.5m at 31 December 2017, 2016 and 2015 respectively are deposits made by Target Group entities to Santos Finance Limited. These amounts are receivable in 2024 and earn interest at 1 month LIBOR less 0.1%.

Amounts owing from related entities within current assets are trade balances between Target Group entities and the Santos Group.

23 Subsequent events

Subsequent to 31 December 2017, in light of the proposed disposal of producing and exploration assets to Ophir, the Santos Group is undertaking an impairment review to reflect the facts and circumstances of the transaction which may result in changes to the carrying value of assets within the Target Group.

The Directors
Ophir Energy plc
123 Victoria Street
London
SW1E 6DE

3 August 2018

Dear Sirs

Package of Southeast Asian assets to be acquired from Santos Limited

We report on the financial information set out in Part IV for the years ended 31 December 2015, 2016 and 2017 ("the Historical Financial Information of the Target Group"). This financial information has been prepared for inclusion in the class 1 circular dated 3 August 2018 of Ophir Energy plc ("the Company") relating to the acquisition of a package of Southeast Asian assets ("the Target") to be acquired from Santos Limited on the basis of the accounting policies set out in Note 3 to the Historical Financial Information of the Target Group. This report is required by Listing Rule 13.5.21 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 class 1 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 class 1 circular.

Responsibilities

The Directors of the Company are responsible for preparing the Historical Financial Information of the Target Group on the basis of preparation set out in Note 2 to the Historical Financial Information of the Target Group and in a form that is consistent with the accounting policies adopted in the Company's latest annual accounts.

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

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

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

Opinion

In our opinion, the Historical Financial Information of the Target Group gives, for the purposes of the class 1 circular dated 3 August 2018, a true and fair view of the state of affairs of the Target as at the dates stated 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 to the Historical Financial Information of the Target Group.

Yours faithfully

Ernst & Young LLP

PART V
PRO FORMA STATEMENT OF NET ASSETS OF THE ENLARGED GROUP

Unaudited pro forma statement of net assets of the Enlarged Group at 31 December 2017

The unaudited pro forma statement of net assets of the Enlarged Group set out below has been prepared to illustrate the effect of the Transaction on the Group's consolidated net assets as at 31 December 2017, as if Completion had occurred at that date. The statement has been prepared in a manner consistent with the accounting policies adopted by the Group in preparing its historical consolidated financial information for the year ended 31 December 2017, on the basis set out below and in accordance with item 20.2 of Annex I of the Prospectus Directive Regulation and Listing Rule 13.3.3 R.

The unaudited pro forma statement of net assets has been prepared for illustrative purposes only and, because of its nature, addresses a hypothetical situation, and does not represent the Enlarged Group's actual financial position. The statement does not purport to represent what the Group's or the Enlarged Group's financial position actually would have been if the Transaction had completed on the date indicated nor does it purport to represent the Group's or the Enlarged Group's financial condition at any future date.

Shareholders should read the whole of this Circular and not rely solely on the unaudited pro forma financial information contained in this Part V: "Pro Forma Statement of Net Assets of the Enlarged Group".

	Group net assets/ (liabilities) as of 31 December 2017	Total net assets of aggregated Target Group	Draw-down or acquisition bridge facility	Working capital adjustments	Related party balance settlement and pre-acquisition dividend	Acquisition accounting adjustment	Pro forma
	(1)	(2)	(3)	(4)	(4)	(5)	
			($000)				
Non-current assets							
Exploration and evaluation assets	247,944	126,543	-	-	-	-	374,487
Oil and gas properties	699,669	129,845	-	-	-	6,634	836,148
Other property, plant and equipment	2,211	-	-	-	-	-	2,211
Investments accounted for using the equity method	120,964	-	-	-	-	-	120,964
Long-term receivables	21,205	71,172	-	-	-	-	92,377
Amounts owing from related parties	-	38,517	-	814	(39,331)	-	-
	1,091,993	366,077	-	814	(39,331)	6,634	1,426,187
Current assets							
Assets classified as held for sale	604,432	-	-	-	-	-	604,432
Inventory	40,647	7,904	-	-	-	-	48,551
Taxation receivable	9,125	1,838	-	(1,838)	-	-	9,125
Trade and other receivables	24,656	40,483	-	(6,031)	-	-	59,108
Cash and cash equivalents	223,779	16,575	126,522	-	(16,750)	(211,982)	138,144
Amounts owing from related entities	-	115	-	(115)	-	-	-
	902,639	66,915	126,522	(7,984)	(16,750)	(211,982)	859,360
Total assets	1,994,632	432,992	126,522	(7,170)	(56,081)	(205,348)	2,285,547
Current liabilities							
Trade and other payables	(52,374)	(34,827)	-	7,670	-	-	(79,531)
Taxation payable	(30,282)	(13,555)	-	1,712	-	-	(42,125)
Provisions	(9,399)	-	-	-	-	-	(9,399)
Derivative financial instruments	(3,582)	-	-	-	-	-	(3,582)
	(95,637)	(48,382)	-	9,382	-	-	(134,637)

	Group net assets/ (liabilities) as of 31 December 2017 (1)	Total net assets of aggregated Target Group (2)	Draw-down or acquisition bridge facility (3)	Working capital adjustments (4)	Related party balance settlement and pre-acquisition dividend (4)	Acquisition accounting adjustment (5)	Pro forma
Non-current liabilities							
Trade and other payables	(15,279)	-	-	-	-	-	(15,279)
Bonds payable	(106,651)	-	-	-	-	-	(106,651)
Defined benefit provision	-	(389)	-	-	-	-	(389)
Other provisions	(51,265)	(89,354)	-	-	-	-	(140,619)
Related party borrowings	-	(10,132)	-	(2,212)	12,344	-	-
Deferred tax liability	(264,491)	(43,172)	-	-	-	-	(307,663)
Borrowings	-	-	(126,522)	-	-	-	(126,522)
	(437,686)	(143,047)	(126,522)	(2,212)	12,344	-	(697,123)
Total liabilities	(533,323)	(191,429)	(126,522)	7,170	12,344	-	(831,760)
Net Assets	1,461,309	241,563	-	-	(43,737)	(205,348)	1,453,787

Note:

(1) The net assets of the Group as at 31 December 2017 have been extracted without material adjustment from the audited consolidated financial information incorporated by reference in Part VI: "Additional Information" of this Circular.

(2) The net assets of the Target Group as at 31 December 2017 have been extracted without material adjustment from the historical financial information of the Target Group included in Part IV: "Historical Financial Information of the Target Group" of this Circular.

(3) Upon completion of the acquisition of the Producing Assets, the Group will draw-down on a up to US$130m acquisition bridge facility. The amount that will be received on draw-down, net of transaction costs, is US$126.5m, and is repayable in full 18 months from the date of the facility agreement. The facility agreement is described in more detail in Part VI: "Additional Information" of this Circular.

(4) The following transactions will occur prior to the completion of the Transaction, and these items were all reflected in the agreed purchase price of $204.5m:

(i) Working capital adjustments with a net $nil impact on the Target Group's net assets.

(ii) Amounts due from the Santos Group to the Target Group of $39.3m will be settled through waiver;

(iii) The cash adjustment of US$16.75m consists of a cash dividend of US$10.0m that will be paid by the Target Group to the Santos Group, and US$6.75m that will be settled by the Group, on behalf of the Target Group; and

(iv) The related party borrowings adjustment consists of US$5.6m of borrowings that will be waived by the Santos Group as a capital contribution and the US$6.75m settlement referred to in 4(iii) above.

(5) The unaudited pro forma statement of net assets has been prepared on the basis that the Transaction will be treated as a business combination in accordance with IFRS 3. However, it does not reflect any fair value adjustments to the acquired assets and liabilities as the fair value measurement of these items will only be performed as at the date of Completion. The fair value adjustments, when finalised, may be material. For the purposes of the pro forma statement of net assets, the excess purchase consideration over the carrying amount of the net assets of $197.8m has been attributed to the Oil & gas properties and no pro forma impairment charge has been applied in the period.

The preliminary fair value uplift of the Oil & Gas assets have been calculated as follows:

	US$'000
Purchase consideration (see (5.i) below)	204,460
Net assets of Target Group as at 31 December 2017 (Note 2)	(241,563)
Intercompany restructure and dividend transactions (Note 4)	43,737
Purchase consideration in excess of net assets (shown as an adjustment to Oil & gas properties)	6,634

(5.i) This reflects the payment of cash consideration of $204.5 million for the acquisition of the Target Group. In addition, it is estimated that transaction expenses of approximately $7.5 million will be incurred, such that the total cash outflow relating to the Acquisition will be $212.0 million. These transaction expenses will be expensed.

(6) The Exploration Assets have $35.5m of commitments reflecting minimum work commitments as stated in the underlying agreements or approved 2018 joint venture budget commitments. If the Group does not complete the acquisition of one or more of the Exploration Assets, the commitment value for that asset(s) will become payable by the Group as a break fee. If the Group completes, but then cease exploration investment at one or more of the assets, an onerous contract provision will be recorded. As the pro forma statement has been prepared on the basis that all the Exploration Assets will complete and exploration activity will continue, these commitments have been excluded from the Enlarged Group's pro forma balance sheet. See Part III "Summary of the Transaction Agreements" for further detail.

(7) No adjustment has been made to reflect the results of either Ophir Group or the Target Group since 31 December 2017.

The Directors
Ophir Energy plc
123 Victoria Street
London
SW1E 6DE

3 August 2018

Dear Sirs

We report on the pro forma financial information (the "Pro Forma Financial Information") set out in Part V of the investment circular dated 3 August 2018, which has been prepared on the basis described therein, 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 Ophir Energy plc in preparing the financial statements for the period ended 31 December 2017. 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 investment circular, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Listing Rule 13.4.1R (6), consenting to its inclusion in the investment circular.

Responsibilities

It is the responsibility of the directors of Ophir Energy plc 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 used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the directors of Ophir Energy plc.

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 Ophir Energy plc.

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.

Opinion

In our opinion:

1. the Pro Forma Financial Information has been properly compiled on the basis stated; and

2. such basis is consistent with the accounting policies of Ophir Energy plc.

Yours faithfully

Ernst & Young LLP

PART VI
ADDITIONAL INFORMATION

1 Responsibility

The Company and the Directors, whose names are set out in paragraph 4 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 Ophir

The Company was incorporated and registered in England and Wales on 18 February 2004 as a private company limited by shares with registered number 05047425 with the name of "Ophir Energy Company Limited". On 12 September 2007, the Company was re-registered as a public limited company and changed its name to "Ophir Energy plc".

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 Level 4, 123 Victoria Street, London SW1E 6DE, United Kingdom and its telephone number is +44 (0)20 7811 2400. The business of the Company, and its principal activity, is to act as the ultimate holding company of the Group.

3 Trend information

Since the start of the financial year, the Group's production assets in Southeast Asia have performed in line with expectations.

The key factors affecting the Company's results of operations and financial condition since 31 December 2017, and those that are expected to affect its results of operations and financial condition in the future, include the following:

- acquisition, exploration, development and production expenditure and success rates;
- oil and gas prices;
- foreign exchange; and
- the Fortuna project in Equatorial Guinea.

3.1 Acquisition, exploration, development and production expenditure and success rates

The Company has incurred substantial expenses related to the acquisition of assets and early stage exploration activities.

The Company has historically incurred expenses in connection with pre-licence exploration activities or in pursuit of new ventures, which it has expensed, as well as post-licence exploration activities, which it has capitalised or written off. In the event that it exits any of its exploration licences then the expenses it has occurred may be written off. The Company also expects to incur further expenses relating to optimisation and field-life extension of its oil and gas-producing assets.

3.2 Oil and gas prices

The Company's exploration and production strategies and its results of operations are influenced significantly by crude oil and natural gas prices. Crude oil prices have risen significantly since the

start of the year which is beneficial for the Company in terms of it receiving higher prices and an increased unit margin.

Natural gas is commonly sold under long term contracts at a price which is linked to that of crude oil and is therefore influenced by the same factors and uncertainties. In some markets, the price of natural gas is determined by reference to gas trading hubs which are largely independent of crude oil, but are nevertheless governed by similar considerations and can as a result also show considerable variation.

Crude oil prices have been volatile in the past and are likely to continue to be volatile in the future. Prices for oil are driven by world supply and demand and a number of other factors, including government regulation and social and political conditions.

The Group may use derivative financial instruments to manage certain exposures to fluctuations in commodity prices.

3.3 Foreign exchange

The Group has currency exposures arising from assets and liabilities denominated in foreign currencies and transactions executed in currencies other than the respective functional currencies. The Group companies, with the exception of Ophir Services Pty Ltd (which has adopted the Australian Dollar as its functional currency), have adopted US Dollar as their functional and reporting currencies as this represents the currency of their primary economic environment as the majority of the Group's funding and expenditure is US Dollars.

The Group's predominant exposure to foreign exchange rates relates to cash and cash equivalents held in Pounds Sterling by Group companies with US Dollar functional currencies. The Group minimises its exposure to foreign exchange fluctuations by holding the majority of its funds in US Dollars, with remaining funds being held mainly in Pounds Sterling (GBP) and Thailand Baht (THB) to meet commitments in those currencies.

The Group may use derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates.

3.4 Fortuna project in Equatorial Guinea

Ophir remains focused on achieving its objectives for its existing assets, specifically FID of the Fortuna project in Equatorial Guinea, which, given the level of cash flows expected from the project if production starts (which would not be in the near term), would also represent an important milestone in accelerating delivery of Ophir's ambition to be fully self-funded.

Following the announcement by Ophir on 31 May 2018 regarding the dissolution of the OneLNG joint venture between Golar LNG and Schlumberger, Ophir and Golar remain actively engaged in discussions with new potential partners and financing parties regarding the Fortuna project. The Block R licence is due to expire at the end of 2018 and, as highlighted in our operations and trading update on 12 July 2018, depending on how these discussions progress, the carrying value of the Block R licence (US$604 million as at 31 December 2017) may need to be reassessed which could have a significant impact on the Group's results.

If the project proceeds, the Board has reaffirmed its current intention not to invest more than US$150 million into the project.

4 Directors and senior management

The names and principal functions of the Directors and the Company's senior management are as follows:

Directors	Position
William (Bill) Schrader	Non-Executive Chairman
Alan Booth	Executive Director & Interim Chief Executive Officer
Anthony (Tony) Rouse	Executive Director & Chief Financial Officer
Dr Carol Bell	Senior Independent Director
David Davies	Independent Non-Executive Director
Vivien Gibney	Independent Non-Executive Director
Dr Carl Trowell	Independent Non-Executive Director

On 18 May 2018, the Company announced that Dr Nicholas (Nick) Cooper was to step down from the Board with immediate effect and that Alan Booth, a non-executive director with extensive experience as a chief executive officer in the upstream oil and gas industry, was appointed as Interim Chief Executive Officer of the Company. The search for a permanent chief executive officer is ongoing.

Senior Management	Position
Dr John Bell	Director – Asia Operations
Philip Laing	General Counsel & Company Secretary
Dr Oliver Quinn	Director – Exploration & Africa
Gawain Ross	Director – Corporate Risk & Services
Dato Sandroshvili	Director – M&A

5 Directors' and senior management's shareholdings and stock options

5.1 Shares

The interests of the Directors and of members of senior management (and of persons connected with them) in the share capital of the Company (all of which are beneficial unless otherwise stated) as at the Latest Practicable Date are as follows (not including options disclosed below):

	As at the Latest Practicable Date	
Name	**No. of Shares**	**As a percentage of total issued Shares**
William (Bill) Schrader	17,700	0.002%
Alan Booth	125,000[1]	0.017%
Anthony (Tony) Rouse	337,775	0.045%
Dr Carol Bell	9,194	0.001%
David Davies	—	—

Name	As at the Latest Practicable Date	
	No. of Shares	As a percentage of total issued Shares
Vivien Gibney	15,000	0.002%
Dr Carl Trowell	—	—
Dr John Bell	329,044	0.044%
Philip Laing	—	—
Dr Oliver Quinn	835	0.000%
Gawain Ross	19,616[(2)]	0.003%
Dato Sandroshvili	—	—

Notes:

(1) Alan Booth holds a beneficial interest in 125,000 shares. The legal interest is held by Interactive Investor Services Nominees Limited.

(2) Gawain Ross, 13,461 shares are vested but unexercised 2014 Deferred Share Plan award and 6,155 are held by his spouse.

5.2 Share options

As at the Latest Practicable Date, the following options to acquire Shares had been granted to the Directors and senior management and remained outstanding under the Share Schemes, such options being exercisable at the price shown below:

Name	Date of Grant	Number of Shares over which options granted	Exercise Price (pence)	Expiry Date
Anthony (Tony) Rouse (Long-Term Incentive Plan)	14/03/2016	559,958	nil	14/03/2020
Dr John Bell (Long-Term Incentive Plan)	14/03/2016	310,992	nil	14/03/2020
Philip Laing (Long-Term Incentive Plan)	14/03/2016	443,659	nil	14/03/2020
Dr Oliver Quinn (Long-Term Incentive Plan)	14/03/2016	342,694	nil	14/03/2020
Gawain Ross (Long-Term Incentive Plan)	14/03/2016	246,037	nil	14/03/2020
Dato Sandroshvili (Employee Share Option Plan)	24/03/2014	150,000	206.00	24/03/2024
Dato Sandroshvili (Long-Term Incentive Plan)	14/03/2016	439,352	nil	14/03/2020

Save as disclosed in this paragraph 5, no Director or senior management, nor their immediate families, nor any person connected with any Director or senior management has any interests (beneficial or non-beneficial) in the share capital of the Company or any of its subsidiaries.

5.3 Long Term Value Creation Plan

With effect from 1 January 2016, Ophir put in place a Long Term Value Creation Plan ("**LTVCP**"). The LTVCP is an incentive scheme based on growth in net asset value ("**NAV**") per share on the occurrence of certain well-defined events (each, a "**NAV Event**"). When a NAV Event takes place, 12.5 per cent of the increase in NAV will be used to create an employee reward pool. When a reward pool is created, it will be distributed to employees in the form of cash and shares. The cash amount represents 25 per cent of the total individual reward and is payable shortly after the NAV Event has occurred. The balance of the award takes the form of deferred shares. For the Executive Directors, the deferred shares vest after three, four and five years but must be held for a minimum of five years. For senior management, the deferred shares vest after three, four and five years without the requirement to hold for a minimum of five years. For all other Ophir employees, the deferred shares vest after one, two and three years, with no minimum holding requirements. Each deferred share vesting represents 25 per cent of the value of the individual rewards.

The Transaction does not constitute a NAV Event.

6 Directors' service contracts

6.1 Save for the service contracts described below, there are no existing or proposed service contracts between any Director or proposed director of the Company and the Company and its subsidiary undertakings.

Alan Booth (Interim Chief Executive Officer) and Anthony (Tony) Rouse (Chief Financial Officer) are the Executive Directors of the Company and are employed by the Company. A summary of their service contracts is set out below:

Name	Continuous employment	Service Agreement Date	Current salary per annum (£)	Notice by the Company	Notice by Executive Director
Alan Booth	18 May 2018	26 June 2018	550,000	1 month	1 month
Anthony (Tony) Rouse	1 October 2014	27 January 2016	325,000	12 months	12 months

6.2 The following remuneration (including benefits and any contingent or deferred compensation) was paid to the Executive Directors for services in all capacities to the Group for the financial year ended 31 December 2017[(1)]:

Director	Salary (£)	Bonus (£)	Benefits in kind (£)	Pension / Super-annuation (£)
Dr Nicholas (Nick) Cooper	550,000[(2)]	—	14,000	61,000
Alan Booth	75,000[(3)]	—	—	—
Anthony (Tony) Rouse	325,000	—	10,000	36,000
Dr William (Bill) Higgs	287,000[(4)]	—	19,000	32,000

Notes:

(1) All figures to the nearest £000.

(2) Dr Nicholas (Nick) Cooper left the Board on 18 May 2018 and will remain employed by the Company until 18 August 2018.

(3) Alan Booth was appointed on 18 May 2018 as Interim Chief Executive Officer and Executive Director. The remuneration details set out above are in respect of his role as an Independent Non-Executive Director during 2017.

(4) Dr William (Bill) Higgs left the Board on 7 August 2017 and ceased employment on 30 September 2017. In addition to the above, he also received a £97,826 loss of office payment.

6.3 Termination provisions

In addition to the notice periods set out above, the relevant employer within the Group has the contractual right (aside from any statutory employment rights which the individuals may have) to terminate each service contract with immediate effect if the Executive Director: (i) does not perform his duties for 180 days in any period of 365 days because of sickness, injury or other incapacity; (ii) has not performed his duties under the service contract to the standard reasonably required by the Board; (iii) commits any serious or persistent breach of his obligations under the service contract; (iv) does not comply with any material term of the service contract (applicable in the service contract of Anthony (Tony) Rouse only); (v) does not comply with any lawful order or direction given to him by the Board; (vi) is guilty of any gross misconduct or conducts himself (whether in connection with his employment or not) in a way which is harmful to any Group company; (vii) is guilty of dishonesty or is convicted of an offence (other than a motoring offence which does not result in imprisonment) whether in connection his employment or not; (viii) commits (or is reasonably believed by the Board to have committed) a breach of any legislation in force which may affect or relate to the business of any Group company; (ix) becomes of unsound mind, is bankrupted or has a receiving order made against him or makes any general composition with his creditors or takes advantage of any statute affording relief for insolvent debtors; (x) becomes disqualified from being a director of a company; or (xi) ceases to be legally entitled to work in the United Kingdom in the role in which he is employed.

The service contract of Alan Booth only also provides for termination with immediate effect if the Executive Director: (i) is in breach of any rules issued by the Company or in breach of the Company's anti-corruption and/or bribery policy; or (ii) has materially damaged the interests of the Company through his actions or failure to act.

The service contracts of the Executive Directors further provide for termination with immediate effect if they fail or are disqualified from maintaining registration with a regulatory body as reasonably required by the Company, or if their directorship of the Company terminates without the consent or concurrence of the Company. They also contain a payment in lieu of notice provision where the relevant employer, at its sole discretion, may pay the basic salary only, as a lump sum or in equal monthly instalments. There is a duty, in the service contract of Tony Rouse only, to mitigate such payments by seeking alternative income, and if alternative income is found, then the instalment payments shall be reduced by that amount or to nil if alternative income is higher than the monthly instalments. There is also a provision in the service contracts of the Executive Directors enabling the relevant employer to put the Executive Director on garden leave, for up to six months for Tony Rouse and up to one month for Alan Booth, at any time after notice to terminate the service contract has been given by the Executive Director or the relevant employer or the Executive Director has resigned without giving due notice and the relevant employer has not accepted the resignation. During the garden leave, period the Executive Director will be entitled to salary and contractual benefits (excluding bonuses). At the end of the garden leave period, the Company may, at its discretion, pay the Executive Director basic salary alone in respect of the balance of any period of notice given by the Company or Executive Director, and, applicable in the service contract of Tony Rouse only, with such payments reduced to the extent alternative income is received.

6.4 Benefits

Bonus

Anthony (Tony) Rouse is entitled to be considered for a discretionary bonus or to participate in any applicable bonus scheme which the Board puts in place for Executive Directors, subject to such conditions as the Board may in its discretion determine from time to time. Tony Rouse's maximum bonus is 50 per cent of his gross annual salary, subject to the satisfaction of certain key performance indicators as determined by the Board and the rules of any applicable bonus scheme from time to time. Any bonus payments made are purely discretionary.

Alan Booth is not entitled to receive any bonus or incentive award.

Benefits in kind

The range of taxable benefits in kind available to Executive Directors includes travel insurance, holiday pay, medical evacuation insurance, sick leave cover and, for Tony Rouse only, also health insurance and life assurance.

Pensions

The Company contributes 11 per cent of Tony Rouse's base salary to personal pension arrangements. Alan Booth is entitled to be enrolled in the Company's pension scheme in accordance with the Company's auto-enrolment obligations under the Pensions Act 2008 but has elected to opt out of the Company's pension scheme.

The terms of the Directors' remuneration are in accordance with the terms of the Directors' Remuneration Policy which was approved by the Shareholders at the Company's AGM held on 10 May 2016, details of which can be found on Ophir's website (www.ophir-energy.com).

6.5 There are five[(1)] Non-Executive Directors as follows:

Name	Title	Date of commencement of appointment	Initial Term[(2)]	Total fees per year
William (Bill) Schrader	Non-Executive Chairman	18 February 2013	3 years	140,000
Dr Carol Bell	Senior Independent Director	3 March 2015	3 years	80,000[(3)(4)]
David Davies	Independent Non-Executive Director	23 August 2016	3 years	75,000[(4)]
Vivien Gibney	Independent Non-Executive Director	14 August 2013	3 years	75,000[(4)]
Dr Carl Trowell	Independent Non-Executive Director	23 August 2016	3 years	75,000[(4)]

Notes:

(1) Alan Booth was an Independent Non-Executive Director until his appointment to the position of Interim Chief Executive Officer on 18 May 2018. He commenced his appointment as Independent Non-Executive Director on 24 April 2013 for an initial term of 3 years.

(2) After the end of the initial term, reappointment is typically for a further three-year period. All Non-Executive Directors are subject to reappointment annually at the Company's AGM and if they are not reappointed, their term automatically terminates without compensation.

(3) Includes a Senior Independent Director fee of £5,000 per annum.

(4) Includes a Board Committee's Chairmanship fee of £5,000 per annum.

6.6 Under each letter of appointment, the appointment takes effect from the date that the Non-Executive Director signs the letter of appointment or the date specified in the letter of appointment and each Non-Executive Director is expected to serve an initial three-year term from the date of their

appointment after their appointment commences. If the appointment is renewed at the end of the initial period, such renewal is for a further three-year term.

6.7 The Company may terminate the appointment of the Chairman and the other Non-Executive Directors, without payment of any compensation: (i) if they commit any material breach of their obligations, commit any gross default or misconduct affecting the business of the Company or the Group or are guilty of conduct tending to bring themselves or the Company or any member of the Group into disrepute during the term of their appointment; and (ii) for failure to be re-elected at an AGM.

6.8 The Chairman and Non-Executive Directors are not entitled to participate in the Company's executive remuneration programmes or pension arrangements.

The Directors and officers of the Company have the benefit of directors and officers insurance and an indemnity from the Company out of the Company's funds against: (i) any liability incurred by or attaching to the Director or officer in connection with any negligence, default, breach of duty or breach of trust by them in relation to the Company or any associated company; and (ii) any other liability incurred by or attaching to the Director or officer in the actual or purported execution and/or discharge of their duties and/or the exercise or purported exercise of their powers and/or otherwise in relation to or in connection with their duties, powers or office other than certain excluded liabilities, including to the extent that such an indemnity is not permitted by law.

7 Major Shareholders of Ophir

As at the close of business on the Latest Practicable Date, so far as the Directors are aware, no person other than those listed below was interested, directly or indirectly, in three per cent. or more of the issued share capital of the Company:

Shareholder	Number of Shares	Percentage of voting rights
Capital Research Global Investors	72,993,069	10.32%
Hotchkis & Wiley Capital Management	68,545,073(1)	9.69%
M&G Investment Management	65,542,448	9.27%
azValor Asset Management	52,634,911	7.44%
Aberdeen Standard Investments (Standard Life)	42,842,909	6.06%
Majedie Asset Management	32,630,064	4.61%
Legal & General Investment Management	30,216,528	4.27%
SailingStone Capital Partners	27,007,429	3.82%

Note:

(1) In addition, Hotchkis & Wiley Capital Management is the legal holder of 13,141,700 Shares but does not hold the voting rights attached to those shares.

8 Related party transactions

Save as disclosed in the notes to the financial statements of the Group for the financial years ended 31 December 2015, 31 December 2016 and 31 December 2017, the text of which is hereby incorporated by reference (see Part VIII: "Information Incorporated by Reference" of this Circular), the Company has not entered into any related party transactions during the period commencing 1 January 2015 and up to the date of this Circular.

9 Material contracts

9.1 The Group

9.1.1 Save as disclosed in Part III: “Summary of the Transaction Agreements” of this Circular, there are no contracts (other than contracts entered into in the ordinary course of business) which contain information which Shareholders would reasonably require to make a properly informed assessment on how to vote on the Resolutions and which have been entered into by members of the Group: (i) within the two years immediately preceding the date of this Circular which are, or may be, material; or (ii) which contain any provision under which any member of the Group has any obligation or entitlement which is material to the Group as at the date of this Circular, other than the bridge facility agreement described below.

9.1.2 Bridge Facility Agreement

(a) The bridge facility agreement was entered into on the date of this Circular by, amongst others, Jaguar 2 (as borrower), the Company and Jaguar 1 (as guarantors), Australia and New Zealand Banking Group Limited ("**ANZ**") (as facility agent and security agent), and ANZ, Société Générale and BNP Paribas (as original lenders, the "**Lenders**"). Under the facility agreement, the Lenders will provide a loan of up to US$130,000,000 to Jaguar 2 to fund the acquisition of the Producing Assets under the Block 12W SPA and the Madura / Sampang SPA.

(b) The Company and Jaguar 1 are guaranteeing Jaguar 2's obligations under the facility agreement. Jaguar 1 and Jaguar 2 have granted (or will grant post-completion of the acquisition) security in favour of the Lenders, including (i) a charge over all the shares in Jaguar 2, (ii) an assignment of intercompany loans from Jaguar 1 to Jaguar 2; (iii) an assignment of the Block 12W SPA and the Madura / Sampang SPA; (iv) a charge over the collection account of Jaguar 2; and (v) a charge over all the shares in Santos Petroleum Ventures B.V., Santos SPV Pty Ltd and Santos Asia Pacific Pty Ltd. Following the completion of the acquisition, Santos Petroleum Ventures B.V., Santos SPV Pty Ltd, Santos Asia Pacific Pty Ltd, Santos Madura and Santos Sampang (the "**Production Asset Targets**") will accede to the facility agreement as additional guarantors and grant security over certain of their assets. The facility benefits from a 3-month clean up period during which Lenders will be restricted from accelerating the facility for the reason of any breach of undertakings or representations in the finance documents, or occurrence of an event of default solely attributable to the Production Asset Targets.

(c) This is a bullet facility with a term of 18 months. The loan will be repaid in full at the end of the 18 month period subject to certain circumstances which trigger mandatory prepayment of the loan (including a change of control of the Company, Jaguar 1, Jaguar 2 or the Production Asset Targets and two cash sweeps of 50% of any excess cash over US$20,000,000 held by Jaguar 2 after 12 months and 15 months from the date of the facility agreement).

(d) The annual interests rate is (i) 4% + LIBOR for the first 6 months from the date of the facility agreement, (ii) 4.5% + LIBOR between 6 months and 12 months after the date of the facility agreement, (iii) 5% + LIBOR between 12 months and 15 months after the date of the facility agreement and (iv) 5.5% + LIBOR thereafter. Jaguar 2 will be entering into hedging transactions with the Lenders in respect of 2,000 bpd of crude oil for the 12 month period from the utilisation date (the “**Mandatory Hedging**”).

(e) All conditions precedent to the provision of the funding under the facility agreement have been satisfied except the following conditions for the reasons set out next to the relevant conditions:

(I) a copy of the resolutions evidencing the approval of shareholders at a general meeting of the Company of the terms of, and the transactions contemplated by, the Transaction Documents. This condition will be satisfied immediately upon receipt of the shareholder approvals requested in this Circular and upon the provision of a copy of the approvals to the Lenders;

(II) a certificate of Jaguar 2 dated on or about the utilisation date confirming, among other things, that all conditions to the completion of the acquisition of the Production Asset Targets have been satisfied. This condition cannot be satisfied until the approval of the shareholders is obtained (which is the last remaining condition to the completion of the acquisition). A signed but undated certificate of Jaguar 2 has been provided to the facility agent and it is agreed with the Lenders that this certificate shall be dated on the date the utilisation request is submitted to the facility agent and the condition will be satisfied immediately upon dating; and

(III) the Mandatory Hedging will be entered into by Jaguar 2 on or around 6 business days prior to the date the acquisition completes.

9.2 The Assets

9.2.1 The following contracts referred to in paragraphs 9.2.2 to 9.2.7 are the only contracts (not being contracts entered into in the ordinary course of business) which contain information which Shareholders would reasonably require to make a properly informed assessment on how to vote on the Resolutions and which have been entered into by the Target Group and/or in respect of the Assets: (i) within the two years immediately preceding the date of this Circular which are, or may be, material; or (ii) which contain any provision under which the Target Group has any obligation or entitlement which is material to the Assets as at the date of this Circular:

9.2.2 Block 12W (Vietnam)

(a) Block 12W PSC

PetroVietnam, OPECO Natural Gas, Ltd and Samedan Vietnam Limited entered into the Offshore Block 12W Vietnam Production Sharing Contract on 17 November 2000 (the "**Block 12W PSC**"). There have been a number of amendments to the Block 12W PSC and changes to the parties thereto including the acquisition by Petroleum Ventures B.V. (now Santos Petroleum Ventures B.V.) of a 37.5% interest in the Block 12W PSC which was certified by the Ministry of Planning and Investment on 18 October 2006. The parties to the Block 12W PSC subsequently assigned a 15% interest in the Block 12W PSC to PVEP, a wholly owned subsidiary of PetroVietnam which was certified by Ministry of Industry and Trade on 25 January 2010.

The current contractors to the Block 12W PSC are Premier Oil Vietnam Offshore B.V. (28.125%), Santos Petroleum Ventures B.V. (31.875%), Premier Oil (Vietnam) Limited (25%) and PVEP (15%) as approved by the amended Investment Certificate issued by the Ministry of Industry and Trade of Vietnam dated 25 January 2010. The laws and regulations of the Socialist Republic of Vietnam apply to the Block 12W PSC. However, in the absence of a specific Vietnamese law or regulation governing any matter that may be raised, the laws of Singapore shall apply.

The terms of the Block 12W PSC were materially amended on 14 February 2007 pursuant to an amendment agreement which merged the production sharing contract for Block 12E offshore Vietnam with the then current Block 12W PSC (the "**Merger Agreement**"). The Merger Agreement was approved by the Ministry of Planning and Investment on 14 June

2007. Pursuant to the Merger Agreement, the Block 12W PSC has a term of 30 Contract Years from the effective date (22 November 2000). The Block 12W PSC is scheduled to expire on 21 November 2030.

Premier Oil Vietnam Offshore B.V. is the operator under the Block 12W PSC.

(b) Block 12W JOA

On 3 September 2004, Delek Energy (Vietnam) LLC (now Premier Oil (Vietnam) Limited) and Premier Oil Vietnam Offshore B.V. entered into an Operating Agreement covering Block 12W, offshore Vietnam (the "**Block 12W JOA**"). On 13 May 2010, the parties to the Block 12W JOA entered into a novation and amendment to the Block 12W JOA which confirms the participating interest of the parties to the Block 12W JOA as Premier Oil Vietnam Offshore B.V. (28.125%), Santos Petroleum Ventures B.V. (31.875%), Premier Oil (Vietnam) Limited (25%) and PVEP (15%).

The Block 12W JOA establishes the respective rights and obligations of the parties thereto with regards to operations under the Block 12W PSC, including the joint exploration, appraisal, development, production and disposition of hydrocarbons from the Block 12W contract area.

Santos Petroleum Ventures B.V. does not hold a right of veto over decisions of the Block 12W operating committee, other than those select decisions requiring unanimous approval, which include: waiving the notice requirements for a meeting of the operating committee, a surrender of all or part of the contract area and an assignment of intellectual property to the operator or a party.

(c) Block 12W FPSO Charter

On 16 October 2009, Premier Oil Vietnam Offshore B.V. (as operator under the Block 12W PSC and on behalf of the co-venturers to the Block 12W PSC (the "**Co-venturers**")), Emas Offshore Construction and Production Pte. Ltd entered into a Time Charter Party (the "**Block 12W FPSO Charter**") with respect to the charter of the FPSO Lewek EMAS, which charter has been novated and amended a number times including a deed of novation pursuant to which Emas Offshore Construction and Production Pte. Ltd transferred all of its rights and obligations under the charter to PV Keez Pte. Ltd (the "**FPSO Owner**").

The FPSO Owner is the current owner under the Block 12W FPSO Charter and the FPSO Lewek EMAS is subject to a first priority mortgage in favour of the FPSO Owner's lenders.

Pursuant to the Block 12W FPSO Charter, each Co-venturer procures a parent company guarantee in favour of FPSO Owner in respect of such Co-venturer's liability to the FPSO Owner under the Block 12W FPSO Charter. In the event of a change in control of a Co-venturer, FPSO Owner is entitled to require a replacement of the original parent company guarantee for the same obligations in form and substance acceptable to the FPSO Owner. As noted in paragraph 2.5 of Part A to Part III "Summary of the Transaction Agreements" of this Circular, Ophir has agreed to provide a replacement guarantee in favour of the FPSO Owner pursuant to the Block 12W SPA. The replacement guarantee does not contain a financial cap but covers underlying obligations of approximately US$40 million. Until a replacement guarantee has been agreed with PV Keez Pte, Ltd., Jaguar 2 has agreed to provide an indemnity to Santos in respect of the existing guarantee.

(d) Block 12W FPSO O&M Contract

On 1 November 2013, Premier Oil Vietnam Offshore B.V. and PV Trans Oilfield Services entered into a contract whereby PV Trans Oilfield Services supports the operation and maintenance of the FPSO Lewek EMAS (the "**Block 12W FPSO O&M Contract**"). The Block

12W FPSO O&M Contract has been amended pursuant to an amendment agreement dated 30 November 2017 whereby the term of the Block 12W FPSO O&M Contract is extended to 13 October 2022. The Block 12W FPSO O&M Contract also contains a compensation schedule detailing the sums payable by Premier Oil Vietnam Offshore B.V. (on behalf of the Co-venturers) to PV Trans Oilfield Services in consideration of the services provided under the Block 12W FPSO O&M Contract.

(e) Block 12W Joint Oil Marketing Agreement

The parties to the Block 12W PSC have entered into a Joint Oil Marketing Agreement dated 16 September 2011 in respect of the Chim Sáo Field, Block 12W Offshore Socialist Republic of Vietnam (the "**Block 12W Joint Oil Marketing Agreement**"). Pursuant to a deed of amendment to the Block 12W Joint Oil Marketing Agreement dated 10 July 2014, the Block 12W Joint Oil Marketing Agreement was amended to apply also to the Dua field and any other fields that may be developed within the Block 12W PSC contract area. The Block 12W Joint Oil Marketing Agreement appoints a subsidiary of PetroVietnam as the marketing agent who is required, in return for a marketing fee, to identify, develop and foster sales opportunities, enter into direct discussions with buyers approved by the marketing committee under the Block 12W Joint Oil Marketing Agreement and prepare and distribute for signature approved sales contracts to Petrovietnam, each contractor to the Block 12W PSC and the applicable buyer.

(f) Block 12W Associated Gas Gathering Agreement

On 30 November 2011, the contractors to the Block 12W PSC (the "**Suppliers**") and Petrovietnam Gas Joint Stock Corporation (the "**Receiver**") entered into an Associated Gas Gathering Agreement for Chim Sáo Field Associated Gas, Block 12W offshore Vietnam (the "**Block 12W AGGA**"). On 3 July 2012, the Block 12W AGGA was amended to also apply to associated gas produced from the Dua field. The Block 12W AGGA shall terminate upon the expiration or termination of the Block 12W PSC unless otherwise terminated in accordance with its terms.

During the term, the Suppliers shall use reasonable endeavours to make gas from the Chim Sáo and Dua fields available for delivery and supply to the Receiver and the Receiver shall use reasonable endeavours to take receipt of such gas.

(g) Block 12W Decommissioning and Abandonment Funding Agreement

On 10 September 2015, the parties to the Block 12W PSC entered into a Decommissioning and Abandonment Funding Agreement pursuant to which the contractors to the Block 12W PSC make contributions to a fund managed by PetroVietnam to make provision for the abandonment obligations in relation to the Block 12W PSC.

9.2.3 Madura (Indonesia)

(a) Madura Offshore PSC

Pertamina and Talisman (Madura) Ltd. entered into the Madura Offshore PSC on 4 December 1997 (the "**Madura Offshore PSC**").

In 2001, Santos Madura acquired a 75% participating interest in the Madura Offshore PSC from Talisman (Madura) Ltd.

In 2005, Petronas Carigali Oversees Sdn. Bhd. (now PC Madura Ltd.) acquired a 25% participating interest in the Madura Offshore PSC from Talisman (Madura) Ltd.

In 2011, a 10% participating interest (7.5% from Santos Madura and 2.5% from PC Madura Ltd.) was assigned to PT Petrogas Pantai Madura, an East Java Province Regional Company, in satisfaction of Indonesian law local participation requirements.

The current parties to the Madura Offshore PSC are SKK Migas (who succeeded Pertamina and SKK Migas as regulator of the Indonesian upstream oil and gas industry), Santos Madura, PC Madura Ltd. and PT Petrogas Pantai Madura.

The Madura Offshore PSC is for a thirty year term and expires on 3 December 2027.

Santos Madura is the operator of the Madura Offshore PSC.

(b) Madura JOA

On 6 June 2002, Santos Madura and Talisman (Madura) Ltd entered into a Joint Operating Agreement in respect of the Madura Offshore PSC (the "**Madura JOA**"). The current parties to the Madura JOA are Santos Madura, PC Madura Ltd. and PT Petrogas Pantai Madura.

The Madura JOA establishes the respective rights and obligations of the parties thereto with regards to operations under the Madura Offshore PSC, including the joint exploration, appraisal, development, production and disposition of hydrocarbons from the Madura offshore contract area.

Santos Madura is the operator under the Madura JOA.

The participating interests of the joint venture partners are as follows:

(i) Santos Madura – 67.5%;

(ii) PC Madura Ltd. – 22.5%; and

(iii) PT Petrogas Pantai Madura – 10%.

Santos Madura and PC Madura Ltd. participated in the sole risk drilling Merem-1 and Meliwis-1. PT Petrogas Pantai Madura did not participate in such drilling activity. Santos Madura assumed all of PT Petrogas Pantai Madura's 10% participating interest in the sole risk drilling operation. The participating interest in Merem-1 and Meliwis-1 are as follows:

(i) Santos Madura 77.5%; and

(ii) PC Madura Ltd. 22.5%.

Santos Madura has a blocking right for all the decisions of the Madura operating committee and therefore any decisions of the operating committee cannot be passed without Santos Madura's approval.

(c) Maleo GSA

On 31 May 2005, Santos Madura and PC Madura Ltd. (as sellers) entered into a gas sale and purchase agreement with PGN (as buyer) for gas supplied from the Maleo gas field. The existing Maleo GSA expires on 13 July 2019. The prices have been renegotiated for delivery of gas beyond this term which will become effective from the commensurate expiry of the existing GSA and subject to the technical capability to produce these volumes.

(d) Peluang GSA

On 15 May 2013, Santos Madura, PC Madura Ltd. and PT Petrogas Pantai Madura (as sellers) entered into a gas sale and purchase agreement with PT PLN (Persero) (as buyer) for gas supplied from the Peluang gas field. The Peluang GSA expired on 30 June 2018.

The sellers have agreed the terms of a new Peluang gas sale and purchase agreement for gas offtake from the Peluang field from 1 July 2018.

(e) Maleo Producer Platform Rental, Operations and Maintenance Services

On 21 December 2017, Santos Madura, in its capacity as operator, and P.T. Radiant Utama Interinsco Tbk. entered into a rental operations and maintenance services agreement for the Maleo producer platform. Pursuant to the agreement, Santos Madura pays a fixed daily fee for the rental of the Maleo producer platform from, and the provision of operations and maintenance services by, P.T. Radiant Utama Interinsco Tbk. At the end of the operating phase of the agreement, P.T. Radiant Utama Interinsco Tbk. is required to demobilise the Maleo producer platform for a fixed fee.

(f) Maleo Tie-in Agreement

On 10 June 2005, Santos Madura and PC Madura Ltd. entered into a tie-in agreement with PT Pertamina (as owner and operator of the East Java Gas Pipeline) to permit the 7.4 kilometre spur-line to be connected to the inlet of the East Java Gas Pipeline.

(g) Madura Joint Account Agreement

On 22 December 2009, Santos Madura entered into a Joint Account Agreement in relation to abandonment and site restoration for the Madura Offshore PSC with BPMIGAS and PT. Bank Negara Indonesia (Persero) Tbk. to establish the joint account in respect of contributions to fund the abandonment and site restoration of the Madura Offshore PSC.

9.2.4 Sampang (Indonesia)

(a) Sampang PSC

Pertamina, Santos Sampang, Coastal Indonesia Sampang Ltd. (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty. Ltd. entered into the Sampang Production Sharing Contract on 4 December 1997 (the "**Sampang PSC**").

The current parties to the Sampang PSC are SKK Migas (who succeeded Pertamina and SKK Migas as regulator of the Indonesian upstream oil and gas industry), Santos Sampang, Singapore Petroleum Sampang Ltd (formerly Coastal Indonesia Sampang Ltd) and Cue Resources Sampang Pty Ltd.

The Sampang PSC is for a thirty year term and expires on 3 December 2027.

Santos Sampang is the operator of the Sampang PSC.

(b) Sampang JOA

On 20 December 1999, Santos Sampang, Coastal Indonesia Sampang Ltd. (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty Ltd entered into a Joint Operating Agreement in respect of the Sampang PSC (the "**Sampang JOA**").

The Sampang JOA establishes the respective rights and obligations of the parties thereto with regards to operations under the Sampang PSC, including the joint exploration, appraisal, development, production and disposition of hydrocarbons from the Sampang contract area.

Santos Sampang is the operator under the Sampang JOA.

The participating interests of the joint venture partners are as follows:

(i) Santos Sampang – 45%;

(ii) Singapore Petroleum Sampang Ltd – 40%; and

(iii) Cue Sampang Pty Ltd – 15%.

Santos Sampang has a blocking right for all the decisions of the Sampang operating committee and therefore any decisions of the operating committee cannot be passed without Santos Sampang's approval.

(c) Oyong GSA

On 19 July 2003, Santos Sampang, Coastal Indonesia Sampang Ptd (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty Ltd (as sellers) entered into a gas sale and purchase agreement with P.T. Indonesia Power (as buyer) for gas supplied from the Oyong gas field. The Oyong GSA will expire in September 2019.

(d) Wortel GSA

On 26 November 2010, Santos Sampang, Singapore Petroleum Sampang Ltd and Cue Sampang Pty Ltd (as sellers) entered into a gas sale and purchase agreement with P.T. Indonesian Power (as buyer) for gas supplied from the Wortel gas field. The Wortel GSA will expire once the total contract quantity has been fulfilled which is anticipated to be in 2020.

(e) Sampang Condensate Agreement

In 2017, Santos Sampang, Singapore Petroleum Sampang Ltd and Cue Sampang Pty Ltd (as sellers) entered into a condensate sale and purchase agreement with PT Pertamina (as buyer) for condensate associated with the Wortel and Oyong gas fields. The Sampang Condensate Agreement will expire in 2021.

(f) Sampang Pipeline Crossing Agreement

On 17 May 2005, Santos Sampang, Singapore Petroleum Sampang Ltd and Cue Sampang Pty Ltd and entered into a pipeline crossing agreement with Pertamina (in its capacity as owner and operator of the East Java Gas Pipeline) to construct and maintain the 56 kilometre pipeline from the Oyong and Wortel fields to an onshore gas processing facility at Grati in East Java, which crosses the East Java Gas Pipeline.

(g) Sampang Onshore Processing Facilities Lease

On 19 July 2003, Santos Sampang, Coastal Indonesia Sampang Ltd (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty Ltd (in their capacity as Sampang joint venture partners) entered into an Onshore Processing Facilities Lease with P.T. Indonesia Power pursuant to which P.T. Indonesia Power granted a lease, together with exclusive and non-exclusive easements over acreage to the Sampang joint venture partners on which the Grati onshore processing facility was built. The Sampang joint venture partners pay to P.T. Indonesia Power an annual lease payment calculated on a per square metre basis. At the end of the term of the Onshore Processing Facilities Lease, P.T. Indonesia Power has the right to purchase the Grati onshore processing facility. If P.T. Indonesia Power declines to purchase the Grati onshore processing facilities the Sampang joint venture partners shall, at their own cost, remove the Grati onshore processing facilities and onshore pipelines from the leased land.

(h) Sampang Onshore Management Agreement

On 19 July 2003, Santos Sampang, Coastal Indonesia Sampang Ltd (now Singapore Petroleum Sampang Ltd) and Cue Sampang Pty Ltd (as Sampang joint venture partners) entered into an Onshore Oil Management Agreement with P.T. Indonesia Power to set forth the rights granted to the Sampang joint venture partners by P .T. Indonesia Power in respect of the Grati onshore processing facility and the Sampang joint venture partners rights to use the land on which the Grati onshore processing facility is built.

(i) Sampang Joint Account Agreement

On 22 December 2009, Santos Sampang entered into a Joint Account Agreement in relation to abandonment and site restoration for the Sampang PSC with BPMGIAS and PT. Bank Negara Indonesia (Persero) Tbk. to establish the joint account in respect of contributions to fund the abandonment and site restoration of the Sampang PSC.

9.2.5 Blocks 123 / 124 (Vietnam)

(a) Block 123 PSC

On 28 May 2008, PetroVietnam, SK Energy Co. Ltd (now SK Innovation Co. Ltd), Santos Vietnam and PVEP entered into a Petroleum Production Sharing Contract with respect to Block 123 offshore the Socialist Republic of Vietnam (the "**Block 123 PSC**"). SK Energy Co. Ltd (now SK Innovation Co. Ltd), Santos Vietnam and PVEP are the contractors under the Block 123 PSC.

Santos Vietnam is designated as the operator under the Block 123 PSC and holds a 50% participating interest. PVEP has a 30% participating interest and SK Innovation Co. Ltd has a 20% participating interest. Until the declaration of the first commercial discovery, Santos Vietnam and SK Innovation Co Ltd bear PVEP's share of all expenditure. Therefore, until the declaration of a first commercial discovery, Santos Vietnam is responsible for 71.429% of expenditure under the Block 123 PSC.

The term of the Block 123 PSC is 30 years from the effective date (12 June 2008). If, at the end of the seven year exploration period under the Block 123 PSC (the "**Block 123 PSC Exploration Period**"), no commercial discovery is made, the Block 123 PSC automatically terminates. The Block 123 PSC Exploration Period is due to expire on 11 June 2019.

The Block 123 PSC contains the following minimum work commitments:

(i) Phase one (Firm commitment – contract years 1, 2, 3 and 4)

The contractor shall perform the acquisition, processing and interpretation of approximately 1,785 kilometres of new 2D seismic and drill two exploration wells.

(ii) Phase two (optional – contract years 5 and 6)

Drill one exploration well.

(iii) Phase three (optional – contract year 7)

Drill one exploration well.

On 5 May 2014, PetroVietnam consented to the Block 123 PSC entering into phase two of the Block 123 PSC Exploration Period, with the contractor allowed to carry forward an outstanding well commitment from phase one to phase two. There are currently two exploration wells outstanding which need to be drilled to fulfil the minimum work commitment. If the contractor does not complete the minimum work commitments in any phase, it has to pay to PetroVietnam a sum equivalent to the outstanding work commitment.

Each contractor is obliged to provide security in favour of PetroVietnam with respect to its obligations under the Block 123 PSC. As noted in paragraph 3.3(d) of Part B to Part III "Summary of the Transaction Agreements" of this Circular, Jaguar 1 is obliged to procure two replacement guarantees in favour of PetroVietnam pursuant to the Blocks 123 / 124 SPA. The form of guarantee which Ophir has agreed to procure in favour of PetroVietnam (subject to PetroVietnam approval) relating to Block 123 requires the guarantor to put at the disposal of Santos Vietnam the technical, personnel, equipment and financing means to enable Santos Vietnam to carry out its obligations under the Block 123 PSC.

(b) Block 123 JOA

On 28 May 2008, PVEP, Santos Vietnam and SK Energy Co. Ltd (now SK Innovation Co. Ltd) entered into a Joint Operating Agreement relating to Block 123, offshore the Socialist Republic of Vietnam (the "**Block 123 JOA**").

Santos Vietnam is designated as the operator under the Block 123 JOA and holds a 50% participating interest. PVEP has a 30% participating interest and SK Innovation Co. Ltd has a 20% participating interest.

The parties to the Block 123 JOA agree to participate in joint operations for the exploration and, if appropriate, the development and production of petroleum within the contract area under the Block 123 PSC.

Santos Vietnam has a blocking right for all the decisions of the Block 123 operating committee and therefore any decisions of the operating committee cannot be passed without Santos Vietnam's approval.

(c) Block 124 PSC

On 13 October 2014, PetroVietnam, Eni Vietnam B.V. and Santos Vietnam entered into a Petroleum Production Sharing Contract with respect to Block 124 offshore the Socialist Republic of Vietnam (the "**Block 124 PSC**"). Eni Vietnam B.V. and Santos Vietnam are the contractors under the Block 124 PSC.

Eni Vietnam B.V. is designated as the operator under the Block 124 PSC and holds a 60% participating interest and Santos Vietnam holds a 40% participating interest under the Block 124 PSC. Within 90 days of the date on which contractor declares the first commercial discovery, PetroVietnam has the option to acquire up to a 30% participating interest in the Block 124 PSC which, in accordance with the Block 124 JOA (defined below), will be contributed by Eni Vietnam B.V. and Santos Vietnam in proportion to their respective participating interests.

The Block 124 PSC has a term of 30 years from the effective date (30 October 2014). If, at the end of the seven year exploration period under the Block 124 PSC (the "**Block 124 PSC Exploration Period**"), there has been no commercial discovery, the Block 124 PSC shall automatically terminate. On 20 June 2018, PetroVietnam approved a two year extension of phase one of the Block 124 PSC Exploration Period which now expires on 29 October 2020. The decision of entering into phase two of the Block 124 PSC Exploration Period shall be at the option of the contractor.

The Block 124 PSC contains the following minimum work commitments:

(i) Phase one: four contract years (firm commitment)

1. Seismic survey (acquisition, processing and interpretation):

   (a) 2D 2,200 kilometres.

   (b) 3D 500 km^2.

2. Drill one exploration well.

(ii) Phase two: 36 months (optional)

1. Seismic Survey (acquisition, processing and interpretation): 3D 300 km^2.

2. Drill one exploration well.

The seismic acquisitions for the Block 124 PSC were completed in the first half of 2018 and therefore the processing and interpretation of the 3D seismic data and the well drilling

requirement are the only minimum work commitments for phase one of the Block 124 PSC Exploration Period that remain outstanding. If the contractor does not complete the minimum work commitments in any phase, it has to pay to PetroVietnam a sum equivalent to the outstanding work commitment.

Each contractor is obliged to provide security in favour of PetroVietnam with respect to its obligations under the Block 124 PSC. As noted above, Jaguar 1 is obliged to procure two replacement guarantees in favour of PetroVietnam pursuant to the Blocks 123 / 124 SPA. The form of guarantee which Ophir has agreed to procure in favour of PetroVietnam (subject to PetroVietnam approval) relating to Block 124 is a financial and performance guarantee relating to the obligations, warranties, duties, undertakings and liabilities of Santos Vietnam under the Block 124 PSC and the punctual payment of amounts owed to PetroVietnam under the Block 124 PSC. This guarantee is not subject to a financial cap however the guarantee stipulates that if the parties to the Block 124 PSC fail to fulfil the minimum work commitments under the Block 124 PSC, the guarantor is liable for Santos Vietnam's 40% participating interest share of the estimated cost for such minimum work commitment contained in the Block 124 PSC. The form of guarantee is limited in duration until the end of the Exploration Period under the Block 124 PSC.

(d) Block 124 JOA

In October 2014 (undated), Eni Vietnam B.V. and Santos Vietnam entered into a Joint Operating Agreement relating to Block 124, offshore the Socialist Republic of Vietnam (the "**Block 124 JOA**").

Eni Vietnam B.V. is designated as the operator under the Block 124 JOA and holds a 60% participating interest. Santos Vietnam has a 40% participating interest under the Block 124 JOA.

The Block 124 JOA establishes the respective rights and obligations of the parties thereto with regard to operations under the Block 124 PSC, including the joint exploration, appraisal, development, production and disposition of hydrocarbons from the contract area under the Block 124 JOA.

Santos Vietnam has a blocking right for all decisions of the Block 124 operating committee, subject to any votes in respect of the minimum work commitment for which Eni Vietnam B.V. in its capacity as operator has a casting vote.

9.2.6 Deepwater Block R (Malaysia)

(a) Deepwater Block R PSC

On 17 January 2012, Petronas, JX Nippon, Inpex and Petronas Carigali Sdn. Bhd. entered into a contract relating to the exploration and production of petroleum from Deepwater Block R Sabah, Malaysia (the "**Deepwater Block R PSC**").

Pursuant to a deed of assignment in respect of the Deepwater Block R PSC between JX Nippon and Santos Sabah dated 29 January 2015, JX Nippon assigned and transferred a 10% participating interest in the Deepwater Block R PSC to Santos Sabah. Pursuant to a deed of assignment in respect of the Deepwater Block R PSC between Inpex and Santos Sabah dated 29 January 2015, Inpex assigned and transferred a 10% participating interest in the Deepwater Block R PSC to Santos Sabah.

The current contractors to the Deepwater Block R PSC are JX Nippon (27.5%), Inpex (27.5%) Petronas Carigali Sdn. Bhd. (25%) and Santos Sabah (20%). Until the fulfilment of the minimum work commitments under the Deepwater Block R PSC, JX Nippon, Inpex and

Santos Sabah are responsible for Petronas Carigali Sdn. Bhd.'s participating interest share of exploration work and expenditure under the Block R JOA (as defined below).

By letters dated 3 December 2015, 13 January 2017 and 12 January 2018 Petronas acknowledged and accepted the completion of the minimum work commitments under the Deepwater Block R PSC. The Deepwater Block R PSC was extended in 2015 and 2016 for the drilling of the two appraisal wells, Bestari-2 and Bestari-3. Petronas has recently provided another one year extension to the Deepwater Block R PSC until January 2019 to allow for Bestari-3 post well-evaluation and future appraisal and development studies. All the minimum work commitments for the exploration period (including the extensions) under the Deepwater Block R PSC have been completed.

The Deepwater Block R PSC has a term of 35 years from the effective date (being 17 January 2012). The Deepwater Block R PSC has a four year exploration period (the "**Deepwater Block R PSC Exploration Period**"). Any sub-block which is not defined as a development area and any area which is not defined as a gas field at the end of the Deepwater Block R PSC Exploration Period shall be relinquished to Petronas and cease to be part of the contract area under the Deepwater Block R PSC. By letter dated 17 October 2017, Petronas approved the extension of the Deepwater Block R PSC Exploration Period of the Deepwater Block R PSC to 16 January 2019.

(b) Block R JOA

On 17 January 2012, JX Nippon, Inpex and Petronas Carigali Sdn. Bhd. entered into a joint operating agreement relating to the exploration and production of petroleum from the Deepwater Block R PSC ("**Block R JOA**"). Pursuant to a novation and amendment agreement dated 29 January 2015, JX Nippon and Inpex each assigned and transferred a 10% participating interest in the Block R JOA to Santos Sabah. The current parties to the Block R JOA are JX Nippon (27.5%), Inpex (27.5%), Petronas Carigali Sdn. Bhd. (25%) and Santos Sabah (20%). JX Nippon is appointed as operator under the Block R JOA.

The Block R JOA sets forth the respective rights and obligations of the parties thereto with respect to the exploration, exploitation, winning and obtaining of petroleum resources under the Deepwater Block R PSC.

Santos Sabah does not have a blocking vote for the operating committee for the Deepwater Block R PSC, although Santos Sabah's approval is required for determination of a development plan to be submitted to Petronas for approval in its capacity as regulator.

(c) Block R Farmout Agreement with JX Nippon

On 3 October 2014, JX Nippon and Santos Sabah entered into a Farmout Agreement in relation to the Deepwater Block R PSC (the "**JX Nippon Farmout Agreement**"). Pursuant to the JX Nippon Farmout Agreement, JX Nippon agrees to assign and transfer a 10% non-operated interest in the Deepwater Block R PSC and Block R JOA to Santos Sabah.

(d) Block R Farmout Agreement with Inpex

On 3 October 2014, Inpex and Santos Sabah entered into a Farmout Agreement in relation to the Deepwater Block R PSC (the "**Inpex Farmout Agreement**"). Pursuant to the Inpex Farmout Agreement, Inpex agrees to assign and transfer a 10% non-operated interest in the Deepwater Block R PSC and Block R JOA to Santos Sabah.

Inpex has acknowledged and accepted a letter from Santos Sabah dated 27 February 2018 stating that Santos Sabah has satisfied its obligations under the Inpex Farmout Agreement.

9.2.7 Block SS-11 (Bangladesh)

(a) SS-11 PSC

On 12 March 2014, the Government of the People's Republic of Bangladesh, Petrobangla, Santos Sangu, KrisEnergy (Asia) Ltd and BAPEX entered into the production sharing contract in respect of Block SS-11, Bangladesh (the "**SS-11 PSC**").

The term of the SS-11 PSC is for a maximum of 33 years for oil and 38 years for gas.

Santos Sangu is the operator of the SS-11 PSC.

BAPEX's 10% participating interest is carried through exploration by Santos Sangu and Kris Energy (Asia) Ltd, each carrying 5%. Following the first commercial discovery, BAPEX shall repay the carried interest amount plus interest (at LIBOR) from the share of production which would otherwise be attributable to its 10% participating interest. If no commercial discovery is found, Ophir will not be reimbursed for BAPEX's share of the exploration costs.

The mandatory work commitments in the SS-11 PSC for the period up to 11 March 2019 are to: (i) acquire 2D seismic of 1,893 km²; (ii) acquire 3D seismic of 300 km²; and (iii) drill one exploration well.

The drilling of one exploration well remains outstanding. It is the intention of the joint venture partners to apply for a two year extension to allow further time to complete the outstanding work commitments. If an extension to the exploration period is not granted and the minimum work commitments are not completed, Petrobangla has the right to call on the bank guarantees provided by Santos Sangu, and KrisEnergy (Asia) Ltd.

Pursuant to the SS-11 ATA, Ophir has agreed to procure: (i) a bank guarantee to secure the contractor's timely performance of the mandatory work program and minimum exploration program under the SS-11 PSC; and (ii) a financial and performance guarantee from Santos Sangu's parent company with respect to the obligations of Santos Sangu under the SS-11 PSC.

(b) SS-11 JOA

On 18 June 2015, Santos Sangu, KrisEnergy (Asia) Ltd. and BAPEX entered into a Joint Operating Agreement in respect of the SS-11 PSC (the "**SS-11 JOA**").

The SS-11 JOA establishes the respective rights and obligations of the parties thereto with regards to operations under the SS-11 PSC, including the joint exploration, appraisal, development, production and disposition of hydrocarbons from the SS-11 PSC contract area.

Santos Sangu is the operator under the SS-11 JOA.

Under the SS-11 PSC, Santos is not able to pass any operating committee resolution without KrisEnergy (Asia) Ltd.'s approval.

10 Litigation

10.1 The Group

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 Group's financial position or profitability.

In 2005 and 2006, Ophir entered into certain agreements with Mr Moto Mabanga pursuant to which Mr Mabanga agreed to provide consultancy services and assistance to Ophir in relation to Blocks 1, 3 and 4 in Tanzania. These agreements were terminated in June 2010 pursuant to a deed of

termination under which Mr Mabanga waived all rights and claims which he had or may have in the future (whether known or unknown) against Ophir. Mr Mabanga has made claims against Ophir alleging misrepresentations in respect of the termination of his services and the valuation of his interest in Blocks 1, 3 and 4, Tanzania. These claims have been rejected by Ophir on the basis that the claims were without merit.

In 2012, Mr Mabanga brought a claim against the Company before the English courts on the basis of the alleged misrepresentations described above. Mr Mabanga's claim was dismissed by summary judgment and costs were awarded against him on an indemnity basis. Mr Mabanga has since commenced related proceedings before the courts of Tanzania, which are pending trial. The Company does not expect such proceedings to have a significant effect on Ophir or the Ophir Group's financial position or profitability.

10.2 The Assets

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 Target Group.

11 Working capital

The Company is of the opinion that, following the Transaction and taking into account the Facilities available to the Enlarged Group, the Enlarged Group 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.

12 Significant changes

12.1 The Group

There has been no significant change in the financial or trading position of the Group since 31 December 2017, the date to which the last published audited financial statements were prepared.

12.2 The Assets

There has been no significant change in the financial or trading position of the Target Group since 31 December 2017, the date to which the last published financial statements were prepared.

13 Competent Person's Report

There have been no material changes since the date of the Competent Person's Report the omission of which would make such report misleading.

14 Incorporation by reference

The following documents (or parts of documents) are incorporated by reference in, and form part of, this Circular:

(a) the Annual Report and audited consolidated financial information of the Company for the year ended 31 December 2015;

(b) the Annual Report and audited consolidated financial information of the Company for the year ended 31 December 2016; and

(c) the Annual Report and audited consolidated financial information of the Company for the year ended 31 December 2017.

Part VIII: "Information Incorporated by Reference" of this Circular sets out the location of references to the above documents within this Circular.

15 Consents

(a) Barclays 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.

(b) BofA Merrill Lynch 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.

(c) Ernst & Young LLP has given and has not withdrawn its written consent to the inclusion in Part IV: "Historical Financial Information of the Target Group" and Part V: "Pro Forma Statement of Net Assets of the Enlarged Group" of this Circular of its reports in the form and context in which they are included.

(d) RISC (UK) Limited has given and not withdrawn its written consent to the inclusion in this Circular of its Competent Person's Report in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular and/or extracts therefrom and references thereto and to the inclusion of its name and references in the form and context in which they are included.

16 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 Level 4, 123 Victoria Street, London SW1E 6DE and at the offices of Linklaters LLP, One Silk Street, London EC2Y 8HQ up to and including the date of the General Meeting:

(a) the Articles of Association of the Company;

(b) the consent letters referred to in paragraph 15 above;

(c) the Competent Person's Report of RISC (UK) Limited set out in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular;

(d) the Transaction Agreements;

(e) the Annual Reports and audited consolidated financial information of the Company for the years ended 31 December 2015, 31 December 2016 and 31 December 2017, together with the audit reports thereon; and

(f) this Circular and the Form of Proxy.

The above documentation will also be available 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.

PART VII
SUMMARY OF PRODUCING ASSETS
RESOURCES AND RESERVES INFORMATION

Private and confidential

Competent Person's Report

The non-core Asian portfolio of Santos

Oil field in Vietnam & gas fields in Indonesia

On behalf of Ophir Energy plc

3 August 2018

17.0177

decisions with confidence

Declaration

Ophir Energy plc ("Ophir") has commissioned RISC (UK) Limited ("RISC") to provide an independent valuation of the Reserves and a review of the Contingent Resources of Santos Limited's ("Santos") Asian assets to form a Competent Person's Report.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from a data room as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Ophir staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all the matters, which an extensive examination may disclose. RISC have not independently verified property title, encumbrances, regulations that apply to these assets. RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

RISC believes its review and conclusions are sound, but no warranty of accuracy or reliability is given to its conclusions.

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

RISC's review was carried out only for the purpose referred to above and may not have relevance in other contexts.

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United Kingdom

Ophir Energy plc
123 Victoria Street
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United Kingdom

1. Executive Summary

Ophir Energy plc (Ophir) is an independent upstream oil and gas company with production, development and exploration assets in Asia and exploration, appraisal and production assets in Africa. Ophir is listed on the London Stock Exchange (LSE).

Ophir retained RISC (UK) Limited (RISC) to provide a Competent Person's Report (CPR) on Santos Limited's (Santos) Asian assets, compliant with the requirements of a Class 1 transaction under the Listing Rules of the London Stock Exchange, for inclusion in a circular. The assets are the Santos operated Sampang PSC offshore East Java, Indonesia which contains the Wortel and Oyong gas fields, the Santos operated Madura Offshore PSC East Java, Indonesia which contains the Peluang and Maleo gas fields and Block 12W offshore Vietnam operated by Premier Oil plc, which contains the Chim Sáo and Dua oil fields. Over 70% of the total value is attributable to the Chim Sáo and Dua oil fields. The assets are summarised in Table 1-1.

Table 1-1: Santos Asian assets summary

Asset		Operator	Working Interest	Status	Licence expiry date	Licence area (km^2)	Comments
Country	PSC						
Indonesia	Sampang	Santos	45%	Production	04/12/2027	534.30	
	Madura	Santos	67.5%	Production	04/12/2027	849.00	Santos has a 77.5% WI in the undeveloped Meliwis Field
Vietnam	Block 12W	Premier Oil	31.875%	Production	20/11/2030	182.26	

Notes:
1. The Sampang PSC has the producing Wortel and Oyong gas fields. There are no remaining commitments or relinquishments.
2. The Madura Offshore PSC has the producing Peluang and Maleo gas fields and the undeveloped Meliwis gas field. There are no remaining commitments or relinquishments.
3. Block 12W has the producing Chim Sáo and Dua fields. There are no remaining commitments or relinquishments.
4. Block 12W original PSC effective Nov 2000 was for a 25-year term for oil and a 30-year term for gas. The PSC was amended in 2007 to give a 30-year term without differentiation between oil and gas.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System (SPE-PRMS)[1]. RISC was instructed to address only reserves and contingent resources on five fields, and therefore prospective resources are not addressed in this report.

RISC has conducted decline curve analysis on Chim Sáo Field and evaluated future development opportunities and in aggregate supports the Vendor's 2P recovery estimates on Chim Sáo and Dua Fields which are based on reservoir simulation. However, RISC have generated its own 1P, 2P and 3P oil production forecasts that better reflect the 2018 production to date which has been higher than previously forecast.

[1] SPE/WPC/AAPG/SPEE 2007 Petroleum Resources Management System.

The gross project oil and gas reserves and net attributable to Santos as at 1 January 2018 are summarised in Table 1-2 and Table 1-3.

Table 1-2: Gross and Net Oil and Condensate Reserves entitlement to PSC's at 1 January 2018

PSC	Gross Oil and Condensate Reserves (MMstb)			Net Oil and Condensate Reserves (MMstb)		
	1P	2P	3P	1P	2P	3P
Sampang	0.0	0.0	0.0	0.0	0.0	0.0
Madura	0.0	0.0	0.0	0.0	0.0	0.0
Block 12W	22.1	33.4	45.0	7.0	10.6	14.4
Total	**22.1**	**33.4**	**45.0**	**7.1**	**10.7**	**14.4**

Notes:

1. Gross reserves are on a gross contractor entitlement basis (after government take & economic cut-off) and mid-price case.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The Wortel Field in the Sampang PSC produces gas condensate, there are no condensate reserves in the Madura Offshore PSC and Block 12W.
4. The reference point for reserves for the Madura Offshore PSC is the inlet to the East Java Gas Pipeline (EJGP), for Sampang PSC is Santos Onshore Processing Facility (OPF) in Grati and for Block 12W is the FPSO for oil and entry to Nam Con Son pipeline for gas.
5. The volumes have been estimated using deterministic methods and have been added arithmetically.

Table 1-3: Gross and Net Gas Reserves entitlement to PSC's at 1 January 2018

PSC	Gross Sales Gas Reserves (Bcf)			Net Sales Gas Reserves (Bcf)		
	1P	2P	3P	1P	2P	3P
Sampang	21	30	40	9	14	18
Madura	11	28	39	7	19	26
Block 12W	18	28	47	6	9	15
Total	**50**	**87**	**125**	**22**	**42**	**59**

Notes:

1. Gross reserves are on a gross contractor entitlement basis (after government take & economic cut-off) and mid-price case.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The Chim Sáo and Dua oil fields produce associated gas.
4. The reference point for reserves for the Madura Offshore PSC is the inlet to the East Java Gas Pipeline (EJGP), for Sampang PSC is Santos Onshore Processing Facility (OPF) in Grati and for Block 12W is the FPSO for oil and entry to Nam Con Son pipeline for gas.
5. Sales Gas resources have been adjusted for fuel and flare.
6. The volumes have been estimated using deterministic methods and have been added arithmetically.

The gross project gas contingent volumes and Santos net working interest share as at 1 January 2018 are summarised in Table 1-4, Table 1-5 and Table 1-6.

Table 1-4: Gross & Net Gas Contingent Volume on Working Interest Basis at 1 January 2018

Area	Working Interest	Gross Gas Contingent Volume (Bcf)	Net Gas Contingent Volume (Bcf)
		2C	2C
Sampang	62.5%	9	6
Madura	62.5%	44	28
Block 12W	31.9%	10	3
Total		**63**	**37**

Notes:
1. Net Contingent Volumes are stated on a Working Interest basis. This is not PRMS compliant.
2. Contingent Volumes on a Net Working Interest basis are not entitlement volumes that an entity would have legal and economic entitlement under the relevant PSC terms. Net Contingent Resources can only be defined on an entitlement basis to be compliant with SPE PRMS definitions.
3. Contingent Volumes have not undergone economic limit testing.
4. The Contingent Volumes in the Sampang and Madura Offshore PSC are considered to have the Project Maturity Status of Development Pending.
5. Madura Contingent Volumes include the Meliwis field and Maleo field tail volumes (section 3.4.3)

Table 1-5: Gross Contingent Volumes (100%) beyond Economic Limit

Area	Gross Contingent Volumes beyond Economic Limit	
	2C Oil (MMbbl)	2C Gas (Bcf)
Sampang	0.0	0
Madura	0.0	<1
Block 12W	2.5	<1
Total	**2.5**	**<1**

Notes:
1. Contingent Volumes represent producible volumes which exist after date of economic limit.
2. The volumes have been estimated using deterministic methods and have been added arithmetically.

Table 1-6: Gross Block 12W Contingent Volumes (100%)

Contingent Resources	2C Oil (MMbbl)
Further infill	4.0
Due Field Blowdown	1.5
Chim Sáo Field Depressurisation	-1.5
Beyond Economic Limit	2.5
Total	**6.5**

Gross field volumes before economic cut off and government take are shown in Table 1-7 and Table 1-8.

Table 1-7: Gross Field Oil & Condensate Volumes and Ophir Net Working Interest Volume at 1 January 2018

PSC	Working Interest	Total Gross Field Oil and Condensate Production (MMstb)			Economic Gross Field Oil and Condensate Production (before Government Take) (MMstb)			Ophir Net Working Interest Oil and Condensate Production (MMstb)		
		P90	P50	P10	P90	P50	P10	P90	P50	P10
Sampang	45.000%	<0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1
Madura	67.500%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Block 12W	31.875%	29.4	40.3	51.3	25.0	37.8	51.3	8.0	12.1	16.4
Total		**29.4**	**40.4**	**51.5**	**25.1**	**37.9**	**51.5**	**8.0**	**12.1**	**16.4**

1. Reserves can only be defined on an entitlement basis. Total Gross Field Oil and Condensate production, Economic Gross Field Oil and Condensate Production (before Government Take) and Ophir Net Working Interest Oil and Condensate Production cannot be classified as Reserves as this is not compliant with SPE PRMS definitions of 1P, 2P and 3P reserves.
2. Economic limit tested at $60/barrel long term oil price and approx. $5.5/MMBtu gas price.
3. Totals may not add due to rounding of figures in table (i.e.: 51.32 + 0.14 displayed as 51.3 + 0.1 with total of 51.5)

Table 1-8: Gross Field Gas Volumes and Ophir Net Working Interest Volume at 1 January 2018

PSC	Working Interest	Total Gross Field Gas Production (Bcf)			Economic Gross Field Gas Production (before Government Take) (Bcf)			Ophir Net Working Interest Gas Production (Bcf)		
		P90	P50	P10	P90	P50	P10	P90	P50	P10
Sampang	45.000%	23	34	45	23	34	45	10	15	20
Madura	67.500%	15	35	48	14	35	48	9	24	32
Block 12W	31.875%	20	31	51	20	31	51	6	10	16
Total		**58**	**100**	**145**	**57**	**100**	**145**	**26**	**49**	**69**

Notes:

1. Reserves can only be defined on an entitlement basis. Total Gross Field Gas production, Economic Gross Field Gas Production (before Government Take) and Ophir Net Working Interest Gas Production cannot be classified as Reserves as this is not compliant with SPE PRMS definitions of 1P, 2P and 3P reserves.
2. Economic limit tested at $60/barrel long term oil price and approx. $5.5/MMBtu gas price.
3. Conversion factors used: Madura - 5.437MMscf/boe, Sampang (Wortel field) - 5.954MMscf/boe, Samang – (Oyong field) - 5.899MMscf/boe, Block 12W (Chim Sáo field) - 4.86159 MMscf/boe.
4. Totals may not add due to rounding of figures in table (i.e.: 51.32 + 0.14 displayed as 51.3 + 0.1 with total of 51.5)

The economic model used to calculate Net Present Values (NPV) for the assets under review in this CPR have been audited by RISC and an independent third party and is considered to be fit for purpose by all parties.

RISC has relied on independent legal advice to determine the licence expiry in Block 12W, Vietnam.

A total of five oil price scenarios have been run and three representing the Low, Mid and High cases are shown in Table 1-9 and Table 1-10.

The valuation with an Effective Date of 1 January 2018 (Table 1-9) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is the value at 1 January 2018.

A valuation has also been made with a Valuation Date of 1 July 2018 (Table 1-10) to meet the requirements of the UK Listing Authority. This is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is the value at 1 July 2018.

Asset NPVs for 1P, 2P and 3P reserves are reported at a nominal discount rate of 10%.

The economic values shown in this report have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore should not be taken to be fair market values.

Table 1-9: Summary of NPVs for Santos Assets in US Dollars with an Effective Date of 1 January 2018 & Valuation Date of 1 January 2018[1]

NPV US$ million	$54/Barrel Long Term			$60/Barrel Long Term			$70/Barrel Long Term		
Asset	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Madura	$9	$19	$28	$9	$19	$28	$9	$19	$28
Sampang	$11	$15	$22	$11	$15	$22	$11	$15	$22
Indonesia	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**
Chim Sáo	$112	$148	$177	$162	$202	$256	$178	$225	$292
Vietnam	**$112**	**$148**	**$177**	**$162**	**$202**	**$256**	**$178**	**$225**	**$292**
Total NPV	**$132**	**$182**	**$226**	**$182**	**$237**	**$306**	**$198**	**$259**	**$342**

[1]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 January 2018.

Table 1-10: Summary of NPVs for Santos Assets in US Dollars with Effective Date of 1 January 2018 & Valuation Date of 1 July 2018[2]

NPV US$ million	$54/Barrel Long Term			$60/Barrel Long Term			$70/Barrel Long Term		
Asset	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Madura	$9	$19	$28	$9	$19	$28	$9	$19	$28
Sampang	$11	$15	$22	$11	$15	$22	$11	$15	$22
Indonesia	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**
Chim Sáo	$118	$155	$185	$170	$212	$269	$187	$236	$307
Vietnam	**$118**	**$155**	**$185**	**$170**	**$212**	**$269**	**$187**	**$236**	**$307**
Total NPV	**$138**	**$189**	**$235**	**$190**	**$246**	**$318**	**$207**	**$270**	**$356**

[2]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 July 2018. Cashflows between 1 January 2018 and 30 June 2018 are escalated to Valuation Date of 1 July 2018 at 10%.

All assets were reviewed by RISC in May 2018 and checked in July 2018. No material changes were noted between these dates and the assets performed as predicted by RISC's analysis.

This report is authorised for release by Mr. Gavin Ward, RISC Partner. Mr Ward meets the requirements of ESMA 2013/319 para 133 subsection (a) as a Competent Person.

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2. Introduction

2.1. Terms of reference

Ophir Energy Plc (Ophir) retained RISC (UK) Limited (RISC) to provide a Competent Persons Report (CPR) on two Indonesia and one Vietnam Production Sharing Contract (PSC), compliant with the requirements of Class 1 transaction under the Listing Rules of the London Stock Exchange for inclusion in a circular/prospectus. This report satisfies the requirements of the European Securities and Markets Authority (ESMA) 2013/319 Appendix III.

2.2. Santos's Asian portfolio

Within Asia, Santos holds upstream oil and gas assets in Indonesia, Vietnam, Malaysia and Bangladesh (Figure 2-1). The assets sold to Ophir include the following interests:

- 31.875% in the Block 12W PSC (Chim Sáo and Dua oil fields), Vietnam;
- 67.5% in the Madura Offshore PSC (Maleo and Peluang gas fields), Indonesia;
- 45% in the Sampang PSC (Oyong and Wortel gas fields), Indonesia;
- 20% in the Deepwater Block R PSC (Bestari oil discovery), Malaysia;
- 45% in the SS-11 PSC, Bangladesh;
- 50% in Block 123 PSC and 40% in Block 124 PSC, Vietnam.

Only the producing assets in Indonesia and Vietnam form part of the package that RISC was asked to review. The Indonesian assets comprise interests in the offshore Madura and Sampang PSCs in East Java and the Vietnam asset comprises an interest in Block 12W in the Nan Con Son Basin.

Figure 2-1: Santos's Asian portfolio

2.3. Basis of assessment

2.3.1. Qualifications

RISC is an independent oil and gas advisory firm. All the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have more than twenty years. RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately forty highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. RISC has completed over 2,000 assignments in sixty-eight countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr. Gavin Ward, RISC Partner. Mr. Ward has a B.Sc. (Hons) Geology & Physics, Aston University UK, an MBA from the Cranfield School of Management UK, is a Chartered Accountant and Fellow of the Association of Chartered Certified Accountants (FCCA). Mr. Ward has 30 years of experience in the sector, is a member of the Society of Petroleum Engineers and is a Council Member of the Petroleum Exploration Society of Great Britain. Mr. Ward is a Competent Person as defined in ESMA 2013/319 para 133 subsection (a) and London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2009.

2.3.2. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The Santos assets assessed in this report comprise producing fields and undeveloped hydrocarbon volumes. Additional licenses that form part of the proposed transaction, but which are not included in this report are:

- Block R PSC, Malaysia;
- SS-11 PSC, Bangladesh;
- Block 123 PSC and Block 124 PSC, Vietnam.

RISC has not had access to the seismic data volume over the Chim Sáo field, Vietnam and is basing its observations on material found in reports provided in the Santos Virtual Data room. Although this has limited our review, it has not made a material impact as the reserves valuations are dependent on assessment of

production data. However, the lack of access to seismic data has impacted RISC's ability to assess some potential volumes from infill drilling programmes and potential volumes which have not been drilled or where there are no plans by the operator to drill.

The Net Present Value estimates presented in this report have not been adjusted for corporate hedging contracts or other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for, or warrant the accuracy or reliability of our conclusions, nor do RISC warrant that our enquiries have revealed all the matters, which an extensive examination may disclose.

Whilst this report has been prepared within the context of the effects of petroleum legislation, taxation, and other regulations, that currently apply to assets, RISC has not independently verified property title, encumbrances, regulations that apply to these assets. RISC has not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses. However, RISC has studied the PSC terms and has reflected these in the economic valuation.

RISC believe its review and conclusions are sound, but no warranty of accuracy or reliability is given to its conclusions.

Under its contract with RISC, Ophir has agreed to release, discharge and indemnify RISC from all or any claims, losses, costs, expenses, actions, demands, judgments, orders, liability at law or in equity however arising including but not limited to any claim or consequential damages or any other proceedings whatsoever incurred by RISC in respect of any claim by a third party (including associates, agents or employees of the client) in connection with all or any of the services provided by RISC to the client under the terms set out in this document.

2.3.3. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Santos and Ophir and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Ophir for the provision of this report, RISC will receive a fee, payable by Ophir. The payment of this fee is not contingent on the intended purpose of this report;
- Neither RISC Directors nor any staff involved in the preparation of this report hold interests in Ophir.

2.3.4. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers in 2007.

2.3.5. Definitions

The following paragraphs briefly describe the categories of hydrocarbon volumes listed in this report:

1. **Reserves** (Proved, Probable and Possible): 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;
2. **Contingent Resources** (Low (1C), Best (2C) and High (3C) estimates): those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies;
3. **Prospective Resources** (Low, Best and High estimates together with an estimate of the "Geological Chance of Success"): those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

2.3.6. Methodology

The report is compliant with ESMA update of the Committee of European Securities Regulators (CESR); "The consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive", last updated in March 2013 (ESMA/2013/319) ESMA 2013/319 Appendix III Oil and Gas Competent Person's Report – recommended content"

The data and information used in the preparation of this report were provided by Ophir supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation based on a review and audit of existing interpretations and assessments as supplied, making adjustments that in our judgment were necessary.

RISC has not conducted a site visit.

Data for the Madura Offshore and Sampang Production Sharing Contract (PSC) were viewed in a Physical Data Room (PDR) in Jakarta during May 2018. Under Indonesia regulations, raw data removal (e.g.: seismic and uninterpreted well logs) was not allowed. As such, RISC's methodology for these PSC's was to verify the range operators in place and estimated ultimate recovery (EUR) estimates and opine on their reasonableness, and where able to do so undertake independent analysis (i.e. material balances) while on location. Details of the findings of our review and the resource estimation process are presented in this report.

Data for Block 12W were made available via a Virtual Data Room during May 2018. This included well by well production data, study reports and JV presentations.

Our assessment for the producing assets is based on production data to end 2017. RISC has reviewed the production history, development plans and costs provided by Santos. RISC has based the net present values presented in this report on gas prices supplied by Ophir and independently verified by RISC staff.

Unless otherwise stated, all resources presented in this report are net entitlement quantities with an effective date of 1 January 2018. All costs are in US Dollars real terms with a reference date of 1 January 2018. Costs are escalated at 2.5%, gas prices are as per in place GSA terms.

3. Indonesia – Madura Offshore and Sampang PSCs

The producing offshore gas fields in the Madura Offshore and Sampang PSC's are in late life and significantly depleted with substantial production history from high quality reservoirs. Upside is limited to reducing reservoir abandonment pressure through ultralow compression and minor well intervention activity in the Oyong field. In the case of the Madura Offshore PSC, the yet to be developed Meliwis field could allow extended "tail end" production from the producing Maleo field which is estimated by Santos to approximately 8.3 Bscf in the 2C Case. The recoverable volumes attributed to the Meliwis field and incremental Maleo "tail end" are categorised as Contingent Resources by Santos, dependent on a Meliwis Final Investment Decision (FID).

The potential Meliwis gas development presents the major upside in the PSC's. The Meliwis Plan of Development (POD) was approved by SKK Migas on the 11 January 2018, however FID is not anticipated until mid-2018, as RISC understands that GSA negotiations for Maleo and Meliwis are currently ongoing and expected to be signed by mid-2018. The development consists of a single well drilled from a wellhead platform tied back to the Maleo facilities.

3.1. Introduction

3.1.1. Asset description

The Madura and Sampang PSC's are located offshore Indonesia in the East Java Basin in water depths of 48 to 65 m with Santos operator of both PSCs. The location of the PSC, fields, relevant working interests and development stage are detailed in Figure 3-1 and Table 3-1.

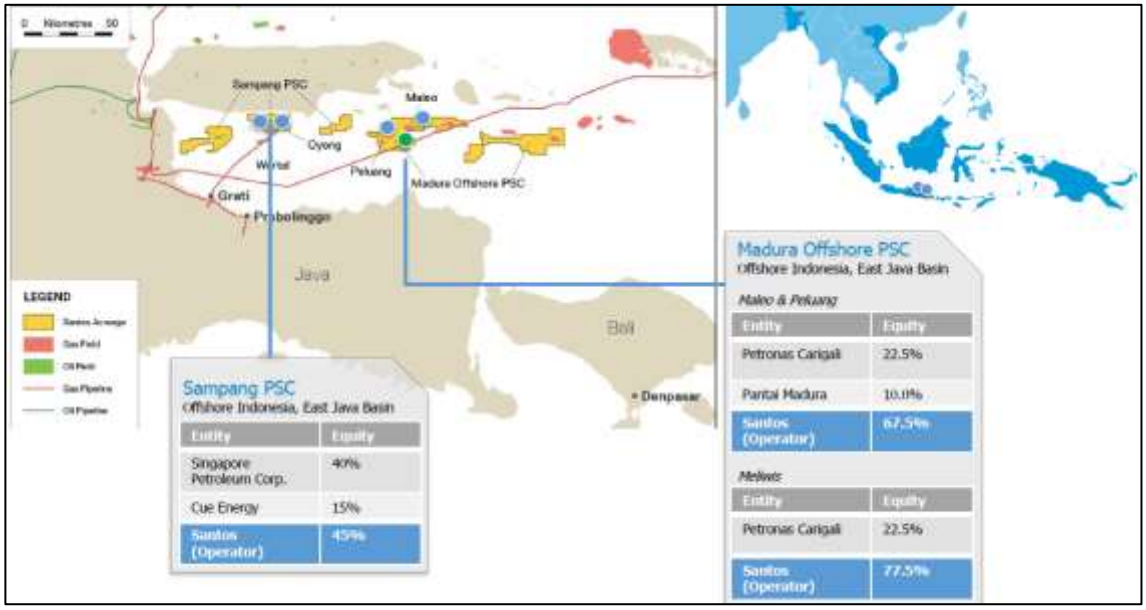

Figure 3-1: Location of the Sampang and Madura Offshore PSC's with relevant Working Interests

Table 3-1: Development stage of the Indonesia assets

PSC	Producing Fields (Start-up)	Potential Further Developments	Near Term Exploration Targets
Sampang	Oyong (2012)	Sampang Sustainability Project Phase II	Paus Biru (2018)
	Wortel (2012)		
Madura	Madeo (2006)	Meliwis (potential FID mid-2018)	Cangak, Berusaha, Molch (2019-2020)
	Pelung (2014)		

A site visit was not carried out as nothing was discovered in the Data Room that made a site visit necessary. Santos have demonstrated competence and capability and have a record of performance that RISC is satisfied with.

3.1.2. Sampang PSC

The Sampang PSC has gas production from the mature Wortel field with two (2) gas producers and the Oyong field with six (6) wells of which only four (4) wells are currently on production.

The Oyong field is a small (3 x 1 km) elongated, west-east four-way dip structure. The structural relief is about 100 m. The reservoir is shallow at about 1,000 m depth with excellent porosity (40%) and a water saturation of 24%.

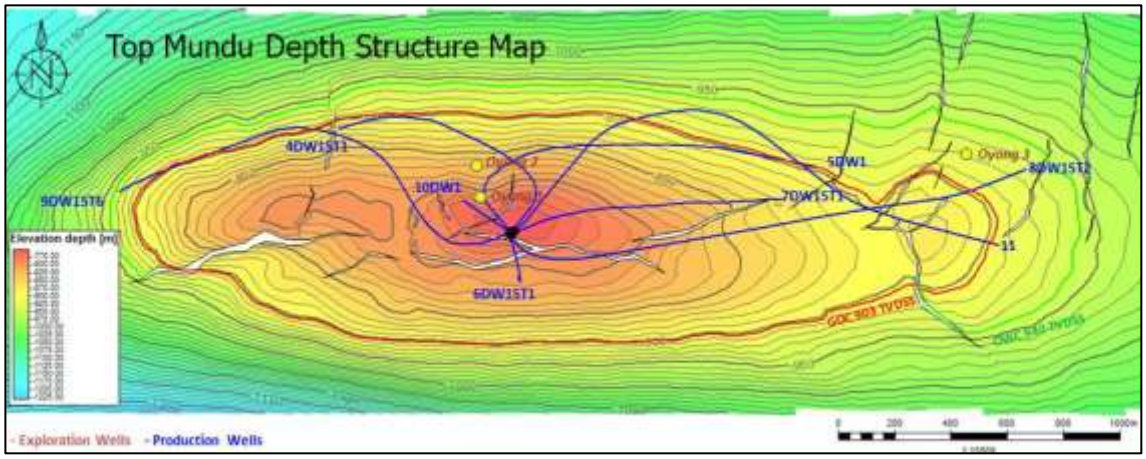

Figure 3-2 Depth map of the Oyong field

The Wortel field is the western limit of a plunging east to west nose, with a major north-south fault defining the eastern limit. This results in small (1.5 x 1.5 km) structure. The structural relief is about 100 m. The reservoir is reasonably shallow at about 1,250 m depth with good porosity (31%) and a water saturation of 38%.

The Wortel and Oyong fields are shallow low-pressure reservoirs located at 1,150 mSS and 750 mSS respectively with initial pressures of 2,138 psia and 1,480 psia. Both fields exhibit degrees of aquifer support.

Production commenced from Oyong in 2007 and from Wortel in 2012. Cumulative gross production to year end 2017 (YE2017) is 190 Bcf sales gas and 9.8 MMstb oil and condensate (Oyong: 103 Bcf and 9.7 MMstb; Wortel: 86.8 Bcf and 0.1 MMstb). Gross average 2017 production was approximately 46 MMscf/d sales gas.

Gas from the Wortel WHP is exported to the Oyong WHP which has compression and is transported via 56 km subsea pipeline to a Santos Onshore Processing Facility (OPF) in Grati. After processing, gas is sold to PT Indonesia Power (Grati Power Plant) and the associated condensate sold to PT Pertamina (Persero).

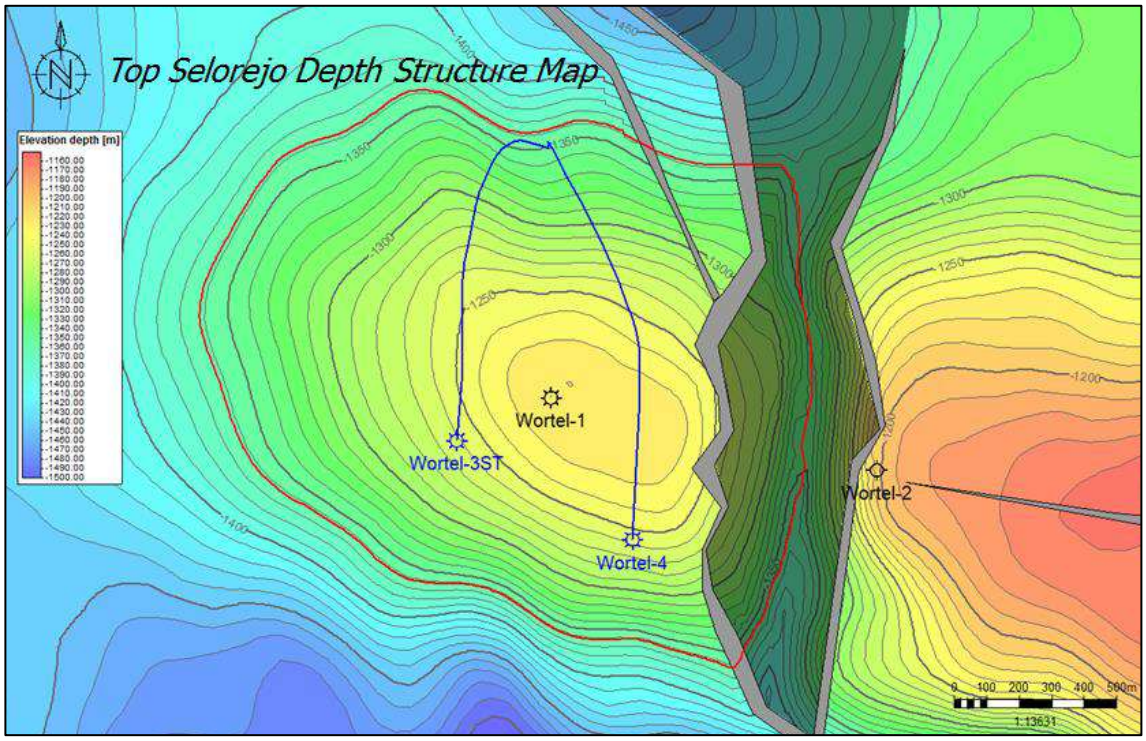

Figure 3-3 Depth map of the Wortel field

3.1.3. Madura Offshore PSC

The Madura Offshore PSC produces gas from the mature Maleo and Peluang fields with four and one gas producers respectively.

The Peluang field is small (3 x 1 km) west-east four-way dip closed structure. The structural relief is about 60 m and the spill point of the field is a saddle to the northwest. The reservoir is shallow at about 1,000 m depth with excellent porosity (41%) and low water saturation (38%).

The Maleo field is a larger (6 x 3 km) and more pronounced structure with a relief of over 100 m, although the height of the gas column is about 60 m. The reservoir is very shallow (500 m) and reservoir quality is again excellent with porosity of 46% and Sw of 19%.

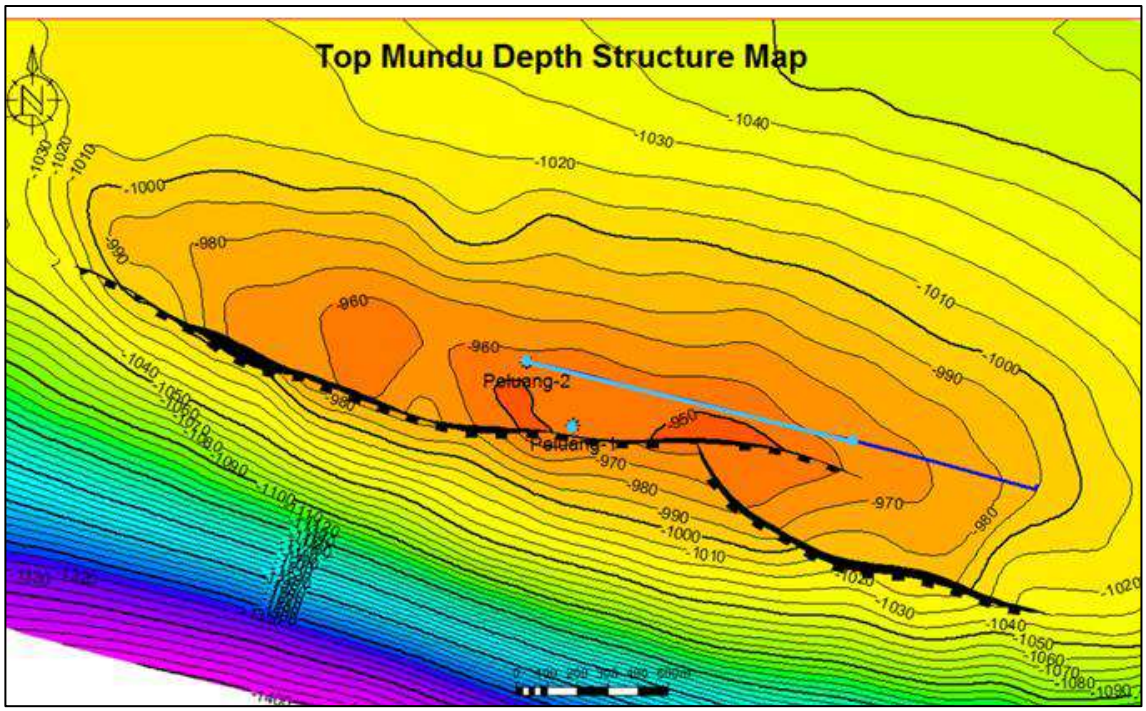

Figure 3-4: Depth map on the Peluang field

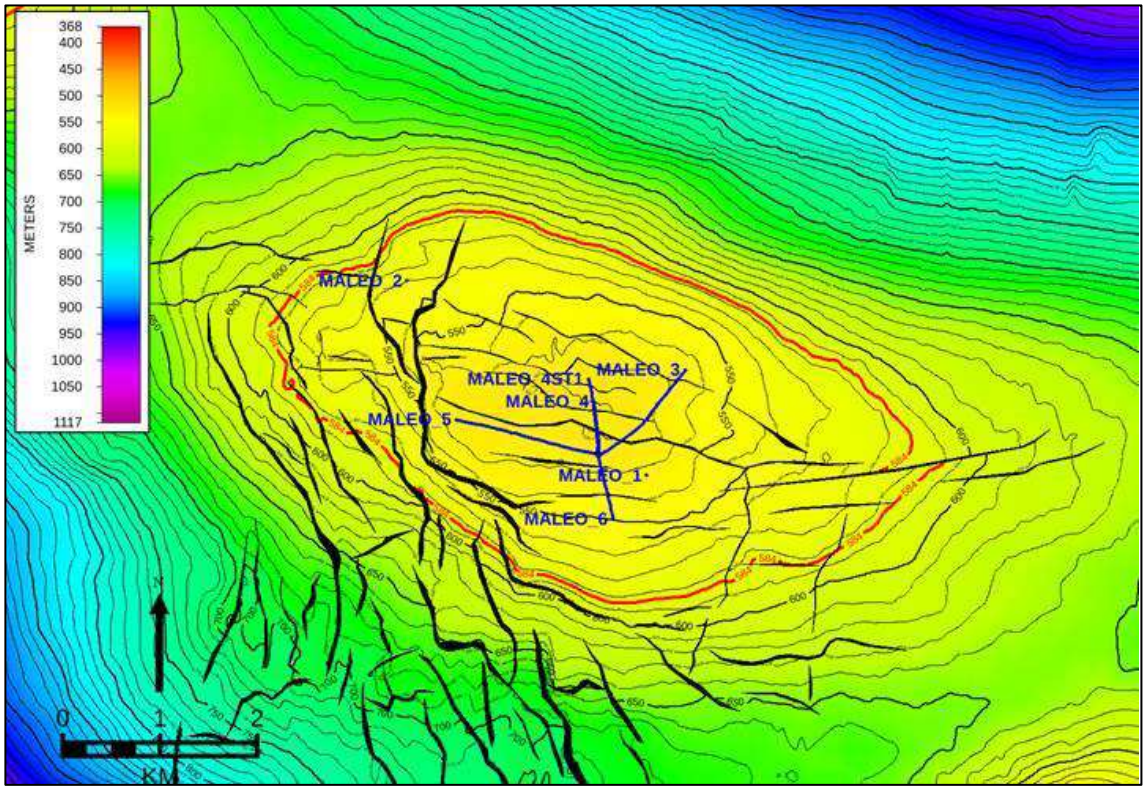

Figure 3-5: Depth map of the Maleo field

Meliwis is a small (2 x 1 km), west-east four-way dip-closured structure (Figure 3-6), probably formed as the result of structural inversion. There is structural relief of about 100 m and the spill point of the field is a saddle to the northwest. There is a major west-east fault within the field which partially offsets the reservoir.

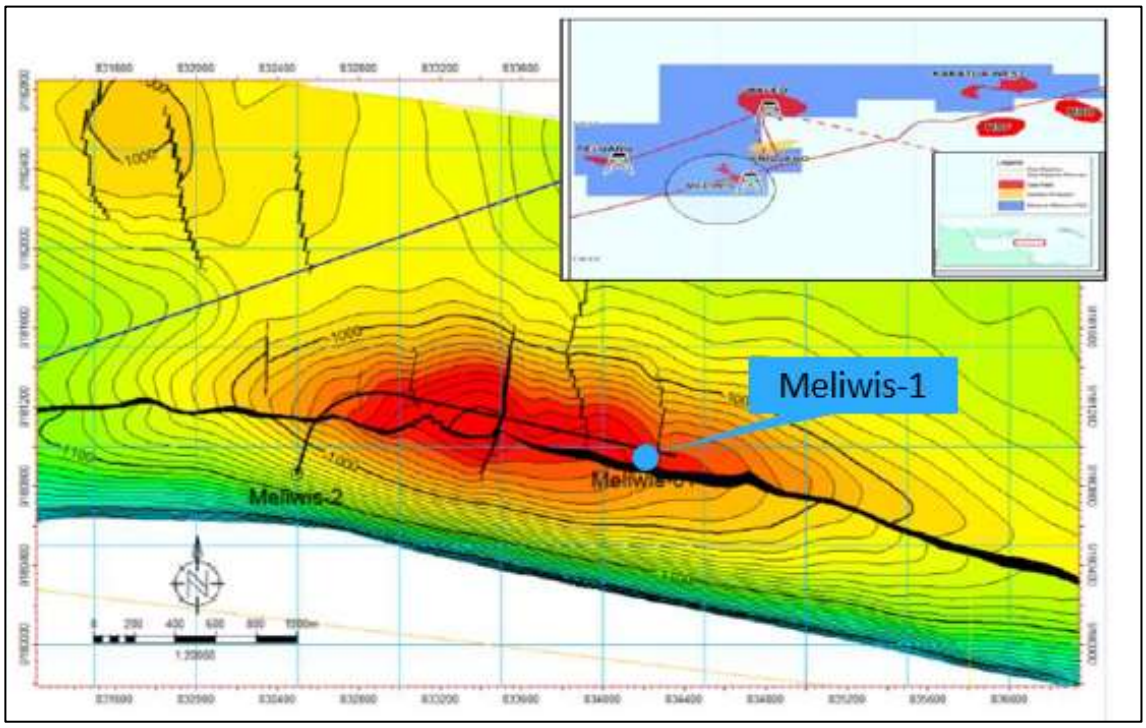

Figure 3-6: Structure map of the Meliwis field

The Maleo and Peluang fields are shallow low-pressure reservoirs located at 515 mSS and 940 mSS respectively with initial pressures of 878 psia and 1,480 psia.

Production commenced from Maleo in 2006 and Peluang in 2014. Cumulative gross production (YE2017) is 306 Bcf and 32 Bcf sales gas respectively. Gross average 2017 production was approximately 54 MMscf/d sales gas.

Gas from the Peluang WHP is exported to the Maleo WHP which is tied back to the leased Maleo Production Platform (MPP), which has gas compression. Gas from both fields is processed on the leased Maleo Producer Platform (MPP) before being sold to separate buyers at the inlet to the East Java Gas Pipeline (EJGP).

The Meliwis development is planned as a single well wellhead platform tie-back to Maleo with a plateau rate of 25 MMscf/d. The POD was submitted during Q4 2017 and approved in January 2018. Final Investment Decision is planned for Q3 2018.

3.1.4. Regional Geology

The Sampang and Madura Offshore PSCs are located with the East Java Basin (Figure 3-7). Existing infrastructure allows for low cost incremental development opportunities.

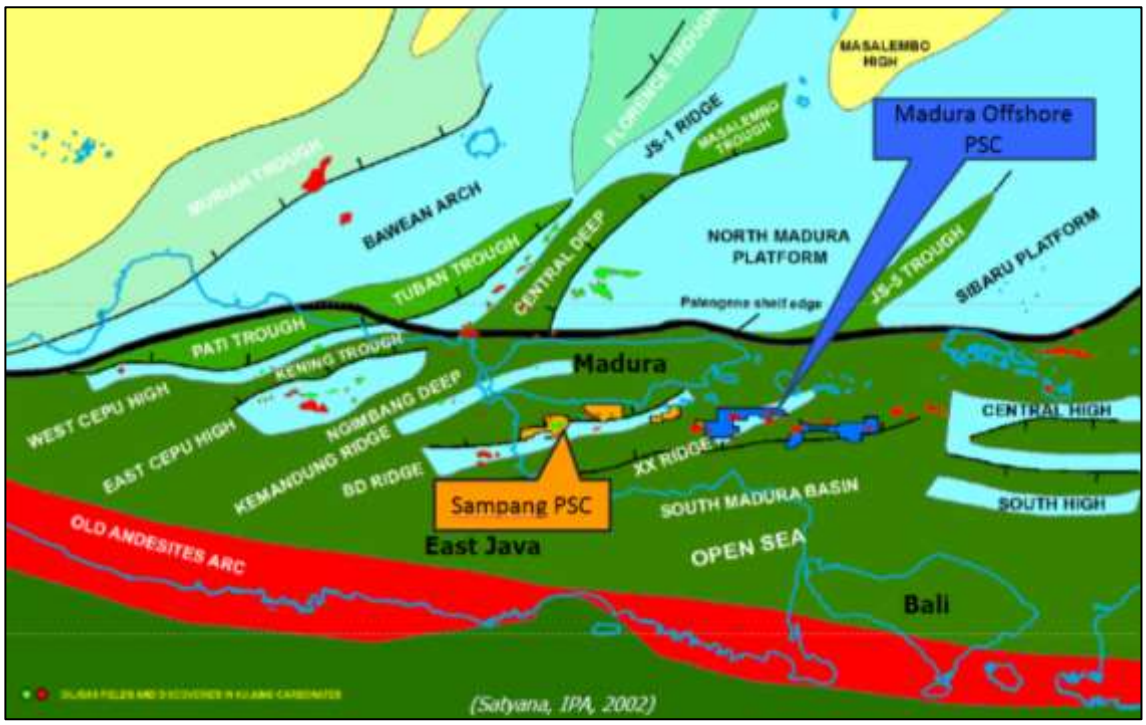

Figure 3-7: East Java Basin tectonic setting

There are many plays within the basin and a geological cross section through the Sampang and Madura Offshore PSCs is shown in Figure 3-8. The resources addressed in this report are in the shallow, gas dominated Mundu Formation carbonate play. A stratigraphic column is shown in Figure 3-9.

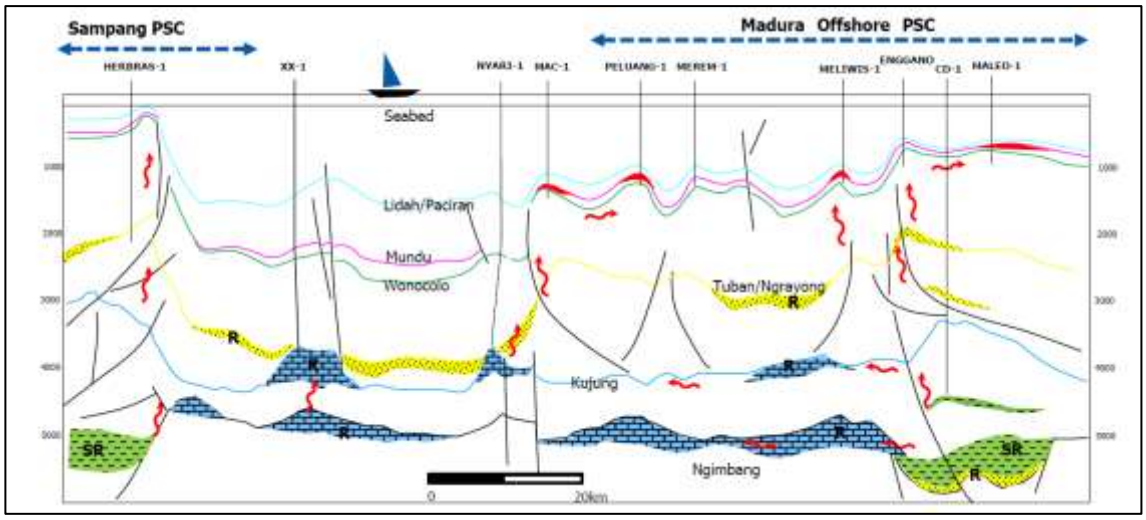

Figure 3-8: Geological cross section through the Sampang and Madura Offshore PSCs

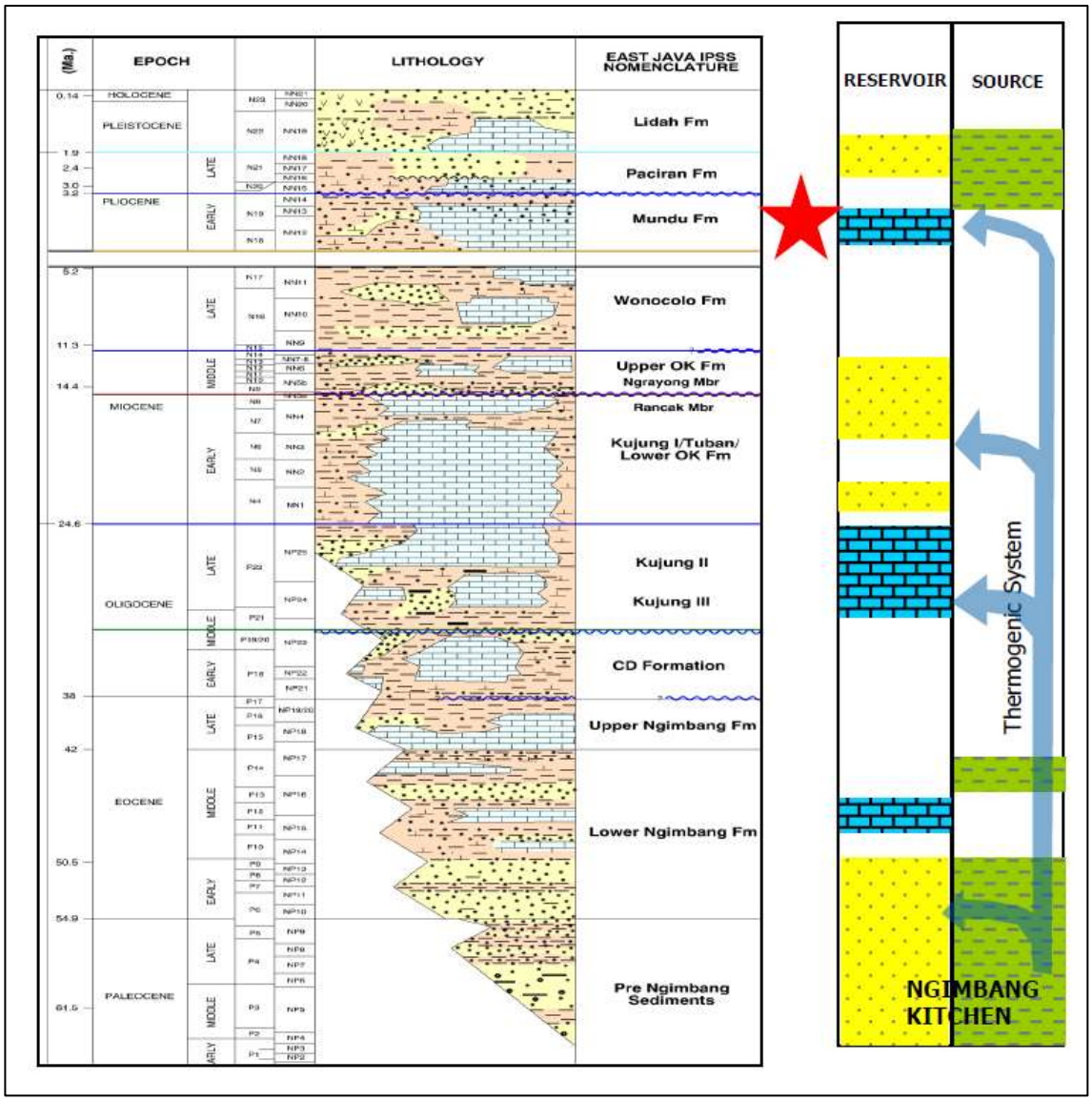

Figure 3-9: East Java Basin stratigraphy

3.2. Subsurface Interpretation

3.2.1. Volumetrics

This section of the report addresses the Meliwis field, which is currently being considered for development. Performance methods have been used to evaluate the producing fields as described in Section 3.3.

RISC has reviewed Santos interpretations provided in the data room. RISC found that these followed standard industry practices and were generally of high quality.

- The seismic interpretation was carried out using the Paradigm software, well to seismic ties carefully made, the interpretations appear reasonable and multiple depth conversion methods were used to explore depth conversion uncertainty;
- Seismic attributes were used to limited extent. Modelling showed that gas sands can be identified using specific attributes;
- Petrophysical analysis generally carried out using the Geolog Multimin approach (industry standard), correlated to core, RCA and SCAL data where available. Cut-offs generally designed to have no impact on net reservoir giving high net to gross;
- Geological modelling was carried out in Petrel by experienced users following industry standard practices. No cut-offs were applied – consistent with petrophysical analysis and reliance on dynamic modelling to assess recovery from low permeability layers;
- A range of GIIP was modeled using a combination of deterministic and stochastic modelling in Petrel. Top structure uncertainty was assessed, but no variation in reservoir thickness was considered.

The Meliwis field was discovered in 2016 by Meliwis-1, some 100 m down-dip of Maleo field. It is covered by fair to good quality 3D seismic data which was acquired in 2005 and reprocessed in 2011.

Meliwis-1 penetrated a 54 m gas column in the upper Mundu Formation with two (2) DSTs (Drill Stem Test) undertaken with no water or condensate produced. The field has high porosity, but permeability is generally low, averaging 4.5 mD and the field is normally pressured. The pressure data do not indicate hydraulic connection with the Maleo and Pelaung fields. No gas water contact (GWC) was penetrated by the well but RISC has interpreted a GWC at 1,022 mSS.

The Meliwis Plan of Development (POD) was approved by SKK Migas on the 11 January 2018 and assumes a weighted average price (WAP) of $7.53/MMbtu.

The reservoir is the Early Pliocene Upper Mundu Formation and consists of globigerine foraminifer[2] (carbonates) deposited in outer shelf setting, along with glauconite and pyrite minerals. The shallow depth and intra-grain porosity gives high porosities (15 to 53%). However, a high degree of bound water contributes to low permeabilities and high-water saturations. The Lower Mundu Formation is poor quality and not considered in resource estimates.

[2] Marine micro organisms

Santos carry a Free Water Level (FWL) at 1,020 mSS, but there is some uncertainty in this. Meliwis-1 encountered top reservoir at 954 mSS, 45 m down dip of crest of structure at about 910 mSS. DST #2 proved gas down to 985 mSS. DST #1 was inconclusive. The lowest Special Core Analysis (SCAL) data point to indicate gas is at 1,017 mSS. The low permeability Lower Mundu would suggest a long transition zone and the interpretation of Sw and FWL is difficult on the log data. Santos have generated a Sw vs Depth model from mercury injection capillary pressure (MICP) analysis on core data. This model indicates a FWL of 1,020 mSS, which coincides with base case structural spill, acoustic impedance seismic data and the lowest SCAL data point. RISC can support the Santos FWL at 1,020 mSS as base case but consider an uncertainty of at least +/- 5 m appropriate.

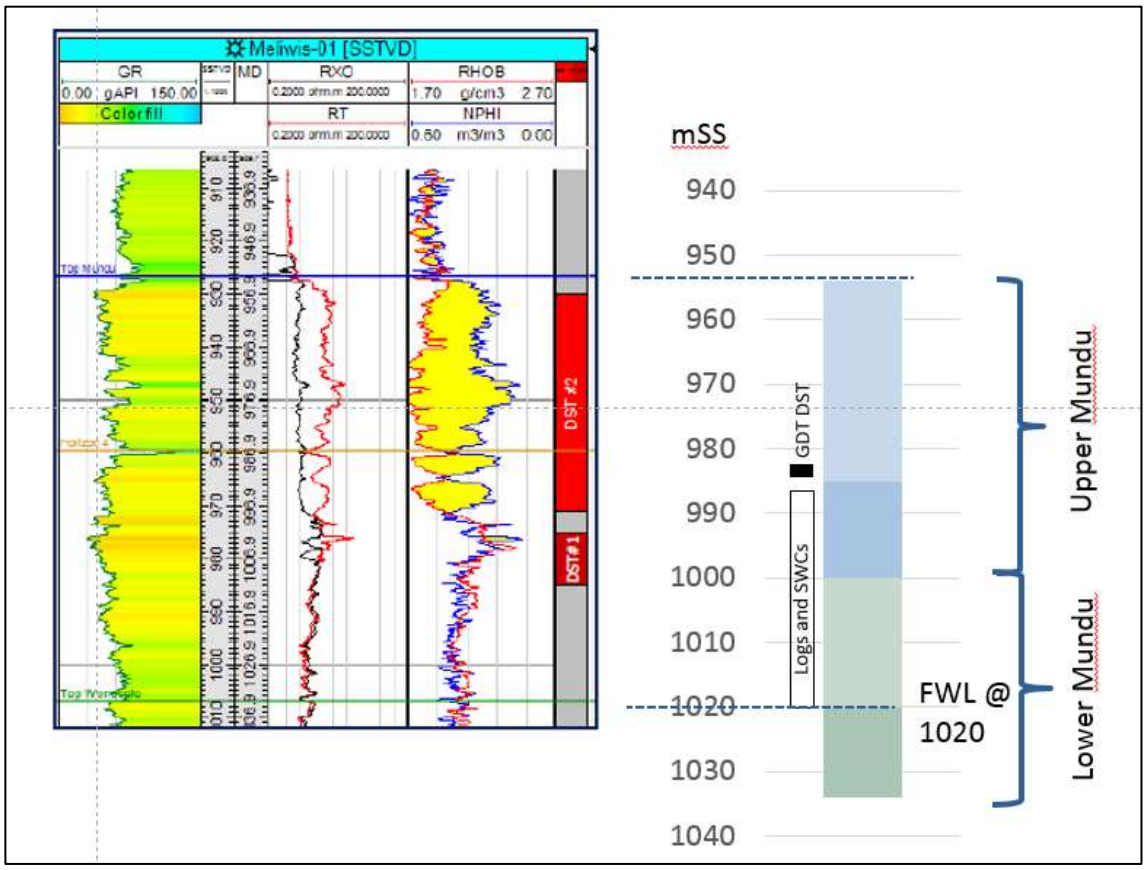

Figure 3-10: Log data and FWL interpretation of Meliwis-1

RISC reviewed the Petrel models prepared by Santos, and compared average reservoir properties for porosity, Sw and FVF and found them to be reasonable and consistent with petrophysical sums and averages and fluid properties.

There are several estimates of in-place resources of the Meliwis field, as shown in Table 3-2.

In RISC's view, these estimates do not adequately address uncertainty. Specifically:

- Uncertainty in FWL has not been addressed;
- Although Santos recognised up to 30 m uncertainty in structure at closing contour, greater uncertainty is considered to be necessary;
- No reservoir thickness uncertainty was applied.

Table 3-2: In-place estimates for the Meliwis field

Source	GIIP (Bcf)		
	P90	P50	P10
Santos Management Presentation	59	69	81
FDP deterministic	58	69	80
FDP Stochastic	61	69	77
Santos Petrel Model	59	69	82
RISC	50	69	92

RISC therefore independently derived in-place estimates using a 1D probabilistic approach (REP), which yielded a broader range (Table 3-3). The GRV model used ranges of area-depth pairs, thickness and contact. The P50 thickness was input to reproduce the Petrel base case GRV, with a +/- 4 m uncertainty applied. Net to gross is 100%, in-line with the petrophysical analysis and geological modelling. Area-depth pairs were taken from Petrel base case map. Area uncertainty was calculated assuming a +/- 15 m uncertainty to depth map across total structure, which considers depth conversion and mapping uncertainty. Average Porosity and Sw from Santos Petrel modelling realisations was assigned as P50 input. The FVF was taken from Santos Petrel model, with +/- 2% uncertainty. RISC considers the revised P10 to P90 is more appropriate for a field of this maturity and well control.

Table 3-3: RISC 1D probabilistic GIIP estimates of the Meliwis field

Source	REP Inputs and Results		
	P90	P50	P10
Thickness (m)	53	57	61
Area Uncertainty	75	100	125
GWC (m)	1015	1020	1025
Porosity (%)	41	44	47
Net to Gross (%)	100	100	100
GRV (km^2m)	90	123	160
Sw (%)	60	63	66
FVF	96	98	100
GIIP (Bcf)	**49.8**	**69.0**	**91.6**

3.2.2. Fluid properties

The Meliwis reservoir fluid is a dry gas with minimal inert gases. Laboratory derived PVT (Pressure, Volume and Temperature) properties are as shown below in Table 3-4. RISC noted traces of H_2S were detected in DST testing, however were not present in lab samples. RISC confirmed the lab derived expansion factor is consistent with correlations.

Table 3-4: Meliwis Reservoir Fluid Properties

Property	Unit	Gas Column
Pressure	psig	1661
Temperature	deg C	70.5
Expansion factor 1/Bg	scf/cf	99
Specific Gravity	-	0.596
Inserts (CO_2 and N_2)	% mol	2.05
C5+	% mol	0.9

3.2.3. Well testing

DST well testing was undertaken with H_2S detected in DST 1. Both DST's indicated limited deliverability with flow rates of 3.9 and 13 MMscf/d. Derivative plots from both DSTs indicated the presence of nearby boundaries, interpreted to be either the primary East West normal fault or the secondary North-South faulting. RISC reviewed the well test interpretation and considers DST 2 reasonable. DST 1 is more problematic noting the low net to gross of approximately 0.112 and the apparent skin of 110 the well test interpretation is questionable. As the zone that DST 1 tested is not included in volumetrics nor considered productive DST 1 and its anomalies are not relevant to the Meliwis development.

Table 3-5: Meliwis DST Results

DST	Zone	Gross interval (m)	Gas rate (MMscf/d)	Kh (mD.m)	S	Remarks
DST 1	A	10	3.9	103	110	Pressure transient response indicates significant skin of 110 with boundary observed approx. 30 m, estimated radius of investigation ~ 337 m. H_2S recorded @ 35 ppm. Effective permeability approx. 10.3 mD. Zone not included in Meliwis development.
DST 2	B	41	13	205	2.5	Lower permeability compared to upper zone DST with boundary observed approx. 14 m. No CO_2 or H_2S evident. Effective permeability approx. 5 mD.

3.2.4. Development Concept

The Meliwis development plan envisages an unmanned Well Head Platform (WHP) in 74 m of water tied back to the Maleo Production Platform (MPP). The development strategy is very similar to successful Peluang development, with the same standalone screen completion design.

A single 4 ½" 1,200 m crestal horizontal well is planned on the northern part of the field, targeting the upper Mundu Formation since 80% of the field gas is in this segment of the field (Figure 3-11). The rational of locating the well parallel to the north side of the main fault is to connect any compartments caused by the north-south striking faults and RISC considers this prudent.

Within the proximal area, faults are not generally hydraulically sealing and RISC notes that fault throw is < 10 m and reservoir is juxtaposed against reservoir. Simulation sensitivities suggest that if the fault is sealing, then the southern compartment is not connected, and recovery will be lower by approximately 7 Bscf.

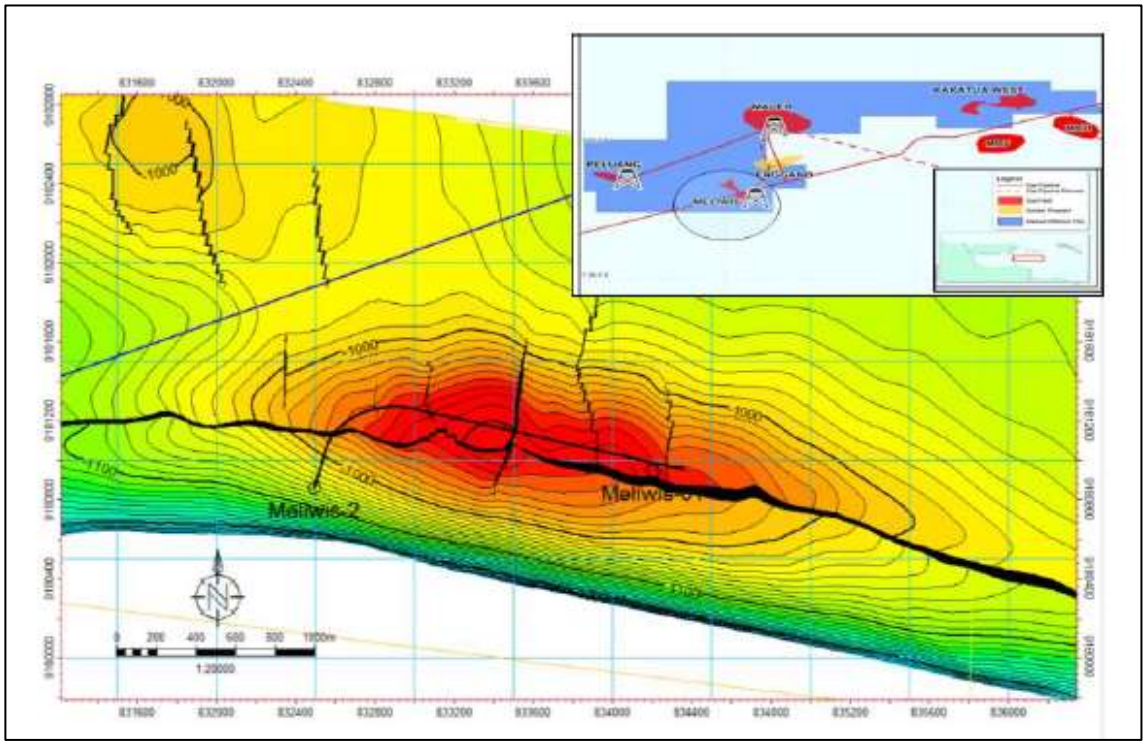

Figure 3-11: Proposed Location of Meliwis - 2 Development Well

3.2.5. Reservoir Modelling

Santos has undertaken multiple realization reservoir modelling to capture structural and petrophysical uncertainties. Three cases were selected by Santos for assigning 1C, 2C and 3C resources, resulting in gas recovery of 19, 34 and, 45 Bscf respectively. This represents a range of recovery factors (RF) of between 35 to 53%. This range of Recovery Factors need to be seen in the context of the relatively high reservoir abandonment pressures due to production constraints of 250 psi FTHP and a slightly lowered 12 MMscf/d compression inlet rate at the MPP and the expectation that the area to the south of the main east-west fault will be drained.

The modelled runs indicate that porosity, residual gas saturations (Sgr) in the upper Mundu, structure and aquifer properties are the most significant parameters on recovery. RISC reviewed the range of SCAL derived relative permeability curves and noted the very low relative permeability for water (Krw) at residual gas saturations, inferring retarded aquifer encroachment into the reservoir.

RISC interrogated Santos's P50 simulation model and noted that the aquifer influx is constrained at the edges by low permeability zones. As reservoir properties in the lower Mundu are poorer, bottom drive aquifer influx is not anticipated. A Carter Tracey edge water aquifer is modelled with a HCPV/Aq pore volume ratio of approximately 4, suggesting limited water drive is anticipated. The initial plateau rate is assumed to be 25 MMscf/d. Pre- and post-simulation saturation profiles indicate the proposed horizontal well does not water out during the production period with the P50 model suggesting a reservoir abandonment pressure of 730 psia.

RISC independently estimated the 2C RF and noted in the unconstrained production P50 case less than 2 Bscf of gas was trapped by aquifer encroachment and this supports the simulation modelling that suggests that aquifer influx is constrained due to low permeability.

Santos undertook offtake sensitives at 20 MMscf/d, as per the SKK POD approved offtake rate, and this indicated no significant impact on gas recovery.

RISC considers the simulation modelling robust and adequately captures the range of uncertainty.

Independent certification of the Contingent Resource has been undertaken by Lemigas in October 2017, and RISC notes their 2C gas Contingent Resource estimate is approximately 37 Bscf, however the documentation does not explain how this figure was derived.

3.3. Historical Production Analysis

The Madura Offshore PSC fields, Maleo and Peluang produce dry gas with minimal inert gases (< 1%). The Maleo field is in decline whilst the Peluang field is on plateau and provides backfill to Maleo. Both fields have a degree of weak aquifer support and there has been no evidence of aquifer water production to date consistent with the crestal location of the production wells.

In the Sampang PSC, the Oyong field was originally produced as an oil field depleting the oil rim. Oil production ceased mid 2017 with minor condensate production continuing into 2018 and the gas cap is now being blown down. The adjacent Wortel field is in decline and produces gas with minor condensate (CGR approximately 5.5 bbl/MMscf). Both fields are interpreted to have a degree of aquifer support. With cessation of oil production, condensate from Wortel is now spiked back into the gas export line.

The fields have high deliverability and the wells are completed with sand control due to the unconsolidated nature of the reservoir. Maleo wells are completed with 5 ½" wire wrapped screens with 7" production tubing and Peluang wells have same lower completion with 4 ½" production tubing. Oyong wells are completed with 4 ½" wire wrapped screens and 4 ½" production tubing whilst Wortel wells have 5 ½" wire wrapped screens and 4 ½" production tubing. To date there has been no evidence of excessive sand production in any of the fields that would suggest failures of the lower completions.

RISC notes regular well tests in the fields over the 2016 to 2017 period have not indicated deterioration in well performance with skin factor generally interpreted below 5 except for Peleuang-2 where recent 2016 and 2017 well testing indicates a significant skin of greater than twenty. Santos has suggested investigating the benefits of acidizing the well to increase well deliverability and potentially recovery, however RISC is not aware of ongoing studies or plans.

Historical production for the fields is shown in Figure 3-12 and Figure 3-13 below.

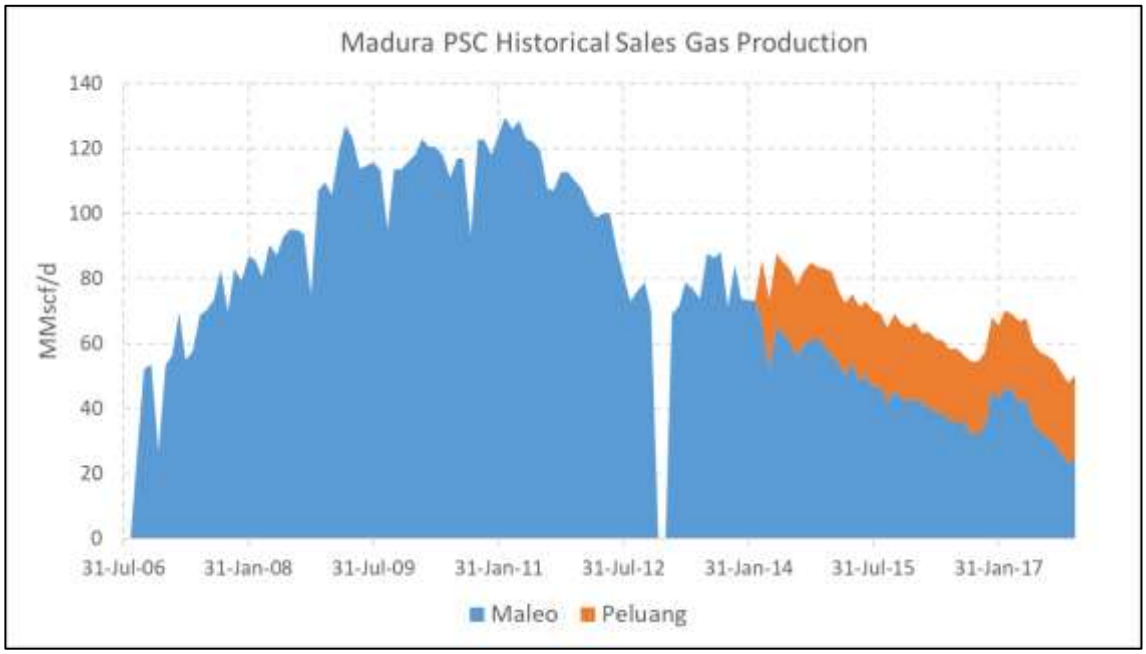

Figure 3-12: Madura Offshore PSC Historical Sales Gas Production

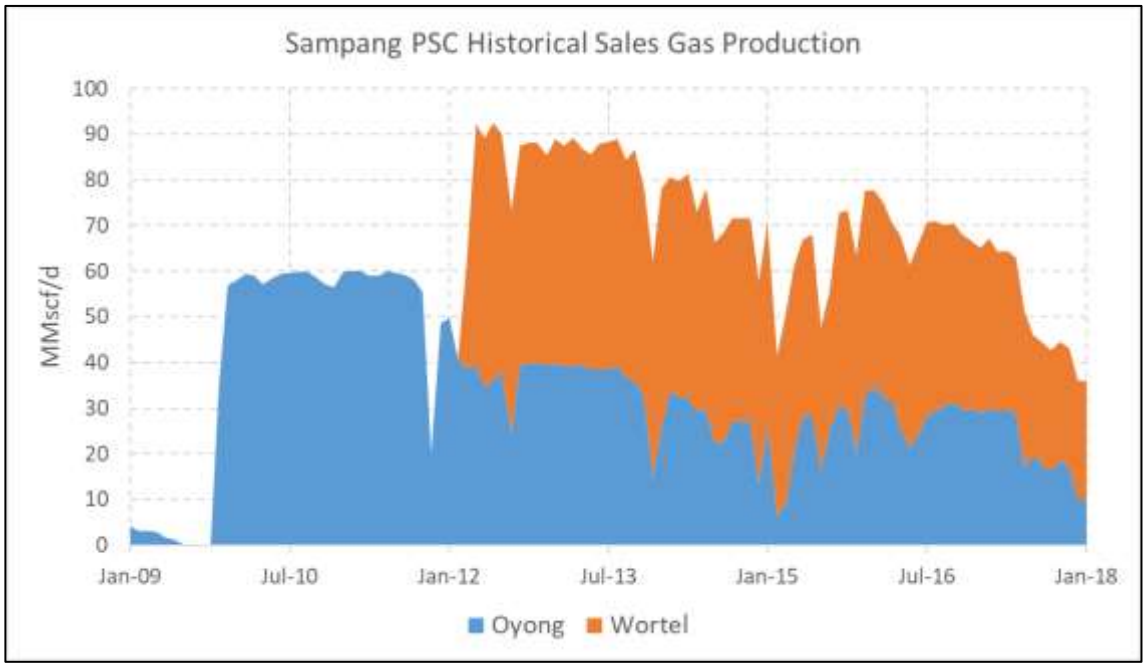

Figure 3-13: Sampang PSC Historical Sales Gas Production

RISC has conducted its own material balance analysis on each field. In general, RISC's work supports the Santos material balance derived estimates of GIIP. The four producing fields are all interpreted to exhibit some degree of aquifer support.

Wortel: Santos presents a high case for the Wortel field based on p/Z modelling and Flowing Material balance analysis, both assuming volumetric depletion drive resulting in a high side case of approximately 160 Bscf. RISC does not support this interpretation.

Maleo: The Havlena Odeh and Cole plots suggests a best case GIIP of approximately 383 Bscf as shown in the left Figure 3-14 and this is contrasted with the 3P GIIP of 423 Bscf as per below which indicates a poorer match as shown in the right of Figure 3-14.

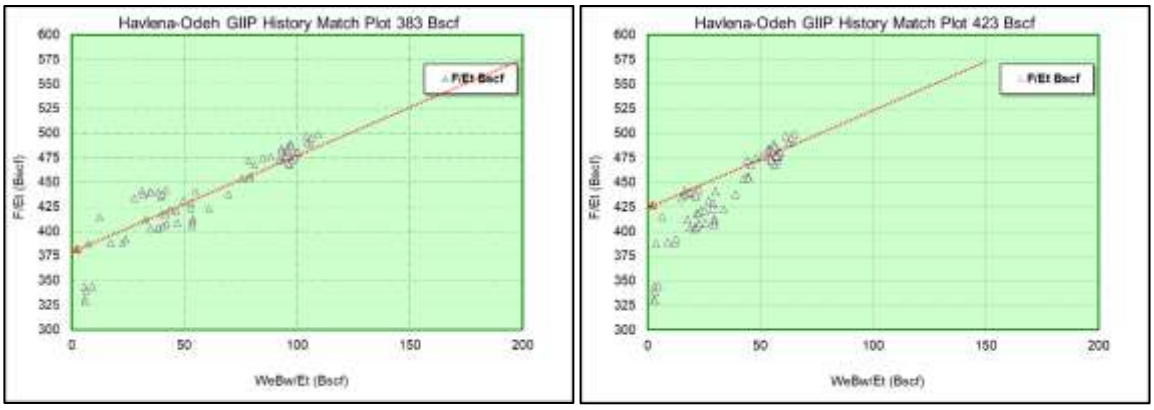

Figure 3-14: Maleo field Havlena Odeh Plots for 383 and 423 Bscf Respectively

3.4. Resources and Production Forecasts

3.4.1. Producing Fields

Santos' resource estimates and production forecasts have been derived from history matched Eclipse simulation models. Multi realizations of over 400 runs (using EnABLE software) has been used to derive a range of forecasts with specific cases selected from the output S-curve distribution to represent 1P, 2P and 3P. RISC has reviewed the EnABLE multi realization methodology and considers it reasonable with the selected 1P, 2P and 3P case GIIPs commensurate with RISC's material balance derived range of GIIP.

RISC has reviewed the quality of the 1P, 2P and 3P pressure history matches on a well by well basis (flowing tubing head) and average reservoir pressure and considers them reasonable apart from Oyong. RISC notes that the Oyong field 2P and 3P history matches are generally better than the 1P matches and have displayed better water production matches than the 1P case. RISC opines the selected 1P case model may be overly conservative.

RISC notes the Peluang and Wortel 1P cases water out due to pronounced aquifer influx, whereas all other fields the 1P, 2P and 3P cases cease flow due to declining reservoir pressure. Maleo 2P and 3P cases appear to liquid load at very late life due to declining well rates. RISC considers uncertainty in drive mechanisms has been adequately captured as well as liquid loading.

RISC has independently verified the 2P simulation model's recovery factors volumetric sweep efficiencies based on initial and abandonment pressures, Swc and Sgr.

In the Madura Offshore PSC, the Maleo MPP gas export compression has a minimum suction flowrate of 15 MMscf/d with a current inlet pressure of 120 psig. Whilst the FTHP of the Maleo field is less than the Peluang field the compressor inlet pressure prevents Peluang backing out Maleo production. Rewheeling will occur in Q4 2019 and will reduce inlet pressure to 50 psi with the AFE approved by both SKK Migas and the JV. FID is anticipated to occur in late July 2018 in conjunction with Meliwis FID and noting incremental capex is minimal and a reasonable expectation exists that FID occur, RISC considers the associated incremental production to be reserves and has included this in its forecasts.

In the Sampang PSC the Wortel field produces to the Oyong WHP. Whilst the Wortel field has a higher FTHP than the Oyong field, this offset somewhat by the 17 km distance from the Oyong WHP and back out effects are not seen with preferential production of Wortel. The Wortel field produces condensate and there is no evidence of declining CGR and as such condensate forecast assumes constant CGR and RISC considers this reasonable. With cessation of oil production from the Oyong field, condensate production from Wortel field is spiked back into the gas export line. Given the low condensate production rate and regular pigging of the gas export pipe line excessive liquid hold up is not anticipated to occur.

Current gas production from the Oyong WHP free flows to the Santos Onshore Processing Facility (OPF) in Grati with landing pressure ranging from 250 to 90 psi with a minimum gas flow to customers of 10 MMscf/d. As discussed in the Contingent Resources section, the proposed SSP Phase-2 will involve reduction in the Grati onshore receiving terminal to 10 psi.

RISC notes that 2018 production in fields such as Maleo has been significantly above the 2018 budget production forecast. RISC has reviewed Santos' revised 2018 field forecasts and modified Santos' simulation forecasts to match actual 2018 production to date. This was achieved by scaling field sales gas rates based on field gas potential. RISC's scaling did not alter volumes produced prior to reaching production constraints. RISC's sales gas production profiles are shown in Figure 3-15 and Figure 3-16.

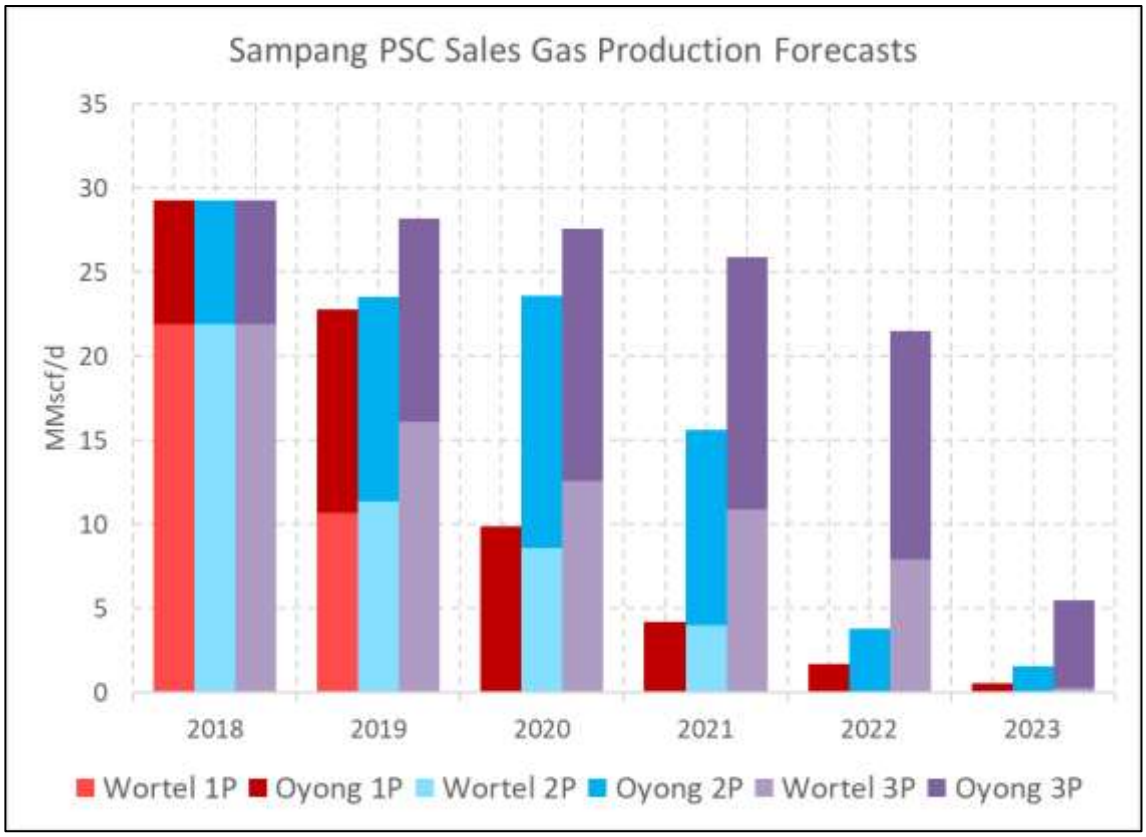

Figure 3-15: Sampang PSC Sales Gas Production Forecasts

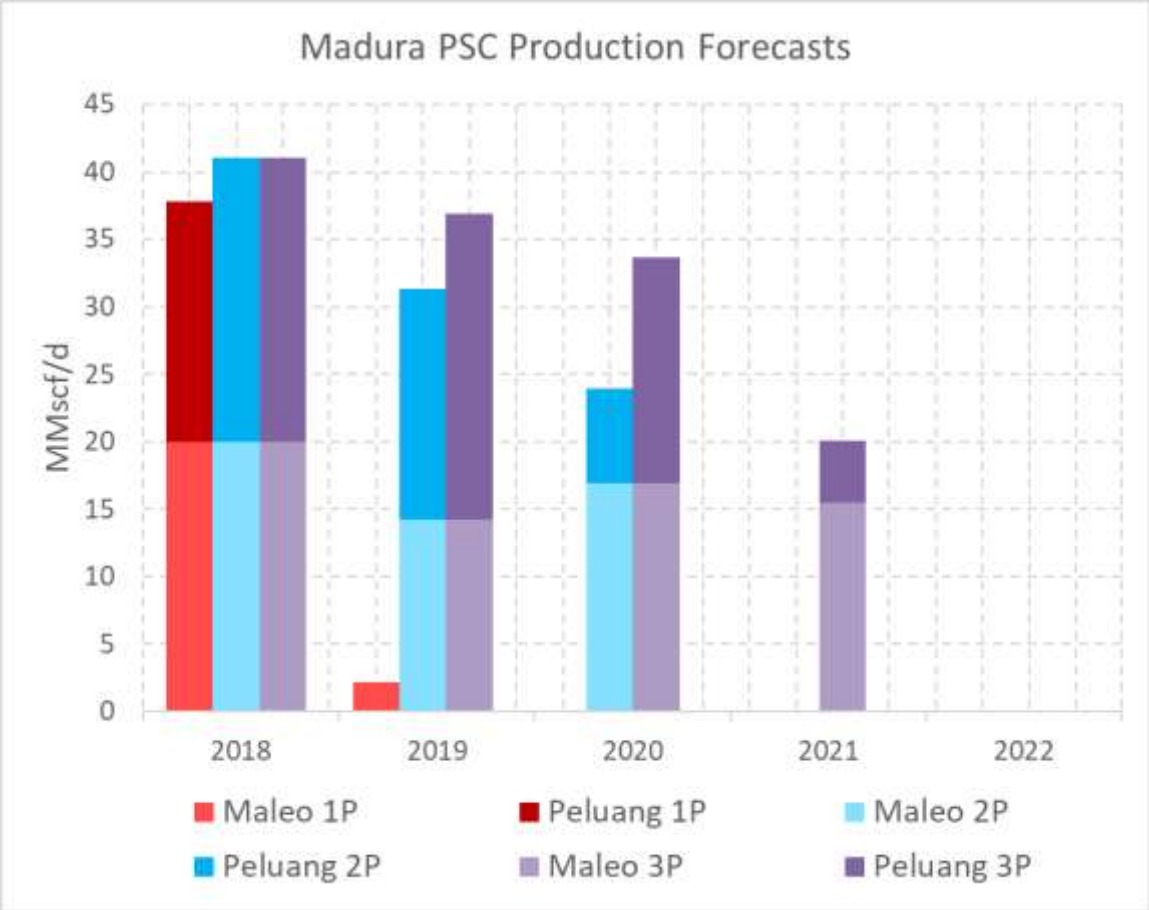

Figure 3-16: Madura Offshore PSC Sales Gas Production Forecasts

3.4.2. Resource Summary

RISC reviewed the estimates of gas consumed in operations (i.e.: fuel, flare and losses) by comparing total gas rates against sales gas rates and notes the estimates of gas consumed in operations in the simulation models are in line with historical gas consumed in operations at PSC levels.

Table 3-6: Sampang PSC Gross reserves as at 1 January 2018

Gas and Condensate	Unit	Gross Reserves		
		1P	2P	3P
Wortel Field Sales Gas	Bscf	10.6	15.1	19.2
Wortel Field Condensate	MMstb	0.0	0.0	0.0
Oyong Field Sales Gas	Bscf	10.0	15.0	20.6
Total Sales Gas	**Bscf**	**20.6**	**30.1**	**39.8**
Total Condensate	**MMstb**	**0.0**	**0.0**	**0.0**

Notes:
1. Gross reserves are on 100% contractor entitlement basis and mid-price case.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas.
3. The notional reference point for gas is the Santos Onshore Processing Facility (OPF) in Grati.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

Table 3-7: Sampang PSC Net reserves as at 1 January 2018

Gas and Condensate	Unit	Net Reserves		
		1P	2P	3P
Wortel Field Sales Gas	Bscf	4.8	6.8	8.6
Wortel Field Condensate	MMstb	0.0	0.0	0.0
Oyong Field Sales Gas	Bscf	4.5	6.8	9.3
Total Sales Gas	**Bscf**	**9.3**	**13.6**	**17.9**
Total Condensate	**MMstb**	**0.0**	**0.0**	**0.0**

Notes:
1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The notional reference point for gas is the Santos Onshore Processing Facility (OPF) in Grati.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

Table 3-8: Madura Offshore PSC Gross reserves as at 1 January 2018

Gas	Unit	Gross Reserves		
		1P	2P	3P
Peluang + Maleo Fields Sales Gas	Bscf	10.9	28.3	38.5
Total Sales Gas	**Bscf**	**10.9**	**28.3**	**38.5**

Notes:
1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Gross reserves are on 100% contractor entitlement basis and mid-price case.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

Table 3-9 Madura Offshore PSC Net reserves as at 1 January 2018

Gas	Unit	Net Reserves		
		1P	2P	3P
Peluang + Maleo Fields Sales Gas	Bscf	7.4	19.1	26.0
Total Sales Gas	**Bscf**	**7.4**	**19.1**	**26.0**

Notes:
1. Sales Gas resources have been adjusted for shrinkage and fuel gas.
2. Net reserves are on a PSC entitlement basis and mid-price case.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.

3.4.3. Contingent Resources

Santos has identified several further development opportunities which are currently classified as Contingent Resources.

3.4.3.1. Oyong Sustainability Project Phase 2

Gas from the Oyong WHP free flows to the Grati onshore receiving terminal which limits the FTHP of Oyong field to approximately 250 psig. Santos has modified existing 1P, 2P and 3P simulation models and lowered the FTHP to 125 psig and reduced the inlet pressure at Grati onshore receiving terminal to 10 psig. This analysis indicates an additional 8.5 Bscf on incremental 2C production is achievable. Santos have classified this volume as a Contingent Resource under the Oyong Sustainability Project (SSP) Phase 2 and RISC supports this. Pre-FEED is currently ongoing with respect to the technical feasibility.

3.4.3.2. Maleo Tail Volume

With Meliwis anticipated to be online in Q2 2019, noting the minimum compression inlet rate of 12 MMscf/d it allows Maleo tail volumes to be produced down to a final Maleo field rate of approximately 6.5 MMscf/d. Whilst the initial Meliwis FTHP of approximately 1,200 psig is far higher than the MPP compression suction inlet pressure of 120 psig, Meliwis' initial production bypasses MPP compression to prevent backing out of Maleo production until Meliwis FTHP has declined. Santos has modified extended 1P, 2P and 3P simulation models to allow the Maleo field to produce to a minimum rate of 6.5 MMscf/d and this analysis indicates an additional 8.3 Bscf on incremental 2C production. Santos have classified this tail volume as Contingent Resources and RISC supports this.

3.4.3.3. Upper Mundu perforation Oyong Field

The estimated Contingent Resources are not material being less than 0.2 Bscf.

3.4.4. Meliwis Production Forecasts

Contingent Resource volumes are those carried by Santos, audited and adjusted by RISC where necessary. RISC has scaled the Santos 1C and 3C cases to reflect its view of the P90 and P10 GIIP. RISC's Meliwis Contingent Resource estimates and production forecasts as shown in Figure 3-17.

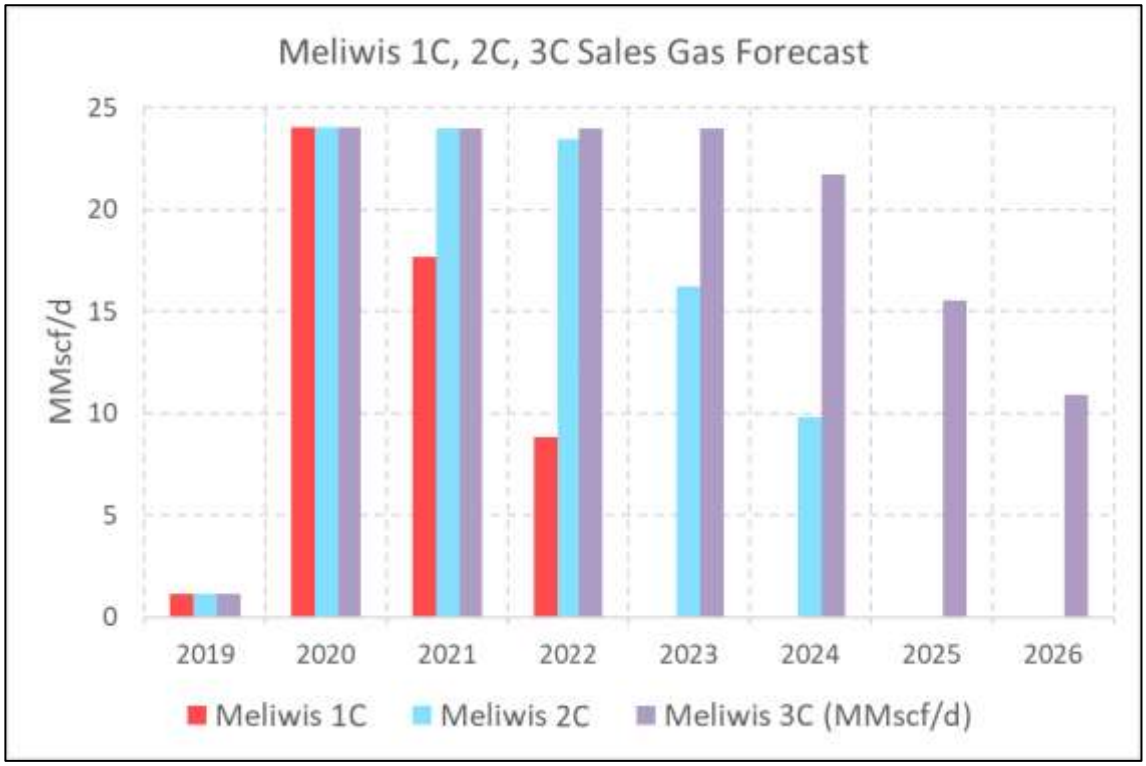

Figure 3-17: RISC Meliwis 1C, 2C and 2C Sales Gas Forecasts

Table 3-10: Meliwis Gross Sales Gas Production

Year	1C Annual Production (Bscf)	2C Annual Production (Bscf)	3C Annual Production (Bscf)
2019	0.40	0.40	0.40
2020	8.75	8.75	8.75
2021	6.46	8.75	8.75
2022	3.21	8.56	8.75
2023	-	5.91	8.75
2024	-	3.58	7.93
2025	-	-	5.67
Total Sales Gas (Bscf)	**18.82**	**35.95**	**49.00**

Notes:

1. Contingent Resources are stated on Gross 100% contractor entitlement basis and have not undergone economic limit testing.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas.
3. The notional reference point for gas is at the inlet to the East Java Gas Pipeline (EJGP).
4. Deterministic evaluation methods have been used.

3.5. Future Expenditure

3.5.1. Sampang PSC

The Wortel and Oyong fields are fully developed. Phase 2 of the Sampang Sustainability Project (SSP2) is a potential further capital project. This involves capital expenditure of approximately $10 million to lower the suction pressure at the Grati Onshore Compressor. However, this project has not been approved and therefore RISC do not include the project in our reserves valuation cases. No other capital expenditures are envisaged (exploration related expenditure is outside the scope of this report).

Operating expenditure is budgeted to be $22 million in 2018. RISC estimate it will remain at around this level in 2019 before reducing slightly to approximately $20 million/year at end of economic life.

Santos advise all abandonment liabilities to have been met, therefore no further provision for abandonment is required.

3.5.2. Madura PSC

The Maleo and Peluang fields are fully developed. The only anticipated capital expenditure is approximately $2 million to restage the Maleo compressor. FID for this project is anticipated in July 2018.

Capital costs for a Meliwis development are estimated to be approximately $70 million for a single well drilled from a WHP tie-back to Maleo. FID is expected in Q3 2018 with start-up late 2019.

Operating expenditure is budgeted to be $33 million in 2018. RISC estimate this will increase to $36 million/year when Meliwis comes online before reducing slightly to approximately $30 million/year at end of economic life.

Santos advise all abandonment liabilities to have been met, therefore no further provision for abandonment is required other than approximately $10 million for Meliwis well P&A and facility decommissioning.

4. Vietnam - Block 12W

4.1. Introduction

4.1.1. Asset description

Block 12W is located offshore Vietnam in the Nan Con Son Basin in a water depth of approximately 95 m (312 ft.) with Premier Oil operator of the PSC. The location of the PSC, fields and relevant working interests are detailed in Figure 4-1.

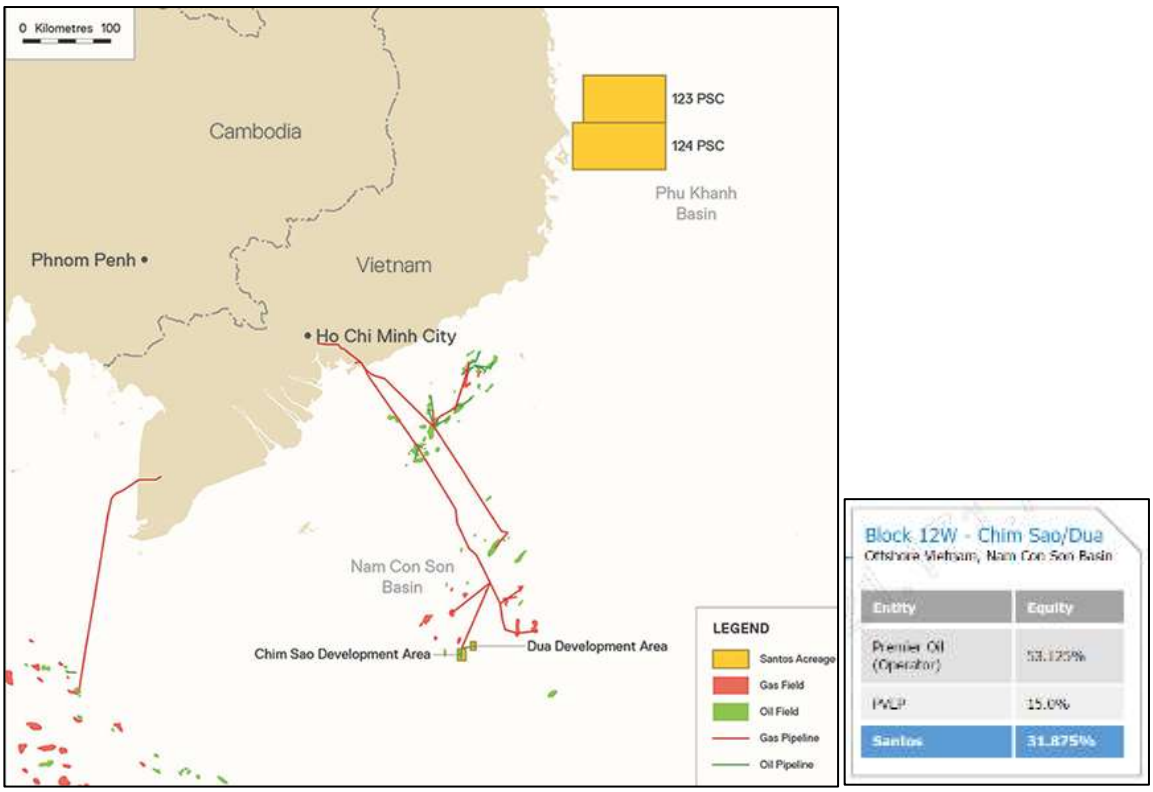

Figure 4-1: Location of the 12W PSC, Vietnam

Block 12W contains the producing Chim Sáo and Dua oil and gas fields. Dua is approximately 20 km from Chim Sáo. Chim Sáo field is a three-way, dip closure trending north-south, with fault closure to the west. It was discovered by wells 12E-CS-1X and 12E-CS-1XST1 and contains oil and gas bearing reservoirs in fluvio-deltaic to shallow marine 'Middle Dua' sands of Miocene age. The main reservoirs are MDS1, MDS5 and MDS6 sands.

The Dua field was discovered in 1974 by Pecten with Dua-1X well. The Dua-2x appraisal well drilled in 1975 was a dry hole. Well 12-A-1X drilled to the south of the structure was also dry. In 2006, Premier drilled Dua-4x, -4xST1, -4xST2 and 5x-RE wells to further delineate the field. Dua Field is split into north and south fault blocks separated by a major east-west trending fault. A three-way dip closure forms the down dip limit of the field to the north, west and south.

Dua contains oil and gas bearing reservoirs in the fluvio-deltaic to shallow marine 'Middle Dua' sands of Miocene age. Main reservoirs are MDS1 & MDS2 in Dua North and MDS3 in Dua South. In 2014, Dua-01, Dua-02 and Dua-03 began producing via subsea tie-back to Chim Sáo, peaking at 9,000 bopd.

Both fields produce through the leased Lewek EMAS FPSO. Chim Sáo produces through thirteen (13) producers to a Well Head Platform with Dua producing through three (3) subsea tiebacks approximately 17 km from the FPSO. The Chim Sáo field is under water injection with seven (7) injectors with the instantaneous voidage compensation (IVC) exceeding 100% since 2014.

Gas is exported to the Dinh Co Terminal via a 96 km pipeline that connects to the Nam Con Son pipeline. Gas is sold to PetroVietnam for domestic power generation.

The Chim Sáo field commenced oil production in 2011 with the Dua field subsea tieback online in 2014. Cumulative gross production to year end 2017 (YE17) was 54.8 MMstb (Chim Sáo: 51.6 MMstb, Dua: 3.1 MMstb) with sales gas of 32.8 Bscf. Gross average 2017 production was approximately 27,000 stb/d oil and 25 MMscf/d of associated gas.

A site visit was not carried out as nothing was discovered in the Data Room that made a site visit necessary. Premier Oil have demonstrated competence and capability and have a record of performance that RISC is satisfied with.

4.1.2. Regional Geology

The Nam Con Son Basin formed in the Upper Oligocene in response to the opening of the South China Sea, Figure 4-2. The syn-rift Upper Oligocene Cau Formation is the principal source rock in the basin. Post-rift clastics dominated by tidal delta complexes were deposited from the Upper Oligocene through to the Late Miocene. The post-rift clastic section includes the primary reservoirs within the Chim Sáo and Dua fields are the Middle Dua Sands (MDS) of Lower Miocene age and the Upper Dua Sands (UDS) of Middle Miocene age. The structural closures of Chim Sáo and Dua were formed during inversion and transpressional movement within the Middle Miocene. A chronostratigraphic chart for the Nam Con Son Basin highlighting the MDS and UDS sands is presented in Figure 4-3.

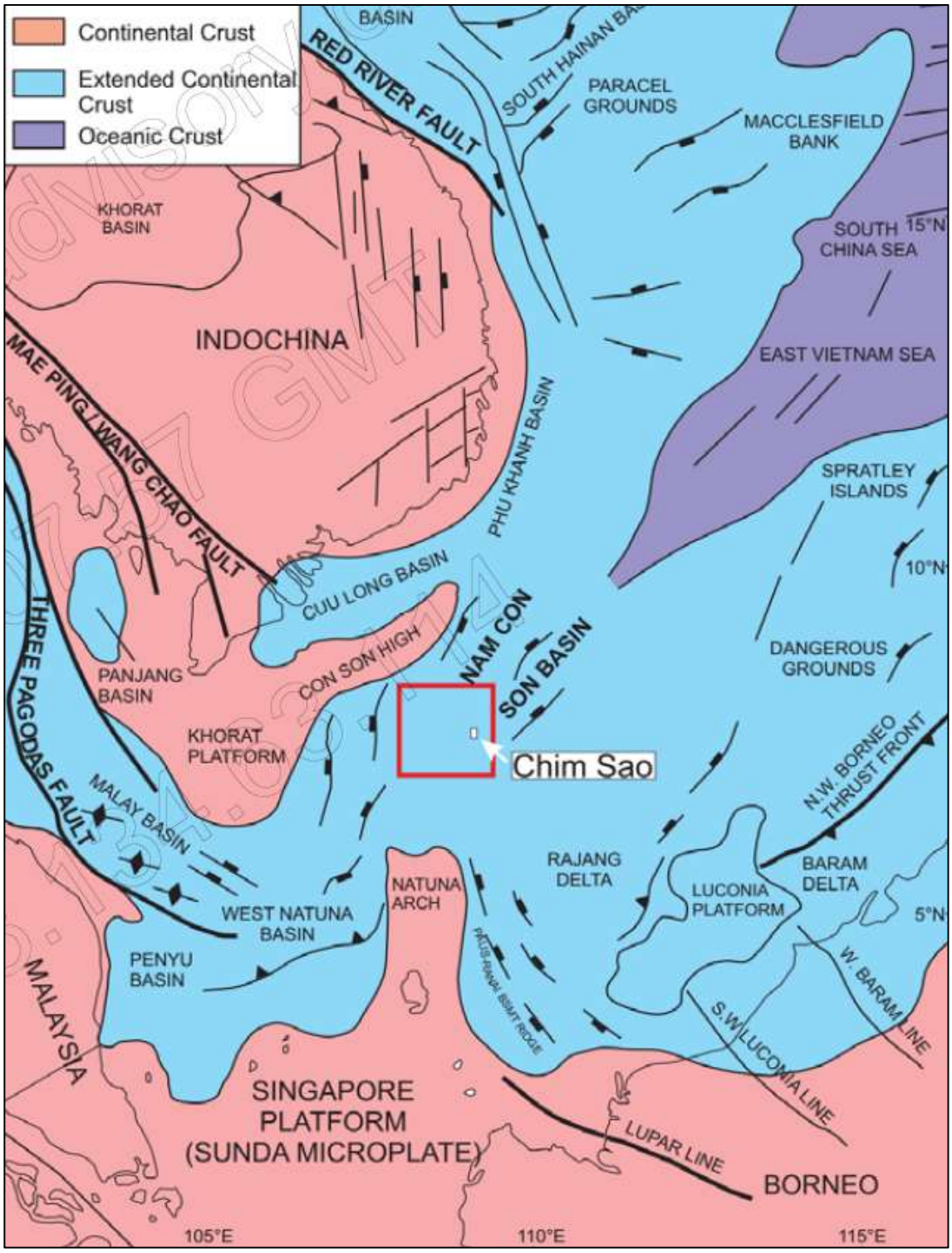

Figure 4-2: Location of the Nam Con Son Basin (Oolithica 2016)

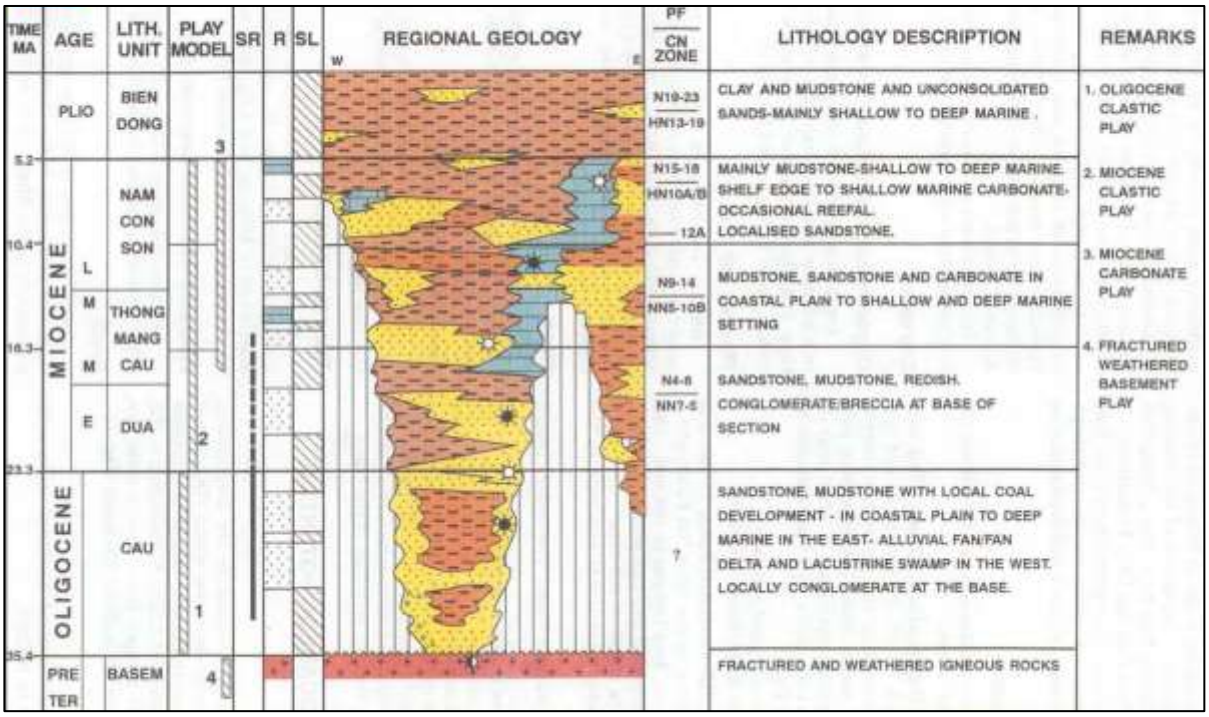

Figure 4-3: Chronostratigraphic chart of the Nam Con Son Basin (after Tin & Ty[3])

[3]Nguyen Trong Tin & Nguyen Dinh Ty, Petroleum geology of the Nam Con Son Basin, Vietnam Petroleum Institute, 1994

4.2. Subsurface interpretation

Three separate accumulations exist in Block 12W. Chim Sáo is the main producing field. Chim Sáo is a north-south trending three -way dip closure with fault closure to the west. The reservoirs accessed are the MDS1, MDS5 and MDS6. Chim Sáo NW is a developed fault block northwest of Chim Sáo field. The reservoirs accessed are the Intra Mang Cau (IMC) 12, UDS1, UDS2 and UDS3. The Dua field is 17 km northeast of the Chim Sáo field. The reservoirs accessed are the MDS1, MDS2, MDS3 and MDS6.

4.2.1. Seismic interpretation

The Dua 3D seismic survey was acquired in 2005. The Chim Sáo 3D seismic survey was acquired in 2007. The seismic interpretation has been validated throughout the drilling campaigns across the fields.

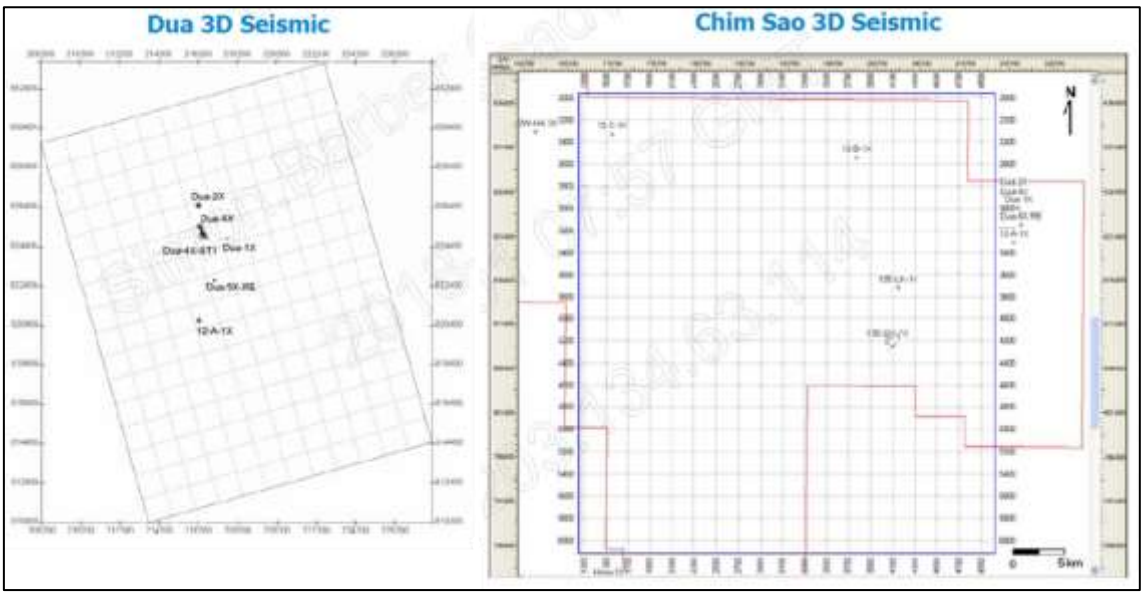

Figure 4-4: Dua and Chim Sáo 3D Seismic Areas

The quality of the 3D seismic data has been sufficient for amplitude work by Santos to characterise the higher quality reservoirs developed across the Chim Sáo Field such as the recognition of channel trends being developed in the MD5 reservoir.

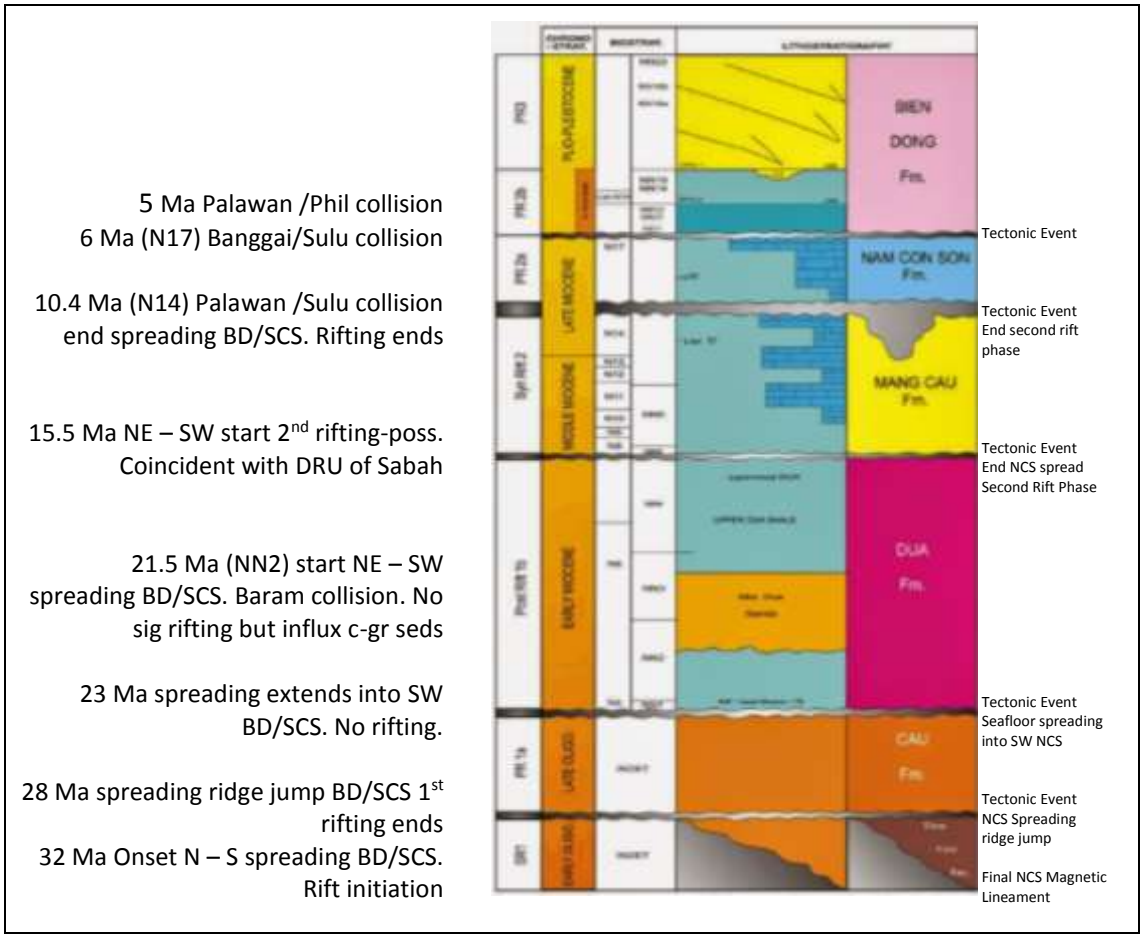

Figure 4-5: Stratigraphy (after Swiecicki & Maynard[4])

RISC has not had access to the seismic data volume over the Chim Sáo field and is basing its observations on material found in reports provided in the Santos Virtual Data room. Although this has limited our review, it has not made a material impact, as our review of the reserves estimates used production performance methods. However, the lack of access to seismic data has impacted RISC's ability to assess some potential volumes from infill drilling programmes and potential volumes which have not been drilled or where there are no plans by the operator to drill.

4.2.2. Reservoir description

The depositional environment of the MDS reservoirs is interpreted to be a fluvio-tidal delta system. The MDS reservoirs are widespread and can be mapped across the three fields. The earlier MDS units are characterised by low accommodation space-controlled deposition leading to sand rich intervals migrating seaward over relatively long distances. Later MDS units are more shaley and heterogeneous.

[4]Seismic Atlas of SE Asian Basins: Nam Con Son (http://geoseismic-seasia.blogspot.com/2014/04/nam-con-son.html)

The depositional models for major producing reservoirs of MDS and MD6 were based on integration of core and cuttings studies, together with FMI, log correlation, seismic-stratigraphic analysis and RMS seismic amplitude maps. The main sand input axis is interpreted to have been oriented broadly west-east and located in the south of the Chim Sáo field, Figure 4-6 and Figure 4-7.

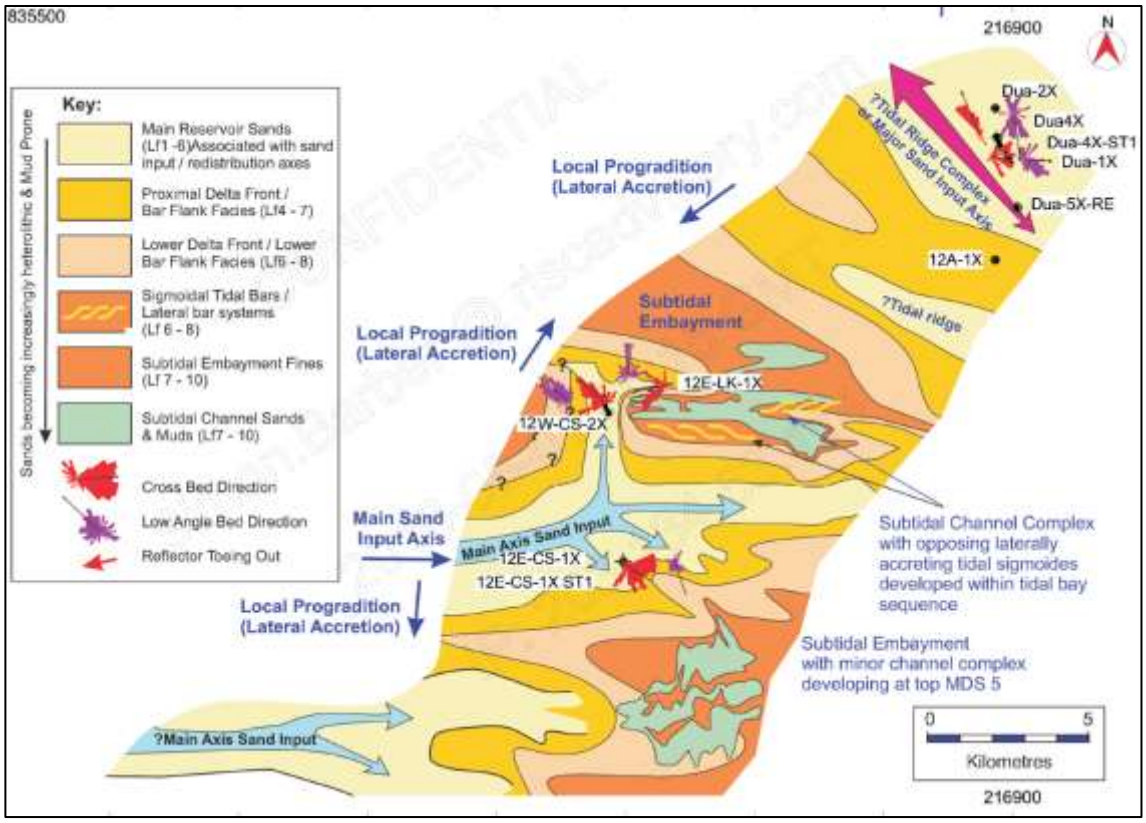

Figure 4-6: MD5 Depositional Facies Map[5]

[5] Oolithica Geoscience Ltd Geological Model Concept Review for MDS Static Model Rebuild Chim Sáo Field, Offshore Vietnam

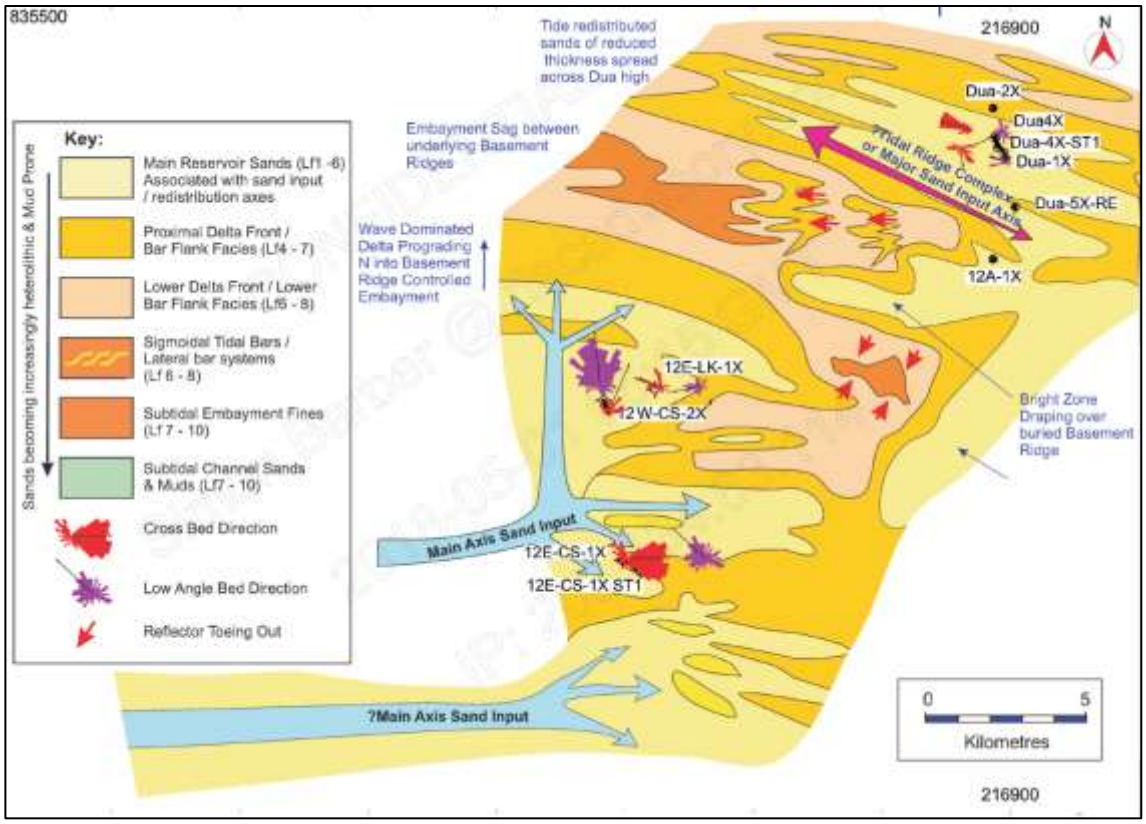

Figure 4-7: MD6 Depositional Facies Map[5]

The MDS1 and MDS0 reservoirs have been less studied. The 2016 model and report by subsurface consultants Oolithica[5] integrated the limited core from 12W-CS-2X well and petrographic data and interpretation of twenty-two existing wells into an updated static model.

A marked north-south facies change is noted across the field in the MDS1 with more sand prone facies predominant in the south of the field. Review of the inverted seismic clay volume led Oolithica to the interpretation that the increased sand in the south of the field was a result of a significant incised valley fill complex in the south of the field. The interpreted channel belt appears to be broadly meandering from west to east, Figure 4-8.

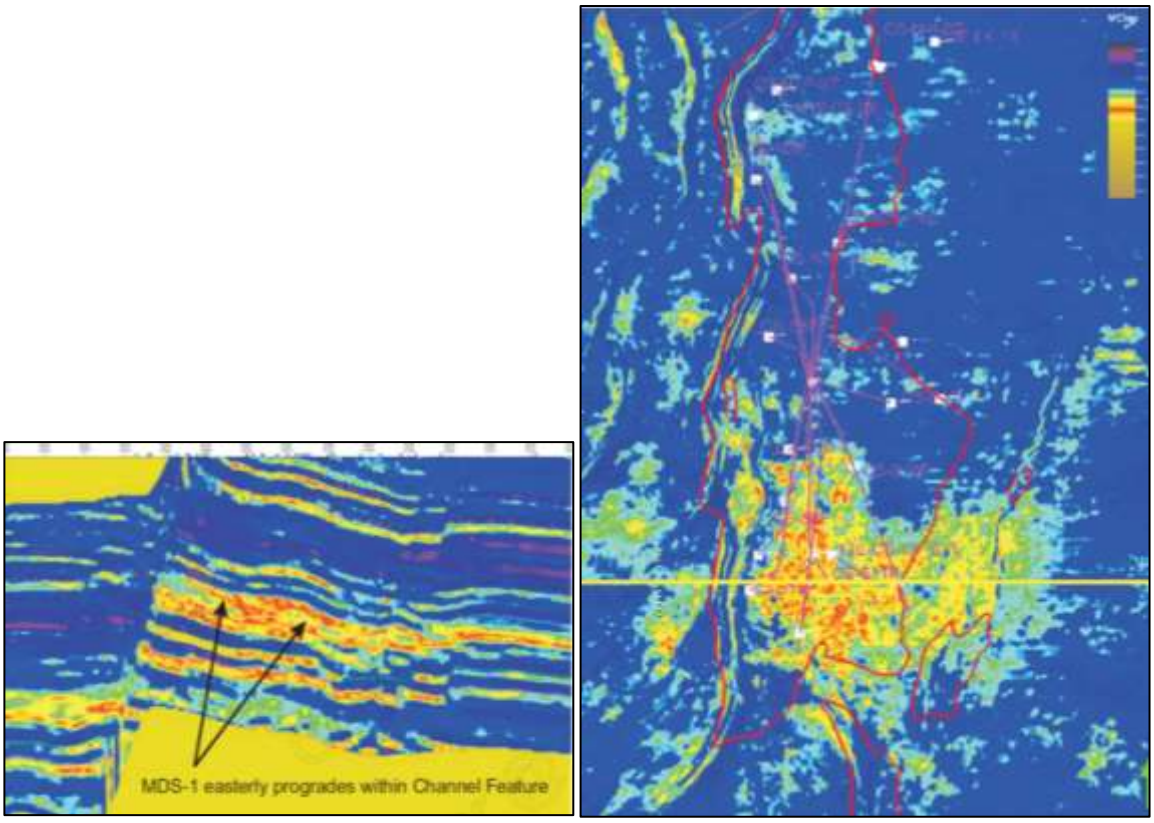

Figure 4-8: MDS1 Inverted Seismic showing incised channel feature in southern area of Chim Sáo field

The Oolithica reservoir model interpretation which has been the basis for the static models created over the field is considered reasonable. Santos provided a Petrel Static Model for the MDS reservoirs from November 2016 for RISC's review.

4.2.3. Petrophysical interpretation

RISC has reviewed petrophysical work undertaken by the Joint Venture over the Chim Sáo and Dua fields. A Petrophysical review of Chim Sáo was conducted by Santos in 2012. A petrophysical field study was conducted over Dua and Chim Sáo by Schlumberger on behalf of Premier in 2007.

The Santos 2012 study had access to core data through the MDS5 and MDS6 reservoir in three of the Chim Sáo wells. The study used well log data from eighteen wells. Wire line log data was available for six of the wells and LWD data was available for the remaining wells. The wireline data was environmentally corrected by Santos whereas the LWD data was environmentally corrected by the Contractor.

In the Santos 2012 study, the petrophysical uncertainties in derived porosity, permeability and water saturation have been constrained by the availability of core data from the MDS5 and MDS6 reservoirs. The only other cored interval was the water bearing MDS1 reservoir in CS-2X. No cores have been taken in any of the other Chim Sáo reservoir intervals.

Produced formation water has been collected and analysed. The Santos 2012 petrophysical study used a Rw of 0.435 ohmm and 0.403 ohmm at 24°C for the MDS5 and MDS6 reservoirs respectively. This was increased from previous studies which had Rw's of 0.206 ohmm at 25°C for the MDS5 and MDS6 reservoirs. This change in increased Rw resulted in an increase in interpreted water saturation (Sw) and a subsequent reduction in calculated oil saturation (So) across the MDS5 and MDS6 reservoirs.

The reservoir properties used in the resource estimate of Premier in 2016 are provided in Figure 4-9.

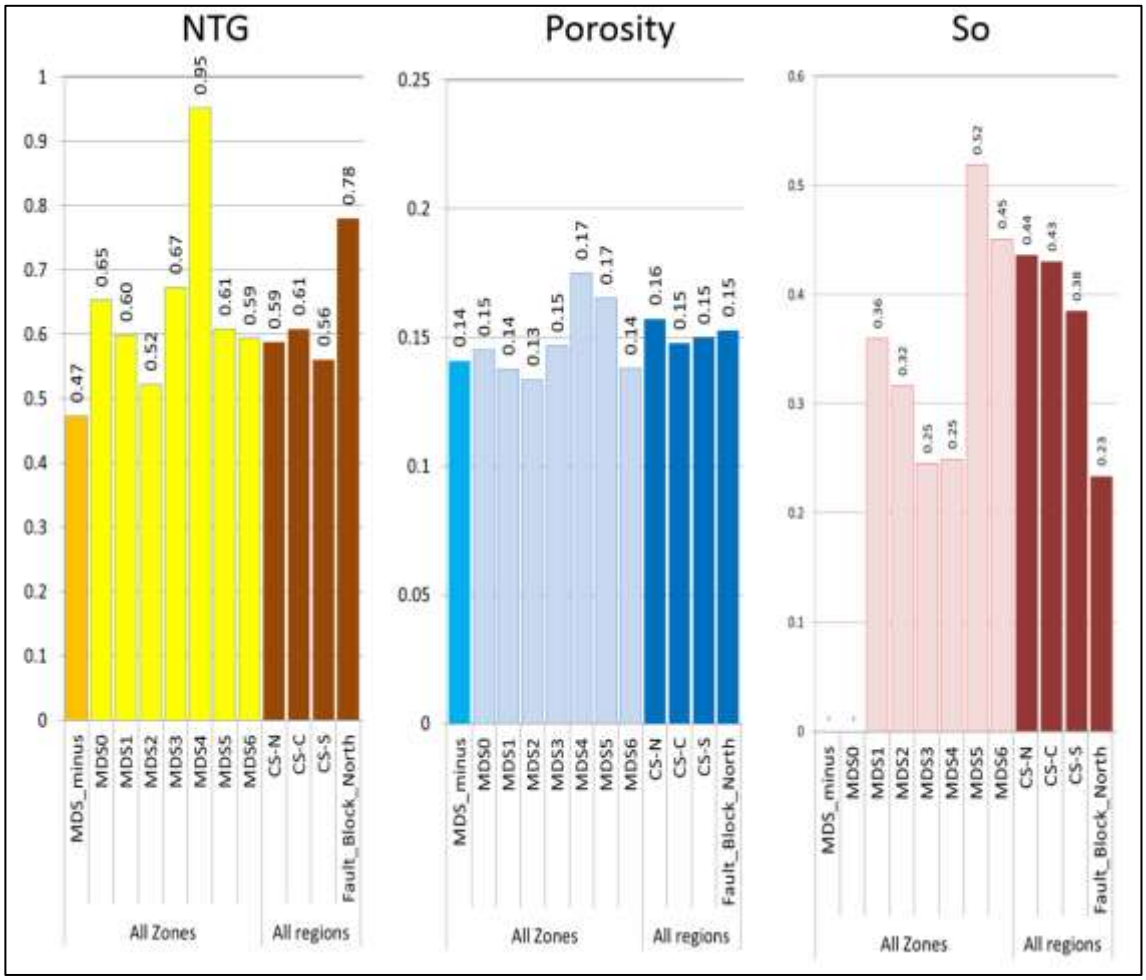

Figure 4-9: Reservoir properties used in the Premier 2016 STOIIP estimate for Chim Sáo

The interpretation of oil saturation will have an impact on the range of STOIIP. The current static model has no uncertainty in reservoir properties resulting in a very tight STOIIP range of (+/- 1.7%).

Ophir have used an oil saturation range of 45%/55%/65% for the MDS5 reservoir in their estimation of STOIIP (Figure 4-10). RISC supports this range.

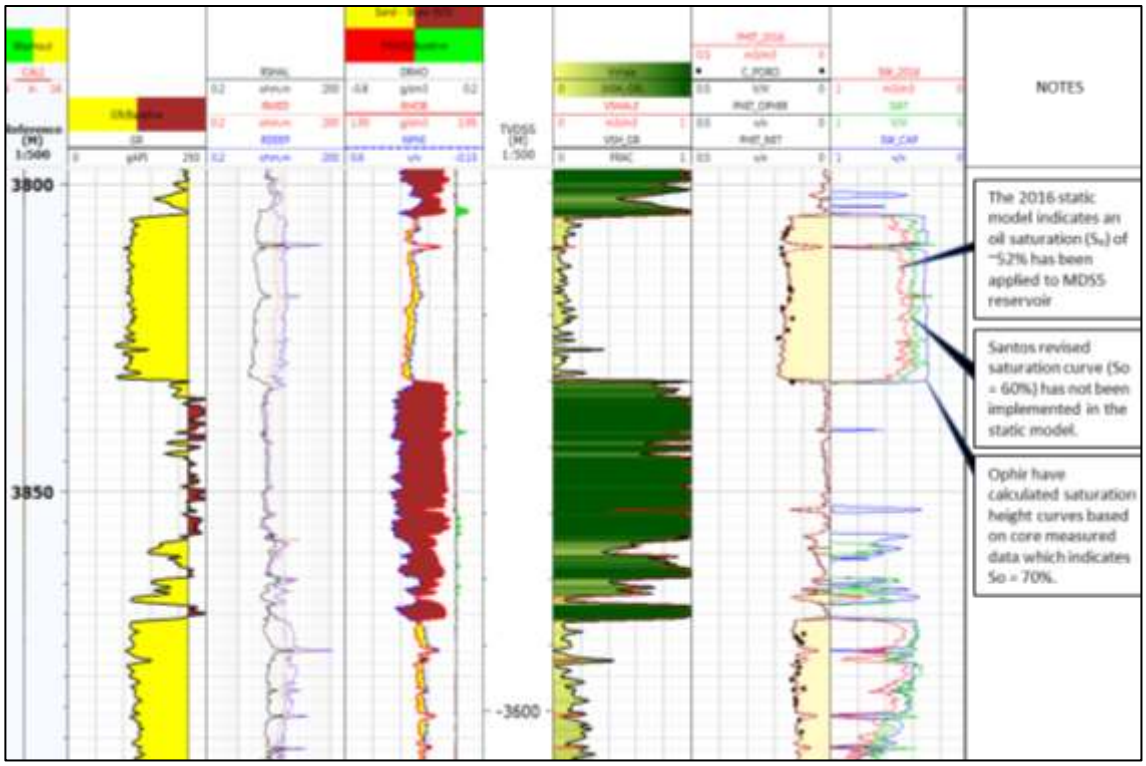

Figure 4-10: MDS5 Reservoir oil saturation interpretation

4.2.4. Fluid contacts

The pressure data indicates a free water level (FWL) from 3,601 m to 3,604 m TVDSS. However, the MDS5 reservoir has a FWL of 3,608 m TVDSS set by the mapped lowest closing contour Figure 4-11. The gas cap in the MD5 reservoir supported by production history matching indicates a GOC at 3,478 m TVDSS.

Although pressure data indicates a FWL from 3,637.1 m to 3,638.5m TVDSS, the MDS6 reservoir also has a FWL of between 3,620 m and 3,632 m TVDSS defined by well data and mapping uncertainty. The oil water contact has been set at 3,632 m TVDSS. The gas cap in the MD6 reservoir supported by production history matching indicates a GOC at 3,572 m TVDSS.

The MDS1 reservoir has a lowest Oil Down To (ODT) depth of 3,335 m TVDSS. The interpreted free water level (FWL) from a reservoir pressure versus depth plot of 3,330 m TVDSS exhibit three different oil gradients and suggests compositional variation. An alternative FWL of 3,325 m TVDSS can be made by using the S10P well aquifer points which are offset by 10 psi. The MDS1 reservoir does not have a gas cap.

A cross section across the Chim Sáo main field illustrates the fluid contacts, Figure 4-12 with the location of the cross section shown in Figure 4-11.

RISC supports the Santos interpretation of the Chim Sáo main field reservoir fluid contacts.

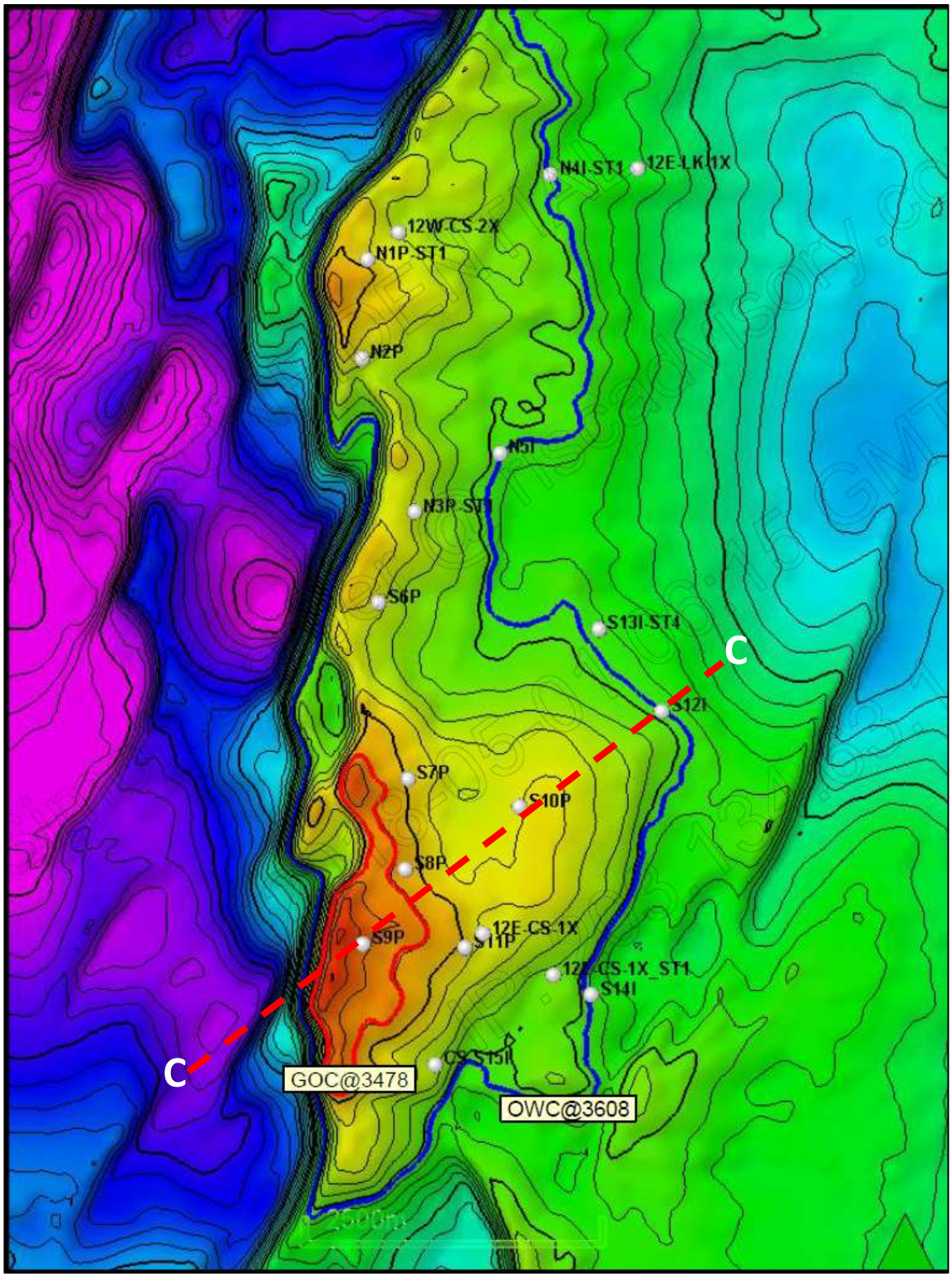

Figure 4-11: Chim Sáo MDS5 Reservoir Structure Map and Fluid Contacts

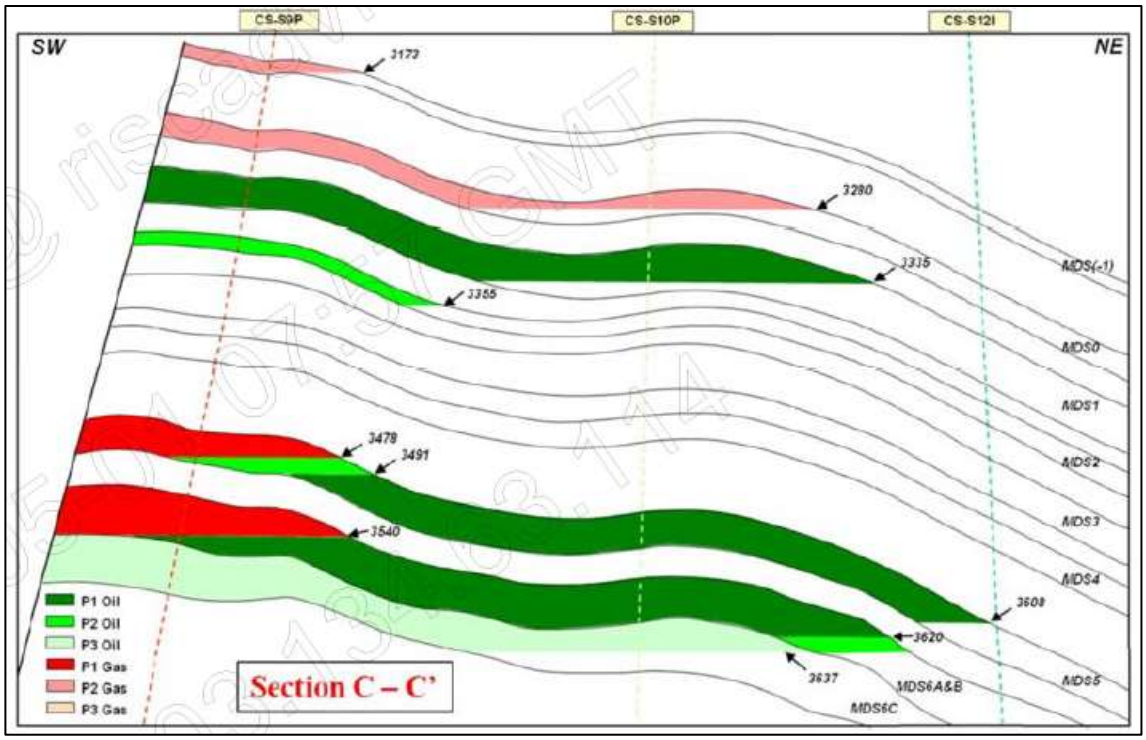

Figure 4-12: SW-NE Section across the Chim Sáo main field

4.2.5. Fluid properties

Chim Sáo fluid samples were taken using the MDT tool and during well tests on CS-1X, CS-2X, CS-S10P and CS-N17XP. The average fluid properties are shown in Table 4-1. The oil has high wax content of 20% and a pour point of 40°C.

Table 4-1: Chim Sáo Oil properties

Sand	Pressure	Bo	GOR	Viscosity	API Gravity
	psia	rb/stb	scf/stb	cp	
UDS1	4122	1.685	1170	0.307	42.6
UDS2	4223	1.815	1386	0.249	42.9
UDS3	4336	1.652	1089	0.459	40.3
MDS1	4737	1.524	950	0.352	40.3
MDS5	5067	1.594	998	0.414	42.2
MDS6	5137	1.573	913	0.381	41.9

As reported by the Operator, fluid sample analysis taken by MDT and well tests show a saturation pressure versus depth trend and a small gas cap in MDS5 and MDS6. The oil samples from the exploration and appraisal wells which were taken in the middle of the oil column were undersaturated. The saturation pressure versus depth trend became apparent after November 2011, when testing S9P well, which tested wet gas instead of oil at the crest of the field. The results of the gas analysis indicated a gas gravity of 0.83, a CGR of 55 stb/MMscf and about 6 mol% inert gases.

Dua oil properties are shown in Table 4-2.

Table 4-2: Dua Oil properties

Sand	Pressure	Bo	GOR	Viscosity	API Gravity
	Psig	rb/stb	scf/stb	cp	
MDS1	4590	1.704	1145	0.217	39.5
Upper Dua	4388	1.749	1247	0.333	39.1
MDS3	4490	1.956	1471	0.208	42.6

The Dua-1X well tested the gas in MDS1 sand but no PVT analysis of the gas has been reported. The only information on the quality of the gas reported has been that the gas has a gravity of 0.73. The measured gas and condensate rates during the test show a CGR of about 40 bbl/MMscf.

Primary stage separator gas from MDS5 has been analysed and contains 7 mol% CO_2, 0.2 mol% nitrogen and no H_2S. It has a gas gravity of 0.8 and HHV of 1,221 BTU/scf (1.29 PJ/Bcf).

4.3. Historical Production Analysis

The Chim Sáo field has produced since November 2011 and the Dua field since 2014. Gross cumulative oil production from both fields was 57.4 MMstb as of May 2018. The peak oil production rate was about 30,000 stb/d and the current rate is about 25,000 stb/d.

Chim Sáo field has thirteen producers and seven water injectors. One producer and injector are in Chim Sáo NW. Dua field has three producers. RISC has conducted decline curve analysis (DCA) on a well by well basis to estimate validate developed reserves. Details in section 4.4.2.

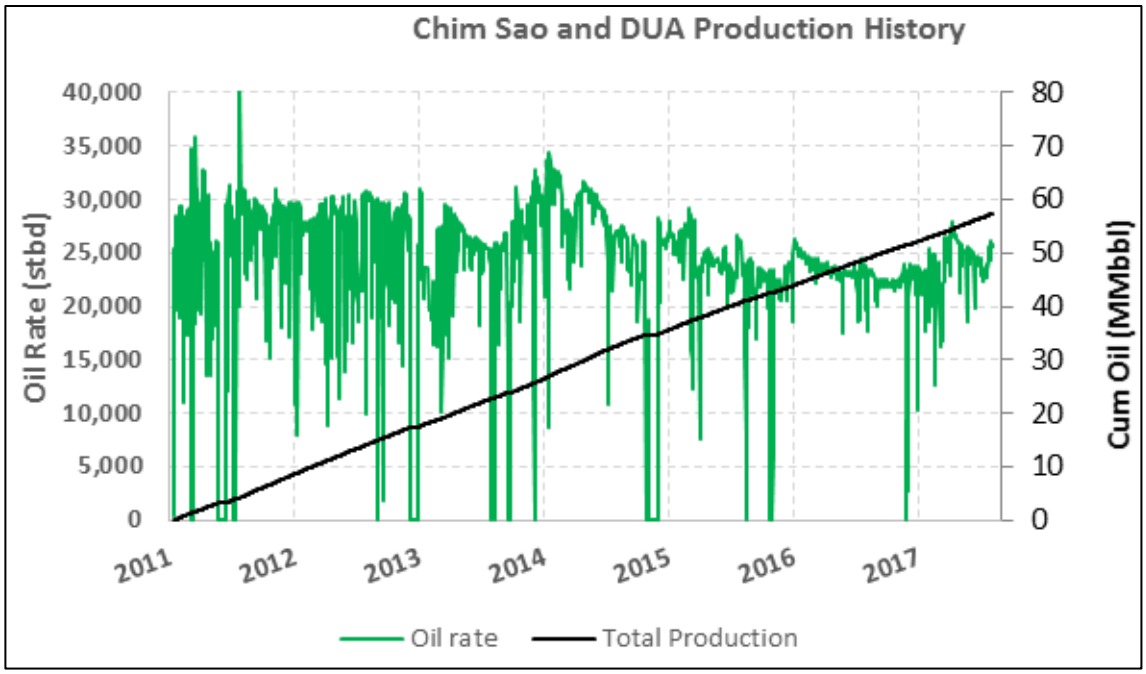

Figure 4-13: Chim Sáo and Dua Oil Production History

4.4. Resources

4.4.1. In-place resource volumes

The Operator's 2016 STOIIP estimates are shown in Figure 4-14. Approximately 94% of the Chim Sáo STOIIP is in the MDS5, MDS6 and MDS1 reservoirs.

RISC has independently estimated the STOIIP of the MDS5, MDS6, and MDS1 reservoirs using grids provided in the Premier 2016 static model and reservoir parameter ranges as provided in Figure 4-9 and supporting documentation found within the Santos Virtual Data room[6].

For the MDS5 reservoir, RISC calculated a STOIIP range of between 94 and 116 MMstb and a P50 of 105 MMstb compared with a 112.9 MMstb high case estimated by Premier.

The MDS5 top and base reservoir maps used for the RISC STOIIP estimate are provided in Figure 4-15. Similar mapping and volume work was carried out on the MDS6 top and base reservoir and the MDS1 top and base reservoir.

[6] 01.01 Project Jaguar – Block 12W Management Presentation.pdf

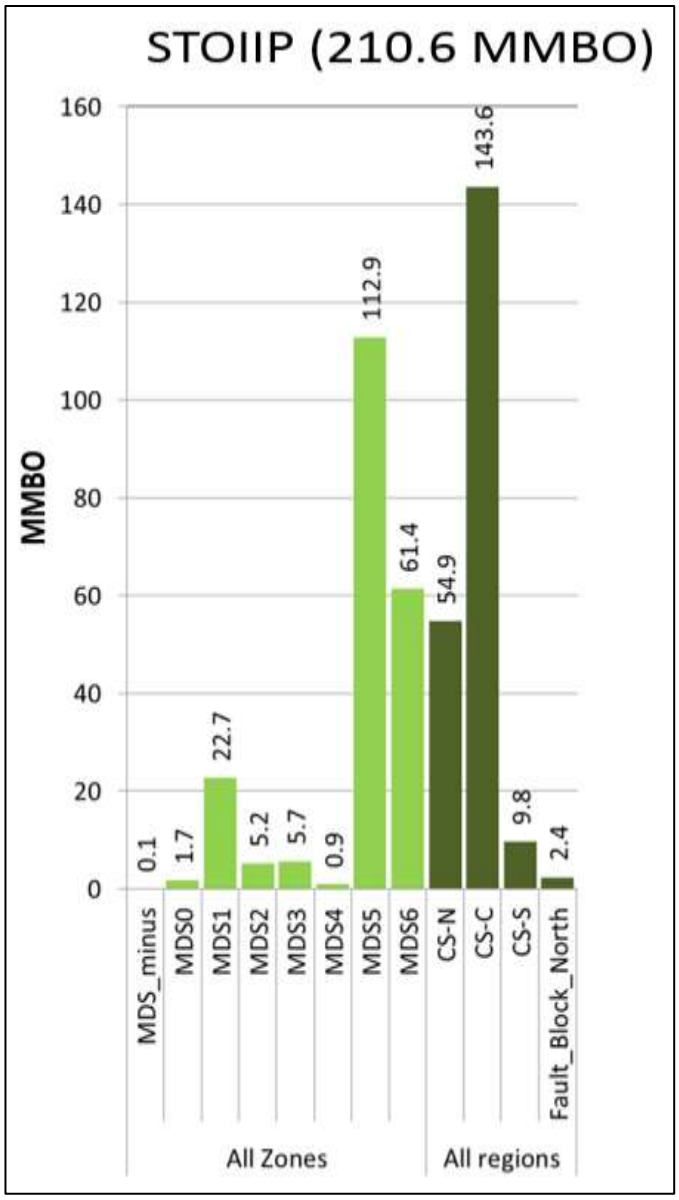

Figure 4-14: Premier 2016 break down by reservoir of Chim Sáo STOIIP estimate

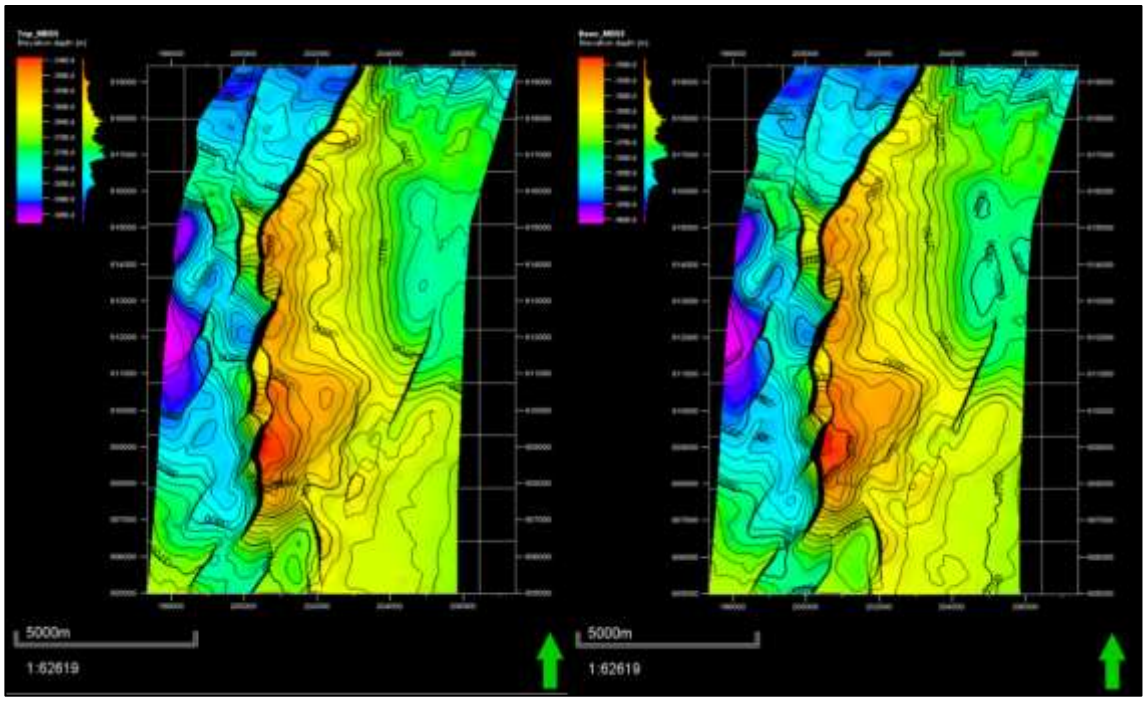

Figure 4-15: Top and Base MDS5 input maps for RISC STOIIP estimate

The reservoir parameter inputs and STOIIP estimate for the MDS5 reservoir are presented in Table 4-3.

Table 4-3: MDS5 STOIIP estimate and reservoir parameter inputs

RISC REP	P99	P50/Single	P1
FWL contact	3,601		3,608
Gas-Oil contact		3,478	
NTG		0.61	
So	45%	55%	65%
Porosity		0.17	
FVF (rb/stb)	1.597		1.704
RISC STOIIP (P90-P50-P10)	**94**	**105**	**116**

For the MDS6 reservoir RISC calculate a STOIIP range of between 46 and 62 MMstb and a P50 of 54 MMstb compared with a 61.4 MMstb high case estimated by Premier.

The reservoir parameter inputs and STOIIP estimate for the MDS5 reservoir are presented in Table 4-4.

Table 4-4: MDS6 STOIIP estimate and reservoir parameter inputs

RISC REP	P99	P50/Single	P1
FWL contact	3,620		3,632
Gas-Oil contact		3,572	
NTG		0.59	
So	35%	45%	55%
Porosity		0.14	
FVF (rb/stb)	1.572		1.652
RISC STOIIP (P90-P50-P10)	**46**	**54**	**62**

For the MDS1 reservoir RISC calculate a STOIIP range of between 14 and 19 MMstb and a P50 of 16 MMstb compared with a 23 MMstb high case estimated by Premier.

The reservoir parameter inputs and STOIIP estimate for the MDS1 reservoir are presented in Table 4-5.

Table 4-5: MDS1 STOIIP estimate and reservoir parameter inputs

RISC REP	P99	P50/Single	P1
FWL contact	3,320		3,335
Gas-Oil contact		NO GAS CAP	
NTG		0.59	
So	30%	35%	40%
Porosity		0.14	
FVF (rb/stb)	1.594		1.605
RISC STOIIP (P90-P50-P10)	**14**	**16**	**19**

4.4.2. Developed Reserves

RISC conducted decline curve analysis (DCA) on a well by well basis using data up to end August 2017 as more recent (by well) data was not made available until after RISC's analysis was completed. Both exponential and harmonic decline curves can be fitted to the production history. A 20:80 weighting between exponential and harmonic has been used for 1P reserves and a harmonic fit has been used to estimate 3P reserves. The 2P reserves case has used a best fit intermediate curve. Wells, CS S8P and CS S9P have not cut water or exhibited production rate decline yet. Recent (March 2018) well test data in combination with the operator's simulation results were used subjectively to guide the start of decline (water production) and an average well decline rate was applied.

Production data related to the two 2017 infill wells that came onto production late 2017 is limited to well test reports. Well 20P is producing dry oil at about 3,000 bpd. Well 5IP is producing dry oil at about 2,000 bpd. RISC has applied an average plateau period followed by an average decline rate guided by operator simulation results to forecast production in these wells.

The well decline curve forecasts were adjusted to match the field cumulative production at year end 2017 and the latest field data to end March 2018.

The total field decline was then compared with harmonic and exponential decline for sum of the wells. The low case (exponential) appeared conservative, therefore a 1P weighted average between the exponential and harmonic was provided for a better match to full field decline. Harmonic was retained as 3P and 2P is midway between 1P and 3P. The change in 1P reserves has only been applied to the base case of developed reserves.

The Vendor's base case model (CS+DUA+CS N5 IP+CS 20P) results were compared to RISC developed producing forecasts shown in Figure 4-16.

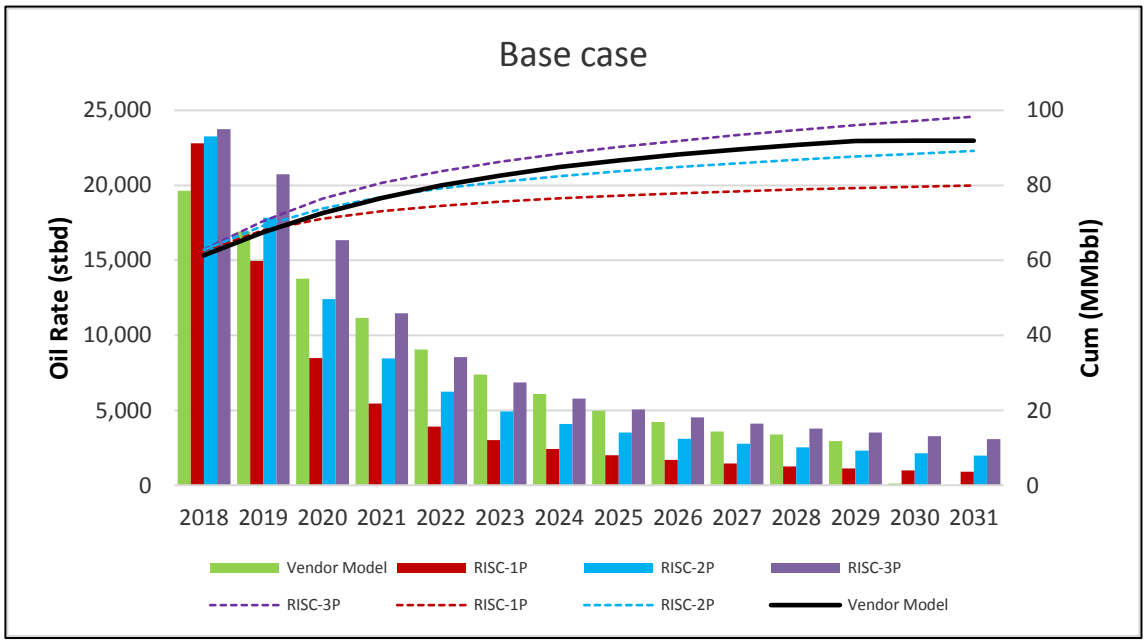

Figure 4-16: Base Case (developed producing reserve) production comparison of RISC vs Vendor model

The Vendor's forecast is based on mid-2017 history matched simulation and displays harmonic like decline. The Vendor's 2018 forecast is low compared to the 2018 year-to-date average of 24,800 bpd to 6 May 2018.

4.4.3. Undeveloped and Developed Non- Producing Reserves

Infill wells 20P and N5IP in 2017 were successful and another well (N21P) is planned for 2020. The 2017 wells have been estimated to provide an incremental 5,000 stb/d dry oil and 4.7 to 8.8 MMstb oil recovery per well. The 2020 infill well is expected to proceed given the 2017 success and has been classified by RISC as reserves. Further infill drilling may be matured but is classified as contingent resources at this stage.

The existing wells are largely completed on the MDS5 and 6 reservoirs with the potential to be recompleted on shallower reservoirs (MDS0, 1, 2, 3, 4) or have additional perforations added in the shallower intervals. In addition, well stimulation may also enhance well productivity.

Perforations in the UDS C3 reservoir were added to well N17XP in September 2016 increasing the wells oil rate by 2,000 bpd and adding 1 to 3 MMstb incremental reserves as shown in Figure 4-17.

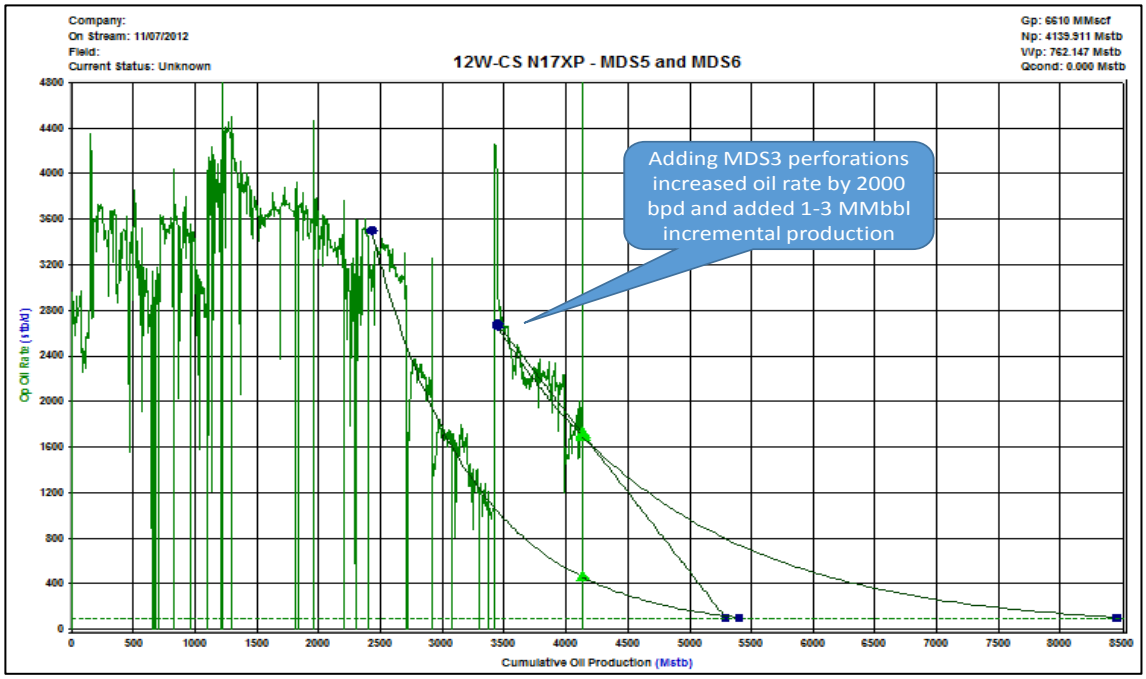

Figure 4-17: Benefit of adding UDS C3 perforations in well N17XP Sept 2016

Well N17XP is in Chim Sáo NW with the better quality UDS reservoir; the performance of these shallower reservoirs may be better than the shallower MDS reservoirs in Chim Sáo main.

Well 16XP discovered good quality reservoir and was completed on MDS1 reservoir (only) in Chim Sáo main. It has produced 2.1 MMstb to date with an estimated ultimate recovery of between 4 and 9 MMstb.

- In 2017 shallower perforations were successfully added to wells N1P and S9P in Chim Sáo main increasing oil production by 1,000 to 1,500 stb/d. There is not yet enough decline history to determine the additional incremental recovery. Subsequent well test indicates the boost to oil production in N1P was short lived but sustained in S9P.
- Shallower perforation in watered out well N2P restored production in 2017 to around 500 bpd but incremental recover appears limited.
- Therefore, two of the four wells with new shallow perforation (N17XP, S9P) have been successful.

RISC consider there is uncertainty in adding shallower perforations but estimate a mid-case volume of approximately 750 bopd per well and incremental oil production of 0.4 to 1.0 MMbbls per well.

The shallower MDS reservoirs MDS1-MDS4 in Chim Sáo main are estimated to contain 35 MMstb STOIIP with 23 MMstb in MDS1. Unlike the main MDS5 and MDS 6 reservoirs, these shallower reservoirs do not have a gas cap. Pressure support and recovery may be limited. The MDS1 reservoir has water injection from injector 18I.

The 2018 well work programme includes re-perforation of existing zones (to enhance productivity) and four firm wells with new perforations in shallower intervals. New shallower perforations in two other wells are contingent work. RISC assigns 3,000 bpd incremental oil and 1.6 to 4 MMstb incremental developed non-producing reserves to these four wells. RISC estimate that additional candidates for adding new shallower perforations will be identified in 2019 and includes the two contingent wells on the 2018 work programme.

Table 4-6: Developed Non-producing recovery from additional shallow perforations

Year	Well new completions	Parameter	1P	2P	3P
2018	4	Initial Rate	2,000	3,000	3,500
		EUR (MMbbl)	1.6	2.8	4
2019	2	Initial Rate	1,000	1,500	1,750
		EUR (MMbbl)	0.8	1.4	2

Ongoing scale clean-out and acid stimulation has less significant effect on well performance and is estimated to be included in the decline analysis.

2018 and 2019 well work along with the 2020 infill well (N21P) profiles were added to the base case (Section 4.4.2) and compared against the Operator's Vendor model. RISC has assumed production start-up for well work and infill well to be in middle of the year.

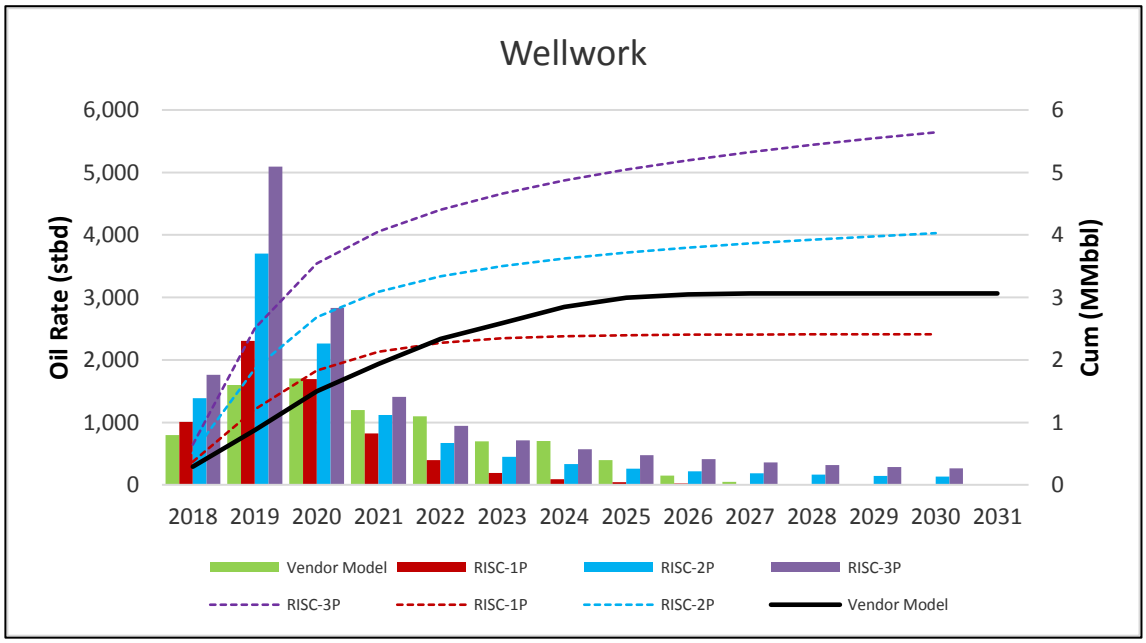

Figure 4-18: Well work production comparison of RISC vs Vendor model

RISC's incremental recovery estimates for well work in 2018 and 2019 are 2.4, 4.0 and 5.6 for 1P, 2P and 3P cases.

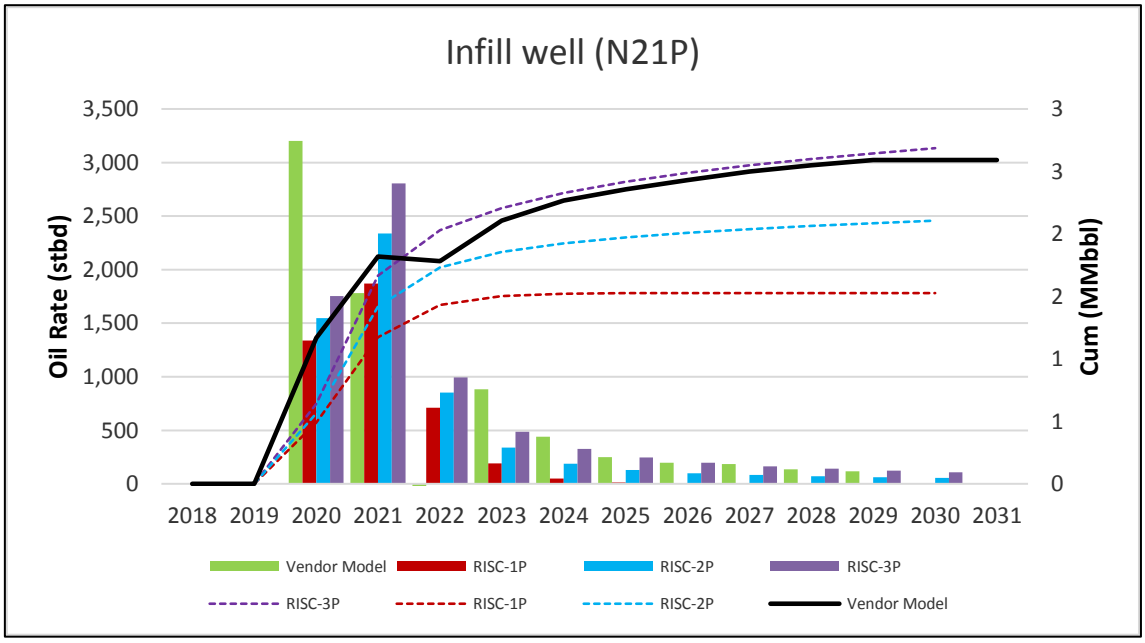

Figure 4-19: N21P infill well production comparison of RISC vs Vendor model

The Vendor forecast appears to assume start-up at the beginning of 2021. RISC assume a mid-2021 start-up with drilling expenditure in 2021. RISC has estimated 1P, 2P and 3P incremental reserves of 1.5, 2.1 and 2.7 MMbbl respectively for the 2020 infill well.

Figure 4-20 shows the total forecast (base + well work + infill).

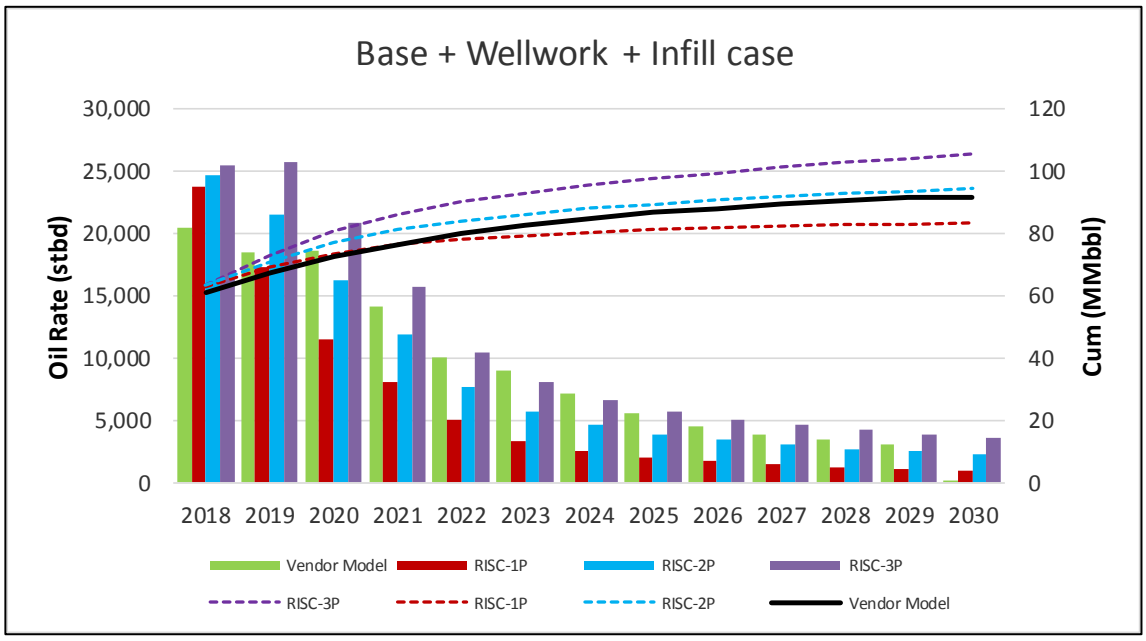

Figure 4-20: Total (Base case + Well work + N21P) production comparison of RISC vs Vendor model

Based on the good agreement between RISC's decline curve analysis and the reservoir simulation projections provided by the Vendor, RISC supports the Vendor model 2P recovery estimates on Chim Sáo and Dua Fields. However, RISC has generated its own 1P, 2P and 3P oil production forecasts that better reflect the 2018 production to date which has been higher than previously forecast.

The value of gas exports from Chim Sáo is small compared to oil production. Currently gas production is controlled to optimise oil production and minimise flaring. As gas production declines, gassy wells can be opened to maintain fuel gas requirements and some gas export.

RISC has estimated gas production using the simulated GOR adjusted to the latest production data. RISC has increased late time GOR and gas production in line with the Operators estimates.

Table 4-7: Block 12W Gross reserves as at 1 January 2018

Oil and Gas	Unit	Gross Reserves		
		1P	2P	3P
Total Sales Gas (Chim Sáo + Dua Field)	**Bcf**	**18.2**	**28.5**	**47.0**
Total Oil (Chim Sáo + Dua Field)	**MMstb**	**22.1**	**33.4**	**45.0**

Notes:
1. Gross reserves are on 100% contractor entitlement basis and mid-price case and exclude production beyond 2030.
2. Sales Gas resources have been adjusted for shrinkage and fuel gas as detailed in Section 5.4.
3. The notional reference point for gas is entry to Nom Con Son pipeline and for oil is exit FPSO.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.
6. Sales gas conversions (HHV) for the Chim Sáo and Dua fields are 1.29 PJ/Bscf.

Table 4-8: Block 12W Net reserves as at 1 January 2018

Gas and Condensate	Unit	Net Reserves		
		1P	2P	3P
Total Sales Gas (Chim Sáo + Dua Field)	**Bcf**	**5.8**	**9.1**	**15.0**
Total Oil (Chim Sáo + Dua Field)	**MMstb**	**7.0**	**10.6**	**14.3**

Notes:
1. Sales Gas resources have been adjusted for shrinkage and fuel gas as detailed in Section 5.4.
2. Net reserves are on a PSC entitlement basis and mid-price case and exclude production beyond 2030.
3. The notional reference point for gas is entry to Nom Con Son pipeline and for oil is exit FPSO.
4. Deterministic evaluation methods have been used.
5. Additions beyond the field level have all been made arithmetically.
6. Sales gas conversions (HHV) for the Chim Sáo and Dua fields are 1.29 PJ/Bscf.

4.4.4. Contingent Resources

Additional infill drilling and re-completions to shallower reservoirs may generate additional contingent oil resources. The STOIIP estimated by RISC and success of 2017 infill wells suggests further infill drilling may be worthwhile. However, such projects have not be identified or quantified by the Operator. RISC estimate two further infill wells recovering 2 MMstb each as contingent resources.

Contingent resources are related to potential gas blowdown in Dua and Chim Sáo fields near the end of oil production. The operator proposes:

- Blow down of Dua from 2021 using a sidetrack of Dua 2P with a shallower completion generating incremental contingent gas and oil resources;
- Potential blowdown of Chim Sáo using existing wells from 2025. This results in a loss of oil production but incremental gas production. As such the project is unlikely to go ahead.
-

RISC has reviewed the Operators production forecasts for these opportunities, consider then reasonable and include them as contingent resources, Table 4-9.

Table 4-9: Gross Chim Sáo Contingent Resources (100%)

Contingent Resources	2C Oil (MMbbl)
Further infill	4.0
Blowdown	1.5
Chim Sáo Depressurisation	-1.5
Beyond Economic Limit	2.5
Total	**6.5**

5. Development Plan and Costs

5.1. Development Plan

The Chim Sáo field is developed with a 16-slot wellhead platform tied back to the leased Lewek EMAS FPSO. The platform has twelve single slots and four dual slots allowing twenty wells to be drilled from the platform. Chim Sáo has thirteen production and seven Injection wells. The Dua field is producing through three subsea wells tied back approximately 17 km to the FPSO. The FPSO is moored in 96 m of water and is located approximately 350 km from land. Gas is exported to the Dinh Co Terminal via a 96 km 10" diameter pipeline that connects to the 26" Nam Con Son pipeline. Gas is sold to PetroVietnam for domestic power generation.

5.2. Capital costs

The valuation encompasses the Base Case (no further development) + Well work + Infill well. The infill well is estimated to cost $20 million. The well work is classified as operating cost.

RISC has made an allowance of $25 million in 2020 for life extension of the wellhead platform and infield lines as these have a design life of ten years and were installed between 2010 and 2011. Other elements of the production system have a longer design life.

5.3. Operating costs

Production operations costs are budgeted to be $111 million in 2018 plus $7 million of support costs. The largest component of operating cost is the FPSO lease rate. RISC has reviewed the contract rate and has seen reference to a production linked FPSO charge which is modelled in the cost forecast. Other operating costs have been held constant throughout field life.

The other component of operating costs is 'well work' which consists of relatively low cost well intervention operations such as perforating, scale removal and acid stimulation. The total cost of the campaign is estimated to be $6 million over the period between 2018 and 2025.

5.4. Abandonment costs

RISC has reviewed a range of estimates for total well P&A and facility abandonment and removal costs for Chim Sáo and Dua from between approximately $170 million to over $200 million. RISC has used an estimate within this range for the economics and Santos advise $141 million gross has already been paid at end 2017 with the balance outstanding. These costs are incurred on a unit of production basis.

6. Commercial

The economic model used to calculate Net Present Values (NPV) for the assets under review in this CPR have been audited by RISC (UK) Limited and an independent third party and is considered to be fit for purpose by all parties.

A summary of the parameters used in the economic valuation can be found in the following sections.

6.1. Summary of Economic Parameters

Economic assessment of the fields has been based on estimates of future production of assessed reserves/resources, forecasts of future capital and operating costs, and the PSC terms. The economic models and data input have been based on 100% project cash flows. Santos's share of value of each asset has then been determined by applying Santos's working interest to the resulting project NPVs.

- Hydrocarbon volume entitlement has been calculated according to the terms of the PSC consistent with industry practice for reporting reserves for interests held under PSCs.
- RISC has not applied adjustments for risk.
- RISC has not valued the hedges.
- RISC has relied on independent legal opinion that Block 12W PSC shall expire in 2030 and has used this date to calculate volumes and values.
- Block 12W original PSC effective November 2000 was for a 25-year term for oil and a 30-year term for gas. The PSC was amended in 2007 to give a 30-year term without differentiation between oil and gas.
- RISC has relied on an independent third party to verify the treatment of Corporate Income Tax and the cross checking of this against historical financial statements of Corporate Income Tax payments filed with the Vietnam tax authorities.
- RISC has verified the Madura Offshore PSC contract terms were appropriate.
- Madura Offshore PSC signed 4 December 1997.
- Madura Offshore PSC Term: 30 years from Effective Date.
- RISC has verified the Sampang PSC contract terms were appropriate.
- Sampang PSC dated 4 December 1997.
- Sampang PSC Term: 30 years from Effective Date.
- The effective date for valuation is set at 1 January 2018.
- Inflation set at 2.5% nominal[7]. 2.5% p.a. applied to costs consistent with the nominal oil price forecast.
- Project NPVs are reported at a discount rate of 10% nominal.

[7]Nominal = Money of the day. Nominal prices, sometimes called current dollar prices, measure the dollar value of a product at the time it was produced. Real prices are adjusted for general price level changes over time, i.e., inflation (escalation) or deflation (de-escalation).

6.1.1. Oil Price

A premium to Brent quality oil of $3/barrel has been advised by a third party for modelling Chim Sáo oil production. This is based on an average premium to Brent realized in the last twelve months April 2017 to May 2018. The realized historical premium for Chim Sáo ranges from a low of $0.7/barrel in October 2015 to as high as $7.6/barrel in July and April 2012. RISC has used $3/barrel long term.

- A total of five oil price scenarios have been run (Figure 6-1):
  1) Average Brent oil price of $70/bbl in 2018 and $70/bbl flat in nominal terms long term (labelled '$70 LT' long term in tables);
  2) Average Brent oil price of $70/bbl in 2018 and $65/bbl flat in nominal terms long term from 2020 (labelled '$65 LT' long term in tables);
  3) Average Brent oil price of $70/bbl in 2018 and $60/bbl flat in nominal terms long term from 2021 (labelled '$60 LT' long term in tables);
  4) Average Brent oil price of $55/bbl in 2018 and $55/bbl flat in nominal terms long term (labelled '$55 LT' long term in tables);
  5) Average Brent oil price of $51/bbl in 2018 and $54/bbl flat in nominal terms long term from 2021 (labelled '$54 LT' long term in tables).

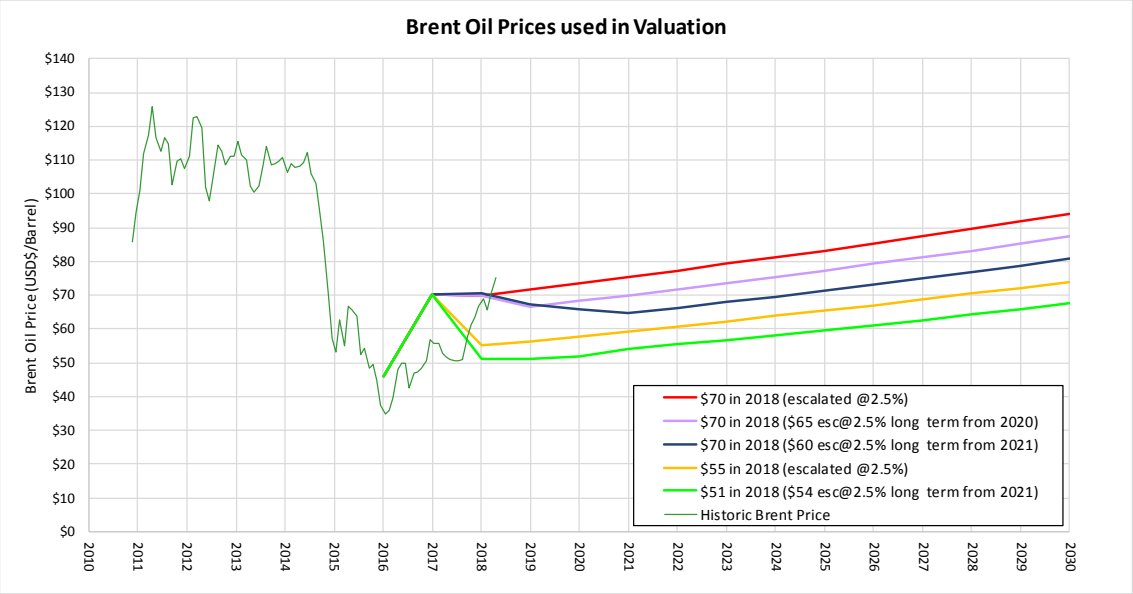

Figure 6-1: Brent Oil Prices used in Valuation

6.1.2. Condensate Price

- **Madura Offshore PSC and Wortel**: A condensate price of $49/barrel in 2018 flat in nominal terms long term and a sensitivity of $51/bbl in 2018 and $54/bbl flat in nominal terms long term from 2021.
- **Sampang – Oyong**: A condensate price of $58/barrel in 2018 flat in nominal terms long term and a sensitivity of $70/bbl in 2018 and $60/bbl flat in nominal terms long term from 2021.

Condensate volumes are low and as such the valuation is not sensitive to condensate price. RISC has reported a condensate price of $49/barrel in 2018 flat in nominal terms long term.

6.1.3. Gas Price

- **Vietnam**: Two price sensitivities were run on gas prices but have not been reported as the sensitivities represent less than 0.5% value change. The value calculated for the gas production represents less than 2% of the asset value.
- **Indonesia**: A set of local market prices for each field has been valued based on contracts and discussions with Santos as part of the data room exercise. These prices average out at approximately $7.0/mmbtu in 2018 and escalate at approximately 3.0% pa. RISC has reported a low side sensitivity with a gas sales price of $5.5/mmbtu in 2018 escalated at 2.5% pa.

6.2. Past petroleum costs

RISC has used past costs provided by Santos to calculate the Cost Recovery of each PSC. RISC has not audited the past costs but has relied on an independent audit report to confirm there are no material costs carried forward for cost recovery.

6.3. Economic results

The NPV estimates have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. NPV's are in nominal terms at 1 January 2018 at 10% discount rate (Table 6-1, Table 6-2 & Table 6-3). All values are listed in US Dollars.

Table 6-1: Summary of Net Present Value of assets in US$ million (1P case) with an Effective Date of 1 January 2018

1P case	Oil Price (US$/Barrel) & NPV US$ million				
Area	**$54 LT**	**$55 LT**	**$60 LT**	**$65 LT**	**$70 LT**
Madura	$9	$9	$9	$9	$9
Sampang	$11	$11	$11	$11	$11
Indonesia	**$20**	**$20**	**$20**	**$20**	**$20**
Chim Sáo	$112	$130	$162	$165	$178
Vietnam	**$112**	**$130**	**$162**	**$165**	**$178**
Total NPV	**$132**	**$151**	**$182**	**$185**	**$198**

Table 6-2: Summary of Net Present Value of assets in US$ million (2P case) with an Effective Date of 1 January 2018

2P case	Oil Price (US$/Barrel) & NPV US$ million				
US$ million	**$54 LT**	**$55 LT**	**$60 LT**	**$65 LT**	**$70 LT**
Madura	$19	$19	$19	$19	$19
Sampang	$15	$15	$15	$15	$15
Indonesia	**$34**	**$34**	**$34**	**$34**	**$34**
Chim Sáo	$148	$164	$202	$213	$225
Vietnam	**$148**	**$164**	**$202**	**$213**	**$225**
Total NPV	**$182**	**$199**	**$237**	**$247**	**$259**

Table 6-3: Summary of Net Present Value of assets in US$ million (3P case) with an Effective Date of 1 January 2018

3P case	Oil Price (US$/Barrel) & NPV US$ million				
US$ million	**$54 LT**	**$55 LT**	**$60 LT**	**$65 LT**	**$70 LT**
Madura	$28	$28	$28	$28	$28
Sampang	$22	$22	$22	$22	$22
Indonesia	**$50**	**$50**	**$50**	**$50**	**$50**
Chim Sáo	$177	$206	$256	$270	$292
Vietnam	**$177**	**$206**	**$256**	**$270**	**$292**
Total NPV	**$226**	**$255**	**$306**	**$319**	**$342**

The valuation with an Effective Date of 1 January 2018 (Table 6-4) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is value at 1 January 2018.

The valuation with a Valuation Date of 1 July 2018 (Table 6-5) is the Net Present Value of the forward production and costs from 1 January 2018 with historic costs before 1 January 2018 considered sunk but used in calculations for tax calculations and future tax payments. Valuation of cash flow is value at 1 July 2018.

Asset NPVs for 1P, 2P and 3P reserves are reported at a nominal discount rate of 10%.

The economic values shown in this report have not been adjusted for other factors (e.g. strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore should not be taken to be fair market values.

Table 6-4: Summary of NPVs for Santos Assets in US Dollars with an Effective Date of 1 January 2018 & Valuation Date of 1 January 2018[1]

NPV US$ million	$54/Barrel Long Term			$60/Barrel Long Term			$70/Barrel Long Term		
Asset	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Madura	$9	$19	$28	$9	$19	$28	$9	$19	$28
Sampang	$11	$15	$22	$11	$15	$22	$11	$15	$22
Indonesia	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**
Chim Sáo	$112	$148	$177	$162	$202	$256	$178	$225	$292
Vietnam	**$112**	**$148**	**$177**	**$162**	**$202**	**$256**	**$178**	**$225**	**$292**
Total NPV	**$132**	**$182**	**$226**	**$182**	**$237**	**$306**	**$198**	**$259**	**$342**

[1]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 January 2018.

Table 6-5: Summary of NPVs for Santos Assets in US Dollars with Effective Date of 1 January 2018 & Valuation Date of 1 July 2018[2]

NPV US$ million	$54/Barrel Long Term			$60/Barrel Long Term			$70/Barrel Long Term		
Asset	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Madura	$9	$19	$28	$9	$19	$28	$9	$19	$28
Sampang	$11	$15	$22	$11	$15	$22	$11	$15	$22
Indonesia	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**	**$20**	**$34**	**$50**
Chim Sáo	$118	$155	$185	$170	$212	$269	$187	$236	$307
Vietnam	**$118**	**$155**	**$185**	**$170**	**$212**	**$269**	**$187**	**$236**	**$307**
Total NPV	**$138**	**$189**	**$235**	**$190**	**$246**	**$318**	**$207**	**$270**	**$356**

[2]Note: Historic costs before 1 January 2018 are considered sunk (Effective Date) but are used in calculations for tax calculations and future tax payments. The valuation of cash flow is value at 1 July 2018. Cashflows between 1 January 2018 and 30 June 2018 are escalated to Valuation Date of 1 July 2018 at 10%.

7. Opportunities and risks

- Oil production from the Chim Sáo field has been better than originally forecast and the two infill wells in 2017 have successfully produced dry oil. Oil production has generally been higher than budget forecasts. Technical analysis suggests that the oil saturation and STOIIP may be greater than operator estimates. An infill well in 2020 and upward re-completion opportunities are planned. However, further infill drilling may be justified given the success of the 2017 well, although such opportunities, location and well planning needs to be developed.
- Both Madura Offshore PSC and Sampang PSC have their costs (capex and opex) recovered under the cost recovery mechanism in the PSCs. This provides minimum incremental capex and opex from the existing infrastructures to support developments of future discoveries in the PSCs.
- The first PODs (Plan of Developments) of both PSCs have already been approved by the Minister of Energy and Natural Resources. This enables Santos to have considerably faster POD approvals in the future as any subsequent PODs only require approvals from SKK Migas.
- Both PSCs are using different gas pipelines to transport their gas to East Java markets. Madura Offshore PSC is using EJGP (East Java Gas Pipeline) with landing point at Porong which can directly access gas markets in central and northern parts of East Java. Sampang PSC is using the 63 km PSC's gas pipeline to transport gas to Grati to access southern part of East Java. The recently operational Pertagas' 56 km 120 MMscfd capacity pipeline connects Grati and Porong and this allows gas from both PSCs to have flexibility to access all markets in East Java.
- The current ongoing Meliwis and Maleo gas sales negotiations with PGN (state-owned gas transmission and distribution company) may not be completed by the target date of July 2018. The Minister of Energy and Natural Resources has not yet approved the gas allocation and gas prices for Meliwis and Maleo.

8. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
bbl/d	US Barrels per day
Bcf	Billion (10^9) cubic feet
Bcm	Billion (10^9) cubic metres
Bfpd	Barrels of fluid per day
bopd	Barrels of oil per day
BTU	British Thermal Units
Boepd	US barrels of oil equivalent per day
Bwpd	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
deg	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
Eg	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
EIA	US Energy Information Administration
EMV	Expected Monetary Value

Term	Definition
EOR	Enhanced Oil Recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
°F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels

Term	Definition
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which 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 that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psig	Pounds per square inch

Term	Definition
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	US Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil

PART VIII
INFORMATION INCORPORATED BY REFERENCE

Information incorporated by reference	Document reference	Page number(s) in this Circular
Ophir Annual Report 2015	Note 38 on page 139 and Note 18 on page 157	94
Ophir Annual Report 2016	Note 36 on page 124 and Note 18 on page 142	94
Ophir Annual Report 2017	Page 98, Note 36 on page 135 and Note 18 on page 152	83, 84 and 94

The parts of these documents which are not incorporated by reference are either not relevant for investors or are covered elsewhere in this Circular. To the extent that any part of any information referred to below itself contains information which is incorporated by reference, such information shall not form part of this Circular.

Copies of the above documents may be inspected during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the registered office of Ophir at Level 4, 123 Victoria Street, London SW1E 6DE and at the offices of Linklaters LLP at One Silk Street, London EC2Y 8HQ up to and including the date of the General Meeting. The documents are also available on Ophir's website (www.ophir-energy.com).

PART IX
GLOSSARY OF TECHNICAL TERMS

1P	low estimate scenario of reserves, taken to be equivalent to proven reserves
2C	best estimate scenario of contingent resources
2P	best estimate scenario of reserves, taken to be equivalent to the sum of proven plus probable reserves
appraisal	the phase of petroleum operations immediately following a successful discovery. Appraisal is carried out to determine size, production rate and the most efficient development of a field
associated gas	natural gas produced with crude oil from the same reservoir
bbl	a unit of volume measurement used for petroleum and its products one US barrel of oil; one US barrel = 35 imperial gallons (approximately), or 159 litres (approximately); 7.5 US barrels = one tonne (approximately, depending upon the oil density); 6.29 US barrels = one cubic metre
bcf	billion cubic feet
block	term commonly used to describe areas over which there is a petroleum or production licence or PSC
blowout	when well pressure exceeds the ability of the wellhead valves to control it
boe	US barrels of oil equivalent derived by converting gas to oil and is dependent on the energy content of the gas
boepd	boe per day
carry	agreement between two parties according to which one of the two agrees to pay for ("**carry**") all or part of the costs attributable to the other, typically conditional on later reimbursement by the latter to the former and "**carried interest**" should be construed accordingly
commercial discovery	discovery of oil and gas which the Company determines to be commercially viable for appraisal and development
condensate	hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons
contingent resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent

	resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status
declaration of commercial discovery	document which assesses the production of oil and gas from a field that is commercially and economically viable
deepwater	any area of water over 250m in depth
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 for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
farm-in	when a company acquires an interest in a block by taking over all or part of the financial commitment for drilling an exploration and/or appraisal well and “farmout” should be construed accordingly
field	a geographical area under which either a single oil or gas reservoir or multiple oil or gas reservoirs lie, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
FPSO	floating production storage and offloading unit
GSA	gas sale and purchase agreement
hydrocarbon	a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate
infill	the addition of new wells into an existing field
infrastructure	oil and gas processing, transportation and off-take facilities
JOA	joint operating agreement
km^2	square kilometres
lead	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 lead generally requires more data to mature it to the prospect level
licence	an exclusive right to explore for petroleum, usually granted by a national governing body
m	metre
MMboe	million boe
MMBtu	millions of British Thermal Units
MMcf	million cubic feet
MMstb	million stb
natural gas	gas, predominantly methane, occurring naturally, and often found in association with crude petroleum

non-operated interest	the participating interest of a person and such person is not appointed as operator under the applicable joint operating agreement and/or production sharing contract
offshore	that geographic area that lies seaward of the coastline
oil	a mixture of liquid hydrocarbons of different molecular weights
onshore	geographic area that lies landward of the coastline
operated interest	the participating interest of a person and such person is appointed as the operator under the applicable joint operating agreement and/or production sharing contract
operator	the company that has legal authority to drill wells and undertake production of oil and gas. The operator is often part of a consortium and acts on behalf of this consortium
participating interest	the proportion of exploration and production costs each party will bear and the proportion of production each party will receive, as set out in an operating agreement
petroleum	a generic name for oil and gas, including crude oil, natural gas liquids, natural gas and their products
petroleum agreement	a PSC, concession agreement or agreement of a similar nature entered into with a government or governmental entity which confers the right to carry out, and governs the conduct of, hydrocarbon exploration, appraisal development and/or production operations
PRMS or **2007 PRMS**	2007 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and the Society of Petroleum Evaluation 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 which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity
PSC	production sharing agreement or contract under which the contractor agrees to fund and carry out pre-agreed work programmes on behalf of the concession owner in return for a share of production revenues
psig	pounds per square inch

reserves	those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reference should be made to the full 2007 PRMS definitions for the complete definitions and guidelines
reservoir	an underground porous and permeable formation where oil and gas has accumulated
resources	contingent and prospective resources, unless otherwise specified
sales gas	natural gas treated and conditioned to meet the gas purchasers specifications
scf	standard cubic feet
stb	stock tank US barrel(s)
tcf	trillion cubic feet
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
upstream	operations stages in the oil and gas industry that involve exploration and production
wellhead	the equipment at the surface of a well used to control the pressure of the well; the point at which the hydrocarbons and water exit the ground

PART X
DEFINITIONS

The following definitions apply throughout this Circular, unless stated otherwise:

AGM	an annual general meeting of Ophir
Articles of Association	the articles of association of the Company which were adopted by special resolution passed on 28 June 2011
Assets	the Producing Assets and the Exploration Assets
BAPEX	Bangladesh Petroleum Exploration and Production Company Limited
Barclays	Barclays Bank PLC, acting through its Investment Bank
Block 123 PSC	has the meaning given to it in paragraph 9.2.5(a) of Part VI: "Additional Information" of this Circular
Block 124 PSC	has the meaning given to it in paragraph 9.2.5(c) of Part VI: "Additional Information" of this Circular
Block 123 / 124 SPA	has the meaning given to it in paragraph 1.1(b) of Part B to Part III: "Summary of the Transaction Agreements" of this Circular
Block 12W PSC	has the meaning given to it in paragraph 9.2.2(a) of Part VI: "Additional Information" of this Circular
Block 12W SPA	has the meaning given to it in paragraph 1(a) of Part A to Part III: "Summary of the Transaction Agreements" of this Circular
Board	the board comprising the Directors
BofA Merrill Lynch	Merrill Lynch International of 2 King Edward Street, London, EC1A 1HQ, United Kingdom
BPMIGAS	Badan Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi, formerly the regulator of the Indonesian upstream oil and gas industry, which has been succeeded by SKK Migas
Chairman	the chairman of the Board
Circular	this document
Commitment Compensation Payment Arrangements	has the meaning given to it in paragraph 1 of Part I: "Letter from the Chairman of Ophir" of this Circular
Companies Act 1985	the Companies Act 1985 (as amended)
Companies Act 2006	the Companies Act 2006 (as amended)
Company or **Ophir**	Ophir Energy plc a company registered in England and Wales with registered number 05047425 whose registered office is at Level 4, 123 Victoria Street, London SW1E 6DE, United Kingdom
Competent Person's Report	the mineral expert report prepared by RISC (UK) Limited contained in Part VII: "Summary of Producing Assets Resources and Reserves Information" of this Circular
Completion	completion of the Transaction in accordance with the Transaction Agreements

CREST	the relevant system (as defined in the CREST Regulations) in respect of which Euroclear UK & Ireland Limited is the operator (as defined in the CREST Regulations) in accordance with which securities may be held and transferred in uncertificated form
CREST Manual	the manual, as amended from time to time, produced by Euroclear UK & Ireland Limited describing the CREST system and supplied by Euroclear UK & Ireland Limited to users and participants thereof
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 participant (as defined in the CREST Regulations)
CREST Regulations	the Uncertificated Securities Regulations 2001 (SI 2001/3755)
CREST sponsor	a CREST participant admitted to CREST as a CREST sponsor
Deepwater Block R PSC	has the meaning given to it in paragraph 9.2.6(a) of Part VI: "Additional Information" of this Circular
Deepwater Block R SPA	has the meaning given to it in paragraph 1.1(a) of Part B to Part III: "Summary of the Transaction Agreements" of this Circular
Directors	the directors of the Company, currently comprising the Directors whose names appear in paragraph 4 of Part VI: "Additional Information" of this Circular
Disclosure Guidance and Transparency Rules or **DTR**	the disclosure guidance and transparency rules made by the FCA pursuant to section 73A of FSMA
Enlarged Group	the Group following Completion
Euroclear	Euroclear UK & Ireland Limited, the operator (as defined in the CREST Regulations) of CREST
Executive Directors	the executive directors of Ophir, currently Alan Booth and Anthony (Tony) Rouse
Exploration Assets	the assets described as the "Exploration Assets" in paragraph 1 of Part I: "Letter from the Chairman of Ophir" of this Circular
Facilities	the Bridge Facility Agreement described in paragraph 9.1.2 of Part VI "Additional Information", the Group's US$250 million Reserve Based Lending Facility and the Group's US$ denominated NOK bond of US$105 million
FCA or **Financial Conduct Authority**	the Financial Conduct Authority or its successor from time to time
FID	final investment decision
Form of Proxy	the form of proxy accompanying this Circular for use by Shareholders in relation to the General Meeting
FSMA or **Financial Services and Markets Act 2000**	Financial Services and Markets Act 2000 (as amended)

General Meeting	the general meeting of the Company to be held at 12:00 p.m. on Monday 20 August 2018 (or any adjournment thereof) at the offices of Linklaters LLP, One Silk Street, London EC2Y 8HQ, notice of which is set out at the end of this Circular
Group	the Company and its subsidiary undertakings and, where the context permits, each of them
Indonesian Interests	has the meaning given to it in paragraph 1 of Part A to Part III "Summary of the Transaction Agreements" of this Circular
Inpex	Inpex Offshore South West Sabah, Ltd
Jaguar 1	Ophir Jaguar 1 Limited, an indirect wholly owned subsidiary of the Company
Jaguar 2	Ophir Jaguar 2 Limited, a wholly owned subsidiary of Jaguar 1
JX Nippon	JX Nippon Oil & Gas Exploration (Deepwater Sabah) Limited
Latest Practicable Date	31 July 2018, being the latest practicable date prior to the publication of this Circular for the purposes of ascertaining certain information contained in this Circular
LIBOR	London interbank offering rate
Listing Rules	the rules and regulations made by the FCA in its capacity as the UKLA under Part 6 of the FSMA and contained in the UKLA's publication of the same name
London Stock Exchange	the regulated market operated by London Stock Exchange plc or its successor
Madura Offshore PSC	has the meaning given to it in paragraph 9.2.3(a) of Part VI: "Additional Information" of this Circular
Madura / Sampang SPA	has the meaning given to it in paragraph 1(b) of Part A to Part III: "Summary of the Transaction Agreements" of this Circular
NAV	net asset value
NAV Event	has the meaning given to it in paragraph 5.3 of Part VI: "Additional Information" of this Circular
Non-Executive Directors	the non-executive directors of Ophir, currently William (Bill) Schrader, Dr Carol Bell, David Davies, Vivien Gibney and Dr Carl Trowell
Notice of General Meeting	the notice of the General Meeting which is set out at the end of this Circular
Pertamina	Perusahaan Pertambangan Minyak dan Gas Bumi Negara, formerly the regulator of the Indonesian upstream oil and gas industry, which was succeeded by BPMIGAS
Petrobangla	Bangladesh Oil, Gas and Mineral Corporation
Petronas	Petroliam Nasional Berhad
PetroVietnam	Vietnam Oil and Gas Corporation
PGN	PT Perusahaan Gas Negara (Persero) Tbk.
Producing Assets	the assets described as the "Producing Assets" in paragraph 1 of Part I: "Letter from the Chairman of Ophir" of this Circular

Prospectus Rules	the prospectus rules made by the FCA pursuant to section 73A of the FSMA
PT Pertamina	PT Pertamina (Persero)
PVEP	PetroVietnam Exploration Production Corporation Limited
Regulatory Information Service	any channel recognised as a channel for the dissemination of regulatory information by listed companies as defined in the Listing Rules
Resolutions	the ordinary resolutions as set out in the Notice of General Meeting at the end of this Circular
Sampang PSC	has the meaning given to it in paragraph 9.2.4(a) of Part VI: "Additional Information" of this Circular
Santos	Santos Limited, a company registered and incorporated in Australia with registered number 007 550 923 whose registered office is at Ground Floor Santos Centre, 60 Flinders Street, Adelaide SA 5000, Australia
Santos Group	Santos Limited and its subsidiary undertakings (excluding the Target Group)
Santos Madura	Santos (Madura Offshore) Pty Ltd
Santos Sabah	Santos Sabah Block R Limited
Santos Sampang	Santos (Sampang) Pty. Ltd
Santos Sangu	Santos Sangu Field Limited
Santos Vietnam	Santos Vietnam Pty. Ltd
Shareholders	the holders of Shares
Share Schemes	the Ophir Energy Company 2006 Share Option Plan, the Ophir Energy Long Term Incentive Plan 2011, the Ophir Energy plc 2012 Deferred Share Plan and the Ophir Energy plc Long Term Value Creation Plan 2016
Shares	the ordinary shares of 0.25 pence each in the capital of the Company
SKK Migas	Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi, the special task force for Indonesian upstream oil and gas business activities established by the government of Indonesia under Presidential Regulation Number 9 of 2013 on Management of Upstream Oil and Gas Business Activities
SS-11 ATA	has the meaning given to it in paragraph 1.1(c) of Part B to Part III: "Summary of the Transaction Agreements" of this Circular
SS-11 PSC	has the meaning given to it in paragraph 9.2.7(a) of Part VI: "Additional Information" of this Circular
Target Group	Santos Sabah, Santos Petroleum Ventures B.V., Santos Vietnam, Santos (SPV) Pty Ltd and its subsidiary Santos Madura, Santos Asia Pacific Pty Ltd and its subsidiary Santos Sampang and the Block SS-11 PSC asset currently owned by Santos Sangu and, where the context permits, each of them

Transaction	the proposed acquisition of the Assets from Santos, as described in paragraph 1 of Part I: "Letter from the Chairman of Ophir" of this Circular
Transaction Agreements	the agreements described in Part III: "Summary of the Transaction Agreements" of this Circular
UK or **United Kingdom**	United Kingdom of Great Britain and Northern Ireland
UK Listing Authority or **UKLA**	the FCA acting in its capacity as the competent authority for the purposes of Part VI of the FSMA
uncertificated or **in uncertificated form**	in respect of a share or other security, where that share or other security is recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which may be transferred by means of CREST
VAT	any value added tax imposed under directive 2006/11 2/EC, the Value Added Tax Act 1994 and/or any primary or secondary legislation supplemental to either of them and/or any equivalent tax in any other jurisdiction

Ophir Energy plc

Incorporated in England and Wales with registered number 05047425

NOTICE OF GENERAL MEETING

NOTICE IS HEREBY GIVEN that a GENERAL MEETING of Ophir Energy plc (the "**Company**") will be held at the offices of Linklaters LLP, One Silk Street, London EC2Y 8HQ on Monday 20 August 2018 at 12:00 p.m. to consider and, if thought fit, pass the following resolutions, which will be proposed as ordinary resolutions. Capitalised terms not defined below are references to those terms as defined in the circular to Shareholders dated 3 August 2018 (the "**Circular**").

Ordinary resolutions

1 THAT, subject to and conditional upon the passing of Resolution 2 below, the Transaction be and is hereby approved on the terms set out in the Transaction Agreements (both as defined in the Circular), 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 Transaction Agreements (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 Transaction and any matters incidental to the Transaction.

2 THAT, subject to and conditional upon the passing of Resolution 1 above, the Commitment Compensation Payment Arrangements (as defined in the Circular) be and are hereby approved on the terms set out in the Transaction Agreements.

By order of the Board,

Philip Laing

General Counsel and Company Secretary

3 August 2018

Registered office:

Level 4, 123 Victoria Street, London SW1E 6DE, United Kingdom

Notes

1 Record Date

Shareholders registered in the Register of Members of the Company as at 6.30 p.m. on Thursday 16 August 2018 (or, in the event of any adjournment, 6.30 p.m. on the date which is two days before the time of the adjourned meeting, excluding non-working days) shall be entitled to attend or vote at the General Meeting in respect of the shares registered in their name at that time.

Changes to entries on the Register of Members after 6.30 p.m. on Thursday 16 August 2018 will be disregarded in determining the rights of any person to attend or vote at the General Meeting.

2 Proxies

Members are entitled to appoint another person as his/her proxy (who need not be a member of the Company) to exercise all or any of their rights to attend, speak and vote on their behalf at the General Meeting.

A member may appoint more than one proxy in relation to the General Meeting provided that each proxy is appointed to exercise the rights attached to a different share or shares held by that member. Members who wish to appoint more than one proxy in respect of their holding may obtain additional Forms of Proxy by contacting the Company's Registrars, Equiniti Limited on 0371 384 2030 or +44 (0)121 415 7047 (if calling from overseas calls are charged at standard overseas call rates). Lines are open Monday to Friday 8.30 a.m. to 5.30 p.m., excluding public holidays in England and Wales. Alternatively, members may photocopy the Form of Proxy provided with this Circular indicating on each copy the name of the proxy appointed and the number of ordinary shares in the Company in respect of which that proxy is appointed. All Forms of Proxy should be returned together in the same envelope.

A Form of Proxy is enclosed with this Notice of General Meeting. Completion of the Form of Proxy will not prevent a member from subsequently attending and voting at the General Meeting in person if they so wish.

The Form of Proxy and any power of attorney or other authority under which it is executed (or a duly certified copy of any such power or authority) must be either: (i) received by post or (during normal business hours only) by hand at the offices of the Company's Registrars, Equiniti Limited, Aspect House, Spencer Road, Lancing BN99 6DA, United Kingdom; or (ii) members may submit their proxies electronically at www.sharevote.co.uk using the Voting ID, Task ID and Shareholder Reference Number set out in the Form of Proxy, in each case so as to be received by no later than 12:00 p.m. on Thursday 16 August 2018, being 48 hours before the time appointed for the holding of the General Meeting, excluding non-working days.

3 Information Rights and Nominated Persons

Persons who have been nominated under Section 146 of the Companies Act 2006 (a "**Nominated Person**") to enjoy information rights do not have a right to vote or appoint a proxy at the General Meeting and the statements of the rights of members in relation to the appointment of proxies in note 2 above do not apply to Nominated Persons. The rights described in that note can only be exercised by members of the Company.

However, a Nominated Person may have the right (under an agreement with the member by whom they were nominated) to be appointed, or to have someone else appointed, as a proxy for the General Meeting. If a Nominated Person has no such proxy appointment right, or does not wish to exercise that right, they may have a right to give voting instructions to the registered shareholder under any such agreement.

4 Corporate Representatives

A corporate shareholder may authorise a person or persons to act as its representative(s) at the General Meeting. Each such representative may exercise (on behalf of the corporate shareholder) the same powers as the corporate shareholder could exercise if they were an individual shareholder in the Company, provided that they do not do so in relation to the same shares.

5 CREST Proxy Instructions

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 Monday 20 August 2018 and any adjournment thereof by following 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 should refer to their CREST sponsor or voting service provider who will be able to take the appropriate action on their behalf.

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 instruction, as described in the CREST Manual (available at www.euroclear.com). The message, regardless of whether it relates to the appointment of a proxy or to 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 issuer's agent (ID: RA:19) by no later than the latest time for receipt of proxy appointments specified in note 2 above. No 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 Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. The CREST Manual is available at www.euroclear.com.

CREST members and, where applicable, their CREST sponsors or voting service provider should note that Euroclear 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, to procure that his/her CREST sponsor or voting service provider takes) 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 are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

The Company will treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Uncertificated Securities Regulations 2001.

6 Total Voting Rights

Holders of the Company's ordinary shares are entitled to attend and vote at general meetings of the Company.

Each ordinary share entitles the holder to one vote on a poll. As at 31 July 2018, being the Latest Practicable Date, the Company's issued share capital consisted of 746,019,407 ordinary shares, including shares held in treasury. As at the Latest Practicable Date, the Company held 38,909,848 shares in treasury. Therefore, the total voting rights in the Company as at the Latest Practicable Date are 707,109,559.

7 Questions

Any member attending the General Meeting has the right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the General Meeting but no such answer need be given if: (a) to do so would interfere unduly with the preparation for the meeting or would involve the disclosure of confidential information; (b) the answer has already been given on a website in the form of an answer to a question; or (c) it is undesirable in the interests of the Company or the good order of the General Meeting that the question be answered.

8 Voting at the General Meeting

The resolutions to be put to the General Meeting will be voted on by way of a poll and not by a show of hands. In this way, the voting preferences of all shareholders are taken into account not only those who are able to physically attend the General Meeting. The results of the poll will be notified to the market in the usual way and published on the Company's website after the meeting.

9 Display Documents

Copies of the Notice of General Meeting, the Articles of Association of the Company, the Circular and the documents listed in the Circular as available for inspection are available for inspection at the registered office of the Company and the offices of Linklaters LLP at One Silk Street, London EC2Y 8HQ during normal business hours on any weekday (excluding Saturdays, Sundays and public holidays) from the date of this Notice until the conclusion of the General Meeting and also at the place of the General Meeting from 9.00 a.m. on the day of the General Meeting until the conclusion thereof.

10 Information Available on the Website

A copy of this Notice and other information required by Section 311A of the Companies Act 2006 can be found at www.ophir-energy.com.

11 Electronic Address

Please note that shareholders may not use any electronic address provided in this Notice of General Meeting or any related documents (including the Form of Proxy) to communicate with the Company for any purpose other than those expressly stated.