11 November 2021

Oil Search and Santos merger update: Court approves distribution of Scheme Booklet and convening of Scheme Meeting

- **The Independent Expert has concluded that the Merger is in the best interests of Oil Search shareholders in the absence of a superior proposal**
- **The Oil Search Board continues to unanimously recommend that Oil Search shareholders vote in favour of the Scheme at the Scheme Meeting in the absence of a superior proposal**

Oil Search Limited (“Oil Search”) and Santos Limited (“Santos”) are pleased to provide the following update in relation to their proposed merger announced to the ASX on 10 September 2021. As set out in that announcement, the Merger is proposed to be effected by a scheme of arrangement under PNG law whereby Santos will acquire all of the shares in Oil Search and Oil Search shareholders will receive 0.6275 new Santos shares for each Oil Search share (‘the Scheme”).

The National Court of Papua New Guinea ("PNG") has today made orders:

- that Oil Search convene a meeting of Oil Search shareholders on Tuesday 7 December 2021, to consider and vote on the proposed Scheme ("Scheme Meeting"); and
- approving the distribution to Oil Search shareholders of an explanatory statement providing information about the Scheme and notice of the Scheme Meeting ("Scheme Booklet").

Scheme Booklet

A copy of the Scheme Booklet, and a Notice of Scheme Meeting, is attached to this announcement.

The Scheme Booklet provides Oil Search shareholders with information about the Scheme.

The Scheme Booklet includes a copy of the Independent Expert's Report prepared by Grant Samuel & Associates Pty Limited ("Independent Expert").

The Independent Expert has concluded that the Merger is in the best interests of Oil Search shareholders in the absence of a superior proposal. A complete copy of the Independent Expert’s Report is included in Annexure A to the Scheme Booklet. Oil Search shareholders should carefully review the Independent Expert's Report in its entirety.

Directors’ recommendation

The Oil Search Board continues to unanimously recommend that Oil Search shareholders vote in favour of the Scheme at the Scheme Meeting in the absence of a superior proposal. Each Oil Search Director intends to vote all the Oil Search shares held or controlled by them in favour of the Scheme, in the absence of a superior proposal.

Oil Search Chairman, Rick Lee, said “The Merger brings together two highly complementary businesses and creates an oil and gas company of significant size with a portfolio of geographically and product diversified long-life and low-cost assets. We look forward to Oil Search’s shareholders participation in the Scheme Meeting and encourage you to vote in favour of the Merger, which the Oil Search Directors believe, is in the best interests of Oil Search shareholders.”

Santos Chairman, Keith Spence, said “The merger represents an attractive combination of two industry leaders to create a regional champion with the balance sheet and strong diversified cashflows necessary to fund growth, the energy transition to a lower carbon future including Santos’ leading carbon capture and storage capability, and deliver shareholder returns.

“We look forward to integrating our businesses to create one high performing team – with a vision of becoming a global leader in the energy transition,” Mr Spence said.

Accessing the Scheme Booklet

Oil Search shareholders who have previously elected to receive communications electronically will receive an email to their nominated email address during the course of this week, that will contain instructions about how to view or download a copy of the Scheme Booklet. Oil Search shareholders who have not made such an election will receive a letter (sent by post to their registered address) containing details of where they can view and download the Scheme Booklet.

Oil Search shareholders who wish to receive a printed copy of the Scheme Booklet may request one by calling the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9:00am and 5:00pm (Sydney time) other than public holidays in Sydney, Australia.

Oil Search shareholders are advised to read the Scheme Booklet in its entirety before making a decision on whether or not to vote in favour of the Scheme.

Scheme Meeting

The Scheme Meeting will be conducted as a virtual meeting at 11:00am (Sydney time) / 10:00am (Port Moresby time) on Tuesday, 7 December 2021. There will be no physical Scheme Meeting. Oil Search shareholders (or their proxies, attorneys or corporate representatives) will be able to attend and vote at the Scheme Meeting through an online platform available at https://web.lumiagm.com/399778470 (meeting ID 399778470).

All Oil Search shareholders are encouraged to vote either by attending and voting at the virtual Scheme Meeting or by lodging a proxy to attend and vote at the virtual Scheme Meeting. The Notice of Scheme Meeting provides information on how to lodge your Proxy Form (if applicable).

Queries

If Oil Search shareholders have any questions in relation to this Scheme Booklet or the Scheme, they can call the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9:00am and 5:00pm (Sydney time) other than public holidays in Sydney, Australia. If you are not able to access the Oil Search Shareholder Information Line you can request a call back from oilsearchmerger@investorinfo.net.au or you can view further information at https://www.oilsearch.com/scheme-meeting.

This ASX announcement was approved and authorised for release by Peter Fredricson, Acting Chief Executive Officer of Oil Search and Kevin Gallagher, Managing Director and Chief Executive Officer of Santos.

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Oil Search

Oil Search Limited (ARBN 055 079 868)

SCHEME BOOKLET

In relation to the proposed merger of Oil Search Limited (**Oil Search**) and Santos Limited (**Santos**) by way of Scheme of Arrangement

VOTE IN FAVOUR

Your Directors unanimously recommend that you **VOTE IN FAVOUR** of the Scheme in the absence of a Superior Proposal

This Scheme Booklet is important and requires your prompt attention. You should read it in its entirety, and consider its contents carefully, before deciding whether or not to vote in favour of the Scheme. If you are in any doubt about what you should do, you should consult with a financial, legal, taxation or other professional adviser.

If you have any questions in relation to this Scheme Booklet or the Scheme, please contact the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9:00am and 5:00pm (Sydney time) other than public holidays in Sydney, Australia.

Financial Advisers

Goldman Sachs

Macquarie Bank

Rothschild & Co

Legal Advisers

Allens > < Linklaters

Important notices

Nature of this Scheme Booklet

This Scheme Booklet is prepared for persons shown in the Oil Search Share Register as holding Oil Search Shares. If you have recently sold all of your Oil Search Shares, please disregard this Scheme Booklet.

This Scheme Booklet provides Oil Search Shareholders with information about a proposed scheme of arrangement under which Santos will acquire all of the issued share capital in Oil Search, subject to the relevant conditions precedent being satisfied or waived (where capable of waiver), including shareholder, regulatory and court approvals, as explained in this booklet. You should review all of the information in this Scheme Booklet carefully. Section 1.1 sets out the reasons why you should vote in favour of the Scheme and section 1.2 sets out the reasons why you may wish to vote against the Scheme.

Defined terms

A number of defined terms are used in this Scheme Booklet. These terms are explained in section 10 of this Scheme Booklet. Some of the documents reproduced in the annexures to this Scheme Booklet have their own defined terms, which are sometimes different to those set out in section 10.

No investment advice

The information contained in this Scheme Booklet does not constitute financial product advice and has been prepared without reference to your individual investment objectives, financial situation, taxation position or particular needs. It is important that you read this Scheme Booklet in its entirety before making any decision as to whether or not to vote in favour of the Scheme or to deal in your Oil Search Shares. If you are in any doubt in relation to these matters, you should consult with a financial, legal, taxation or other professional adviser.

Not an offer

This Scheme Booklet does not constitute or contain an offer to Oil Search Shareholders, or a solicitation of an offer from Oil Search Shareholders, in any jurisdiction.

Regulatory information

This Scheme Booklet is an explanatory statement for the scheme of arrangement between Oil Search and the Scheme Shareholders for the purposes of section 250(2)(a) of the PNG Companies Act. A copy of the proposed Scheme is included in this Scheme Booklet in Annexure C.

Notice of Scheme Meeting

The Notice of Meeting is set out in Annexure E.

Oil Search's Shareholder's right to appear at the Second Court Hearing

At the Second Court Hearing, the Court will consider whether to approve the Scheme following the vote at the Scheme Meeting.

Any Oil Search Shareholder may appear at the Second Court Hearing, expected to be held in Port Moresby, National Capital District on Thursday, 9 December 2021 at the National Court of Justice of Papua New Guinea at Waigani, Port Moresby, PNG.

Any Oil Search Shareholder who wishes to oppose approval of the Scheme at the Second Court Hearing may seek to do so by filing with the Court and serving on Oil Search a notice of appearance in the prescribed form together with any affidavit that the Oil Search Shareholder proposes to rely on and subject to any Court direction.

It is possible that, because of restrictions imposed in response to the COVID-19 pandemic, the Second Court Hearing will be (or will also be) conducted by remote access technology, including via a dedicated video conferencing service or telephone conferencing. Any change to the date or arrangements for the conduct of the Second Court Hearing will be announced on the ASX website (www.asx.com.au), the PNGX website (https://www.pngx.com.pg/) and will also be notified on Oil Search's Website.

Important notice associated with the Court Order under section 250(2)(b) of the PNG Companies Act

The fact that under section 250(2)(b) of the PNG Companies Act, the Court has ordered that a meeting be convened and has directed that an explanatory statement accompany the Notice of Meeting does not mean that the Court:

- has formed any view as to the merits of the proposed Scheme or as to how members should vote (members must reach their own decision on this matter); or
- has prepared, or is responsible for, the content of the explanatory statement.

Disclaimer as to forward-looking statements

Certain statements appearing in this Scheme Booklet (including in the Independent Expert's Report) may be in the nature of forward-looking statements. Forward-looking statements generally may be identified by the use of forward-looking words such as "believe", "aim", "expect", "anticipate", "intending", "foreseeing", "likely", "should", "planned", "may", "estimate", "potential", or other similar words. Similarly, statements that describe the objectives, plans, goals, intentions or expectations of Oil Search, Santos or the Merged Group are or may be forward-looking statements.

Forward-looking statements should not be taken to be forecasts or predictions that events will occur or that objectives, plans, goals, intentions or expectations will be achieved. Such statements are only opinions and are subject to inherent risks and uncertainties. Those risks and uncertainties include factors and risks specific to Oil Search, Santos, the Merged Group and/or the industries in which they operate, as well as general economic conditions, prevailing exchange rates and interest rates and conditions in financial markets. Actual events or results may differ materially from the events or results expressed or implied in any forward-looking statement and deviations are both normal and to be expected. Neither Oil Search nor Santos, nor any of their respective affiliates, officers, directors, employees or advisers or any person named in this Scheme Booklet or involved in the preparation of this Scheme Booklet makes any representation or warranty (either express or implied) as to the accuracy or likelihood of fulfilment of any forward-looking statement, or any events or results expressed or implied in any forward-looking statement. Accordingly, you are cautioned not to place undue reliance on those statements.

The forward-looking statements in this Scheme Booklet reflect opinions held only at the date of this Scheme Booklet. Subject to any continuing obligations under relevant laws, the ASX Listing Rules or PNGX Listing Rules, Oil Search, Santos and their respective affiliates, officers, directors, employees and advisers, disclaim any obligation or undertaking to update or revise any such statements after the date of this Scheme Booklet, to reflect any change in expectations in relation to such statements or any change in events, conditions or circumstances on which any such statement is based.

Responsibility statement

Oil Search has prepared, and is responsible for, the Oil Search Information. Neither Santos nor any of its affiliates, officers, directors, employees or advisers assumes any responsibility for the accuracy or completeness of such information.

Santos has prepared, and is responsible for, the Santos Information. Neither Oil Search nor any of its affiliates, officers, directors, employees or advisers assumes any responsibility for the accuracy or completeness of such information.

Grant Samuel has prepared the Independent Expert's Report (including the Independent Technical Expert's Report) and the Independent Expert takes responsibility for that report. Neither Oil Search nor Santos, nor any of their respective affiliates, officers, directors, employees or advisers assume any responsibility for the accuracy or completeness of the information contained in the Independent Expert's Report (including the Independent Technical Expert's Report). The Independent Expert's Report (including the Independent Technical Expert's Report) is set out in Annexure A.

Ernst & Young as Investigating Accountant has prepared the Investigating Accountant's Report in relation to the Scheme and Investigating Accountant takes responsibility for that report. Neither Oil Search nor Santos, nor any of their respective affiliates, officers, directors, employees or advisers assume any responsibility for the accuracy or completeness of the information contained in the Investigating Accountant's Report. The Investigating Accountant's Report is set out in Annexure B.

Computershare has had no involvement in the preparation of any part of this Scheme Booklet other than being named as the Oil Search Share Registry. Computershare has not authorised or caused the issue of, and expressly disclaims and takes no responsibility for, any part of this Scheme Booklet.

Foreign jurisdictions

The release, publication or distribution of this Scheme Booklet in jurisdictions other than PNG, Australia, New Zealand, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America may be restricted by law or regulation in such other jurisdictions. Persons outside of PNG, Australia, New Zealand, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America who come into possession of this Scheme Booklet should seek advice on and observe any such restrictions. Any failure to comply with such restrictions may constitute a violation of applicable laws or regulations.

This Scheme Booklet has been prepared in accordance with PNG law and the information contained in this Scheme Booklet may not be the same as that which would have been disclosed if this Scheme Booklet had been prepared in accordance with the laws and regulations outside of PNG. This Scheme Booklet and the Scheme do not constitute an offer of securities in any place in which, or to any person to whom, it would not be lawful to make such an offer.

A Scheme Shareholder whose address shown in the Oil Search Share Register is a place outside of Australia (including its external territories), New Zealand, PNG, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America as at the Record Date will be an Ineligible Foreign Shareholder.

Important notices

United States

The New Santos Shares to be issued under the Scheme have not been and will not be registered under the US Securities Act of 1933 (**US Securities Act**) or applicable US state securities laws. Santos intends to rely on an exemption from the registration requirements of the US Securities Act provided by section 3(a)(10) thereof and intends to rely on exemptions from registration under applicable state securities laws in connection with the issuance of New Santos Shares to US resident Oil Search Shareholders under the Scheme. For the purpose of qualifying for this exemption, Santos will advise the Court that its approval of the Scheme will be relied upon by Santos as an approval of the Scheme following a hearing on the fairness of the terms and conditions of the Scheme to Oil Search Shareholders at which hearing all such shareholders are entitled to appear in person or through counsel to support or oppose the approval of the Scheme and with respect to which notification has been given to all Oil Search Shareholders.

In connection with the implementation of the Scheme, and the issuance of the New Santos Shares, approval of the Scheme by the Court will be relied upon by Santos and constitute the basis for New Santos Shares to be issued without registration under the US Securities Act in reliance upon the exemption from the registration requirements of the US Securities Act provided in section 3(a)(10). Neither the US Securities and Exchange Commission nor any securities regulator in any state in the US has reviewed this Scheme Booklet or approved or disapproved the offer or sale of securities referred to in this Scheme Booklet. No securities referred to in this Scheme Booklet will be listed for trading on a securities exchange in the United States of America.

Hong Kong

Warning: The contents of this Scheme Booklet have not been reviewed or approved by any regulatory authority in Hong Kong. You are advised to exercise caution in relation to the Scheme. If you are in any doubt about any of the contents of this Scheme Booklet, you should obtain independent professional advice.

This Scheme Booklet does not constitute an offer or invitation to the public in Hong Kong to acquire or subscribe for or dispose of any securities. This Scheme Booklet also does not constitute a prospectus (as defined in section 2(1) of the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32 of the Laws of Hong Kong)) or notice, circular, brochure or advertisement offering any securities to the public for subscription or purchase or calculated to invite such offers by the public to subscribe for or purchase any securities, nor is it an advertisement, invitation or document containing an advertisement or invitation falling within the meaning of section 103 of the Securities and Futures Ordinance (Cap. 571 of the Laws of Hong Kong).

Accordingly, unless permitted by the securities laws of Hong Kong, no person may issue or cause to be issued this Scheme Booklet in Hong Kong, other than to persons who are "professional investors" as defined in the Securities and Futures Ordinance and any rules made thereunder or in other circumstances which do not result in this document being a "prospectus" as defined in the Companies (Winding Up and Miscellaneous Provisions) Ordinance or which do not constitute an offer to the public within the meaning of the Companies (Winding Up and Miscellaneous Provisions) Ordinance.

No person may issue or have in its possession for the purposes of issue, this Scheme Booklet or any advertisement, invitation or document relating to these securities, whether in Hong Kong or elsewhere, which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than any such advertisement, invitation or document relating to securities that are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance and any rules made thereunder.

Copies of this Scheme Booklet may be issued to a limited number of persons in Hong Kong in a manner that does not constitute any issue, circulation or distribution of this Scheme Booklet, or any offer or an invitation in respect of these securities, to the public in Hong Kong. This document is for the exclusive use of Oil Search Shareholders in connection with the Scheme. No steps have been taken to register or seek authorisation for the issue of this Scheme Booklet in Hong Kong.

This Scheme Booklet is confidential to the person to whom it is addressed and no person to whom a copy of this Scheme Booklet is issued may issue, circulate, distribute, publish, reproduce or disclose (in whole or in part) this Scheme Booklet to any other person in Hong Kong or use for any purpose in Hong Kong other than in connection with consideration of the Scheme by Oil Search Shareholders.

Ireland

This Scheme Booklet has not been, and will not be, registered with or approved by any securities regulator in Ireland or elsewhere in the European Union. Accordingly, this Scheme Booklet may not be made available, nor may the New Santos Shares be offered for sale, in Ireland except in circumstances that do not require a prospectus under Article 1(4) of Regulation (EU) 2017/1129 of the European Parliament and the Council of the European Union (**the Prospectus Regulation**).

In accordance with Article 1(4) of the Prospectus Regulation, an offer of Shares in Ireland is limited:

- to persons who are "qualified investors" (as defined in Article 2(e) of the Prospectus Regulation);
- to fewer than 150 natural or legal persons (other than qualified investors); or
- in any other circumstance falling within Article 1(4) of the Prospectus Regulation.

Malaysia

No approval from, or recognition by, the Securities Commission of Malaysia has been, or will be, obtained in relation to any offer of the New Santos Shares. The New Santos Shares may not be issued or transferred in Malaysia except to persons who are Oil Search Shareholders in compliance with the Scheme.

New Zealand

This Scheme Booklet is not a New Zealand disclosure document and has not been registered, filed with or approved by any New Zealand regulatory authority under or in accordance with the *Financial Markets Conduct Act 2013* or any other New Zealand law.

The offer of New Santos Shares under the Scheme is being made to existing shareholders of Oil Search in reliance upon the *Financial Markets Conduct (Incidental Offers) Exemption Notice 2016* and, accordingly, this Scheme Booklet may not contain all the information that a disclosure document is required to contain under New Zealand law.

Singapore

This Scheme Booklet and any other document relating to the Scheme have not been, and will not be, registered as a prospectus with the Monetary Authority of Singapore and the Scheme is not regulated by any financial supervisory authority in Singapore. Accordingly, statutory liabilities in connection with the contents of prospectuses under the Securities and Futures Act, Cap. 289 (the **SFA**) will not apply.

This Scheme Booklet and any other document relating to the Scheme may not be made the subject of an invitation for subscription, purchase or receipt, whether directly or indirectly, to persons in Singapore except pursuant to exemptions in Subdivision (4) Division 1, Part XIII of the SFA, including the exemption under section 273(1)(c) of the SFA, or otherwise pursuant to, and in accordance with the conditions of, any other applicable provisions of the SFA.

Any offer is not made to you with a view to New Santos Shares being subsequently offered for sale to any other party. You are advised to acquaint yourself with the SFA provisions relating to on-sale restrictions in Singapore and comply accordingly.

This Scheme Booklet is being furnished to you on a confidential basis and solely for your information and may not be reproduced, disclosed, or distributed to any other person. Any investment referred to in this Scheme Booklet may not be suitable for you and it is recommended that you consult an independent investment advisor if you are in doubt about such investment.

Neither Oil Search nor Santos is in the business of dealing in securities or holds itself out, or purports to hold itself out, to be doing so. As such, Oil Search and Santos are neither licensed nor exempted from dealing in securities or carrying out any other regulated activities under the SFA or any other applicable legislation in Singapore.

United Kingdom

Neither this Scheme Booklet nor any other document relating to the Scheme has been delivered for approval to the Financial Conduct Authority in the United Kingdom and no prospectus (within the meaning of section 85 of the *Financial Services and Markets Act 2000*, as amended (**FSMA**)) has been published or is intended to be published in respect of the New Santos Shares.

This Scheme Booklet does not constitute an offer of transferable securities to the public within the meaning of the UK Prospectus Regulation or the FSMA. Accordingly, this document does not constitute a prospectus for the purposes of the Prospectus Regulation or the FSMA.

Any invitation or inducement to engage in investment activity (within the meaning of section 21 FSMA) received in connection with the issue or sale of the New Santos Shares has only been communicated or caused to be communicated and will only be communicated or caused to be communicated in the United Kingdom in circumstances in which section 21(1) FSMA does not apply to Oil Search or Santos.

In the United Kingdom, this Scheme Booklet is being distributed only to, and is directed at, persons (i) who fall within Article 43 (members of certain bodies corporate) of the *Financial Services and Markets Act 2000 (Financial Promotions) Order 2005*, or (ii) to whom it may otherwise be lawfully communicated (together **relevant persons**). The investments to which this document relates are available only to, and any invitation, offer or agreement to purchase will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document.

Important notices

Privacy

Oil Search, Santos and their agents and representatives may collect personal information in the process of implementing the Scheme. Such information may include the name, contact details and shareholdings of Oil Search Shareholders and the names of persons appointed by those persons to act as a proxy, attorney or corporate representative at the Scheme Meeting. The primary purpose of the collection of personal information is to assist Oil Search to conduct the Scheme Meeting and to implement the Scheme, including to issue the Scheme Consideration. Without this information, Oil Search may be hindered in its ability to issue this Scheme Booklet and to implement the Scheme. Personal information of the type described above may be disclosed to the Oil Search Share Registry, the Santos Share Registry (to enable it to issue the Scheme Consideration), third party service providers (including print and mail service providers and parties otherwise involved in the conduct of the Scheme Meeting), authorised securities brokers, any member of Santos, Oil Search and its Related Bodies Corporate, and Oil Search's and Santos' advisers and service providers. Oil Search Shareholders have certain rights to access personal information that has been collected. Oil Search Shareholders should contact the Oil Search Share Registry in the first instance, if they wish to access their personal information. Oil Search Shareholders who appoint a named person to act as their proxy, attorney or corporate representative should ensure that they inform that person of these matters.

Santos estimates and reserves

The estimates of Santos' petroleum reserves and contingent resources contained in this Scheme Booklet are as at 31 December 2020. It is noted that Final Investment Decision was taken on the Barossa project post 31 December 2020 and it is expected that the associated contingent resource volumes will be reclassified to reserves at 31 December 2021. Outside of the Final Investment Decision taken during 2021, Santos is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Santos has conducted due diligence in relation to Oil Search's petroleum estimates but has not independently verified all such information and expressly disclaims any responsibility for it, to the maximum extent permitted by law. No representation or warranty, express or implied, is made as to the fairness, currency, accuracy, adequacy, reliability or completeness of Oil Search's petroleum estimates. Given Santos has not independently validated Oil Search's petroleum estimates, it should not be regarded as reporting, adopting or otherwise endorsing those estimates.

Santos prepares its petroleum reserves and contingent resources estimates in accordance with the 2018 Petroleum Resources Management System (**PRMS**) sponsored by the Society of Petroleum Engineers (**SPE**). Unless otherwise stated, all references to petroleum reserves and contingent resources quantities in this Scheme Booklet are Santos' net share. Reference points for Santos' petroleum reserves and production are defined points within Santos' operations where normal exploration and production business ceases, and quantities of produced product are measured under defined conditions prior to custody transfer. Fuel, flare and vent consumed to the reference points are excluded. Petroleum reserves are aggregated by arithmetic summation by category and as a result, proved reserves may be a very conservative estimate due to the portfolio effects of arithmetic summation. Petroleum reserves are typically prepared by deterministic methods with support from probabilistic methods. Conversion factors: 1PJ of sales gas and ethane equals 171,937 boe; 1 tonne of LPG equals 8.458 boe; 1 barrel of condensate equals 0.935 boe; 1 barrel of crude oil equals 1 boe.

The estimates of Santos' petroleum reserves and contingent resources in this Scheme Booklet are based on and fairly represent information and supporting documentation prepared by, or under the supervision of Mr Paul Lyford who is a full-time employee of Santos and a member of the SPE. Mr. Lyford meets the requirements of QPRRE as defined in Chapter 19 and rule 5.41 of the ASX Listing Rules and consents to the inclusion of this information in the form and context in which they appear in this Scheme Booklet. All estimates of petroleum reserves and contingent resources reported by Santos are prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator or evaluators. Processes are documented in the Santos Reserves Policy which is overseen by a Reserves Committee. The frequency of reviews is dependent on the magnitude of the petroleum reserves and contingent resources and changes indicated by new data. If the changes are material, they are reviewed by the Santos internal technical leaders and externally audited.

Santos engages independent experts GaffneyCline, Netherland, Sewell & Associates, Inc. and RISC Advisory Pty Ltd to audit and/or evaluate its reserves on an annual basis.

Oil Search estimates and reserves

The estimates of Oil Search's petroleum reserves and contingent resources contained in this Scheme Booklet are as at 31 December 2020. Oil Search is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed. Oil Search prepares its petroleum reserves and contingent resources estimates in accordance with the 2007 PRMS sponsored by the SPE. Unless otherwise stated, all references to petroleum reserves and contingent resources quantities in this Scheme Booklet are net share. The following reference points for Oil Search's petroleum reserves and production are assumed: (i) Oil volumes, include both oil and condensate recovered by lease processing, where reference point is at the outlet of the relevant process facility. Volumes are adjusted to stock-tank using field standard conditions; (ii) Hides GTE, the custody transfer point at the wellhead; (iii) PNG LNG Project, the outlet to the LNG plant; (iv) SE Gobe gas, the outlet to the Gobe facility; and (v) fuel, flare and shrinkage upstream of the reference points have been excluded. Petroleum reserves are aggregated by arithmetic summation by category and as a result, proved reserves may be a very conservative estimate due to the portfolio effects of arithmetic summation. Oil Search's reserves and contingent resources have been estimated using both deterministic and probabilistic methods. Conversion factors: Oil Search converts gas reserves to boe at the PNG LNG-specific ratio of 5100 scf/boe. Contingent resource gas converted to boe at 6000 scf/boe.

Oil Search has conducted due diligence in relation to Santos' petroleum estimates but has not independently verified all such information and expressly disclaims any responsibility for it, to the maximum extent permitted by law. No representation or warranty, express or implied, is made as to the fairness, currency, accuracy, adequacy, reliability or completeness of Santos' petroleum estimates. Given Oil Search has not independently validated Santos' petroleum estimates, it should not be regarded as reporting, adopting or otherwise endorsing those estimates.

The estimates of Oil Search's petroleum reserves and contingent resources in this Scheme Booklet are based on and fairly represent information and supporting documentation prepared by, or under the supervision of Mr Andrei Judzewitsch who is a full-time employee of Oil Search and a member of the SPE. Mr Judzewitsch meets the requirements of QPRRE as defined in Chapter 19 and rule 5.41 of the ASX Listing Rules and consents to the inclusion of this information in the form and context in which they appear in this Scheme Booklet.

Oil Search engages independent experts Netherland, Sewell & Associates, Inc. and Ryder Scott periodically to audit and/or evaluate its reserves. The estimated reserves are management assessments and take into consideration reviews by these independent third parties under the Company's reserves audit program which requires an external audit of each material producing field every three years as well as other assumptions, interpretations and assessments.

Pro forma estimates and reserves

Unless otherwise stated, the pro-forma petroleum reserve and resource estimates in this Scheme Booklet are expressed as a combination of (by arithmetic summation): (a) Santos' petroleum resource estimates sourced from, and quoted as at the balance date (ie, 31 December 2020) of the Reserves Statement in Santos' Annual Report for the year ended 31 December 2020 released to the ASX on 18 February 2021; and (b) Oil Search resource estimates sourced from, and quoted as at the balance date (ie, 31 December 2020) of the 'Reserves Statement' in Oil Search's Annual Report for the year ended 31 December released to ASX and PNGX on 23 February 2021.

Effect of rounding

A number of figures, amounts, percentages, estimates, calculations of value and fractions in this Scheme Booklet are subject to the effect of rounding. Accordingly, the actual calculation of these figures may differ from the figures set out in this Scheme Booklet.

Charts and diagrams

Any diagrams, charts, graphs or tables appearing in this Scheme Booklet are illustrative only and may not be drawn to scale. Unless stated otherwise, all data contained in diagrams, charts, graphs and tables is based on information available as at the Last Practicable Trading Date. Any discrepancies in any chart, graph or table between totals and sums of amounts presented or listed therein or to previously published financial figures are due to rounding.

Times and dates

Unless otherwise stated, all times referred to in this Scheme Booklet are times in Port Moresby, PNG. All times and dates are indicative only and are subject to the Court approval process and the satisfaction (or, where capable, waiver) of the Conditions Precedent to the implementation of the Scheme. The Conditions Precedent are summarised in section 9.13 and set out in full in clause 3.1 of the Merger Implementation Deed.

Currency and exchange

Unless otherwise stated, all references in this Scheme Booklet to:

- 'A$', 'AUD', 'Australian dollars' and 'cents' are to Australian currency;
- 'US$', 'USD' and 'US dollars' are to United States currency; and
- 'K' or 'PNG kina' are to PNG currency.

Date of this Scheme Booklet

This Scheme Booklet is dated 11 November 2021.

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Timetable and key dates

Event	Date
Date of this Scheme Booklet	**11 November 2021**
First Court Date	**11 November 2021**
Scheme Meeting Proxy Forms Last date and time for receipt of proxy forms (including proxies lodged online), powers of attorney or certificates of appointment of body corporate representatives for the Scheme Meeting.	11:00am (Sydney time) 10:00am (Port Moresby time) **Sunday, 5 December 2021**
Scheme Meeting Record Date Time and date for determining eligibility to vote at the Scheme Meeting.	7:00pm (Sydney time) 6:00pm (Port Moresby time) **Sunday, 5 December 2021**
Scheme Meeting As a result of the potential health risks associated with large gatherings and the ongoing COVID-19 pandemic, the Scheme Meeting will be virtual (online only). Oil Search Shareholders who participate in the Scheme Meeting via the online platform will be able to listen to the Scheme Meeting, cast an online vote and ask questions online. Further details relating to the Scheme Meeting are set out in section 3.5(b) of this Scheme Booklet and in the Notice of Meeting in Annexure E.	11:00am (Sydney time) 10:00am (Port Moresby time) **Tuesday, 7 December 2021**
If the Scheme is approved by Oil Search Shareholders at the Scheme Meeting	
Second Court Date For approval of the Scheme	**Thursday, 9 December 2021**
Effective Date The date on which the Scheme becomes Effective and is binding on Oil Search Shareholders. Announcement to the ASX and PNGX. Last day of trading in Oil Search Shares – Oil Search suspended from trading on the ASX and PNGX with effect from close of trading.	**Friday, 10 December 2021**
If the Scheme is approved by the Court and becomes Effective	
New Santos Shares commence trading on ASX on a deferred settlement basis [1]	**Monday, 13 December 2021**
Opt-in Notice Last date and time for receipt of Opt-in Notices by Unmarketable Parcel Shareholders requesting to receive the Scheme Consideration as New Santos Shares.	6:00pm (Sydney time) 5:00pm (Port Moresby time) **Monday, 13 December 2021**
Record Date Determination of entitlement of Scheme Shareholders to receive the Scheme Consideration.	7:00pm (Sydney time) 6:00pm (Port Moresby time) **Tuesday, 14 December 2021**
Implementation Date Transfer of all Scheme Shares to Santos and issue of Scheme Consideration to Scheme Shareholders (or Sale Agent on behalf of Ineligible Foreign Shareholders and those Unmarketable Parcel Shareholders who have not opted to receive New Santos Shares.) [2]	**Friday, 17 December 2021**
New Santos Shares trading commences on an ordinary settlement basis	**Monday, 20 December 2021**
Expected despatch of holding statements for New Santos Shares	**Monday, 20 December 2021**

All dates are indicative only and, among other things, are subject to all necessary approvals from the Court and any other regulatory authority. Any changes to the above timetable (which may include an earlier or later date for the Scheme Meeting or Second Court Hearing) will be announced through the ASX and PNGX and notified on Oil Search's Website.

All references to time in this Scheme Booklet are references to Port Moresby, PNG time, unless otherwise stated. Any obligation to do an act by a specified time in a PNG time zone must be done at the corresponding time in any other jurisdiction, other than the issue of New Santos Shares which will, at all times, align with the Sydney times displayed.

Oil Search Shareholders who have elected to receive communications electronically will receive an email that contains instructions about how to view or download a copy of this Scheme Booklet, and to lodge their proxy online. This Scheme Booklet will also be available for viewing and downloading on Oil Search's Website.

1) The exact number of New Santos Shares to be issued to you will not be known until after the Record Date and will not be confirmed to you until after you receive your holding statements following the Implementation Date. Therefore, please be aware that, if you trade in Santos Shares during the deferred settlement period and prior to receipt of your holding statement, you do so at your own risk. See sections 3.5(e) and 7.2(e) for further details.

2) New Santos Shares will be issued to the Sale Agent on behalf of Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares. See section 3.2(e) and section 3.2(f).

Letter from the Chairman of Oil Search

Richard Lee, AM Chairman, Oil Search Limited

11 November 2021

Dear Oil Search Shareholder,

On 10 September 2021, Oil Search and Santos announced that they had entered into a Merger Implementation Deed in relation to a proposed all-scrip merger of the two companies (the **Merger**). The Merger is to be effected by a scheme of arrangement under PNG law under which Santos will acquire all of the shares in Oil Search in return for the issue of New Santos Shares to Oil Search shareholders [1] (the **Scheme**) at a ratio of 0.6275 New Santos Shares for each Oil Search Share (the **Scheme Consideration**). [2] On implementation of the Scheme, existing Oil Search Shareholders would own approximately 38.5% of Santos (ie, the Merged Group) and existing Santos Shareholders would own approximately 61.5%.

In order for the Scheme to proceed, various conditions must be satisfied including approval at a meeting of Oil Search Shareholders (the **Scheme Meeting**) and then by the PNG National Court. The Scheme is also subject to certain PNG and other regulatory approvals being obtained, and to certain other conditions described in section 9.13(a).

The purpose of this Scheme Booklet is to provide you with information about the Scheme to assist you in voting on the Scheme at the Scheme Meeting.

Oil Search Board recommendation

The Oil Search Board unanimously recommends that Oil Search shareholders vote in favour of the Scheme, in the absence of a Superior Proposal. Each Oil Search Director intends to vote all the shares they hold or control in Oil Search in favour of the Scheme, again, in the absence of a Superior Proposal.

In its assessment of the Merger, the Board has had regard to a range of factors, including:

- the underlying values of Oil Search's and Santos' businesses, and each party's relative contribution to the underlying value of the Merged Group's business;
- the trading prices of Oil Search and Santos shares prior to announcement of the possible Merger on 20 July 2021, including the implied offer premium and each party's relative contribution to the pro-forma Merged Group market capitalisation, based upon those trading prices;
- the broader strategic, commercial and funding related benefits which the Board expects to flow from the Merger; and
- the future risks and challenges for Oil Search as a standalone entity.

Having regard to all of these factors, the Oil Search Board believes that Oil Search Shareholders will be better off if the Merger proceeds than if it does not.

Key reasons for the Oil Search Directors' recommendation

The key reasons for the Oil Search Directors' recommendation are as follows:

- The Merger brings together two highly complementary businesses and creates an oil and gas company of significant size with a portfolio of geographically and product diversified long-life and low-cost assets. The Merged Group portfolio will include: three producing LNG projects (PNG LNG, DLNG and GLNG); oil fields in PNG; two producing Australian gas hubs (Western Australia and Cooper Basin); and four major development projects (Alaska, Papua LNG, Dorado and Barossa).
- The Merged Group is expected to be positioned as one of the largest ASX-listed companies, sitting within the S&P/ASX 20 on a free float market capitalisation basis [3] and one of the top 20 largest global oil and gas companies on a total market capitalisation basis [4]. This increased financial scale and share liquidity is expected to give the Merged Group a greater relevance to equity markets and therefore an ability to attract a wider pool of both debt and equity investors.
- The Merger is expected to unlock material pre-tax synergies. Santos expects these pre-tax synergies to be between US$90 – US$115 million per annum (excluding integration and other one-off costs) after full integration. While there is no guarantee that this will be replicated in relation to the Merger, Santos has a track record, with respect to its recent acquisitions of both Quadrant Energy and ConocoPhillips' Northern Territory assets, in achieving and upsizing synergy estimates. See sections 1.1(c) and 6.3 for details of those expected synergies.

1) Other than Ineligible Foreign Shareholders or Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares, who will receive their respective pro rata proportion of the Sale Proceeds of the New Santos Shares which would otherwise have been issued to them under the Scheme.

2) If the Merger is not implemented until CY22 and either Santos or Oil Search pays a final CY21 dividend or interim CY22 dividend before the Implementation Date, the Scheme Consideration may be subject to adjustment for that dividend. See section 3.2(b).

3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.

4) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (ie, petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.

Key reasons for the Oil Search Directors' recommendation continued

- The implied value of the Scheme Consideration represents:
  - a 16.8% premium to the closing price of an Oil Search Share on 19 July 2021;
  - a 16.4% premium to the one-month volume weighted average price (**VWAP**) to 19 July 2021; and
  - a 16.0% premium to the three-month VWAP to 19 July 2021.

  Based on the closing price of Santos shares on 5 November 2021, being the Last Practicable Trading Date, the implied value of the Scheme Consideration is A$4.29 per Oil Search Share.
- Oil Search faces funding constraints on a standalone basis. The oil and gas sector is also subject to growing funding constraints, as capital and bank markets have responded to ESG concerns by reducing the flow of funding to the sector. The Merged Group will have significant financial scale and a strong funding platform as a result of:
  - the expected maintenance of Santos' 'investment grade' credit ratings, which enables Santos to access debt capital markets on more favourable terms;
  - the Merged Group's pro-forma liquidity is $5.7 billion – as at 30 June 2021, the pro-forma cash for the Merged Group was $2.9 billion and the pro-forma undrawn facilities were$2.8 billion;
  - the relatively modest financial leverage of the Merged Group, with pro-forma 2021 net debt/EBITDAX of 1.5 times; and
  - the combined cashflows from the two businesses.
- The Merged Group's improved funding platform should allow the Merged Group to maximise the value of its key development assets. It will assist the Merged Group in obtaining funding for its projects in a timely manner and on more favourable terms than Oil Search would be able to achieve on a standalone basis. This reduces the risk that Oil Search may need to sell-down growth projects prematurely, or agree development funding on less favourable terms. In particular, this funding platform should give the Merged Group the capacity to progress the development of Oil Search's Pikka project in Alaska in a timely manner, or otherwise realise value for Pikka on a more optimal basis.
- The potential for better alignment of joint venture interests across PNG projects. At present, Santos has a 13.5% interest in PNG LNG but has no interest in either P'nyang or the planned Papua LNG project, whereas Total Energies SE (the main proponent of the Papua LNG project) has no interest in PNG LNG or P'nyang. The Merged Group will have flexibility to sell down part of its 42.5% interest in PNG LNG, therefore potentially facilitating a realignment of interests across PNG LNG, P'nyang and Papua LNG. Such a realignment would be likely to improve coordination across these projects and, more importantly, help accelerate the development of Papua LNG and thereafter, P'nyang, as well as additional capacity in PNG LNG. This has the potential to deliver significant value accretion for the benefit of all participants.
- The Merged Group will benefit from the combined experience of both the Oil Search and Santos management teams and boards, with the expectation of further development and implementation of industry best practices and shared learnings across both organisations.
- The Merged Group will be formed from strong ESG foundations and is expected to build on each of Oil Search's and Santos' ESG programs and initiatives. The cash generated from the Merged Group's growth assets is expected to provide an increased capacity to invest in projects and technologies that will be required to build a sustainable business in a low carbon environment. It is expected that this strengthened financial profile will also provide greater optionality to invest in a greater number and variety of carbon reduction projects and technologies.

Risks and challenges for Oil Search as a standalone entity

While the Oil Search Board continues to believe in the strength and attractiveness of Oil Search's business and assets, Oil Search does face a number of risks and challenges on a standalone basis.

In particular, as mentioned above, it faces funding constraints which bear on its ability to develop its growth assets in a manner which maximises value for shareholders. Bank debt markets are becoming more difficult for oil and gas sector participants. Oil Search is unlikely to be able to secure an 'investment grade' credit rating due to its asset concentration, and incorporation, in PNG, and therefore cannot access more liquid global debt capital markets on attractive terms, if at all.

Oil Search faces major potential funding commitments in the near future, in relation to both the Pikka Phase 1 development in Alaska and the proposed Papua LNG project. This is particularly the case in relation to Pikka, which is approaching FID. If the Merger does not proceed, there is a risk that Oil Search is not able to realise funding for Pikka on acceptable terms. This is discussed in more detail in section 1.1.

Letter from the Chairman of Oil Search

Reasons why you may not want to vote in favour of the Merger

While the Oil Search Board unanimously recommends that Oil Search Shareholders vote in favour of the Scheme, it recognises that there are reasons why shareholders may not want to vote in favour of the Merger. These are set out in section 1.2, and include the following:

- You may wish to confine your investment and exposure to a business with Oil Search's specific characteristics on a standalone basis. Oil Search's main assets are its production and development assets in PNG and its development assets in Alaska. As stated above, the Merged Group will have a different operational profile and a different geographic, asset and earnings mix, which is expected to result in a number of benefits to Oil Search Shareholders as set out above, but may also include:
  - proportionally greater and earlier decommissioning costs than Oil Search on a standalone basis;
  - proportionally greater costs and risks relating to climate change and carbon emissions than Oil Search on a standalone basis. The Merged Group will have a higher greenhouse gas (**GHG**) intensity portfolio (see section 1.2(c)); and
  - lower operating margins on its assets outside of PNG. Please refer to section 7.3 for further details.
- You may take the view that the merger ratio implied by the Scheme Consideration does not give existing Oil Search Shareholders an appropriate share of the Merged Group and the combination benefits of the two business. As discussed above, the Scheme Consideration implies that on implementation of the Scheme, existing Oil Search Shareholders will own approximately 38.5% of the Merged Group and existing Santos Shareholders will own approximately 61.5%.
- You may also be dissuaded from voting in favour of the Scheme because:
  - of the risks associated with the integration of the Oil Search and Santos businesses. For example, while the Scheme is expected to deliver substantial synergies after full integration, these synergies are not guaranteed;
  - the future value of the New Santos Shares is not certain; and
  - the tax consequences of the Scheme for you may not suit your financial position.

Independent Expert

Oil Search appointed Grant Samuel as the Independent Expert to provide a report on whether the Merger is in the best interests of Oil Search shareholders. Grant Samuel has appointed GaffneyCline as the Independent Technical Expert to prepare the Independent Technical Expert's Report contained in the Independent Expert's Report.

In its report, the Independent Expert has concluded that the Merger is in the best interests of shareholders in the absence of a Superior Proposal. A complete copy of the report is included in Annexure A to this Scheme Booklet. Oil Search Shareholders should carefully review the Independent Expert's Report in its entirety.

Oil Search Shareholders should note that, in its report, the Independent Expert has made an assessment of the underlying value of each of Oil Search and Santos and, on the basis of its view of those relative underlying values, has suggested that Oil Search Shareholders are contributing a greater proportion to the underlying value of the Merged Group than the 38.5% which they will receive under the terms of the Merger. However, the Independent Expert also notes the strategic, commercial and funding benefits of the Merger, and has ultimately concluded that Oil Search Shareholders are likely to be better off if the Merger proceeds than if it does not.

The Independent Expert's Report is discussed further in section 1.3.

Letter from the Chairman of Oil Search

How to Vote

Your vote is important and I encourage you to vote on this significant proposed transaction by attending the Scheme Meeting scheduled to be held online at 11:00am (Sydney time) / 10:00am (Port Moresby time) on Tuesday, 7 December 2021 or alternatively, by appointing a proxy, attorney or, if you are a body corporate, a duly appointed corporate representative to attend and vote on your behalf. If you do not wish to, or are unable to, attend the Scheme Meeting, I encourage you to submit a directed proxy vote by either completing the proxy form enclosed with this Scheme Booklet or by lodging your proxy online at www.investorvote.com.au in accordance with the instructions there (as applicable) so that it is received by no later than 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021.

As at the Last Practicable Trading Date, if you hold 116 or less Oil Search Shares, you may be an Unmarketable Parcel Shareholder as at the Record Date. Scheme Shareholders who hold 116 Oil Search Shares or less as at the date of this Scheme Booklet will receive an Opt-In Notice and must opt-in to receive New Santos Shares as Scheme Consideration. Unless the Opt-In Notice is received prior to the Opt-In Notice Date (which is, based on the current timetable, expected to be 6:00pm (Sydney time) / 5:00pm (Port Moresby time) on Monday, 13 December 2021), Unmarketable Parcel Shareholders will receive a cash payment. Further detail is set out in section 3.2(f). The number of Oil Search Shares that deem a Scheme Shareholder to be an Unmarketable Parcel Shareholder may change as the trading price of Santos Shares fluctuates.

Even if you plan to attend the Scheme Meeting via the online platform, you are still encouraged to submit a directed proxy in advance of the Scheme Meeting so that your vote can still be counted if you encounter any issues in attending the Scheme Meeting (for example, if there is an issue with your internet connection on the day of the Scheme Meeting).

The Scheme will only be effective and implemented if it is approved by at least 75% of votes cast on the Scheme Resolution by Oil Search Shareholders.

If you wish for the Scheme to proceed, it is important that you vote in favour of the Scheme.

Further Information

This Scheme Booklet sets out important information regarding the Merger, including the reasons for the Oil Search Board's recommendation and the Independent Expert's Report. It also sets out reasons why you may wish to vote against the Scheme.

Please read this document carefully and in its entirety as it will assist you in making an informed decision on how to vote. I would also encourage you to seek independent financial, legal and taxation advice before making any investment decision in relation to your shares.

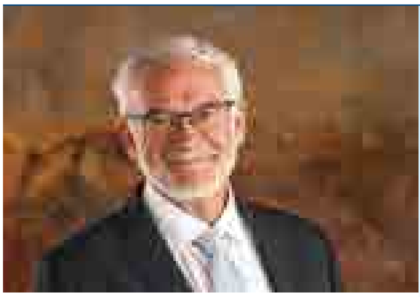
If you require any further information, please call the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9:00am and 5:00pm (Sydney time) other than public holidays in Sydney, Australia

On behalf of the Oil Search Board, I would like to thank you for your ongoing support.

I look forward to your participation in the Scheme Meeting and encourage you to vote in favour of the Merger, which the Oil Search Directors believe, is in the best interests of Oil Search Shareholders.

Yours sincerely

Richard Lee, AM
Chairman
Oil Search Limited



Letter from the Chairman of Santos

Keith Spence Chairman, Santos Limited

Dear Oil Search Shareholder,

On behalf of the Santos Board, I am pleased to provide you with the opportunity to participate in the all-scrip combination between Santos and Oil Search. The Merger will create a regional champion of size and scale with a diversified portfolio of long-life, low-cost oil and gas assets and a pro forma market capitalisation of approximately A$23 billion. [1]

Under the Merger, Oil Search Shareholders will receive 0.6275 new Santos Shares for each Oil Search Share held on the Record Date. [2] On completion of the Merger, Oil Search Shareholders will own approximately 38.5% of Santos.

Since the implementation of Santos' *Transform, Build and Grow* strategy in 2016, Santos has generated some of the strongest shareholder returns of our ASX-listed oil and gas peers. Moreover, Santos' low-cost and disciplined operating model positions Santos well to continue to deliver strong shareholder returns into the future. Oil Search shareholders now have an opportunity to participate in the potential benefits flowing from being a Santos shareholder, whilst retaining exposure to Oil Search's businesses and assets.

The Merger will combine two industry leaders to create a merged entity expected to be among the top-20 ASX-listed companies by market capitalisation [3] and the 20 largest global oil and gas companies by market capitalisation. [4] More broadly, the Merger will offer Oil Search and Santos shareholders the opportunity to be shareholders in a merged entity with:

- greater relevance to the equity market with the size and liquidity to attract a wider pool of investors;
- a unique and diversified portfolio of high-quality, long-life and low-cost oil and gas assets;
- a strong balance sheet and ESG credentials providing improved access to additional capital to fund growth and the energy transition with an investment grade credit rating;
- the capability to unlock expected pre-tax combination synergies of US$90-115 million per annum; [5]
- increased opportunities for optimisation of the combined portfolio through the alignment of joint venture interests across PNG projects; and
- market-leading ESG initiatives through the combination of Santos' leading carbon capture and storage capability and Oil Search's unique social initiatives in PNG and the United States of America.

Santos is Australia's largest domestic gas supplier, a leading Asia Pacific LNG supplier and aims to be a world-leading gas and liquid fuels company. Sustainability is core to driving long-term shareholder value.

Santos has played a significant role in meeting the energy security needs of Australia and Asia by supplying reliable and affordable natural gas for more than 50 years. As the world transitions to a low-carbon economy, Santos expects to continue to meet the energy needs of our customers.

Santos is an industry-leader in the energy transition and has previously announced that it intends to pursue a net zero scope 1 and 2 emissions by 2040 target. Our response to climate change management is embedded within our business strategy and has delivered clear results, including reducing our emissions intensity per unit of production by 20 per cent in the past three years.

Our decarbonisation ambitions includes investment in critical emission reduction technologies like carbon capture and storage (**CCS**). In November 2021, we took the final investment decision on our Moomba CCS project in the Cooper Basin following the successful registration of the project with the Clean Energy Regulator. Moomba CCS is one of the largest and lowest-cost CCS projects globally and will have the capacity to capture and store underground approximately 1.7 million tonnes of CO_2 per annum. In addition, we have signed a Memorandum of Understanding with the Timor-Leste regulator to consider repurposing Bayu-Undan facilities into a CCS project with capacity to store up to 10 million tonnes of CO_2 per annum.

1) Based on closing price of $4.23 for Oil Search and $6.83 for Santos on 5 November 2021, being as at the Last Practicable Trading Date.
2) If the Merger is not implemented until CY22 and either Santos or Oil Search pays a final CY21 dividend or interim CY22 dividend before the Implementation Date, the Scheme Consideration may be subject to adjustment for that dividend. See section 3.2(b).
3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.
4) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.
5) The following items have factored into the calculation of the expected pre-tax synergies (excluding integration and one-off costs) expected to be unlocked through the Merger: integration of procurement, contracting and development costs; reduced corporate overheads; reduced information technology and borrowing costs; efficiencies from organisational optimisation. The potential synergy numbers represent current expectations, and are subject to a number of assumptions, including as to future events which involve inherent uncertainties and contingencies. The final synergy value will only be determined following implementation of the Scheme and completion of the Merged Group's detailed review of its operations. Please refer to section 6.3 for further information in respect of the expected synergies and their value and section 7.2(f) for the associated risks in relation to realisation of such synergies.

Letter from the Chairman of Santos

CCS is also a potential enabler for the production of low or net zero emission hydrogen from natural gas and emerging technologies such as direct air capture. The IPCC and IEA both recognize the importance of CCS to achieve global emission reduction targets and the Merged Group will benefit from this technology and experience that Santos brings. Our access to depleted gas reservoirs in a number of our core assets not only provides the opportunity to develop CCS at scale, but also provides the opportunity to defer decommissioning expenditure at mature assets. In November 2021, we announced that Santos is partnering with Australia's national science agency, CSIRO, to develop direct air capture technology which removes CO_2 directly from the atmosphere. The CO_2 can then be safely and stored in CCS projects. The technology will be trialled at Moomba in South Australia, from where the captured CO_2 will be transported to Santos' Moomba CCS project.

These projects represent the intent to commit real capital towards a decarbonisation pathway for Santos assets, and which Oil Search shareholders can share in the benefits from, post-merger.

Santos is a high performance business that is sustainable through the commodity price cycle and has a proven track record as a low-cost operator with a diversified portfolio of five core producing assets and attractive growth projects spanning Australia, Papua New Guinea and Timor-Leste which Oil Search shareholders will benefit from. Santos, as an operator of the majority of our assets in the portfolio, has increased optionality to optimise the assets in the Merged Group through sell downs and create strategic alignment across the projects.

Santos believes the Merger is a logical and strategic oil and gas industry M&A transaction that the Santos Board considers will be beneficial to Oil Search and Santos shareholders as detailed in this Scheme Booklet.

The Oil Search Board has unanimously recommended that you vote in favour of the Scheme, in the absence of a Superior Proposal. In addition, the Merger is unanimously supported and endorsed by the Santos Board, who consider this transaction to be a unique and compelling opportunity to deliver shareholder value.

I encourage you to read this Scheme Booklet carefully and vote in favour of the Scheme at the Scheme Meeting to be held on 7 December 2021. As an Oil Search shareholder, your vote is important to ensure that the Merger is implemented for the expected benefit of both Oil Search shareholders and Santos shareholders.

I look forward to welcoming you as a shareholder of Santos following the successful implementation of the Merger.

Yours sincerely,

Keith Spence
Chairman, Santos Limited

1 Key considerations relevant to your vote

Key reasons to vote **FOR** the Merger
✔ The Merger brings together two highly complementary businesses and creates an oil and gas company of significant size with a portfolio of geographically and product diversified long-life and low-cost assets.
✔ The Merged Group is expected to have greater relevance to the equity market with the size and liquidity to attract a wider pool of investors.
✔ The Scheme is expected to unlock material pre-tax synergies. Santos expects these pre-tax synergies to be between US$90 and US$115 million per annum (excluding integration and other one-off costs) after full integration.
✔ The implied value of the Scheme Consideration represents a premium to the trading prices of Oil Search shares prior to announcement of the Scheme.
✔ The Merged Group will have both scale and a strong funding platform. Oil Search faces funding constraints on a standalone basis. The Merged Group's improved funding platform should allow the Merged Group to maximise the value of its key development assets.
✔ The Merged Group is expected to benefit from increased opportunities for optimisation of the combined portfolio through the alignment of joint venture interests across PNG projects.
✔ The Merged Group will benefit from the combined experience of both the Oil Search and Santos management teams and boards.
✔ The Merged Group will be formed from strong ESG foundations and is expected to build on each of Oil Search's and Santos' ESG programs and initiatives.

Key reasons to vote **AGAINST** the Merger
✘ You may wish to confine your investment and exposure to a business with Oil Search's specific characteristics on a stand-alone basis.
✘ You may take the view that the merger ratio implied by the Scheme Consideration does not reflect the underlying value of Oil Search's contribution to the Merged Group.
✘ You may be concerned about the risks associated with the integration of the Oil Search and Santos businesses.'
✘ The future value of the New Santos Shares is not certain.
✘ The tax consequences of the Scheme for you may not suit your financial position.
✘ You may consider that there is a potential for a Superior Proposal to be made in the foreseeable future.

1 Key considerations relevant to your vote

The Scheme has a number of advantages and disadvantages which may affect Oil Search Shareholders in different ways depending on their individual circumstances. Oil Search Shareholders should seek professional advice on their particular circumstances, as appropriate. While Oil Search Directors acknowledge the reasons to vote against the Scheme, they believe the advantages of the Scheme outweigh the disadvantages.

This section 1 contains the following:

– section 1.1 provides a summary of the reasons why the Oil Search Board unanimously recommends that Oil Search Shareholders should vote in favour of the Scheme;

– section 1.2 sets out reasons why you may wish to vote against the Scheme; and

– section 1.3 sets out the conclusion reached by the Independent Expert on the Scheme, as contained in the Independent Expert's Report, a complete copy of which is included as Annexure A to this Scheme Booklet.

You should read this Scheme Booklet in full, including the Independent Expert's Report, before deciding how to vote at the Scheme Meeting.

1.1 Why you should vote in favour of the Scheme

In its assessment of the Merger, the Board has had regard to a range of factors, including:

– the underlying values of Oil Search's and Santos' businesses, and each party's relative contribution to the underlying value of the Merged Group's business;

– the trading prices of Oil Search and Santos shares prior to announcement of the possible Merger on 20 July 2021, including the implied offer premium and each party's relative contribution to the pro-forma Merged Group market capitalisation, based upon those trading prices;

– the broader strategic, commercial and funding related benefits which the Board expects to flow from the Merger; and

– the future risks and challenges for Oil Search as a standalone entity.

The key reasons for the Oil Search Directors' recommendation are as follows.

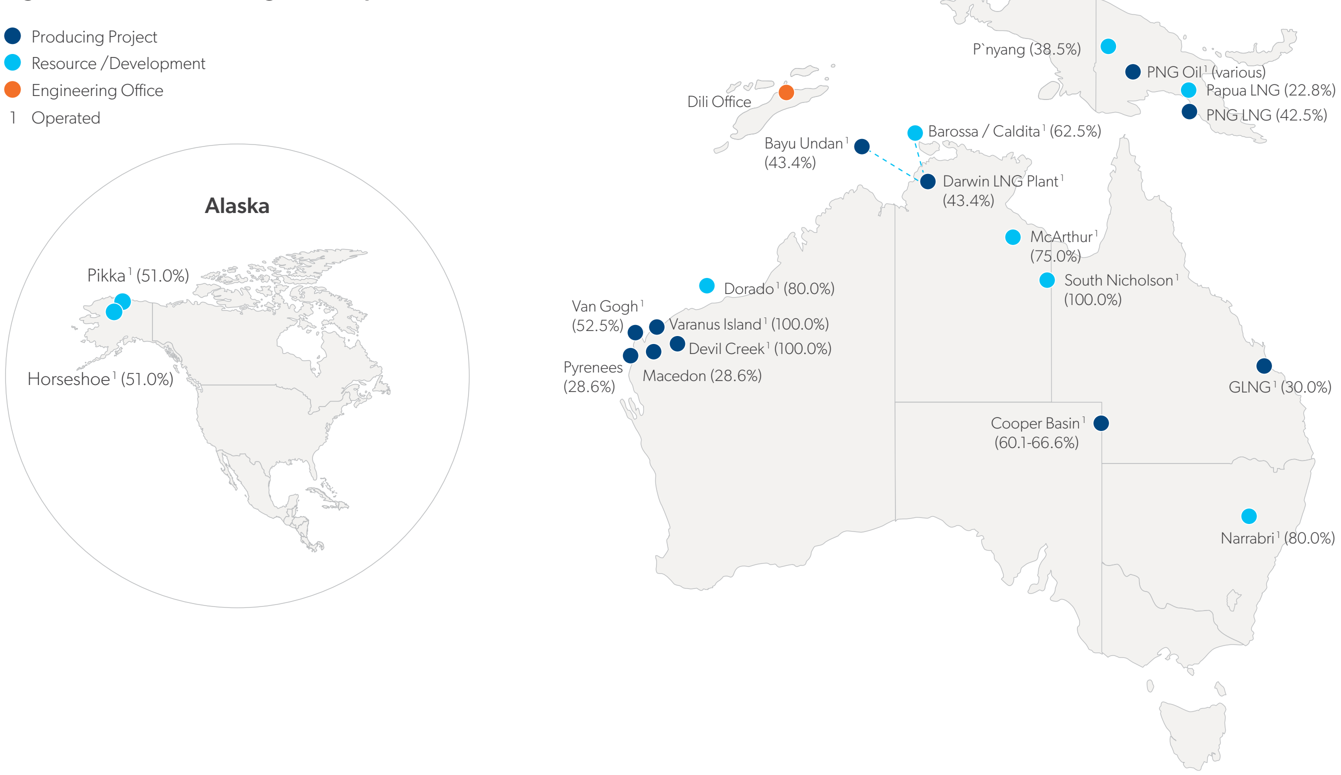
a) The Merger will create a significant oil and gas company with geographic and asset diversification

The Merger brings together two highly complementary businesses and creates a significant oil and gas company with a portfolio of geographically and product diversified long-life and low-cost assets. The Merged Group will have high-quality, long-life, low-cost assets across Australia, PNG, Timor-Leste and the United States of America with significant growth optionality. Through its scale and operating capacity across procurement, marketing and trading, the Merged Group will be well placed to compete with global peers.

The diversified portfolio of the Merged Group will enable it to have multiple independent sources of low-cost cash flows making it resilient throughout the oil price cycle. In addition, the Merged Group's operated footprint across major assets will assist in managing development timelines and maximise value.

The Merged Group portfolio will include three producing LNG projects (PNG LNG, Darwin LNG and GLNG); producing oil fields in PNG; two producing Australian gas hubs (Western Australia and Cooper Basin); and four major development projects (Alaska, Papua LNG, Dorado and Barossa).

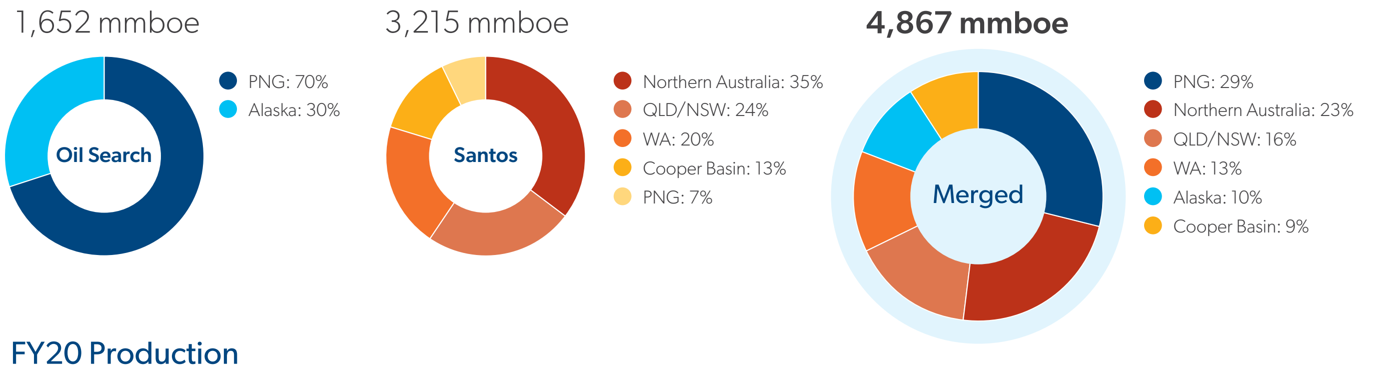
Figure 1: Location of Merged Group assets



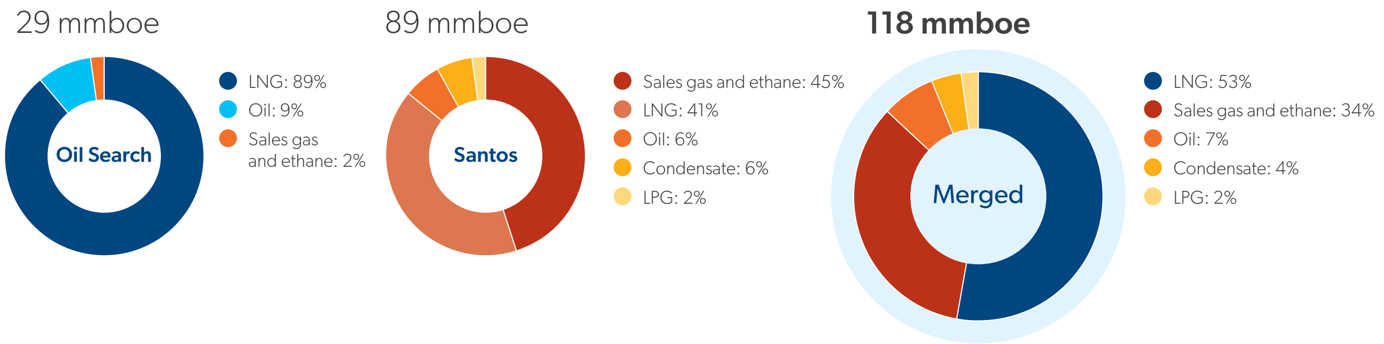
a) The Merger will create a significant oil and gas company with geographic and asset diversification continued

Figure 2: Reserves and resources[1]

Reserves and Resources (2P + 2C)



FY20 Production



b) The Merged Group is expected to have greater relevance to global equity markets with the size and liquidity to attract a wider pool of investors

The Merged Group is expected to:

i) be positioned as one of the largest ASX-listed companies, sitting within the S&P/ASX 20 on a free float market capitalisation basis,[2] with a pro forma market capitalisation of approximately A$23 billion;[3]

ii) be one of the top 20 largest global oil and gas companies on a total market capitalisation basis;[4] and

iii) have greater equity market relevance as a result of this increased size and liquidity, with the potential to attract a wider pool of investors.

c) The Merger is expected to unlock material pre-tax synergies. Santos expects these pre-tax synergies to be between US$90 – US$115 million per annum (excluding integration and other one-off costs) after full integration

Santos has identified opportunities to deliver between US$90 and US$115 million per annum (excluding integration and other one-off costs) of cost synergies after full integration.

Santos expects the annual synergies to be realised through a combination of operational and corporate efficiencies, including:

- integration of procurement, contracting and development;
- reduction of corporate overheads, listing, audit, board, information technology, insurance and borrowing costs; and
- leveraging operations and maintenance capability across the portfolio.

While there is no guarantee that this will be replicated in relation to the Merger, Santos has a track record, with respect to its recent acquisitions of both Quadrant Energy and ConocoPhillips' Northern Territory assets, in achieving and upsizing synergy estimates.

Upon implementation, existing Oil Search Shareholders will own approximately 38.5% of the Merged Group and will therefore benefit from approximately 38.5% of the impact of any realised synergies.

Further information regarding the potential cost synergies expected to result from implementation of the Scheme can be found in section 6.2(d) and 6.3.

1) Numbers may not add due to rounding.

2) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.

3) Calculated by adding the ASX market capitalisation of Oil Search at the Last Practicable Trading Date to the ASX market capitalisation of Santos as at the Last Practicable Trading Date.

4) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.

d) The implied value of the Scheme Consideration represents a premium to the recent trading prices of Oil Search Shares prior to announcement of the Scheme

The implied value of the Scheme Consideration represents:

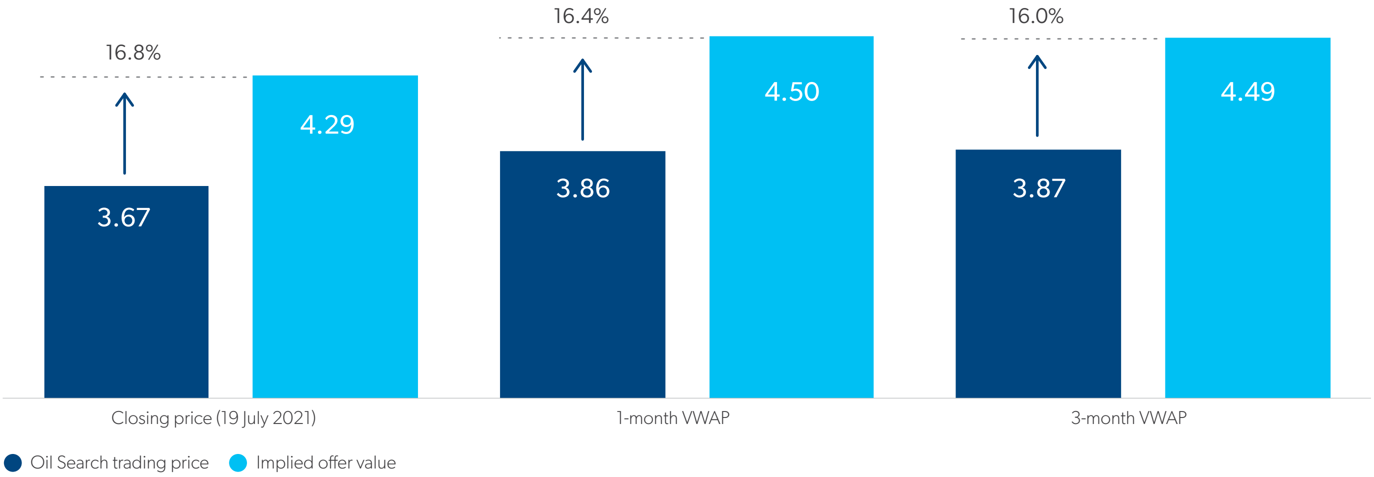
i) a 16.8% premium to the closing price of an Oil Search Share on 19 July 2021;

ii) a 16.4% premium to the one-month VWAP to 19 July 2021; and

iii) a 16.0% premium to the three-month VWAP to 19 July 2021.[1]

Based on the closing price of Santos Shares on 5 November 2021, being the Last Practicable Trading Date, the implied value of the Scheme Consideration is A$4.29 per Oil Search Share.

Figure 3: Implied value of the scheme consideration (as at 19 July 2021)



e) The Merged Group will benefit from a strengthened financial profile

Oil Search faces funding constraints on a standalone basis. The oil and gas sector is also subject to growing funding constraints, as capital and bank markets have responded to ESG concerns by reducing the flow of funding to the sector. The Merged Group will have both scale and a strong funding platform as a result of, amongst other factors:

i) the expected maintenance of Santos' 'investment grade' credit ratings, which enables Santos to access larger, more liquid global debt capital markets on more favourable terms. Oil Search is unlikely to secure an 'investment grade' credit rating;

ii) the Merged Group's pro-forma liquidity is $5.7 billion – as at 30 June 2021, the pro-forma cash for the Merged Group was $2.9 billion and the pro-forma undrawn facilities were $2.8 billion;[2]

iii) the relatively modest financial leverage of the Merged Group with pro-forma 2021 net debt/EBITDAX of 1.5 times); and

iv) the combined cashflows from the two businesses.

Santos currently has an investment grade credit rating with two ratings agencies, being rated BBB by Fitch and BBB- by S&P. The Merged Group is expected to retain these 'investment grade' credit ratings following the Merger, however, credit rating agencies will only update their credit assessments post completion of the transaction.

This improved funding platform should allow the Merged Group to maximise the value of its key development assets. It will assist the Merged Group in obtaining funding for these projects in a timely manner and on more favourable terms than Oil Search would be able to achieve on a standalone basis.

Oil Search faces major potential funding commitments, both in relation to Pikka Phase 1 development in Alaska and the proposed Papua LNG project. This is particularly the case in relation to Pikka, which is approaching FID. In February 2021, Oil Search announced that it intended to sell down a 15% equity interest in the project (i.e. reducing its stake to 36%). Such a sale would reduce Oil Search's funding obligation while providing further commercial and technical validation of the project. To date, no divestment of interest has occurred. The Merged Group's funding platform should provide the Merged Group the funding capacity to progress the development of Oil Search's Pikka project in Alaska in a timely manner, or otherwise realise value for Pikka on an optimal basis. This funding platform should also assist the Merged Group to fund other key development projects, such as Papua LNG, Dorado and Barossa.

The oil and gas sector is subject to growing funding constraints, as capital and bank markets have responded to ESG concerns by reducing the flow of funding to the sector. Oil Search is unlikely to be able to secure an 'investment grade' credit rating whilst being incorporated in PNG, and therefore cannot access debt capital markets on attractive terms. The Merged Group's scale and strong funding platform position also mean that it is better placed to deal with these constraints than Oil Search on a standalone basis.

1) Based on the closing price of Santos Shares and Oil Search Shares on 19 July 2021 being the last trading day prior to the announcement of the non-binding indicative merger proposal from Santos on 20 July 2021. Based on that closing price of Santos shares on 19 July 2021 the Scheme Consideration had an implied value of A$4.29 per Oil Search Share at that time.

2) Based on the arithmetic sum of Santos and Oil Search liquidity (comprising cash and committed undrawn debt facilities) as at 30 June 2021 as disclosed in Santos' and Oil Search's 2021 half year results and assuming the facilities currently available to Santos and Oil Search either remain in place or are replaced with facilities with equivalent limits.

f) The Merged Group is expected to benefit from increased opportunities for optimisation of the combined portfolio through the alignment of joint venture interests across PNG projects

Following the Merger, the Merged Group will hold an enhanced position in the world-class PNG LNG project. It will subsequently have the ability to improve alignment between the PNG LNG and Papua LNG projects, supporting the Papua LNG final investment decision, jobs growth and long-term income for the Independent State of Papua New Guinea and its people.

At present, Santos has a 13.5% interest in PNG LNG but has no interest in either P'nyang or the planned Papua LNG project, whereas Total Energies SE (the main proponent of the Papua LNG project) has no interest in PNG LNG or P'nyang.

The Merged Group will have flexibility to sell down part of its 42.5% interest in PNG LNG, therefore potentially facilitating a realignment of interests across PNG LNG, P'nyang and Papua LNG. Such a realignment would be likely to improve coordination across these projects and, more importantly, help accelerate the development of P'nyang and Papua LNG as well as additional capacity in PNG LNG. This has the potential to deliver significant value accretion for the benefit of all participants.

g) The Merged Group will benefit from the combined experience of both the Oil Search and Santos management teams and board

The Merged Group will benefit from the combined experience of both the Oil Search and Santos management teams and boards, with the expectation of further development and implementation of industry best practices and shared learnings across both organisations. The Chief Executive Officer and Managing Director of the Merged Group will be the current Santos Chief Executive Officer and Managing Director, Mr Kevin Gallagher.

h) The Merged Group will be formed from strong ESG foundations and is expected to build on each of Oil Search's and Santos' ESG programs and initiatives

The Merged Group will be formed from strong ESG foundations and is expected to build on each of Oil Search's and Santos' ESG programs and initiatives. See sections 4.5 and 5.5 for a description of Oil Search's and Santos' existing programs, and section 6.2(e) in relation to the Merged Group.

The cash generated from the Merged Group's growth assets is expected to provide an increased capacity to invest in projects and technologies that will be required to build a sustainable business in a low carbon environment. It is expected that this strengthened financial profile should also provide greater optionality to invest in a greater number and variety of carbon reduction projects and technologies.

i) The all-scrip Scheme Consideration means existing Oil Search Shareholders will participate in the expected benefits of combining the two businesses

On implementation of the Scheme, existing Oil Search Shareholders will own approximately 38.5% of the Merged Group. The all-scrip Scheme Consideration means that Scheme Shareholders will become shareholders in the Merged Group and will access the expected benefits of combining with Santos, while retaining exposure to Oil Search's portfolio of world-class assets. Shareholders in the Merged Group may be able to access dividend franking credits to the extent that franked dividends are declared by Santos in respect of Australian income of the Merged Group for 'qualified persons' under applicable Australian laws. Oil Search has not historically paid franked dividends.

Oil Search Shareholders are also expected to benefit from a high-quality management team that will be selected based on the principle that the best executive for the job will be offered the relevant role having regard to the skills, experience, knowledge and expertise required to manage the Merged Group and its assets.

j) Since the announcement of Santos' non-binding indicative proposal to the ASX no Superior Proposal has emerged

Since the announcement of Santos' non-binding indicative merger proposal to the ASX on 20 July 2021 and up to the date of this Scheme Booklet, no Competing Proposal has emerged and, as at the date of this Scheme Booklet, the Oil Search Board is not aware of any Competing Proposal that is likely to emerge.

1.2 Why you may wish to vote against the Merger

While the Oil Search Board unanimously recommends that Oil Search Shareholders vote in favour of the Scheme, it recognises that there are reasons why shareholders may not want to vote in favour of the Merger, including the following.

a) You may wish to confine your investment and exposure to a business with Oil Search's specific characteristics on a standalone basis

While the Oil Search and Santos businesses are largely complementary, the operational profile, size and asset geography and exposure, earnings mix and risk profile of the two companies on a standalone basis are different. Sections 4 and 5 set out further detail on the standalone businesses of Oil Search and Santos respectively. Further information about the Merged Group can be found in section 6.

Oil Search Shareholders may wish to keep their Oil Search Shares and preserve their investment in a publicly listed company with the specific characteristics of Oil Search (such as its current operational profile, operating margins, capital structure, size and geography). The change in investment profile under the Merger may be a disincentive to such shareholders.

b) You may take the view that the merger ratio implied by the Scheme Consideration does not reflect the underlying value of Oil Search's contribution to the Merged Group

You may take the view that the merger ratio implied by the Scheme Consideration does not give existing Oil Search Shareholders an appropriate share of the Merged Group and the combination benefits of the two business. As discussed above, the Scheme Consideration implied that on implementation of the Scheme, existing Oil Search Shareholders would own approximately 38.5% of the Merged Group and existing Santos Shareholders would own approximately 61.5%.

In its report, the Independent Expert has made an assessment of the underlying value of each of Oil Search and Santos and on the basis of those relative underlying values has expressed a view that Oil Search Shareholders are contributing a greater proportion to the underlying value of the Merged Group than the 38.5% which they will receive under the terms of the Merger. The Independent Expert's Report is discussed further in section 1.3. Oil Search Shareholders should carefully review the Independent Expert's Report in its entirety.

c) You may be concerned about certain additional risks associated with Santos' business

If the Scheme is implemented, there will be a change in the risk profile to which Oil Search Shareholders are exposed. Oil Search Shareholders are currently exposed to various risks as a result of their investment in Oil Search. If the Scheme is implemented, Oil Search will merge its business with that of Santos and Oil Search Shareholders will receive New Santos Shares. As a consequence, Scheme Shareholders will be exposed to risk factors relating to Santos, and to certain additional risks relating to the Merged Group and the integration of the two companies. These include risks relating to the operation of a broader suite of assets than Oil Search currently operates, different geographies that Oil Search is not currently exposed to, and other risks relating to the two companies.

In particular, the profile of the Merged Group may include:

i) proportionally greater and earlier decommissioning costs;

ii) proportionally greater costs and risks relating to climate change and carbon emissions than Oil Search on a standalone basis as the Merged Group will have a higher greenhouse gas (**GHG**) intensity portfolio; and

iii) lower operating margins on its assets outside of PNG.

In relation to the GHG intensity of the Merged Group portfolio, you may consider that the energy market is likely to move towards supply from lower GHG intensity projects for existing and future energy demand. Santos and therefore the Merged Group may have higher potential exposure to future regulatory changes leading to higher carbon prices and taxes than Oil Search as a standalone entity given the majority of its assets are in Australia and the emissions intensity of the Merged Group portfolio is higher (noting, however, that Santos' Australian producing assets operate under the Safeguard Mechanism and have approved carbon emissions baselines which are not currently the subject of any carbon costs, but may be exposed in the future). This means that the consequences of this risk may be greater for the Merged Group than Oil Search as a standalone entity. The Merged Group's portfolio will have production capacity with greater GHG emissions intensity per barrel of oil equivalent compared to Oil Search on a standalone basis. The GHG intensity of Oil Search's standalone portfolio for calendar year 2020 is 31 ktCO2e / mmboe compared to 55 ktCO2e / mmboe for Santos's standalone portfolio for the financial year ended 30 June 2020 on a scope 1 and scope 2 basis.[1] This higher GHG intensity portfolio may change demand for products, increase exposure to higher costs associated with carbon prices and taxes and have additional financial, reputational and compliance risks.

In relation to the lower operating margins on its assets outside of PNG, you should note that the PNG LNG assets will represent a reduced proportion of the Merged Group asset portfolio, and you may therefore be concerned that the Merged Group's portfolio of producing assets will have a lower overall EBTIDAX margin than the standalone Oil Search portfolio. Santos' EBITDAX margin for the consolidated Group is 54% compared to Oil Search's consolidated EBITDAX margin of 67% for the year ended 31 December 2020. The Merged Group will, however, benefit from a diversified portfolio of assets and a mixture of fixed price gas and oil linked revenue streams.

Additionally, there are a number of risks specific to holding New Santos Shares which are described in further detail in section 7.3.

Oil Search Shareholders should take these risks into account before deciding whether or not to vote in favour of the Scheme.

d) You may be dissuaded from voting in favour of the Scheme because of the risks associated with the integration of the Oil Search and Santos businesses

As detailed in section 6.3 of this Scheme Booklet, one of the benefits of the Scheme is the potential for the Merged Group to realise synergies and efficiencies following implementation of the Scheme. It is expected that these synergies will take time to be fully realised across the Merged Group.

However, you may consider that the integration of Oil Search and Santos may be more difficult, may take more time, or may cost more than currently anticipated. Oil Search Shareholders may also believe that a failure to achieve a meaningful level of synergies within an acceptable timeframe or in their entirety may have an unforeseen or adverse effect on the operations, financial performance or financial position of the Merged Group.

Further information regarding risks associated with the integration of Oil Search and Santos can be found in section 7.3.

e) The future value of the New Santos Shares is not certain

If the Scheme is implemented, Oil Search Shareholders (other than an Ineligible Foreign Shareholder or Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares) will receive New Santos Shares. The value of these New Santos Shares will depend on the price at which Santos Shares trade on the ASX on or after the Effective Date.

1) All GHG intensity numbers are in relation to the equity portfolio GHG emissions.

e) The future value of the New Santos Shares is not certain continued

Following implementation of the Scheme, the price of Santos Shares may rise or fall based on market conditions and the Merged Group's financial and operational performance. If the price of Santos Shares falls, the value of New Santos Shares received as Scheme Consideration will decline. If the price of Santos Shares increases, the value of the New Santos Shares received as Scheme Consideration will increase.

As such, there is no guarantee as to the future value of the Scheme Consideration to be received by Oil Search Shareholders if the Scheme is implemented.

f) The tax consequences of the Scheme for you may not suit your financial position

Implementation of the Scheme may trigger different or adverse taxation consequences for certain Oil Search Shareholders. The tax treatment may vary depending on the nature and characteristics of each Oil Search Shareholder and their specific circumstances. The tax consequences of the Scheme may not suit an Oil Search Shareholder's financial position. A general guide to the taxation implications of the Scheme is set out in section 8. This guide is expressed in general terms only and Oil Search Shareholders should seek professional taxation advice regarding the tax consequences applicable to their own circumstances.

g) You may consider that there is a potential for a Superior Proposal to be made in the foreseeable future

It is possible that, if Oil Search were to continue as an independent listed entity, a Superior Proposal could materialise in the future, such as a takeover bid with a higher price or an alternative proposal with better long-term prospects for the Oil Search businesses. Implementation of the Scheme will mean that Oil Search Shareholders will not receive the benefit of any such proposal.

However, since the announcement of Santos' non-binding indicative merger proposal to the ASX on 20 July 2021 and up to the date of this Scheme Booklet, no Competing Proposal has emerged and, as at the date of this Scheme Booklet, the Oil Search Board is not aware of any Competing Proposal that is likely to emerge.

1.3 What is the opinion of the Independent Expert?

Oil Search appointed Grant Samuel as the Independent Expert to provide a report on whether the Merger is in the best interests of Oil Search Shareholders. Grant Samuel appointed GaffneyCline as the Independent Technical Expert to prepare the Independent Technical Expert's Report contained in the Independent Expert's Report.

The Independent Expert notes that "The PNG Companies Act and the PNG regulatory regime generally do not prescribe the preparation of a "best interests" opinion and so accordingly there is no relevant legal definition of the expression "in the best interests". Given that the Scheme is proceeding under PNG law and regulation, Australian regulation is not applicable. In this context, Grant Samuel has assumed that the Merger will be in the best interests of Oil Search shareholders if they are likely to be better off if the Merger proceeds than if it does not."

The Independent Expert's Report provides that: "*In the circumstances, an overall judgement on the merits of the Merger is finely balanced. At a minimum, Grant Samuel believes that it is appropriate for the Merger to be put before shareholders for their consideration. Grant Samuel's view is that Oil Search shareholders are likely to be better off if the Merger proceeds than if it does not. Accordingly, the Merger is in the best interests of shareholders, in the absence of a superior proposal.*"

A complete copy of the report is included in Annexure A to this Scheme Booklet. Oil Search Shareholders should carefully review the Independent Expert's Report in its entirety.

Oil Search Shareholders should note that, in its report, the Independent Expert has made an assessment of the underlying value of each of Oil Search and Santos and, on the basis of its view of those relative underlying values, has suggested that Oil Search Shareholders are contributing a greater proportion to the underlying value of the Merged Group than the 38.5% which they will receive under the terms of the Merger. However, the Independent Expert also notes the strategic, commercial and funding benefits of the Merger, and has ultimately concluded that Oil Search Shareholders are likely to be better off if the Merger proceeds than if it does not.

In the Independent Expert's summary of their opinion on page 2 of the Independent Expert's Report, the Independent Expert states that:

> *Grant Samuel's analysis suggests that the financial terms of the Merger are not reflective of the relative contributions of underlying value by Oil Search and Santos. Oil Search shareholders are contributing around 43-44% of the aggregate estimated underlying value of the Merged Group compared to the 38.5% of the Merged Group that they will receive. Even after taking into account the value of the cost savings expected to be realised, the analysis indicates that the Merger will result in a reduction in the underlying value attributable to Oil Search shareholders.*
>
> *These relativities do not correspond with those based on share market values. On one view, underlying value is in any event of limited relevance, since shareholders could only access underlying value through a fully priced cash takeover offer for Oil Search. Parties who might be interested in bidding for Oil Search will have had ample opportunity to do so prior to the Scheme meeting to approve the Merger. In the absence of such an offer, shareholders could justifiably attribute more significance to share market values. The Merger terms provided a premium to Oil Search shareholders of around 16% at the time of announcement of the Merger.*
>
> *A relative weighting of the valuation issues against the broader benefits of the Merger is not straightforward. The dilution of underlying value implied by the Merger terms is material. There is clearly a risk that the funding and other strategic benefits do not fully compensate shareholders for this dilution. On the other hand:*
>
> - *the options to maximise the value realised for Pikka and, over time, to optimise the development of its PNG interests are significant benefits of the Merger that are not available to Oil Search on a standalone basis;*
> - *any estimates of underlying value are inherently uncertain, particularly in the current environment; and*
> - *Oil Search faces real challenges in funding its growth opportunities on a standalone basis.*

2 Frequently asked questions

Question	Answer	More Information
An Overview of the Scheme		
Why have I received this Scheme Booklet?	This Scheme Booklet has been sent or made available to you because you are an Oil Search Shareholder and eligible Oil Search Shareholders are being asked to vote on the Scheme, which, if approved, will result in Santos acquiring all of the Scheme Shares and Scheme Shareholders receiving the New Santos Shares. This Scheme Booklet is intended to help you decide how to vote on the Scheme Resolution which needs to be passed at the Scheme Meeting to allow the Scheme to proceed.	N/A
What is the Merger?	The Merger is the proposed combination of Oil Search and Santos, pursuant to the Scheme. If the Scheme proceeds, Santos will acquire all of the shares in Oil Search in return for the issue of New Santos Shares to Oil Search Shareholders[1] at a ratio of 0.6275 New Santos Shares for each Oil Search Share (the **Scheme Consideration**).[2] On implementation of the Scheme, existing Oil Search Shareholders would own approximately 38.5% of Santos (ie, the Merged Group) and existing Santos Shareholders would own approximately 61.5%.	**Section 3**
What does the Oil Search Board recommend and how do Oil Search Directors intend to vote?	The Oil Search Board unanimously recommends that Oil Search Shareholders vote in favour of the Scheme at the Scheme Meeting, in the absence of a Superior Proposal. Each Oil Search Director intends to vote (or procure the voting of) all Oil Search Shares held or controlled by them in favour of the Scheme, in the absence of a Superior Proposal. The reasons for the Oil Search Board's recommendation are outlined in the Letter from the Chairman of Oil Search and section 1.1.	**Section 1.1** provides a summary of the reasons why the Oil Search Directors consider that eligible Oil Search Shareholders should vote in favour of the Scheme. **Section 1.2** provides a summary of some of the reasons why eligible Oil Search Shareholders may wish to vote against the Scheme.
What is the opinion of the Independent Expert?	In its report, the Independent Expert has concluded that the Merger is in the best interests of shareholders in the absence of a Superior Proposal. A complete copy of the report is included in Annexure A to this Scheme Booklet. Oil Search Shareholders should carefully review the Independent Expert's Report in its entirety. Oil Search Shareholders should note that, in its report, the Independent Expert has made an assessment of the underlying value of each of Oil Search and Santos and, on the basis of its view of those relative underlying values, has suggested that Oil Search Shareholders are contributing a greater proportion to the underlying value of the Merged Group than the 38.5% which they will receive under the terms of the Merger. However, the Independent Expert also notes the strategic, commercial and funding benefits of the Merger, and has ultimately concluded that Oil Search Shareholders are likely to be better off if the Merger proceeds than if it does not.	A copy of the Independent Expert's Report is contained in **Annexure A**.
Who is Santos?	Santos is a leading Australian oil and gas company listed on the ASX, with a diverse portfolio of high quality natural gas, LNG, oil and strategic infrastructure assets in Australia, PNG and Timor-Leste. Santos' corporate purpose is to provide sustainable returns to its shareholders by supplying reliable, affordable and cleaner energy to improve the lives of people in Australia and Asia.	Further information about Santos is set out in **section 5**.

1) Other than Ineligible Foreign Shareholders or Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares, who will receive their respective pro rata proportion of the Sale Proceeds of the New Santos Shares which would otherwise have been issued to them under the Scheme.

2) If the Merger is not implemented until CY22 and either Santos or Oil Search pays a final CY21 dividend or interim CY22 dividend before the Implementation Date, the Scheme Consideration may be subject to adjustment for that dividend. See section 3.2(b).

2 Frequently asked questions

Question	Answer	More Information
What choices do I have as an Oil Search Shareholder?	As an Oil Search Shareholder, you have the following choices in relation to the Scheme: – vote in favour of the Scheme Resolution at the Scheme Meeting; – vote against the Scheme Resolution at the Scheme Meeting; – sell your Oil Search Shares on the ASX or PNGX prior to the Effective Date; or – do nothing.	For key considerations that may be relevant to your vote, see **section 1**.
Why should I vote in favour of the Scheme?	Section 1.1 sets out a number of reasons to vote in favour of the Scheme.	**Section 1.1**
Why may I consider voting against the Scheme?	Section 1.2 sets out a number of reasons why you may wish to vote against the Scheme.	**Section 1.2**
Can I sell my Oil Search Shares now?	You can sell your Oil Search Shares on market at any time before close of trading on the ASX or PNGX on the Effective Date (which is currently expected to be Friday,10 December 2021) at the then prevailing market price. If the Scheme proceeds, Oil Search intends to apply to the ASX and PNGX for Oil Search Shares to be suspended from official quotation on the ASX and PNGX from close of trading on the Effective Date. You will not be able to sell your Oil Search Shares on market after this time.	N/A
What will Oil Search Shareholders receive under the Scheme?		
What will I receive if the Scheme becomes Effective?	If the Scheme becomes Effective, Oil Search Shareholders will receive the Scheme Consideration, being 0.6275 New Santos Shares for each Oil Search Share held on the Record Date (or, in respect of Ineligible Foreign Shareholders or Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares, their respective pro rata proportion of the Sale Proceeds).	**Section 3.2**
What is the premium being offered?	The implied value of the Scheme Consideration represents: – a 16.8% premium to the closing price of an Oil Search Share on 19 July 2021; – a 16.4% premium to the one-month VWAP to 19 July 2021; and – a 16.0% premium to the three-month VWAP to 19 July 2021.[1] Based on the closing price of Santos Shares on 5 November 2021, being the Last Practicable Trading Date, the implied value of the Scheme Consideration is A$4.29 per Oil Search Share.	**Section 3.2**
When will I receive the Scheme Consideration?	If the Scheme proceeds, on the Implementation Date, Santos will issue you the New Santos Shares to which you are entitled and enter your name in the register of Santos. Holding statements in relation to the New Santos Shares will be despatched to Scheme Shareholders as soon as practicable after the Implementation Date and no later than 10 Business Days after the Implementation Date. If you are an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, your pro-rata proportion of the Sale Proceeds will be paid to you in accordance with the process outlined in section 3.3. If the Scheme Meeting is adjourned or the Effective Date is otherwise delayed, the issue of the Scheme Consideration will also be delayed.	**Section 3.2**(d)

1) Based on the closing price of Santos Shares and Oil Search Shares on 19 July 2021 being the last trading day prior to the announcement of the non-binding indicative merger proposal from Santos on 20 July 2021. Based on that closing price of Santos shares on 19 July 2021 the Scheme Consideration had an implied value of A$4.29 per Oil Search Share at that time.

2 Frequently asked questions

Question	Answer	More Information
Will I be able to trade the New Santos Shares on the ASX or PNGX?	Yes. Santos Shares currently trade on the ASX and, if the Scheme becomes Effective, the New Santos Shares will trade on the ASX. Subject to receipt of any exemptions for activities required by Santos from the ASX, ASIC, PNGX and the PNG Securities Commission, on completion of the Merger, Santos will seek to establish a secondary listing on PNGX on standard terms and conditions for an exempt foreign listing. In the event that Santos establishes a secondary listing of Santos Shares on the PNGX, if the Scheme becomes Effective, the New Santos Shares will also trade on the PNGX. It is expected that you will be able to trade the New Santos Shares on the ASX on a deferred settlement basis from Monday, 13 December 2021. See section 3.5(e) on the risks relating to deferred settlement trading.	N/A
I am a foreign Oil Search Shareholder. Does that make me an Ineligible Foreign Shareholder?	An Ineligible Foreign Shareholder is a Scheme Shareholder whose address as shown in the Oil Search Share Register on the Record Date is a place outside Australia and its external territories, New Zealand, PNG, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America.	**Section 3.2**(e)
How will Ineligible Foreign Shareholders be treated under the Scheme?	Ineligible Foreign Shareholders will not be issued New Santos Shares under the Scheme. Instead, the New Santos Shares that would otherwise have been issued to such shareholders will be issued to a Sale Agent. As soon as reasonably practicable after the Implementation Date, the Sale Agent will sell all New Santos Shares issued to the Sale Agent on the ASX at such price and on other terms as the Sale Agent reasonably determines in good faith. Santos will pay, or procure that the Sale Agent pay, to Ineligible Foreign Shareholders their pro-rata proportion of the Sale Proceeds.	See **Section 3.3** for further detail on how the net sale proceeds will be calculated.
What is an Unmarketable Parcel Shareholder?	An Unmarketable Parcel Shareholder is a Scheme Shareholder (other than an Ineligible Foreign Shareholder) who, based on their holding of Scheme Shares on the Record Date, would on the Implementation Date, otherwise be entitled to receive less than a 'marketable parcel' of New Santos Shares. A 'marketable parcel' means Santos Shares with a market value of A$500 or more, assessed by reference to the price of Santos Shares on the ASX at the close of trading on the trading day prior to the Record Date.	**Section 3.2**(f)
How will Unmarketable Parcel Shareholders be treated under the Scheme?	An Unmarketable Parcel Shareholder may elect to receive the Scheme Consideration as New Santos Shares by providing Oil Search with a duly completed Opt-in Notice prior to the Opt-in Notice Date (that is, 6:00pm (Sydney time) / 5:00pm (Port Moresby time) on Monday, 13 December 2021). The Opt-in Notice Date is the Business Day before the Record Date, currently expected to be Tuesday, 14 December 2021. Unmarketable Parcel Shareholders who do not provide Oil Search with a duly completed Opt-in Notice by the Opt-in Notice Date will not be issued New Santos Shares under the Scheme. Instead, the New Santos Shares that would otherwise have been issued to such shareholders will be issued to a Sale Agent. As soon as reasonably practicable after the Implementation Date, the Sale Agent will sell all New Santos Shares issued to the Sale Agent on the ASX at such price and on other terms as the Sale Agent reasonably determines in good faith. Santos will pay, or procure that the Sale Agent pay, to the relevant Unmarketable Parcel Shareholders their pro rata proportion of the Sale Proceeds.	**Section 3.2**(f)
Can I choose to receive cash for my Oil Search Shares?	No. There is no option for Oil Search Shareholders to elect to receive cash instead of the Scheme Consideration. However, once you have received your New Santos Shares, you may sell some or all of these on the ASX (or PNGX if Santos establishes a secondary listing on the PNGX). Alternatively, you may elect to sell your Oil Search Shares on the ASX or PNGX at any time before the close of trading on the Effective Date.	N/A

2 Frequently asked questions

Question	Answer	More Information
Can I subscribe for additional New Santos Shares under the Scheme?	No. There is no option for Scheme Shareholders to elect to receive or to subscribe for additional New Santos Shares under the Scheme. Oil Search Shareholders may purchase additional Santos Shares through normal trading on the ASX (or PNGX if Santos establishes a secondary listing on the PNGX) after implementation of the Scheme.	N/A
How will fractional Scheme Consideration be treated?	If, pursuant to the calculation of your Scheme Consideration you would be entitled to a fraction of a New Santos Share, the fractional entitlement will be rounded down to the nearest whole number of New Santos Shares, with fractions of 0.5 or more being rounded up.	**Section 3.2**(b)
Can I choose to keep my Oil Search Shares?	No. If the Scheme becomes Effective, your Oil Search Shares will be transferred to Santos and you will receive the Scheme Consideration. This will be the case even if you did not vote or you voted against the Scheme, provided that the Scheme is approved by the Requisite Majority of Oil Search Shareholders and by the Court at the Second Court Hearing.	N/A
Can I sell my Oil Search Shares now?	Yes. You can sell your Oil Search Shares on the ASX or PNGX at any time before the close of trading up to and on the Effective Date. Oil Search intends to apply to the ASX and PNGX for Oil Search Shares to be suspended from official quotation on the ASX and PNGX (respectively) from close of trading on the Effective Date. You will not be able to sell your Oil Search Shares on-market after this time. If you sell your Oil Search Shares on the ASX or PNGX prior to the Effective Date: – you will not receive the Scheme Consideration; – you may be required to pay brokerage on the sale of your Oil Search Shares; and – there may be different tax consequences for you compared with those that would apply if the Scheme became Effective.	N/A
Will I still be eligible for dividends?	On the current timetable, it is anticipated that the Scheme will be implemented prior to the end of 2021. On that timetable, you will not receive further Oil Search dividends, but on implementation of the Scheme you will receive Santos Shares, and would become eligible for dividends declared and paid by Santos. If implementation of the Scheme occurs in 2022, each of Oil Search and Santos is permitted to declare and pay a final dividend for the full calendar year 2021 (**CY21 Dividend**) and an interim dividend in respect of first half calendar year 2022 (**Interim CY22 Dividend**) prior to implementation of the Scheme, provided that such dividend is paid in the ordinary course and accordance with its existing dividend policy. If either party pays a CY21 Dividend or an Interim CY22 Dividend prior to the Implementation Date, the dividend may result in an adjustment of the Scheme Consideration if the dividends paid by the parties are not in accordance with the merger ratio implied by the Scheme Consideration as agreed in the Merger Implementation Deed. Further detail is set out in section 9.13(b).	**Section 9.13**(b)
Will I have to pay stamp duty or brokerage fees?	No. You will not be required to pay any stamp duty or brokerage fees in relation to your participation in the Scheme, unless you are an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who has not provided a duly completed Opt-in Notice. If you are an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who has not provided a duly completed Opt-in Notice, applicable brokerage and other selling costs, taxes and charges will be deducted from the proceeds of sale by the Sale Agent of the New Santos Shares that would otherwise have been issued to you.	**Section 8**

2 Frequently asked questions

Question	Answer	More Information
Voting at the Scheme Meeting		
What vote is required to approve the Scheme?	For the Scheme to proceed, the Scheme Resolution must be passed by the Requisite Majority, being at least 75% of the votes cast on the Scheme Resolution by eligible Oil Search Shareholders (either in person, by proxy or corporate representative).	**Section 3.5**(a) and the Notice of Meeting contained in **Annexure E** sets out further details regarding the Requisite Majority and your entitlement to vote.
Am I entitled to vote?	Each Oil Search Shareholder who is registered on the Oil Search Share Register on the Scheme Meeting Record Date (currently expected to be 7:00pm (Sydney time) / 6:00pm (Port Moresby time) on Sunday, 5 December 2021) is entitled to vote at the Scheme Meeting.	The Notice of Meeting contained in **Annexure E** sets out further details on your entitlement to vote.
How do I vote?	You can vote: – in person by attending the Scheme Meeting; or – by appointing a proxy, attorney or, if you are a body corporate, a duly appointed corporate representative, to attend the Scheme Meeting and vote on your behalf. You can appoint a proxy by completing the proxy form enclosed with this Scheme Booklet or by lodging your proxy online at www.investorvote.com.au in accordance with the instructions there (as applicable) so that it is received by no later than 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021.	The Notice of Meeting contained in **Annexure E** sets out further details on your entitlement to vote and how to submit a proxy form.
When and where will the Scheme Meeting be held?	Having regard to the uncertainty and potential health risks associated with large gatherings during the COVID-19 pandemic, the Scheme Meeting will be virtual (ie, online only). Oil Search Shareholders and their authorised proxies, attorneys and corporate representatives may participate in the Scheme Meeting online at https://web.lumiagm.com/399778470. Oil Search Shareholders who participate in the Scheme Meeting via the online platform will be able to listen to the Scheme Meeting, cast an online vote and ask questions online. Please monitor Oil Search's Website, ASX and PNGX announcements where updates will be provided if it becomes necessary or appropriate to make alternative arrangements for the holding or conduct of the meeting. Please see the Notice of Scheme Meeting in Annexure E and the Virtual Meeting Guide on Oil Search's Website for further details relating to the conduct of the Scheme Meeting. The Scheme Meeting may be postponed or adjourned, including if satisfaction of a Condition Precedent is delayed. Any such postponement or adjournment will be announced by Oil Search to the ASX and PNGX.	The Notice of Meeting contained in **Annexure E** sets out further details on your entitlement to vote.
When will the result of the Scheme Meeting be known?	The result of the Scheme Meeting will be available shortly after the conclusion of the meeting and will be announced to the ASX and PNGX once available. Even if the Scheme Resolution is passed at the Scheme Meeting, the Scheme is subject to satisfaction of the other Conditions Precedent including approval by the Court at the Second Court Hearing.	N/A
What happens to my Oil Search Shares if I do not vote, or if I vote against the Scheme, and the Scheme become Effective?	If you do not vote, vote against the Scheme or vote in favour of the Scheme, and the Scheme becomes Effective, the outcome for your Oil Search Shares will be the same – any Oil Search Shares held by you on the Record Date will be transferred to Santos and you will receive the Scheme Consideration, notwithstanding that you may not have voted or voted against the Scheme.	N/A

2 Frequently asked questions

Question	Answer	More Information
Can I oppose the Scheme at the Second Court Hearing?	As an Oil Search Shareholder, you have a right to appear and make submissions, subject to any Court directions, at the Second Court Hearing which is expected to be held in Port Moresby, National Capital District on Thursday, 9 December 2021 at the National Court of Justice of Papua New Guinea at Waigani, Port Moresby, PNG.	N/A
Do I have to give any warranties in relation to my Scheme Shares?	Yes. Each Scheme Shareholder will be deemed to have warranted to Santos that all of their Scheme Shares will, at the date of transfer under the Scheme, be fully paid and free from all mortgages, charges, liens, encumbrances and interests of third parties of any kind and that they have full power and capacity to sell and transfer their Scheme Shares (together with all rights and entitlements attaching to such shares) to Santos, and as at the Record Date, they have no existing right to be issued any other Scheme Shares or any other form of securities in Oil Search.	**Section 9.12**
Implementation of the Scheme		
Are there any conditions to be satisfied?	There are certain conditions that will need to be satisfied or waived (where capable of waiver) before the Scheme can become Effective. In summary, as at the date of this Scheme Booklet, the outstanding conditions include: – approval from eligible Oil Search Shareholders at the Scheme Meeting; – Court approval; – there being no action by a Government Agency or Court order which would restrain or prohibit the implementation of the Scheme; – approvals from the PNG Securities Commission, ICCC and CFIUS; – ASX waivers and approvals; – no Oil Search Material Adverse Change occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date; – no Oil Search Prescribed Occurrence occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date; – no Oil Search Regulated Event occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date; – no Santos Material Adverse Change occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date; – no Santos Prescribed Occurrence occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date; and – no Santos Regulated Event occurring between the date of the Merger Implementation Deed and 8:00am on the Second Court Date. Subject to the terms of the Merger Implementation Deed, the Scheme will not proceed unless all the Conditions Precedent are satisfied (or waived, if applicable) before 10 June 2022 (or such later date as Oil Search and Santos may agree) in accordance with the Merger Implementation Deed. As at the date of this Scheme Booklet, the Oil Search Directors are not aware of any reason why these conditions should not be satisfied or waived (where capable of waiver).	**Section 9.13**(a)
Is the Scheme conditional on any regulatory approval being obtained?	As discussed above, the Scheme is conditional on a number of regulatory approvals, including approvals from the PNG Securities Commission, clearance from the ICCC and clearance or confirmation from CFIUS in the United States of America. CFIUS clearance in respect of the Transaction has been received. Information about regulatory approvals are set out in sections 3.7 and 7.3(bb).	**Section 3.7** and **7.3**(bb).
What happens if the Scheme does not proceed?	If the Scheme is not approved at the Scheme Meeting, or another condition to the Scheme is not satisfied or waived (where capable of waiver), the Scheme will not be implemented. If the Scheme is not implemented, Scheme Shareholders will not receive the Scheme Consideration but will retain their Oil Search Shares. In these circumstances, Oil Search will, in the absence of another proposal, continue to operate as a stand-alone company listed on the PNGX and ASX and you will continue to hold your Oil Search Shares and continue to be exposed to risks and opportunities associated with your investment in Oil Search.	N/A

2 Frequently asked questions

Question	Answer	More Information
What happens if a Competing Proposal is proposed for Oil Search?	Since the announcement of Santos' non-binding indicative proposal to the ASX on 20 July 2021 and up to the date of this Scheme Booklet, no Competing Proposal has emerged. The Merger Implementation Deed prohibits Oil Search from soliciting a Competing Proposal. However, the Oil Search Directors' recommendation is subject to no Superior Proposal being received. Oil Search is permitted to respond to any Competing Proposal should the Oil Search Board determine that the Competing Proposal could reasonably be expected to become a Superior Proposal, and that failing to respond would likely constitute a breach of their fiduciary or statutory duties. Note that the Merger Implementation Deed gives Santos the right to match a Competing Proposal and includes an obligation on Oil Search to pay a Break Fee in the event that any Oil Search Director changes their recommendation in favour of a Competing Proposal. Further details of the key terms of the Merger Implementation Deed are provided in section 9.13.	**Section 9.13**(c)
What happens if a Competing Proposal is proposed for Santos?	Since the announcement of Santos' non-binding indicative merger proposal to the ASX on 20 July 2021 and up to the date of this Scheme Booklet, no Competing Proposal has emerged in respect of Santos. The Merger Implementation Deed prohibits Santos from soliciting a Competing Proposal. However, Santos is permitted to respond to any Competing Proposal should the Santos Board determine that the Competing Proposal could reasonably be expected to become a Superior Proposal, and that failing to respond would likely constitute a breach of their fiduciary or statutory duties. In certain circumstances, Oil Search or Santos may terminate the Merger Implementation Deed if a Superior Proposal in respect of Santos is received or announced which requires as a condition that the Scheme not be implemented. In such circumstances, Santos may be required to pay a Break Fee to Oil Search in the event that any Santos director makes a public statement that they no longer support the Merger and recommend a Superior Proposal for Santos. Further details of the key terms of the Merger Implementation Deed are provided in section 9.13.	**Section 9.13**
Under what circumstances is a Break Fee payable by Oil Search?	Under the Merger Implementation Deed, Oil Search must pay a Break Fee of A$80 million if certain specified events occur, including where any Oil Search Director changes their recommendation in favour of a Competing Proposal. However, no Break Fee is payable for the reason that eligible Oil Search Shareholders do not approve the Scheme at the Scheme Meeting.	**Section 9.13**(e) sets out a detailed explanation of the circumstances in which a Break Fee is payable.

2 Frequently asked questions

Question	Answer	More Information
Taxation implications of the Scheme		
What are the Australian and PNG taxation implications of the Scheme for Oil Search Shareholders?	The tax consequences of the Scheme will depend on your personal situation. A general outline of the main Australian and PNG taxation implications of the Scheme for certain Oil Search Shareholders is set out in section 8 of this Scheme Booklet. As this outline is general in nature, you should consult with your own taxation advisers for detailed tax advice regarding the Australian, PNG and, if applicable, other foreign taxation implications for participating in the Scheme in light of the particular circumstances which apply to you, before making a decision as to how to vote on the Scheme.	**Section 8**
Will I be entitled to scrip-for-scrip Capital Gains Tax rollover relief?	Australian tax resident Scheme Shareholders who make a capital gain from the disposal of their Scheme Shares may be eligible to choose CGT scrip-for-scrip roll-over relief (provided certain conditions are met). Broadly, CGT scrip-for-scrip roll-over relief enables Scheme Shareholders to disregard the capital gain they make from the disposal of their Scheme Shares under the Scheme. If a capital loss arises, CGT scrip-for-scrip roll-over relief is not available. Scheme Shareholders do not need to inform the Australian Taxation Office (**ATO**), or document their choice to claim CGT scrip-for-scrip roll-over relief in any particular way, other than to complete their income tax return in a manner consistent with their choice. Oil Search is in the process of applying for a class ruling from the ATO regarding the income tax implications for Scheme Shareholders of participating in the Scheme, and the availability of CGT scrip-for-scrip roll-over relief in respect of the Scheme Consideration to be received by Scheme Shareholders, if the Scheme is implemented.	**Section 8**

2 Frequently asked questions

Question	Answer	More Information
Overview of Merged Group		
What will the Merged Group look like if the Scheme is implemented?	The Merger brings together two highly complementary businesses that will create a regional champion of size and scale with a diversified portfolio of long-life, low-cost oil and gas assets across Australia, Timor-Leste, PNG, and the United States of America, with a pro forma market capitalisation of approximately A$23 billion.[1] The Merged Group is expected to be an S&P ASX20 company by free float market capitalisation[2] and amongst the 20 largest global oil and gas companies by market capitalisation.[3]	**Section 6**
Who will be the directors of the Merged Group?	If the Scheme is implemented, three existing non-executive directors from the Oil Search Board will be invited to join the Santos Board. The Santos Board will comprise nine non-executive directors and the Chief Executive Officer and Managing Director of Santos. Santos intends to offer directorship to one Oil Search director who is a PNG national. The Chairman of the Santos Board will be the current chairman, Mr Keith Spence.	**Section 6.6**
Who will be the senior executive team for the Merged Group?	The Chief Executive Officer and Managing Director of the Merged Group will be Santos' current Chief Executive Officer and Managing Director, Mr Kevin Gallagher. Members of the Merged Group's senior management team will be selected based on the principle that the best executive for the job will be offered the relevant role having regard to the skills, experience, knowledge and expertise required to manage the Merged Group and its assets.	**Section 6.6**
What will the dividend policy of the Merged Group be?	Following implementation of the Scheme, Santos intends to continue to pay ordinary dividends that are sustainable through the oil price cycle, targeting a payout ratio in the range of 10% to 30% of free cash flow[4] generated per annum, consistent with Santos' existing dividend policy.[5]	**Section 6.7**(f)
Further information		
Where can I get further information?	For further information, you can call the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9:00am and 5:00pm (Sydney time) other than public holidays in Sydney, Australia	N/A

1) Based on closing price of $4.23 for Oil Search and $6.83 for Santos as at the Last Practicable Trading Date.

2) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.

3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.

4) Free cash flow is a non-IFRS measure calculated as operating cash flow less investing cash flow net of acquisitions and disposals and major growth capex, less lease liability payments.

5) This differs from Oil Search's existing dividend policy which is to pay dividends of between 35-50% of core net profit after tax, subject to Board discretion.

3 Overview of the Merger

3.1 Background to the Merger

On 25 June 2021, Oil Search received a confidential, non-binding indicative all-scrip merger proposal from Santos to be implemented through a scheme of arrangement under which Oil Search Shareholders would receive 0.589 New Santos Shares for each Oil Search Share held at the relevant record date. That initial proposal was rejected by the Oil Search Board on the basis that, while the Oil Search Board agreed that there was strategic logic in a combination of the two companies, the Oil Search Board considered that the merger terms proposed by Santos were not fair for Oil Search Shareholders.

On 2 August 2021, following further negotiations between Oil Search and Santos, Oil Search announced that it had received an improved non-binding and indicative proposal under which Santos would acquire all of the shares in Oil Search for a consideration of 0.6275 New Santos Shares for each Oil Search Share held at the relevant record date.

Following completion by the parties of reciprocal due diligence, on 10 September 2021, Oil Search announced that it had entered into a Merger Implementation Deed with Santos, in relation to the acquisition by Santos of all shares in Oil Search, pursuant to the Scheme.

For the Scheme to proceed, eligible Oil Search Shareholders must vote in favour of the Scheme by the Requisite Majority, and the Scheme must be approved by the Court. The Scheme is also subject to the satisfaction or waiver (where capable of waiver) of the other Conditions Precedent described in section 9.13(a).

If the Scheme becomes Effective, Oil Search will become a wholly-owned Subsidiary of Santos and part of the Merged Group, and will be delisted from the ASX and PNGX. On implementation of the Scheme, existing Oil Search Shareholders would own approximately 38.5% of the Merged Group and existing Santos Shareholders would own approximately 61.5%.[1]

If the Scheme is not approved, Scheme Shareholders will not receive the Scheme Consideration and Oil Search Shareholders will retain their Oil Search Shares.

In these circumstances, Oil Search will, in the absence of another proposal, continue to operate as a stand-alone entity listed on the ASX and PNGX and Oil Search Shareholders will retain their Oil Search Shares and continue to be exposed to the risks and opportunities associated with their current investment in Oil Search.

3.2 Scheme Consideration

a) Scheme Consideration

If the Scheme is approved and implemented, Scheme Shareholders (other than Ineligible Foreign Shareholders or Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares) will receive 0.6275 New Santos Shares for each Oil Search Share held as at the Record Date.[2] If implementation of the Scheme occurs in 2022 and either Santos or Oil Search pays a CY21 Dividend or Interim CY22 Dividend before the Implementation Date, the Scheme Consideration may also be subject to adjustment for that dividend, as set out in further detail in section 3.2(b) below.

All New Santos Shares issued to Scheme Shareholders under the Scheme will rank equally in all respects with all existing Santos Shares on issue as at the Implementation Date. The rights and liabilities attached to the New Santos Shares are described in section 5.10.

If the Scheme Meeting is adjourned or the Effective Date is otherwise delayed, the issue of the Scheme Consideration will also be delayed.

b) Adjustments for dividends

It is currently anticipated that the Implementation Date will be Friday, 17 December 2021. However, to the extent that there are delays in the timetable such that implementation of the Scheme occurs in calendar year 2022, Oil Search and Santos are each permitted to pay a CY21 Dividend and an Interim CY22 Dividend, provided that such dividends are declared and paid in the ordinary course and in accordance with their existing dividend policies, and provided such dividends are declared before the Record Date of the Scheme and paid before the Implementation Date. Any dividends declared by Oil Search or Santos operate as an adjustment to the Scheme Consideration if they are not declared in accordance with the merger ratio implied by the Scheme Consideration as agreed in the Merger Implementation Deed. The adjustment formula is set out in section 9.13(b).

c) Fractional entitlements

If, pursuant to the calculation of your Scheme Consideration you would be entitled to a fraction of a New Santos Share, the fractional entitlement will be rounded to the nearest whole number of New Santos Shares, with fractions of 0.5 or more being rounded up.

d) Provision of Scheme Consideration to Scheme Shareholders

On the Implementation Date, Santos must:

- issue to each Scheme Shareholder (other than Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares) such number of New Santos Shares as that Scheme Shareholder is entitled to as Scheme Consideration; and
- enter into the Santos Share Register the name and address of each Scheme Shareholder in respect of the aggregate number of New Santos Shares issued to them.

1) Subject to adjustment for any final CY21 and interim CY22 dividends paid by Santos or Oil Search in the ordinary course and in accordance with existing dividend policy. Details of the adjustment mechanism are set out in section 3.2(b).

2) The Scheme Consideration for Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares is set out in section 3.2(e) and 3.2(f).

d) Provision of Scheme Consideration to Scheme Shareholders continued

As soon as practicable after the Implementation Date and no later than 10 Business Days after the Implementation Date, Santos must send or procure the despatch to each Scheme Shareholder, to their registered address as at the Record Date, a holding statement representing the number of New Santos Shares issued to that Scheme Shareholder pursuant to this Scheme. [1]

e) Ineligible Foreign Shareholders

A Scheme Shareholder will be an Ineligible Foreign Shareholder for the purposes of the Scheme if their address shown in the Oil Search Share Register on the Record Date is a place outside Australia and its external territories, New Zealand, PNG, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America.

On the Implementation Date, Santos will be under no obligation to issue any New Santos Shares to any Ineligible Foreign Shareholder, and will instead issue the New Santos Shares that would otherwise have been issued to an Ineligible Foreign Shareholder to a nominee appointed by Santos (the **Sale Agent**) to be sold, as described in section 3.3.

As soon as reasonably practicable after the Implementation Date, the Sale Agent will sell all New Santos Shares issued to the Sale Agent on the ASX at such price and on other terms as the Sale Agent determines in good faith. Following such sale, Santos will pay, or procure the Sale Agent pay, to Ineligible Foreign Shareholders their pro rata proportion of the Sale Proceeds, as described in section 3.3.

f) Unmarketable Parcel Shareholders

A Scheme Shareholder will be an Unmarketable Parcel Shareholder if they are not an Ineligible Foreign Shareholder and if, based on their holding of Scheme Shares on the Record Date, they would on the Implementation Date, be entitled to receive less than a 'marketable parcel' of New Santos Shares. A 'marketable parcel' means Santos Shares with a market value of A$500 or more, assessed by reference to the price of Santos Shares on the ASX at the close of trading on the trading day prior to the Record Date.

An Unmarketable Parcel Shareholder may elect to receive the Scheme Consideration as New Santos Shares by providing Oil Search with a duly completed Opt-in Notice prior to the Opt-in Notice Date (which is currently expected to be 6:00pm (Sydney time) / 5:00pm (Port Moresby time) on Monday, 13 December 2021). The Opt-in Notice Date is the Business Day before the Record Date, currently expected to be Tuesday, 14 December 2021.

On the Implementation Date, Santos will be under no obligation to issue any New Santos Shares to any Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, and will instead issue the New Santos Shares that would otherwise have been issued to such Unmarketable Parcel Shareholders to the Sale Agent to be sold, as described in section 3.3.

As soon as reasonably practicable after the Implementation Date, the Sale Agent will sell all New Santos Shares issued to the Sale Agent on the ASX at such price and on other terms as the Sale Agent reasonably determines in good faith. Following such sale, Santos will procure that the Sale Agent pay, or procure the payment, to such Unmarketable Parcel Shareholders their pro rata proportion of the Sale Proceeds, as described in section 3.3.

3.3 Sale facility – Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who have not opted-in

As discussed above, Santos will be under no obligation to issue any New Santos Shares to any Ineligible Foreign Shareholder, or to any Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, and will instead issue the New Santos Shares that would otherwise have been issued to such shareholders to the Sale Agent.

As soon as reasonably practicable after the Implementation Date, the Sale Agent will then sell all New Santos Shares issued to the Sale Agent on the ASX at such price and on other terms as the Sale Agent reasonably determines in good faith. Santos will procure that the Sale Agent pay, or procure the payment, to each Ineligible Foreign Shareholder, and to each Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, their pro rata proportion of the net sale proceeds (after deducting any applicable brokerage, stamp duty and other costs, taxes and charges) (the **Sale Proceeds**), calculated in accordance with the following formula and rounded down to the nearest cent:

$$A = (B/C) \times D$$

where:

A is the amount to be paid to the Ineligible Foreign Shareholder or Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares;

B is the number of New Santos Shares attributable to, and that would otherwise have been issued to, that shareholder, had it not been an Ineligible Foreign Shareholder or Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, and which are instead issued to the Sale Agent;

C is the total number of New Santos Shares attributable to, and which would otherwise have been issued to, all Ineligible Foreign Shareholders and Unmarketable Parcel Shareholder who do not opt-in to receive New Santos Shares collectively, and which are instead issued to the Sale Agent; and

D is the Sale Proceeds.

1) Santos is not required to send or procure the despatch of a holding statement to a Scheme Shareholder who does not have a Registered Address or where Oil Search and Santos reasonably believe that such Scheme Shareholder is not known at their Registered Address.

The pro rata proportion of the Sale Proceeds will be paid to each Ineligible Foreign Shareholder and Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares, by:

- electronic funds transfer into the Ineligible Foreign Shareholder's or relevant Unmarketable Parcel Shareholders' nominated bank acount as advised to the Oil Search Share Registry as at the Record Date; or
- if no bank account has been nominated, payment will be made by sending an Australian dollar cheque by mail to the relevant Ineligible Foreign Shareholder's or Unmarketable Parcel Shareholder's registered address as shown on the Oil Search Share Register as at the Record Date.

Neither Santos nor Oil Search gives any assurance as to the price that will be achieved for the sale of the New Santos Shares described above. The sale of the New Santos Shares will be a risk borne by the Ineligible Foreign Shareholder or Unmarketable Parcel Shareholder (if applicable).

Under the Scheme, each Ineligible Foreign Shareholder or Unmarketable Parcel Shareholder who does not opt-in to receive New Santos Shares is taken to appoint Santos as its agent to receive on its behalf any financial services guide or other notices which may be issued by the Sale Agent to that Ineligible Foreign Shareholder or Unmarketable Parcel Shareholder who do not opt-in to receive New Santos Shares, as the case may be.

3.4 Oil Search ADR Holders

In the case of Oil Search ADR Holders, BNY Mellon, as the depositary with respect to the Oil Search ADR program, and subject to the terms of the Oil Search ADS Deposit Agreement, will endeavour to vote in accordance with instructions it receives from Oil Search ADR Holders in connection with the Scheme. If the Scheme is implemented, BNY Mellon will receive the Scheme Consideration on behalf of Oil Search ADR Holders. See section 4.7(c) for further information.

Pursuant to the terms of the Oil Search ADS Deposit Agreement and at Oil Search's request, BNY Mellon will also arrange to provide copies of this Scheme Booklet to brokers and other securities intermediaries that hold Oil Search ADRs through The Depository Trust Company (**DTC**) on behalf of customers, for distribution by them to those customers. BNY Mellon will provide each registered Oil Search ADR Holder with this Scheme Booklet and such other information related to the Scheme distributed to Oil Search Shareholders. BNY Mellon will provide each Oil Search ADR Holder with a voting instruction card by which the Oil Search ADR Holder may instruct BNY Mellon how to vote the Oil Search Shares represented by the Oil Search ADR Holder's Oil Search ADRs (in the manner, and prior to the time, advised by BNY Mellon). Oil Search ADR Holders should contact BNY Mellon for any additional information.

To the extent BNY Mellon does not receive instructions on or before the Instruction Cutoff Date, it will not vote the Oil Search Shares represented by Oil Search ADRs. See section 4.7(c) and 9.23 for further information with respect to matters pertaining to Oil Search ADR Holders.

3.5 Key steps in the Scheme

a) Overview of the Scheme approval requirements

The Scheme will become Effective and be implemented only if it is:

- approved by the Requisite Majority of eligible Oil Search Shareholders at the Scheme Meeting to be held on Tuesday, 7 December 2021; and
- approved by the Court at the Second Court Hearing to be held on Thursday, 9 December 2021.

Approval by Oil Search Shareholders eligible to vote at the Scheme Meeting requires the Scheme Resolution to be approved by the Requisite Majority, being at least 75% of the votes cast on the Scheme Resolution by eligible Oil Search Shareholders (either in person, by proxy or corporate representative).

b) Scheme Meeting

i) Date and time of Scheme Meeting

In accordance with an order of the Court dated Thursday, 11 November 2021, Oil Search has convened the Scheme Meeting to be held virtually through an online platform on Tuesday, 7 December 2021 commencing at 11:00am (Sydney time) / 10:00am Port Moresby time). Oil Search Shareholders and their authorised proxies, attorneys and corporate representatives may participate in the Scheme Meeting via the online platform will be able to listen to the Scheme Meeting, cast an online vote and ask questions online.

The notice convening the Scheme Meeting is set out in Annexure E to this Scheme Booklet and the terms of the Scheme are contained in Annexure C to this Scheme Booklet. The purpose of the Scheme Meeting is for Oil Search Shareholders to consider and vote on the Scheme Resolution.

The fact that the Court has ordered the Scheme Meeting does not mean that the Court has formed a view as to the merits of the Scheme or as to how Oil Search Shareholders should vote on the Scheme Resolution. On these matters, Oil Search Shareholders must reach their own decision. In any event, the Court must approve the Scheme at the Second Court Hearing before the Scheme can become Effective.

ii) Scheme Resolution

At the Scheme Meeting, Oil Search Shareholders eligible to vote at the record date for the Scheme Meeting will be asked to consider and, if thought fit, pass the Scheme Resolution to approve the Scheme.

iii) Entitlement to vote

Each Oil Search Shareholder who is registered on the Oil Search Share Register on the Scheme Meeting Record Date is entitled and eligible to vote at the Scheme Meeting.

c) Second Court Hearing

In the event that:

- the Scheme is approved by the Requisite Majority of Oil Search Shareholders at the Scheme Meeting; and
- all other conditions (except Court approval of the Scheme) have been satisfied or waived (where capable of waiver),

then Oil Search will apply to the Court for orders approving the Scheme.

Each Oil Search Shareholder has the right to appear at the Second Court Hearing, subject to any direction of the Court.

d) Effective Date

If the Court makes orders approving the Scheme and all other conditions have been satisfied or waived (where capable of waiver), the Scheme will become Effective on the date specified by the Second Court Order, which is expected to be the Business Day after the date of the Second Court Order (currently expected to be Friday, 10 December 2021). Oil Search will, on the Scheme becoming Effective, give notice of that event to ASX and PNGX.

At the closing of trading on the Effective Date, Oil Search Shares will be suspended from trading.

If the Scheme becomes Effective, then Oil Search and Santos will become bound to implement the Scheme in accordance with the terms of the Scheme and the Deed Poll.

e) New Santos Shares to trade on deferred settlement basis

Santos will seek confirmation from the ASX that, as from the Business Day after the Effective Date (or such later date as ASX requires), the New Santos Shares to be issued as Scheme Consideration will be listed for quotation on the official list of the ASX.

The New Santos Shares issued as part of the Scheme Consideration are expected to commence trading on the ASX, initially on a deferred settlement basis and, with effect from the first Business Day after the Implementation Date (or such later date as ASX requires), on an ordinary settlement basis.

The exact number of New Santos Shares to be issued to each Scheme Shareholder will not be known until after the Record Date and will not be confirmed to each Scheme Shareholder until they receive their holding statements following the Implementation Date. It is the responsibility of each Scheme Shareholder to confirm their holdings of New Santos Shares before they trade them to avoid the risk of committing to sell more than will be issued to them.

Oil Search Shareholders who sell New Santos Shares before they receive their holding statements or confirm their holdings of New Santos Shares do so at their own risk. Neither Oil Search nor Santos takes any responsibility for such trading.

f) Record Date

Scheme Shareholders will be entitled to receive the Scheme Consideration in respect of the Oil Search Shares they hold as at the Record Date.

i) Dealings on or prior to the Record Date

For the purpose of establishing the persons who are Scheme Shareholders, dealings in Oil Search Shares will be recognised by Oil Search provided that:

a) in the case of dealings of the type to be effected using CHESS (Clearing House Electronic Subregister System), the transferee is registered in the Oil Search Share Register as the holder of the relevant Oil Search Shares by the Record Date; and

b) in all other cases, registrable transfers or transmission applications in respect of those dealings, or valid requests in respect of other alterations, are received by the Oil Share Registry by 5:00pm (Sydney time) / 4:00pm (Port Moresby time) on the Record Date at the place where the Oil Search Share Register is located (in which case Oil Search must register such transfers or transmission before 7.00pm (Sydney time) on that day).

For the purposes of establishing the persons who are Scheme Shareholders or for any other purpose (other than to transfer to Santos pursuant to the Scheme and any subsequent transfers by Santos and its successors in title), Oil Search will not accept for registration or recognise any transfer or transmission application in respect of Oil Search Shares received after such times, or received prior to such times but not in actionable or registrable form (as appropriate).

ii) Dealings after the Record Date

For the purposes of determining entitlements to the Scheme Consideration, Oil Search must maintain the Oil Search Share Register in its form as at the Record Date until the Scheme Consideration has been paid to the Scheme Shareholders. The Oil Search Share Register in this form will solely determine entitlements to the Scheme Consideration.

After the Record Date each entry on the Oil Search Share Register relating to the Scheme Shares will cease to have effect except as evidence of entitlement to the Scheme Consideration in respect of such Scheme Shares.

g) Implementation Date

The Implementation Date is the third Business Day after the Record Date. The Implementation Date is currently expected to be Friday, 17 December 2021.

On the Implementation Date:

i) Scheme Shareholders will receive the Scheme Consideration, being 0.6275 New Santos Shares for each Oil Search Share held on the Record Date; and

ii) Santos will issue New Santos Shares on behalf of Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares to the Sale Agent to be sold, as described in section 3.3.

Transfers of Oil Search Shares to Santos will be effected by way of an electronic transfer.

h) Delisting of Oil Search

Following the implementation of the Scheme, Oil Search will apply for the termination of the official quotation of Oil Search Shares on the ASX and PNGX and for Oil Search to be removed from the official list of the ASX and PNGX.

Oil Search intends to give notice to BNY Mellon directing it to terminate the Oil Search Deposit Agreement if the Scheme becomes Effective. Oil Search ADR Holders will receive notice of termination from BNY Mellon, and the termination will be effective 90 days from the date of that notice or the date on which there are no Oil Search ADRs outstanding, whichever is earlier.

i) End Date

Subject to the terms of the Merger Implementation Deed, the Scheme will lapse and be of no further force or effect (and implementation will not occur) if the Effective Date has not occurred on or before 10 June 2022 (or such later date as Oil Search and Santos may agree), in accordance with the Merger Implementation Deed.

3.6 Conditions precedent to implementation of the Scheme

The implementation of the Scheme is subject to the Conditions Precedent which must be satisfied or waived (where capable of waiver) for the Scheme to proceed. A summary of the Conditions Precedent is included in section 9.13(a) and the Conditions Precedent are set out in full in clause 3.1 of the Merger Implementation Deed, a full copy of which is attached to the Oil Search and Santos ASX announcement on 10 September 2021, which can be obtained from the ASX, PNGX or from Oil Search's Website.

Subject to the terms of the Merger Implementation Deed, the Scheme will not proceed unless all the Conditions Precedent are satisfied (or waived, if applicable) before 10 June 2022 (or such later date as Oil Search and Santos may agree) in accordance with the Merger Implementation Deed.

3.7 Regulatory approvals

As discussed in sections 3.6 and 9.15, the Scheme is conditional on a number of regulatory approvals, including approvals from the PNG Securities Commission, clearance from the ICCC and clearance or confirmation of no action from CFIUS in the United States of America.

The relevant applications have been made to both the PNG Securities Commission and the ICCC. Santos and Oil Search have had discussions with the PNG Government and various agencies and have been advised that these regulatory approvals are progressing. CFIUS clearance in respect of the Transaction has been received.

Other than the requirement for clearance from the ICCC in PNG, the Scheme is not conditional on any other competition clearances. However, it should be noted that the competition laws of various countries may, in certain circumstances, seek to regulate transactions that occur outside of those countries, even where there is no substantial lessening of competition in a market in that country. It is possible that a competition regulator of a foreign country from outside the jurisdiction of PNG may take the view that the Merger required clearance under the law of that country. Should a foreign competition regulator take that view in circumstances where clearance was not obtained, the regulator may raise an issue or attempt to take action against the Merged Group, such as imposing a fine. Such fines may be for material amounts. Failure to obtain clearance, or to pay a fine which is imposed, may also have an adverse effect on the capacity of the Merged Entity to conduct business in that foreign country in the future, for example, through restrictions on selling to existing or potential customers in that country, or through an inability to obtain other regulatory approvals, if required for the Merged Group's business, in that country in the future.

3.8 Timetable

An indicative timetable for the Merger appears on page 4. All dates are indicative only and, among other things, are subject to all necessary approvals from the Court and any other regulatory authority. Any changes to the timetable (which may include an earlier or later date for the Scheme Meeting or Second Court Hearing) will be announced through the ASX and PNGX and notified on Oil Search's Website.

4 Information about Oil Search

4.1 Overview of Oil Search

Established in 1929 in PNG, Oil Search is listed on the ASX (ASX:OSH) and PNGX (PNGX:OSH). Oil Search's portfolio comprises:

- a 29% interest in the operating PNG LNG Project (operated by ExxonMobil);
- oil and gas assets in PNG which contribute approximately 20% of feedstock gas to PNG LNG and produce all of PNG's oil (with ExxonMobil, Santos, MRDC, Kumul and JX Nippon);
- a 22.8% interest (before back-in from the PNG government) in Papua LNG, being in part a downstream brownfield LNG growth opportunity (operated greenfield upstream by TotalEnergies and downstream brownfield by ExxonMobil); and
- a 51% interest in Alaska oil assets, including the Pikka Unit which is the largest recent United States of America onshore conventional oil discovery (operated by Oil Search, with Repsol as the working interest partner).

Based on 2020 production, the Oil Search Group has a 1P Reserves life of 14 years, a 2P reserves life of 16 years, and 2P plus 2C resources life of 58 years.[1]

4.2 Business of the Oil Search Group

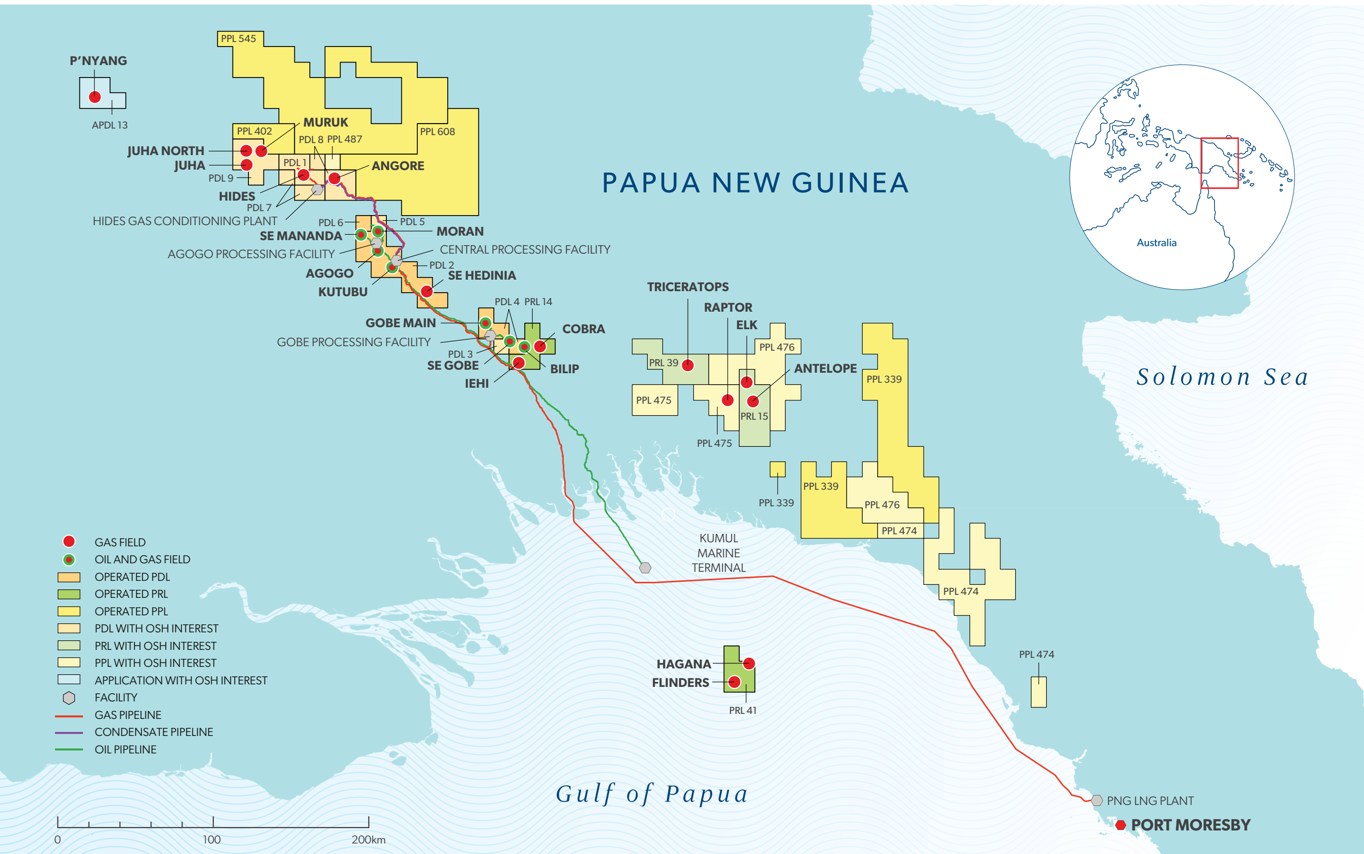
The Oil Search Group operates primarily in PNG, the United States of America and Australia. As at 31 December 2020, 84% of the Oil Search Group's assets are located in PNG.[2] As at 31 December 2020, even if Oil Search develops all the discoveries in its portfolio, it will remain predominantly a gas producer (gas would comprise approximately 63% of the total portfolio, oil and condensate 37%).

As at 31 December 2020, the Oil Search Group had 1,122 employees worldwide, with offices in Port Moresby, Sydney, Anchorage, Tokyo and Abu Dhabi.

a) PNG

The Oil Search Group has an interest in, and operates, all of PNG's producing oil fields. Oil Search has operated all of PNG's producing oil fields since 2003. Oil Search's PNG operations include exploration, development, production, sale of hydrocarbons and abandonment activities related to the Oil Search Group's interests in operated and non-operated assets. In addition, Oil Search also has investments in power generation assets, forestry assets and ownership of drilling rigs in PNG.

The Oil Search Group holds a 29% interest in the ExxonMobil-operated PNG LNG project, exporting LNG to major markets in northeast Asia. Additionally, the Oil Search Group holds a 22.8% interest in the Elk-Antelope gas fields (before state back in of 22.5% at FID which will reduce its interest to 17.7%), which are expected to underpin the proposed construction of two additional LNG trains, with approximately 5.4 mmtpa capacity in the project known as Papua LNG. The Fiscal Stability Agreement for Papua LNG was signed in February 2021, paving the way for a Front-End Engineering and Design (**FEED**) entry decision by the joint venture partners in early 2022.



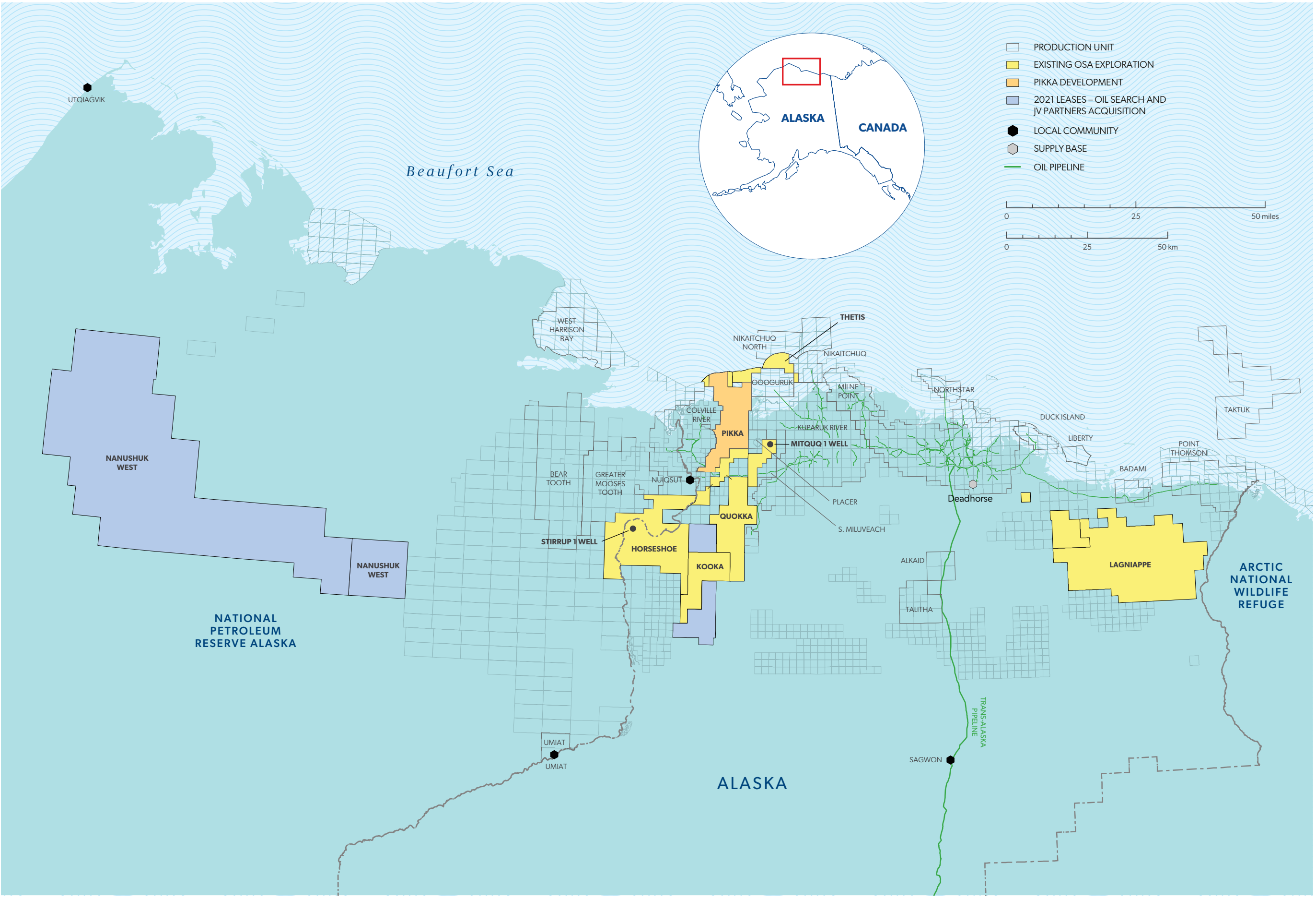
1) 2P gas volumes have been converted to barrels of oil equivalent using an Oil Search specific conversion factor of 5,100 scf = 1 boe. This represents a weighted average, based on Oil Search's reserves portfolio, using the actual calorific value of each gas volume at its point of sale. 2C gas volumes have been converted to barrels of oil equivalent using an industry standard conversion factor of 6,000 scf/boe.

2) This number represents non-current assets excluding deferred tax assets in PNG.

b) Alaska

The Oil Search Group's Alaskan operations includes exploration, evaluation and development of hydrocarbons in the United States of America.

In 2018, the Oil Search Group acquired a portfolio of oil and exploration leases (the **Pikka Unit**) on the Alaskan North Slope in the United States of America, a prolific, well-established oil province with considerable export capacity. As well as being one of the largest conventional onshore oil discoveries in the United States of America in the last few decades, the Alaskan portfolio contains exploration and appraisal opportunities with high potential resource upside. The phase one development of the Pikka Unit was approved for FEED entry by the Oil Search Group and its working interest partners in February 2021.

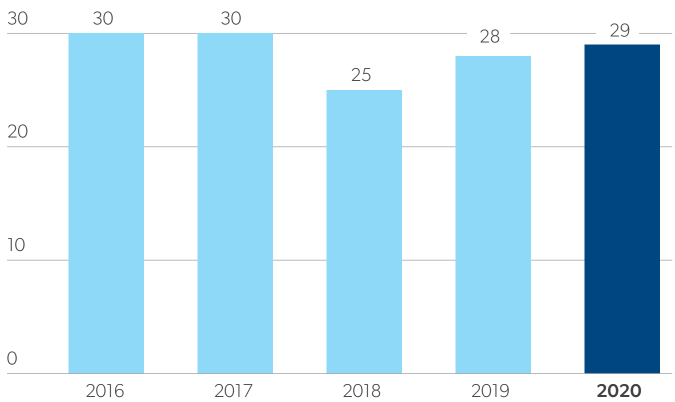


4.3 Production

The Oil Search Group's 2020 production was 29.0 million barrels of oil equivalent (**mmboe**), with PNG LNG contributing 25.7 mmboe and the Oil Search Group's operated assets contributing 3.3 mmboe.

The chart to the right shows the Oil Search Group's production for the last five years, with 2018 production adversely affected by the PNG highlands earthquake in February of that year.

Production (mmboe)



4 Information about Oil Search

The table below sets out the Oil Search Group's production summary for 2020.

	Full Year	
	Dec 2020	Dec 2019
Production [1,5]		
PNG LNG production [2]		
LNG (mmscf)	114,456	110,768
Gas to power (mmscf) [3]	495	598
Domestic gas (mmscf)	651	—
Condensate ('000 bbls)	2,738	2,852
Naphtha ('000 bbls)	318	305
Total PNG LNG ('000 boe)	**25,723**	**24,994**
Oil Search operated production		
Oil production ('000 bbls)		
Kutubu	1,534	1,392
Moran	1,051	132
Gobe Main	11	13
South East Gobe	23	33
Total oil production ('000 bbls)	**2,619**	**1,571**
Hides GTE [4]		
Sales gas (mmscf)	1,804	5,088
Liquids ('000 bbls)	31	96
South East Gobe gas to PNG LNG (mmscf) [3]	1,483	1,470
Total operated production ('000 boe)	**3,295**	**2,953**
Total production ('000 boe)	**29,017**	**27,947**

2020 operated oil production was delivered on target at 2.6 million barrels, notwithstanding shipment and other deferrals due to COVID-19.

4.4 Reserves

During 2020, the Oil Search Group's total booked 2P reserves reduced from 67 million barrels (**mmbbl**) of oil and condensate and 2,102 billion cubic feet (**bcf**) of gas to 61 mmbbl and 1,960 bcf respectively. Movement in reserves during 2020 was primarily driven by production, though some small variations also occurred due to changes in price forecasts and project timing.

Additionally, during 2020, 2C contingent oil resources increased to over 547.2 mmbbl of oil, primarily due to successful exploration and appraisal activity in Alaska. The Stirrup and Mitquq discoveries added 102.1 mmbbl of oil, with another 20.4 mmbbl increase within the Pikka Unit field. The increase in Alaskan resources is based on analysis of drilling and appraisal work conducted through 2019 and 2020 by independent expert Ryder Scott.

As part of the Oil Search Group's focus on pursuing value-accretive developments, several licences in PNG which were assessed as non-viable were relinquished in 2020, resulting in contingent resource write-downs. This decrease in PNG contingent resources encompassed the Kimu, Uramu, Barikewa, and Mananda licences.

1) Numbers may not add due to rounding.
2) Production net of fuel, flare, shrinkage and SE Gobe wet gas.
3) South East Gobe wet gas reported at inlet to plant, inclusive of fuel, flare and naphtha.
4) Hides GTE production is reported on a 100% basis for gas and associated liquids purchased by the Hides GTE Project Participant (100% owned by Oil Search) for processing and sale to the Porgera power station. Sales gas volumes are inclusive of approximately 2% unrecovered process gas.
5) Gas and LNG volumes have been converted to barrels of oil equivalent using an Oil Search specific conversion factor of 5,100 scf = 1 boe, which represents a weighted average, based on Oil Search's reserves portfolio, using the actual calorific value of each gas volume at its point of sale. Minor variations to the conversion factors may occur over time.

The Oil Search Group's reserves and resources summary as at 31 December 2020 is shown below.

		Oil and Condensate (million barrels)	Gas (billion standard cubic feet)
1P	**Total**	**48.0**	**1,735.9**
	Developed	33.8	1,232.0
	Undeveloped	14.3	503.9
2P	**Total**	**61.0**	**1,960.4**
	Developed	43.1	1,361.4
	Undeveloped	18.0	599.0
2C	**Total**	**547.2**	**3,956.4**
Total 2P + 2C		**608.3**	**5,916.8**

The Oil Search Group's petroleum resource estimates are prepared and reported in accordance with the 2007 PRMS.

Proved reserves (1P) + proved and probable reserves (2P) as at 31 Dec 2020 [1,2]

	End 2019 reserves		2020 activities			End 2020 reserves	
Licence/Field	**Total**	**Production**	**Discoveries/ extensions/ revisions**	**Acquisitions/ divestments**	**Total**	**Developed**	**Undeveloped**
1P proved reserves							
Proved oil and condensate reserves (million stock tank barrels) [3]							
PDL2 – Kutubu	9.9	1.5	—	—	8.3	7.0	1.4
PDL2/5/6 – Moran Unit	6.0	1.1	—	—	4.9	3.6	1.3
PDL4 – Gobe Main	0.01	0.01	0.01	—	0.01	0.01	—
PDL3/4 – SE Gobe [5]	—	0.02	0.02	—	—	—	—
PDL1 – Hides [7]	—	—	—	—	—	—	—
PNG LNG project [6]	38.0	3.1	(0.2)	—	34.7	23.2	11.5
Total	**53.9**	**5.7**	**(0.2)**	**—**	**48.0**	**33.8**	**14.3**
Proven gas reserves (billion standard cubic feet)							
PDL3/4 – SE Gobe [5]	—	1.5	1.5	—	—	—	—
PDL1 – Hides [7]	1.7	0.3	(1.4)	—	—	—	—
PNG LNG project [4,6]	1,872.4	115.5	(21.0)	—	1,735.9	1,232.0	503.9
Total	**1,874.1**	**117.3**	**(20.9)**	**—**	**1,735.9**	**1,232.0**	**503.9**
2P proved and probable reserves							
Proved and probable oil and condensate reserves (million stock tank barrels) [3]							
PDL2 – Kutubu	15.2	1.5	—	—	13.7	11.0	2.7
PDL2/5/6 – Moran Unit	9.5	1.1	—	—	8.5	6.2	2.2
PDL4 – Gobe Main	0.02	0.01	0.00	—	0.01	0.01	—
PDL3/4 – SE Gobe [5]	—	0.02	0.05	—	0.02	0.02	—
PDL1 – Hides [7]	—	—	—	—	—	—	—
PNG LNG project [6]	42.3	3.1	(0.4)	—	38.8	25.8	13.0
Total	**67.1**	**5.7**	**(0.3)**	**—**	**61.0**	**43.1**	**18.0**
Proved and probable gas reserves (billion standard cubic feet)							
PDL3/4 – SE Gobe [5]	—	1.5	6.9	—	5.4	5.4	—
PDL1 – Hides [7]	2.2	0.3	(1.9)	—	—	—	—
PNG LNG project [4,6]	2,099.7	115.5	(29.2)	—	1,955.0	1,356.0	599.0
Total	**2,101.9**	**117.3**	**(24.2)**	**—**	**1,960.4**	**1,361.4**	**599.0**

For footnotes, refer to end-of-table (next page).

Contingent resources (2C) as at 31 Dec 2020[1,8]

Licence/Field	End 2019 2C resources	Production	Discoveries/ Extensions/ Revisions	Acquisitions/ divestments	End 2020 2C Resources
Oil and condensate resources (million stock tank barrels)[3]					
PNG LNG project fields oil and condensate	1.8	—	0.3	—	2.1
Other PNG oil and condensate[9]	57.1	—	(5.6)	—	51.5
Alaska – Pikka project oil and condensate[10]	371.1	—	20.4	—	391.5
Alaska – other oil and condensate[10]	—	—	102.1	—	102.1
Total	**430.0**	**—**	**117.2**	**—**	**547.2**
Gas resources (billion standard cubic feet)					
PNG LNG project fields gas	125.2	—	16.8	—	142.0
Other PNG gas[9]	4,509.8	—	(695.5)	—	3,814.4
Total	**4,635.1**	**—**	**(678.6)**	**—**	**3,956.4**

1) Numbers may not add due to rounding.

2) Kutubu and Moran oil fields proved Reserves (1P) and proved and probable (2P) Reserves are as certified by independent auditor Netherland, Sewell & Associates, Inc. (**NSAI**) in 2017. 1P and 2P PNG LNG project Reserves are based on Contingent Resources estimates prepared in 2019 by independent auditor, NSAI. Gobe Main and SE Gobe 1P and 2P Reserves are based on Oil Search 2019 technical estimates. All Reserves estimations use Oil Search's corporate assumptions to calculate economic limit.

3) Crude oil, and separator and plant condensates.

4) For the PNG LNG project, shrinkage has been applied to raw gas for the field condensate, plant liquids recovery, and fuel and flare.

5) Due to planned well work activities and the renegotiation of pricing with PNG LNG, SE Gobe is now expected to be cash flow positive on a 2P basis in the medium term. These assessments use Oil Search's 2020 corporate economic assumptions and remain based on third party wet gas sales to the PNG LNG Project at the Gobe plant outlet at the post-sales agreement field interest of 22.3%.

6) PNG LNG Project Reserves comprise the Kutubu, Moran, Gobe Main, SE Hedinia, Hides, Angore and Juha fields. Minor volumes associated with proposed domestic gas sales have been included as part of PNG LNG reserves.

7) Hides Reserves associated with the GTE Project under existing contract. Due to the issues with the Porgera Mine through 2020 and the continued uncertainty of resumption of operations in 2021, no reserves are booked for Hides GTE. Any gas volumes that were previously to be produced from Hides GTE are now expected be produced by PNG LNG. Production volumes shown in this Reserves report are based on Oil Search's entitlement in PDL 1 (16.7%).

8) Contingent Resources are quantities of petroleum estimated to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. There may be a chance that accumulations containing Contingent Resources will not achieve commercial maturity.

9) Other gas, oil and condensate resources comprise Oil Search's other PNG fields including Elk-Antelope, SE Mananda, Juha North, P'nyang, Iehi, Cobra, Flinders, and Muruk and may also include resources beyond the current economic limit of producing oil and gas fields. These gas resources may include fuel, flare, and shrinkage depending on the choice of reference point.

10) Alaskan oil and condensate contingent resources comprise Oil Search's 51% working interest before royalties in Alaskan assets, incorporating the Nanushuk and satellite reservoirs. All 2C contingent resources are based on contingent resources as certified in 2019 and 2020 by independent auditor, Ryder Scott.

4.5 Environment, Social, Governance and Sustainability

Oil Search has a strong track record of partnering with communities, host governments and other key stakeholders to deliver enduring and tangible positive outcomes. Oil Search is committed to a sustainable future as the preferred oil and gas company for all stakeholders and in this role will deliver low-cost, low GHG intensity, high-value energy.

In 2020, Oil Search launched a 7-Pillar Sustainability Model for action. This comprises the pillars of climate, environment, community, health & safety, people, integrity and economic sustainability.

Oil Search has a strategy to focus on low cost, low greenhouse gas emission intensity growth projects that are aligned with the objectives of the Paris Agreement. The Company has committed to reducing its operated GHG intensity by more than 30% by 2030. Oil Search anticipates that this target will be achieved by implementing near term GHG reduction programs within Oil Search's existing operated assets and progressing its low cost, low GHG intensity Pikka project. The PNG business unit has developed a carbon abatement cost curve to identify the highest value GHG reduction opportunities and has begun implementation of those programs. By using low GHG intensity technology and improving the design of the project, Pikka will be a low GHG intensity asset and is a key part of achieving Oil Search's 2030 operated GHG intensity target. In 2020, Oil Search reported on its sustainability performance across the key themes of supporting employees of Oil Search, fostering an inclusive and diverse workforce, keeping the workforce safe, responding to changing community priorities, responsible delivery of low-cost, low GHG intensity energy, continually improving environmental management and improving economic sustainability and governance practices.

On 15 April 2021, Oil Search published its annual sustainability report. A copy of this report can be found at https://www.oilsearch.com/__data/assets/pdf_file/0011/54686/20210415_2020-Sustainability-Report_Final.pdf.

4.6 Board of Directors and Executive Leadership Team

a) Oil Search Board

As at the date of this Scheme Booklet, the Oil Search Board comprises the following Oil Search Directors.

Name	Current Position
Mr Richard Lee AM	Chairman, Non-executive Director
Ms Susan Cunningham	Non-executive Director
Dr Eileen Doyle	Non-executive Director
Ms Fiona Harris AM	Non-executive Director
Dr Agu Kantsler	Non-executive Director
Mr Michael Utsler	Non-executive Director
Mr Musje Werror	Non-executive Director

b) Oil Search's Executive Leadership Team

As at the date of this Scheme Booklet, Oil Search's key management personnel are each of the Oil Search Directors and the following individuals.

Name	Current Position
Mr Peter Fredricson	Acting Chief Executive Officer
Mr Leon Buskens	Executive Vice President & Co-Head PNG
Mr Michael Drew	Executive Vice President Corporate, General Counsel & Group Secretary
Mr Bruce Dingeman	Executive Vice President & President Alaska
Mr Diego Fettweis	Executive Vice President Commercial
Mr Bart Lismont	Executive Vice President & Co-Head PNG
Ms Beth White	Executive Vice President Group Finance (Acting), Sustainability & Technology

4.7 Capital Structure

a) Capital Structure and market capitalisation

As the date of this Scheme Booklet, Oil Search has:

- 2,077,850,664 Oil Search Shares on issue; [1]
- 356,611 Oil Search Alignment Rights on issue;
- 6,396,647 Oil Search Share Rights on issue;
- 4,781,470 Oil Search Performance Rights on issue; and
- 22,971 Oil Search NED Rights on issue. [2]

See sections 9.2 and 9.3 for further information on the intended treatment of the Oil Search Equity Incentives and Oil Search NED Rights in connection with the Scheme.

As at the Last Practicable Trading Date, Oil Search had a market capitalisation of approximately A$8,789,308,309 (based on a closing price of A$4.23 per Oil Search Share and 2,077,850,664 Oil Search Shares on issue).

b) Substantial shareholders

As at the Last Practicable Trading Date, based on substantial shareholder notice filings released to the ASX and PNGX, [3] the substantial holders of Oil Search are as follows.

Name	Number of Oil Search Shares [4]	Percentage
UBS Group AG and its related bodies corporate	134,404,202	6.47%

The shareholdings listed in this section 4.7(b) are as disclosed to Oil Search by the shareholders in substantial holding notices. Information in regard to substantial holdings arising, changing, or ceasing after the Last Practicable Trading Date time or in respect of which the relevant announcement is not available on the ASX or PNGX, are not included above.

1) This number includes 1,329,081 Oil Search Restricted Shares and 42,240 NED Restricted Shares on issue.
2) The number of reported Oil Search Share Rights in Oil Search's Appendix 3H disclosed to the ASX and PNGX on 29 October 2021 includes the 22,971 Oil Search NED Rights on issue and other Oil Search Share Rights that have subsequently lapsed.
3) These substantial notices can be found on Oil Search's website at https://www.oilsearch.com/investors/asx-releases.
4) This refers to the number of Oil Search Shares in which the person or any associate has a Relevant Interest as noted in the substantial shareholder notice.

c) Oil Search ADR program

Oil Search has a sponsored ADR program in place with The Bank of New York Mellon (**BNY Mellon**) governed by the Oil Search ADS Deposit Agreement.

An ADR is created when a broker purchases Oil Search Shares on the ASX or PNGX and delivers those to BNY Mellon's local custodian bank, which then instructs BNY Mellon as the depositary bank to deliver ADRs. Each Oil Search ADR represents five Oil Search Shares. The official Oil Search ADR ticker code is 'OISHY'.

If the Scheme is implemented, following receipt of the Scheme Consideration, BNY Mellon will sell (or procure the sale of) the New Santos Shares and distribute the proceeds after deduction of BNY Mellon's fee for cancellation of the Oil Search ADRs and any applicable expenses or taxes, as provided in the Oil Search ADS Deposit Agreement to the Oil Search ADR Holders upon surrender by them of the Oil Search ADRs, in proportion to the number of Oil Search ADRs held by them. Following the implementation of the Scheme, the Oil Search ADR program will be terminated.

If Oil Search ADR Holders wish to receive New Santos Shares directly in connection with the implementation of the Scheme at the time New Santos Shares are received by Oil Search Shareholders, they will need to surrender their Oil Search ADRs for cancellation, pay BNY Mellon's fees for cancellation of the ADRs and become direct holders of Oil Search Shares prior to the time, Record Date and participate directly in the Scheme as an Oil Search Shareholder. An Oil Search ADR Holder wishing to do this would need to have a securities account to which ASX or PNGX listed shares can be delivered. It is uncertain how long it would take to become a direct Oil Search Shareholder. Therefore, Oil Search ADR Holders wishing to do so should take action as soon as possible.

4.8 Subsidiaries and interests in joint arrangements

a) Subsidiaries

As at the date of this Scheme Booklet, Oil Search was the ultimate holding company of the following Subsidiaries.

Name	Principal place of business/ country of incorporation	Ownership interest
Oil Search (Middle Eastern) Limited	British Virgin Islands	100%
Oil Search (Iraq) Limited	British Virgin Islands	100%
Oil Search (Libya) Limited	British Virgin Islands	100%
Oil Search (Tunisia) Limited	British Virgin Islands	100%
Oil Search (Newco) Limited	British Virgin Islands	100%
Oil Search (Gas Holdings) Limited	PNG	100%
Oil Search (Tumbudu) Limited	PNG	100%
Oil Search Highlands Power Limited	PNG	100%
Markham Valley Renewables Limited	PNG	100%
Oil Search (PNG) Limited	PNG	100%
Oil Search (Drilling) Limited	PNG	100%
Oil Search (Exploration) Inc.	Cayman Islands	100%
Oil Search (LNG) Limited	PNG	100%
Oil Search Finance Limited	British Virgin Islands	100%
Oil Search Power Holdings Limited	PNG	100%
Markham Valley Biomass Limited [1]	PNG	100%
Oil Search Foundation Limited [2]	PNG	100%
Papuan Oil Search Limited	Australia	100%
Oil Search (Uramu) Pty Limited	Australia	100%
Oil Search (USA) Inc.	USA	100%
Oil Search (Alaska) LLC	USA	100%
Oil Search Limited Retention Share Plan Trust	Australia	100%
Pac LNG Investments Limited	PNG	100%
Pac LNG Assets Limited	PNG	100%
Pac LNG International Limited	PNG	100%
Pac LNG Overseas Limited	PNG	100%
Pac LNG Holdings Limited	PNG	100%

1) This entity is in the process of changing its name to PNG Biomass Limited.

2) Oil Search Foundation Limited is the trustee of the Oil Search Foundation Trust, a not-for-profit organisation established for charitable purposes in PNG. This trust is not controlled by Oil Search and is not consolidated within the Oil Search Group.

b) Interests in joint operations

As at the date of this Scheme Booklet, Oil Search's interests in joint operations are as follows. The principal activities of the following joint operations, in which the Oil Search Group holds an interest, are for the exploration, production and transportation of crude oil and natural gas.

	Principal place of business	Ownership interest
Exploration licences / leases		
PPL 339 [2]	PNG	35%
PPL 374	PNG	40%
PPL 375	PNG	40%
PPL 487	PNG	37.5%
PRL 3	PNG	38.51%
PPL 474	PNG	25%
PPL 475	PNG	25%
PPL 476	PNG	25%
PRL39	PNG	25%
Quokka (Atlas A, Kachemach) [2]	USA	38.76%
Kooka (Grizzly) [2]	USA	51%
Lagniappe A (Hue Shale) [2]	USA	75%
Lagniappe B (East of Hue Area) [2]	USA	50%
Lagniappe C (East of Hue Area) [1]	USA	50%
Thetis [2]	USA	51%
Horseshoe [2]	USA	51%
Pikka Unit [2,3]	USA	51%
Nanushuk West A [1]	USA	36%
Nanushuk West B [1]	USA	50%
Production assets and other arrangements		
PNG LNG Project	PNG	29%
Papua New Guinea Liquefied Natural Gas Global Company LDC	PNG	29%

c) Interests in joint ventures

As at the date of this Scheme Booklet, Oil Search's interests in joint ventures are as follows.

	Principal place of business	Ownership interest
NiuPower Limited	PNG	50%
NiuEnergy Limited	PNG	50%

1) United States licences acquired in 2020.

2) Operated by an Oil Search Group Member.

3) This includes Pikka East and Pikka North.

d) Interests in other arrangements

The Oil Search Group participates in arrangements with other parties that have the same legal form as a joint operation but are not subject to joint control. As at the date of the Scheme Booklet, Oil Search's interest in these arrangements are as follows.

	Principal place of business	Ownership interest
Production assets and other arrangements		
PNG LNG Project[1]	PNG	29%
Hides gas-to-electricity project[1]	PNG	100%
PDL 2 Kutubu[1]	PNG	60.05%
South East Mananda[1]	PNG	72.27%
Moran Unit[1]	PNG	49.51%
South East Gobe Unit[1]	PNG	22.34%
Gobe Main[1]	PNG	10%
Kutubu pipeline system[1]	PNG	60.05%
Exploration and retention licences		
APPL623 (PPL 233)[1,2]	PNG	100%
PRL41[1]	PNG	100%
PPL 339[1]	PNG	35%
PPL 374	PNG	40%
PPL 375	PNG	40%
PPL 474	PNG	25%
PPL 475	PNG	25%
PPL 476	PNG	25%
PPL 545[1]	PNG	40%
PPL 608[1]	PNG	100%
PPL 402[1]	PNG	37.5%
PRL 14[1]	PNG	62.56%
PRL 15 (Papua LNG Project)	PNG	22.84%

4.9 Recent Oil Search share price history

Oil Search Shares are listed on the PNGX and ASX under the trading symbol 'OSH'.

On 20 July 2021, Oil Search announced its receipt of Santos' non-binding indicative merger proposal. The closing price of Oil Search Shares on 19 July 2021 (being the last trading day prior to the announcement of Santos' non-binding indicative proposal) was A$3.67 per Oil Search Share.

On 10 September 2021, Oil Search announced that it had entered into a Merger Implementation Deed with Santos, in relation to the acquisition by Santos of all shares in Oil Search, by way of the Scheme. The closing price of Oil Search Shares on 9 September 2021 (being the last trading day prior to the announcement of Oil Search and Santos' entry into the Merger Implementation Deed) was A$3.65 per Oil Search Share.

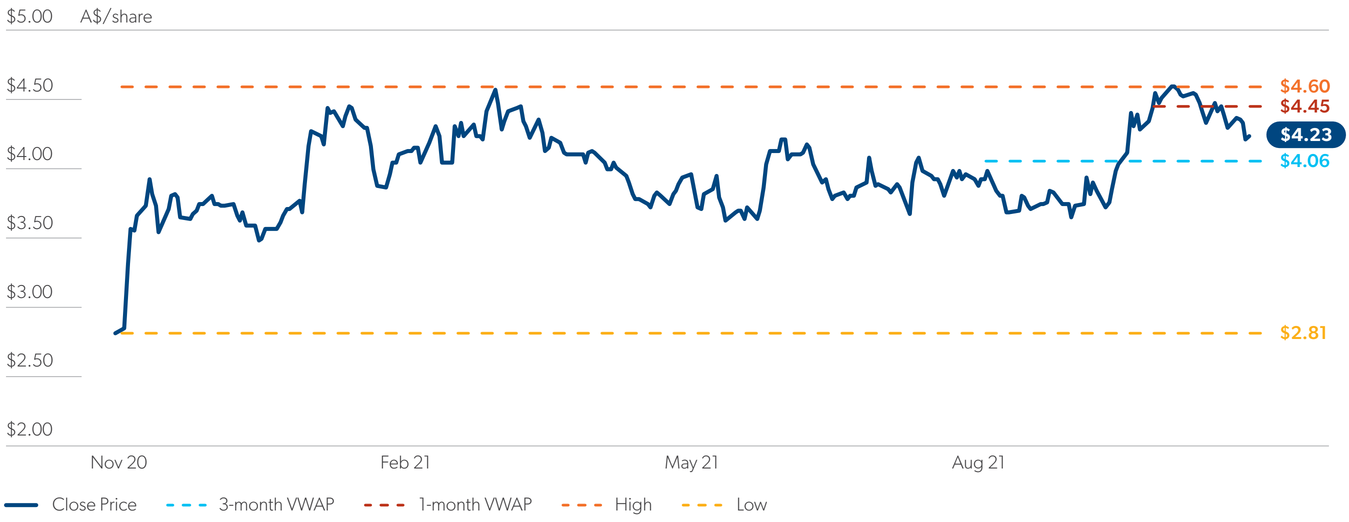
1) Operated by an Oil Search Group Member.

2) Subject to regulatory approval.

4 Information about Oil Search

Figure 4 – Oil Search last Twelve Months Share Price and Trading Volumes

The graph below shows the closing Oil Search share price during the twelve months ended 5 November 2021 (being the Last Practicable Trading Date).



Up to and including 5 November 2021, being the Last Practicable Trading Date:

– the last recorded Oil Search share price on 5 November 2021 was A$4.23;

– the 1-month VWAP of the Oil Search Shares was A$4.45;

– the 3-month VWAP of the Oil Search Shares was A$4.06; and

– the lowest and highest Oil Search Share prices during the preceding twelve months was A$2.81 and A$4.60, respectively.

4.10 Historical financial information

This section contains the following historical information of Oil Search:

– historical income statements for the years ended 31 December 2019 and 31 December 2020 and for the half-year ended 30 June 2021 (**Oil Search Historical Income Statements**);

– historical statements of financial position as at 31 December 2019 and 31 December 2020 and for the half-year ended 30 June 2021 (**Oil Search Historical Statements of Financial Position**); and

– historical statements of cash flow for the financial years ended 31 December 2019, 31 December 2020 and half year ended 30 June 2021 (**Oil Search Historical Statements of Cash Flows**),

together, the **Oil Search Historical Financial Information**).

Further historical financial information can be found on Oil Search's Website. The financial statements are presented in United States dollars and the majority of amounts are rounded down to the nearest US$1,000 (where rounding is applicable). Accordingly, totals in tables may not add due to rounding.

a) Basis of presentation of Oil Search Historical Financial Information

The Oil Search Historical Financial Information presented in this Scheme Booklet is in an abbreviated form and does not contain all of the presentations and disclosures that are usually provided in an annual report and should therefore be read in conjunction with the financial statements of Oil Search for the respective periods, including the description of the significant accounting policies contained in those financial statements and the notes to those financial statements. The Oil Search Historical Income Statements, Oil Search Historical Statements of Financial Position and Oil Search Historical Statements of Cash Flows are derived from the Oil Search financial statements for the years ended 31 December 2019 and 31 December 2020, which have been lodged with the ASX and PNGX and are available on Oil Search's Website. Oil Search's financial statements for the years ended 31 December 2019 and 31 December 2020 were audited by Deloitte Touche Tohmatsu (**Deloitte**) in accordance with International Standards on Auditing. Deloitte issued unmodified audit opinions on these financial statements. Oil Search's financial statements for the half-year ended 30 June 2021 were reviewed by Deloitte who issued an unmodified review conclusion in relation to Oil Search's Half-Year Financial Statements.

The significant accounting policies used in the preparation of the Oil Search Historical Financial Information are consistent with those set out in Oil Search's annual reports for the years ended 31 December 2019 and 31 December 2020. The Oil Search Historical Financial Information has been prepared in accordance with the recognition and measurement principles contained in International Financial Reporting Standards (**IFRS**), including Interpretations, adopted by the International Accounting Standards Board.

Further details on Oil Search's financial performance and financial statements for FY20 as announced to the ASX and PNGX on 23 February 2021 and for H1FY21 as announced to the ASX and PNGX on 24 August 2021 can be found on Oil Search's Website.

b) Oil Search Historical Income Statements of Profit and Loss and Other Comprehensive Income

	Half Year ended 30 June 2021 US$'000	Full Year ended 31 December 2020 US$'000	Full Year ended 31 December 2019 US$'000
Revenue	667,686	1,074,153	1,584,808
Cost of sales	(352,128)	(729,404)	(833,770)
Gross profit	**315,558**	**344,749**	**751,038**
Other income	28,313	58,124	67,169
Other expenses	(66,897)	(209,000)	(133,278)
Impairment expense	—	(374,207)	(5,865)
Profit/(Loss) from operating activities	**276,974**	**(180,334)**	**679,064**
Finance costs	(83,910)	(204,164)	(255,303)
Interest income	3,842	13,803	24,342
Share of net profit from investments in joint ventures	1,851	5,091	627
Profit/(Loss) before income tax	**198,757**	**(365,604)**	**448,730**
Income tax (expense)/ benefit	(59,773)	44,947	(136,310)
Net profit/(loss) after tax	**138,984**	**(320,657)**	**312,420**
Other comprehensive loss			
Items that may be reclassified to profit or loss:			
Foreign currency translation differences for foreign operations	(680)	(1,083)	(2,085)
Costs of hedging:			
Changes in the fair value of cash flow hedges – net of tax	(19,690)	—	—
Cumulative losses reclassified to profit or loss – net of tax	5,150	—	—
Total comprehensive income/(loss) for the period/year	**123,764**	**(321,740)**	**310,335**

	US Cents	US Cents	US Cents
Basic earnings per share	6.69	(16.62)	20.50
Diluted earnings per share	6.66	(16.62)	20.41

c) Oil Search Historical Statement of Financial Position

	30 June 2021 US$'000	31 December 2020 US$'000	31 December 2019 US$'000
Current assets			
Cash and cash equivalents	503,599	540,842	396,232
Receivables	186,197	169,446	272,087
Inventories	131,396	127,789	104,038
Prepayments	20,058	29,958	19,867
Derivative financial instruments	1,302	—	—
Total current assets	**842,552**	**868,035**	**792,224**
Non-current assets			
Other assets	79,470	80,161	81,450
Other financial assets	78,654	75,206	67,939
Exploration and evaluation assets	2,788,228	2,740,763	2,998,021
Oil and gas assets	5,717,920	6,020,599	6,124,358
Other plant and equipment	448,417	472,943	488,300
Investments in joint ventures	61,384	59,534	54,443
Deferred tax assets	1,038,265	1,071,024	909,721
Total non-current assets	**10,212,338**	**10,520,230**	**10,724,232**
Total assets	**11,054,890**	**11,388,265**	**11,516,456**
Current liabilities			
Payables	169,085	187,139	337,022
Provisions	24,504	7,595	28,523
Borrowings	442,925	725,376	654,513
Current tax payable	70,661	49,346	100,663
Total current liabilities	**707,175**	**969,456**	**1,120,721**
Non-current liabilities			
Payables	19,157	18,579	10,331
Provisions	698,646	849,520	688,395
Borrowings	2,556,546	2,581,418	3,140,069
Deferred tax liabilities	1,389,684	1,398,993	1,298,529
Total non-current liabilities	**4,664,033**	**4,848,510**	**5,137,324**
Total liabilities	**5,371,208**	**5,817,966**	**6,258,045**
Net assets	**5,683,682**	**5,570,299**	**5,258,411**
Shareholders' equity			
Share capital	3,857,120	3,857,120	3,158,390
Reserves	(14,475)	737	(1,719)
Retained earnings	1,841,037	1,712,442	2,101,740
Total shareholders' equity	**5,683,682**	**5,570,299**	**5,258,411**

d) Oil Search Historical Statement of Cash Flows

	Half Year ended 30 June 2021 US$'000	Full Year ended 31 December 2020 US$'000	Full Year ended 31 December 2019 US$'000
Cash flows from operating activities			
Receipts from customers and third parties	648,556	1,141,505	1,632,493
Payments to suppliers and employees	(167,006)	(453,572)	(566,707)
Interest received	892	7,707	17,561
Finance costs paid	(78,512)	(192,931)	(237,562)
Income tax paid	(9,734)	(11,632)	(32,659)
Payments for exploration and evaluation – seismic, G&A, G&G	(9,902)	(58,532)	(40,663)
Payments for site restoration	(992)	(26,475)	(17,822)
Purchase of derivative financial instruments	(29,430)	—	—
Net cash from operating activities	**353,872**	**406,070**	**754,641**
Cash flows from investing activities			
Payments for other plant and equipment	(10,546)	(36,139)	(36,401)
Payments for exploration and evaluation	(39,847)	(167,044)	(650,686)
Payments for development assets	(6,016)	(139,335)	(39,540)
Payments for producing assets	(12,623)	(49,533)	(78,648)
Payments for power assets	—	—	(6,282)
Loan to third party in respect of exploration and evaluation	(500)	(1,188)	(1,750)
Net cash used in investing activities	**(69,532)**	**(393,239)**	**(813,307)**
Cash flows from financing activities			
Dividend payments	(10,389)	(68,641)	(205,746)
Purchase of treasury shares	(4,697)	(2,923)	—
Proceeds from share issue	—	713,486	—
Costs related to share issue	—	(14,756)	—
Repayment of borrowings	(621,197)	(737,402)	(1,064,200)
Proceeds from borrowings	330,000	275,000	1,150,000
Loan provided to third party	(500)	(1,188)	(1,750)
Lease payments/others	(14,800)	(31,797)	(23,963)
Net cash (used in)/from financing activities	**(321,583)**	**131,779**	**(145,659)**
Net (decrease)/increase in cash and cash equivalents	(37,243)	144,610	(204,325)
Cash and cash equivalents at the beginning of the period/year	540,842	396,232	600,557
Cash and cash equivalents at the end of the period/year	**503,599**	**540,842**	**396,232**

4.11 Material changes to Oil Search's financial position

As at the date of this Scheme Booklet, within the knowledge of the Oil Search Directors and other than as disclosed in this Scheme Booklet or announced on the ASX and PNGX, there have been no material changes to the financial position of Oil Search since 30 June 2021, being the date of Oil Search's half year reviewed accounts.

4.12 2021 production guidance

In its full year results announcement released to the ASX and PNGX on 23 February 2021, Oil Search provided 2021 production guidance in the range of 25.5 to 28.5 mmboe, comprising 23 to 25 mmboe from PNG LNG and 2 to 4 mmboe from the Oil Search Group's operated assets. On 26 October 2021, Oil Search updated its production guidance for the full year 2021 to 26.0 to 28.0 mmboe which was within the previously guided range and it maintains this guidance as at the date of this Scheme Booklet.

4.13 Change of control provisions in material contracts of the Oil Search Group

a) Debt financing arrangements

Under the terms of Oil Search's financing arrangements in relation to the PNG LNG Project, Oil Search is required to notify the financiers of a proposed or actual change of control of its participating subsidiaries. Oil Search intends to provide that notice to the intercreditor agent with the result being that there would be no default by its participants triggered upon change of control which occurs under the Scheme.

Under the terms of the bilateral and syndicated facility arrangements entered into by Oil Search (PNG) Limited as borrower, Oil Search will be required to:

i) notify the relevant financier and/or agent of any material change in the operations or performance of Oil Search (PNG) Limited, such as a change in management control, shareholding or other event which results in a material change in its credit risk. Oil Search intends to provide this notification prior to implementation of the Scheme with the result being that there will not be a breach of undertaking; and
ii) seek the prior consent of the relevant financier and/or agent:
    a) in respect of the delisting of Oil Search Limited from the ASX in accordance with the Scheme; and
    b) to ensure that no review event occurs in connection with any change of control or merger as a result of the implementation Scheme.

Oil Search intends to seek consents from the relevant financiers and agents prior to implementation of the Scheme where agreed with Santos.

Further information in relation to the approach of the Merged Group to the debt financing agreements following implementation is set out in section 6.7(d).

b) Port Moresby power station

Under the terms of the Operations and Maintenance Agreement, NiuPower Limited is required to provide notice to Wartsila Papua New Guinea Ltd prior to a change in ownership, merger, consolidation or similar corporate change. This would include implementation of the Scheme. Failure to do so is a breach of the terms of this agreement. NiuPower Limited will notify Wartsila Papua New Guinea Ltd, as required under the Operations and Maintenance Agreement, prior to the Second Court Date which will avoid any such breach.

4.14 Publicly available information

As an ASX listed company and a 'disclosing entity' for the purpose of section 111AC(1) of the Australian Corporations Act, Oil Search is subject to regular reporting and disclosure obligations. Continuous disclosure requirements also apply to Oil Search under ASX Listing Rule 3.1. Broadly, these require Oil Search to announce price sensitive information to the ASX as soon as it becomes aware of information, subject to exceptions including for confidential information. Copies of these announcements can be obtained free of charge from Oil Search's Website, the ASX website at www.asx.com.au or the PNGX website at https://www.pngx.com.pg/.

The Registrar of Companies and Investment Promotion Authority of PNG (**IPA**) also maintain records of documents lodged with them by Oil Search. Certain documents can be obtained from the IPA website at: https://www.ipa.gov.pg/. Please note, IPA may charge a fee in respect of such services.

ASIC also maintains a record of documents lodged with it by Oil Search which can be obtained using services provided by ASIC, information in respect of which can be found on the ASIC website at www.asic.gov.au. Please note, ASIC may charge a fee in respect of such services.

Oil Search Shareholders may obtain a copy of the annual financial report for Oil Search for the financial year ended 31 December 2020 free of charge from Oil Search's Website (see https://www.oilsearch.com/investors/performance/annual-reports).

5 Information about Santos

5.1 Overview of Santos

Santos is a leading Australian oil and gas company, with a diverse portfolio of high-quality natural gas, LNG, oil and strategic infrastructure assets in Australia, PNG and Timor-Leste. Santos was founded in 1954 and is now one of Australia's largest domestic gas suppliers and a leading supplier of LNG to the Asia-Pacific region. Santos is listed on the ASX (ASX: STO).

Santos' business is underpinned by a diverse portfolio of high-quality natural gas, oil and strategic infrastructure assets in the following regions:

- (**Cooper Basin**) Santos owns a majority interest in and operates Australia's largest conventional onshore oil and gas field development in the Cooper and Eromanga Basins. Depleted reservoirs across the Cooper Basin provide the foundations for Santos' first Carbon Capture and Storage project (**Moomba CCS**);
- (**Queensland and New South Wales**) Santos developed the Gladstone LNG (**GLNG**) project together with its partners, in which Santos has an interest of 30% and is the upstream operator;
- (**PNG**) Santos owns a 13.5% interest in the PNG LNG project, which is an integrated development operated by ExxonMobil;
- (**Northern Australia and Timor–Leste**) Santos owns 43.4% of and operates the Bayu-Undan and Darwin LNG (**DLNG**) project. Santos is also developing the Barossa project (which will backfill DLNG), of which it currently owns a 62.5% operated interest, which will be reduced to 50% (subject to execution and completion of the planned sale of 12.5% to JERA); and
- (**Western Australia**) Santos is the largest supplier of domestic gas to the Western Australian market. Santos owns 100% of and operates the Varanus Island and Devil Creek domestic gas processing hubs and owns a 28.6% non-operator interest in the Macedon gas processing hub.

Santos' purpose is to provide sustainable returns to its shareholders by supplying reliable, affordable and cleaner energy to improve the lives of people in Australia and Asia.

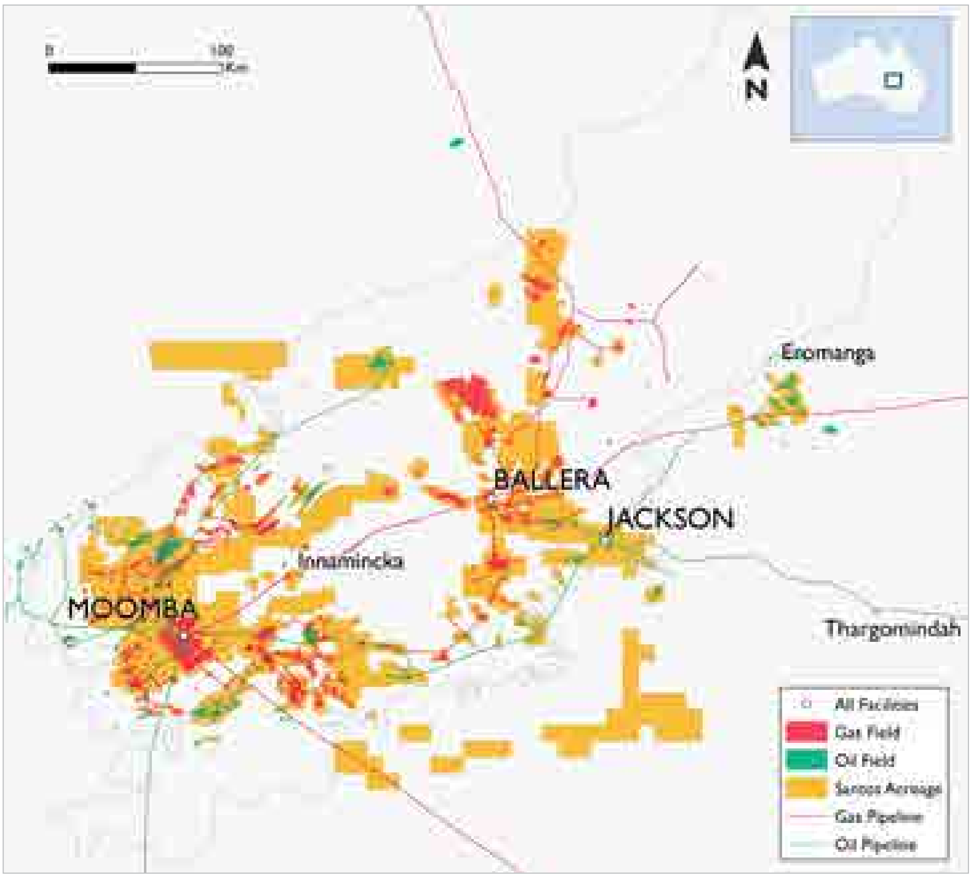
As at the Last Practicable Trading Date, Santos' market capitalisation was A$14 billion.[1] In 2020, Santos delivered production of 89 mmboe, sales volume of 107 mmboe, revenue from product sales of US$3,387 million, and EBITDAX of US$1,898 million.

5.2 Business of the Santos Group

Santos' operations are focused on five core, long life natural gas asset hubs.

a) Cooper Basin

Santos' operations in the Cooper and Eromanga Basins comprise one of Australia's largest conventional onshore oil and gas field developments, with operations spanning the borders of northeast South Australia and southwest Queensland. Santos operates in the Cooper Basin through a series of unincorporated joint ventures in which its interest ranges from 60.1% to 66.7%. Santos' main joint venture partner in the Cooper Basin is Beach Energy.



1) Based on closing price of $6.83 for Santos on the Last Practicable Trading Date.

a) Cooper Basin continued

As of 31 December 2020, Santos operated more than 850 producing gas wells and more than 400 producing oil wells in the Cooper Basin. From the Cooper Basin, Santos produces natural gas, ethane, crude oil and gas liquids. Gas and ethane are primarily sold to domestic retailers and industrial users, while gas liquids, crude oil, naphtha, propane and butane are sold in both the domestic and export markets.

Santos' producing fields are supported by extensive infrastructure to undertake primary processing and to distribute products, including the Moomba oil and gas production facility, which connects to pipelines enabling Santos to sell gas to east coast gas markets.

Santos' strategy in the Cooper Basin is to deliver production growth by being a low-cost business, increasing reserves, investing in new technology to lower development and exploration costs, reducing emissions and increasing utilisation of infrastructure.

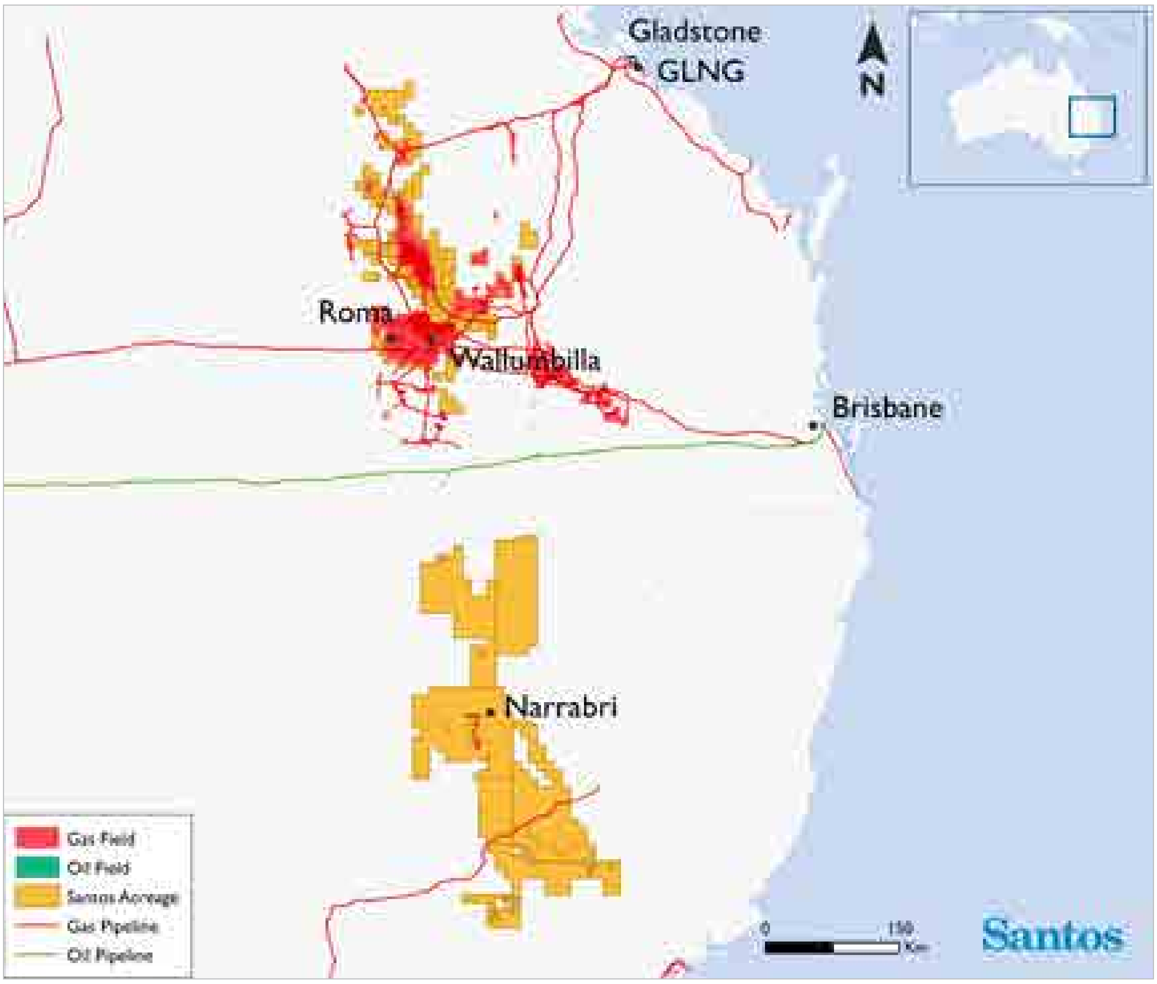
The operating model in the Cooper Basin is to execute a drilling program that maintains stable production and targets more than 100% 2P reserves replacement on a three-year rolling average by converting 2C contingent resources to reserves. Based on 2020 annual production and 2P reserves plus 2C contingent resources as at 31 December 2020, the Cooper Basin had a reserves plus resources life of more than 20 years.

Santos' EBITDAX margin for its Cooper Basin assets was 42% for the year ended 31 December 2020, and its share of Cooper Basin production was 16.8 mmboe.

Santos has detailed plans for a significant carbon capture and storage (CCS) project at Moomba that will capture, compress and dehydrate carbon dioxide from the Moomba gas plant and inject it into depleted gas reservoirs. Santos plans to develop Moomba CCS as 66.7% owner and operator of the project, and announced the final investment decision to proceed with the project in November 2021, following successful registration with the Clean Energy Regulator.

b) Queensland and New South Wales

Santos is a major upstream gas producer in Queensland's onshore Surat and Bowen Basins. Together with its joint venture partners, Santos developed the GLNG project, in which Santos owns a 30% interest and where it is the upstream operator.



b) Queensland and New South Wales continued

GLNG produces LNG for export to global markets from the LNG plant at Gladstone. Gas is also sold into the domestic market. In calendar year 2020, GLNG produced 6.0 Mt of LNG for export, and Santos' share of production from its Queensland and New South Wales assets was 13.4 mmboe.

GLNG includes a two-train natural gas liquefaction plant with combined capacity of approximately 8.6 mmtpa and infrastructure to transport gas from coal seam gas fields in the Surat and Bowen basins. As of 31 December 2020, the GLNG project operated 1,820 production wells.

Santos aims to increase equity gas supply through upstream development, extract value from existing infrastructure and drive efficiencies to operate at lowest cost.

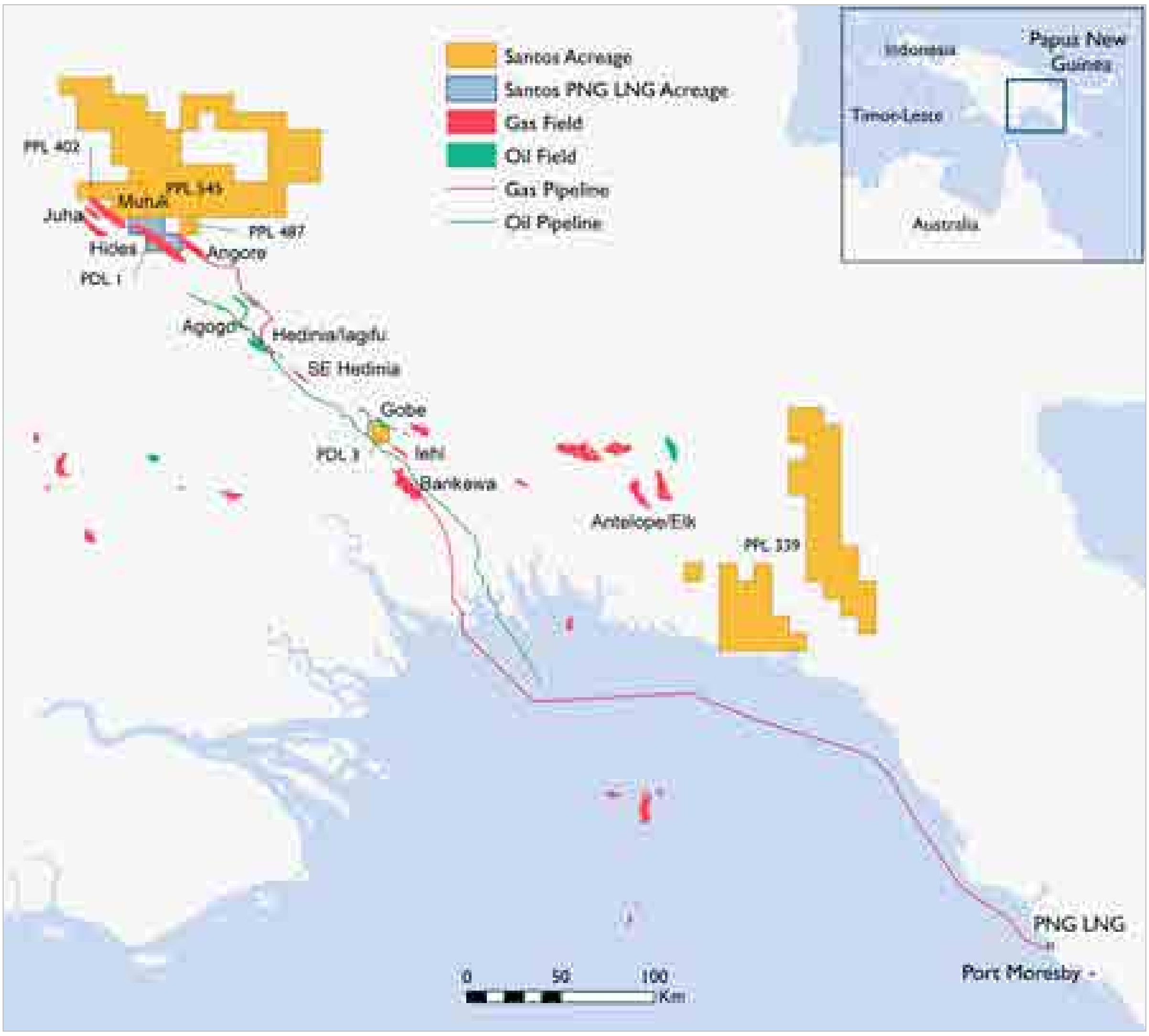
The operating model in Queensland is to execute a drilling program that develops the GLNG acreage and builds equity gas supply to the LNG plant at Gladstone. GLNG also purchases gas from the Santos portfolio and third-party suppliers.

In addition, Santos is progressing the proposed Narrabri domestic gas project in NSW. The project received environmental approvals from the state and federal governments in 2020 (which were upheld following a judicial review process as further described in section 5.15(c)).

Santos' EBITDAX margin for its Queensland and New South Wales assets was 54% for the year ended 31 December 2020.

c) PNG

Santos' business in PNG is centered on the PNG LNG project, in which it owns a 13.5% interest. The PNG LNG project is an integrated development operated by a wholly-owned subsidiary of ExxonMobil. Together, the PNG LNG project owns and operates the Hides, Angore and Juha gas fields, and also sources gas from a number of third-party gas fields.



5 Information about Santos

c) PNG continued

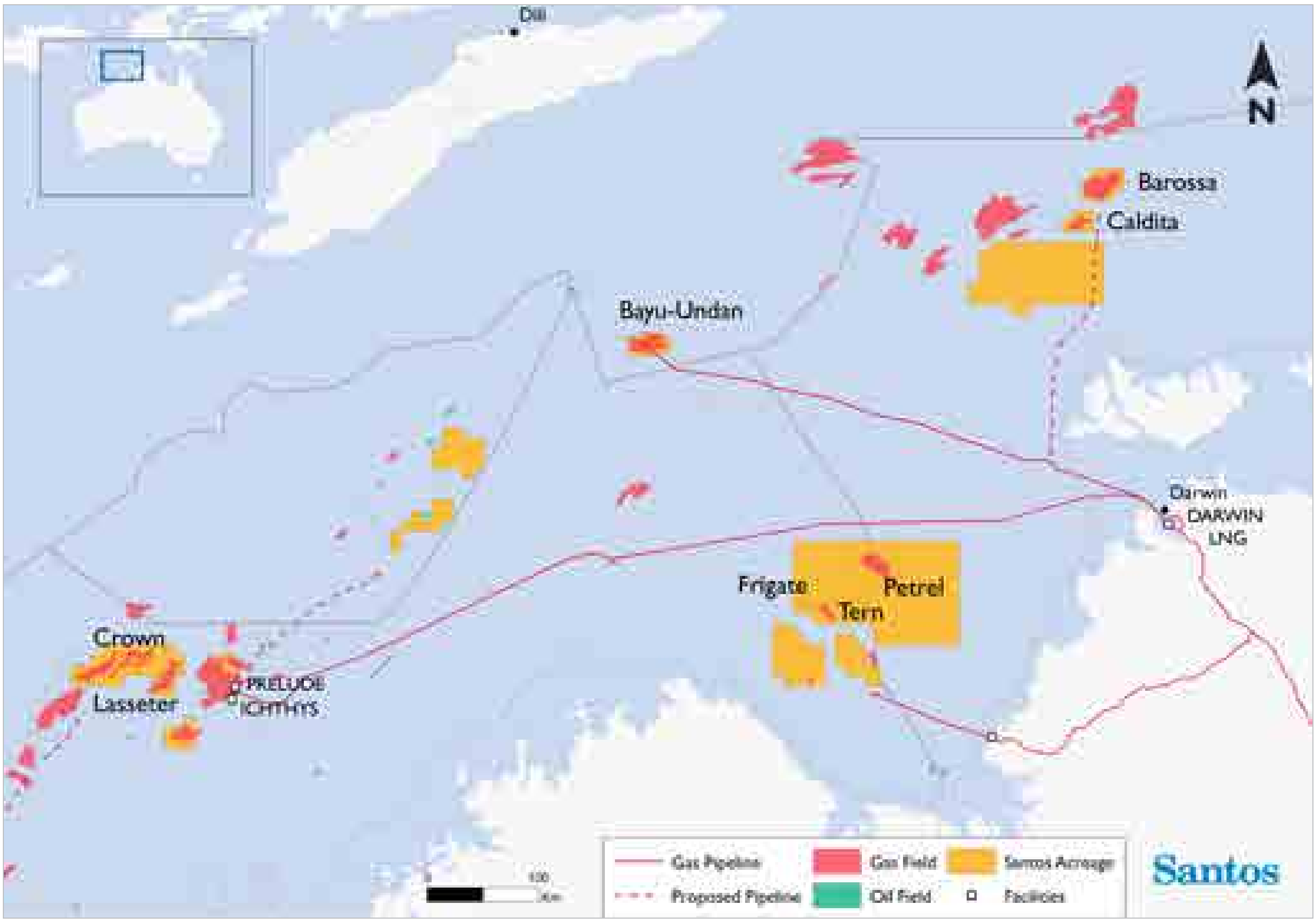
The PNG LNG project includes gas production and processing connected by over 700 kilometers of onshore and offshore pipelines to a two-train LNG plant and storage facility located near Port Moresby.

The PNG LNG project produces LNG for export as well as selling gas and gas liquids. The LNG plant produced a record 8.8 million tonnes of LNG in calendar year 2020 that was shipped through 115 cargoes. Santos' EBITDAX margin for its PNG assets was 78% for the year ended 31 December 2020.

Santos' strategy in PNG is to work closely with its partners to support and participate in backfill and expansion opportunities in connection with the PNG LNG project.

d) Northern Australia and Timor-Leste

Santos' business in northern Australia and Timor-Leste is focused on the DLNG project. Santos owns 43.4% of and operates the DLNG project, which consists of a single train natural gas liquefaction plant and storage facility and the Bayu-Undan gas field situated approximately 500 kilometers off the coast of Darwin and approximately 250 kilometers off the southern coast of Timor-Leste.



The Bayu-Undan offshore processing facility includes a central production and processing complex with a floating storage and offloading vessel that separates and processes condensate and LPG products and transports the natural gas via the Bayu-Undan to Darwin pipeline to the DLNG plant for liquefaction and export.

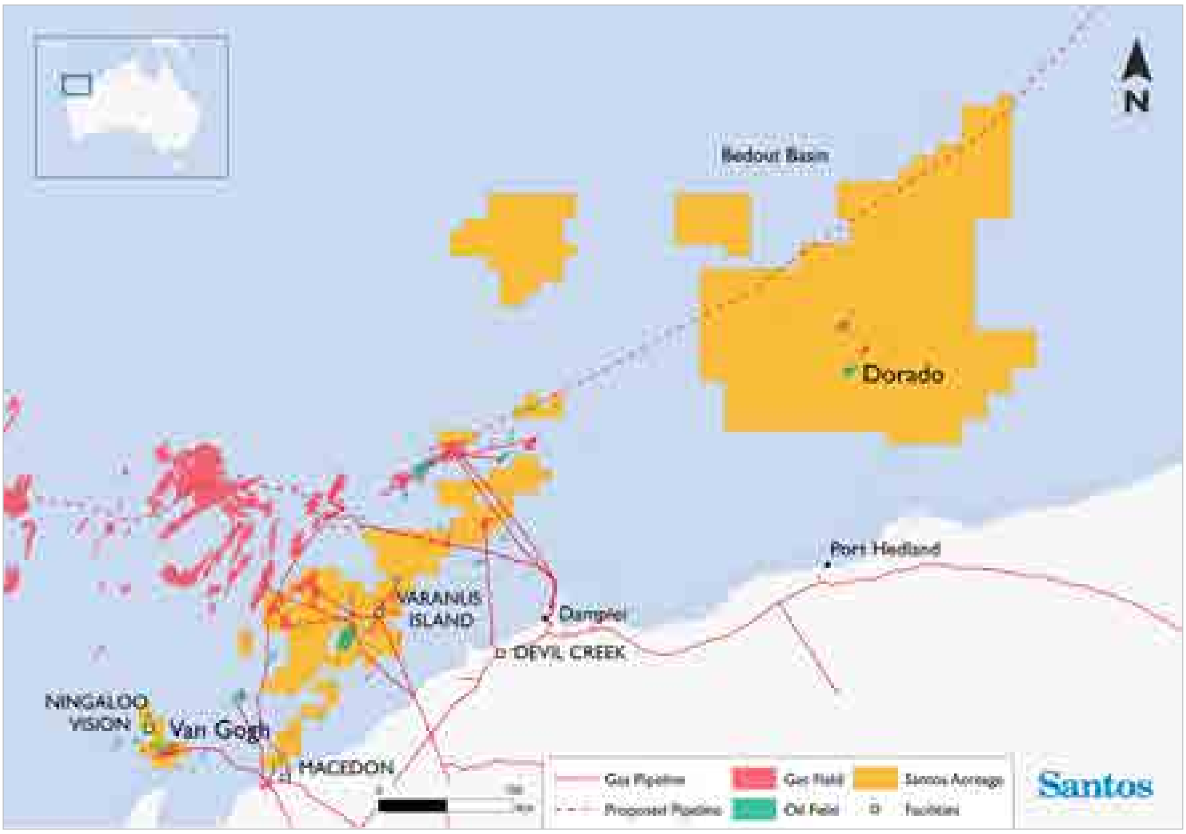
The LNG plant located near Darwin has a single LNG train with a capacity of approximately 3.7 mtpa. The plant, which was constrained by upstream production supply, produced three million tonnes of LNG in 2020 which was shipped through 48 cargoes.

Santos' EBITDAX margin for its Northern Australia and Timor-Leste assets was 44% for the year ended 31 December 2020, and Santos' share of production from its Northern Australia and Timor-Leste assets was 14.5 mmboe in calendar year 2020.

In March 2021, Santos reached a Final Investment Decision to develop the Barossa field at an estimated capital expenditure of US$3.6 billion to first LNG (of which Santos' share will be US$1.8 billion, assuming it completes the planned 12.5% sell-down to JERA Co., Inc., reducing Santos' share in Barossa to 50%). The Barossa field will enable the continued operation of DLNG beyond the life of the Bayu-Undan field.

e) Western Australia

Santos is the largest supplier of domestic gas to the Western Australian market as well as a significant producer of oil and natural gas liquids. Santos owns 100% of and operates the Varanus Island and Devil Creek domestic gas processing hubs and owns a 28.6% non-operator interest in the Macedon gas processing hub (which is operated by BHP).



Santos owns interests in and operates a range of offshore oil and gas fields which are in various stages of exploration, appraisal, development and production. Santos supplies approximately 45-50% of the domestic gas market in Western Australia as of 31 December 2020.

Santos' share of production from its Western Australian assets was 31.1 mmboe in calendar year 2020.

Santos continues to develop potential infill gas opportunities at its Western Australian assets. In 2021, Santos also completed the Phase 2 infill program for the Van Gogh oil field. Further, Santos has entered into the FEED-phase for a potential phase 1 oil and liquids development of the Dorado field (in which Santos has an 80% interest) in the Bedout Basin, offshore Port Hedland in North Western Australia.

5.3 Production

In the financial year ended 31 December 2020, Santos delivered a record annual production of 89.0 mmboe.

The tables below summarise Santos' production volume for the financial year ended 31 December 2020 and the financial year ended 31 December 2019 by asset and by product. The production volume figures reflect Santos' share of production at jointly owned assets based on Santos' percentage ownership in the assets.

a) Product volume by asset

	For the year ended 31 December 2020 (mmboe)	For the year ended 31 December 2019 (mmboe)
Cooper Basin	16.8	15.8
Queensland and NSW	13.4	13.0
Papua New Guinea	13.2	12.8
Northern Australia and Timor-Leste	14.5	3.1
Western Australia	31.1	30.9
Total	**89.0**	**75.5**

b) Production volume by product

	For the year ended 31 December 2020 (mmboe)	For the year ended 31 December 2019 (mmboe)
LNG	36.9	25.3
Sales gas and ethane	40.0	37.2
Oil	5.1	7.7
Condensate	5.1	4.0
LPG	1.9	1.3
Total	**89.0**	**75.5**

5.4 Reserves

a) Summary of Santos' 1P and 2P reserves

The following table summarises Santos' 1P, and 2P reserves as of 31 December 2020.

	As of 31 December 2020	
	1P[1]	2P[2]
Product		
Sales gas (PJ)	2,650	4,960
Crude oil (mmbbl)	22	39
Condensate (mmbbl)	16	33
LPG (000 tons)	466	1,269
All products		
Developed (mmboe)	349	490
Undeveloped (mmboe)	147	443
Total (mmboe)	**496**	**933**
Proportion of total reserves that are unconventional	33%	35%

b) Reserves by core asset hubs

The following tables shows Santos' 1P and 2P reserves across its five core asset hubs as of 31 December 2020.[3]

	As of 31 December 2020 1P reserves			
Asset	Sales gas (PJ)	Crude oil (mmbbl)	Condensate	LPG (000 tons)
Cooper Basin	243	7	3	441
Queensland and NSW	956	—	—	—
Papua New Guinea	647	0	5	—
Northern Australia and Timor-Leste	72	—	0	25
Western Australia	733	15	7	—
Total	**2,650**	**22**	**16**	**466**
Proportion of total 1P reserves that are unconventional				33%

1) 1P sales gas reserves include 792 PJ GLNG and 157 PJ other Santos non-operated Eastern Queensland assets.

2) 2P sales gas reserves include 1,491 PJ GLNG and 405 PJ other Santos non-operated Eastern Queensland assets.

3) Santos aggregates its petroleum reserves by arithmetic summation in each category and, as a result, its 1P reserves may be a very conservative estimate due to the portfolio effects of arithmetic summation. Reserves figures are rounded down to the nearest whole number, and some totals in the tables may not add due to rounding. Items that round to zero are represented by the number 0, while items that are actually zero are represented with a dash "—".

b) Reserves by core asset hubs continued

Asset	As of 31 December 2020 2P reserves			
	Sales gas (PJ)	Crude oil (mmbbl)	Condensate	LPG (000 tons)
Cooper Basin	652	16	8	1,084
Queensland and NSW	1,906	—	—	—
Papua New Guinea	964	0	9	—
Northern Australia and Timor-Leste	162	—	3	186
Western Australia	1,277	23	12	—
Total	**4,960**	**39**	**33**	**1,269**
Proportion of total 2P reserves that are unconventional				35%

c) Undeveloped, Developed and total reserves

The following tables shows Santos' developed, undeveloped and total reserves across its five core assets as of 31 December 2020. Any material concentrations of undeveloped reserves that have remained undeveloped for more than five years are:

i) intended to be developed when required to meet contractual obligations; and

ii) have not been developed to date because they have not yet been required to meet contractual obligations.

Assets	As of 31 December 2020 1P reserves		
	Developed (mmboe)	Undeveloped (mmboe)	Total (mmboe)
Cooper Basin	45	11	56
Queensland and NSW	108	56	164
Papua New Guinea	75	41	116
Northern Australia and Timor-Leste	13	—	13
Western Australia	108	39	147
Total	**349**	**147**	**496**

Assets	As of 31 December 2020 2P reserves		
	Developed (mmboe)	Undeveloped (mmboe)	Total (mmboe)
Cooper Basin	93	52	145
Queensland and NSW	108	220	328
Papua New Guinea	116	58	174
Northern Australia and Timor-Leste	18	14	32
Western Australia	154	100	254
Total	**490**	**443**	**933**

5.5 Environment, Social, Governance and Sustainability

Santos is Australia's biggest domestic gas supplier, a leading Asia-Pacific LNG supplier and aims to be a world-leading gas and liquid fuels company. Sustainability is core to driving long-term shareholder value.

Santos has played a significant role in meeting the energy security needs of Australia and Asia by supplying reliable and affordable natural gas for more than 50 years. As the world transitions to a low-carbon economy, Santos expects to continue to meet the energy needs of our customers.

Santos is an industry-leader in the energy transition and has previously announced a net zero scope 1 and 2 emissions by 2040 target. Santos' response to climate change management is embedded within its business strategy and has delivered clear results, including reducing emissions intensity per unit of production by 20 per cent in the past five years.

Santos is committed to realising a global future where temperature increase is limited to below 2 degrees Celsius. Santos recognises the importance of a credible net-zero emissions plan in retaining access to equity and debt capital markets in order to raise funding for its growth projects and the energy transition, and sees these plans as a key competitive advantage. Santos' investment grade credit rating is expected to provide access to debt capital markets on attractive terms.

Santos considers a sustainable future depends on natural gas and is investing in the step-change technology of CCS, which will allow it to reduce emissions from its operations. Santos' existing capabilities and infrastructure support the potential for large-scale production of cleaner fuels, including hydrogen, through the use of CCS.

In November 2021, Santos took the final investment decision on the Moomba CCS project in the Cooper Basin following the successful registration of the project with the Clean Energy Regulator. Moomba CCS is one of the largest and lowest-cost CCS projects globally and will have the capacity to capture and store underground approximately 1.7 million tonnes of CO_2 per annum. The Cooper Basin has the potential to store over 20 million tonnes of CO_2 per annum for more than 50 years and Santos is exploring new sources of CO_2, such as direct air capture. The CO_2 will be permanently stored in the depleted reservoirs which have held oil and gas in sealed structures for millions of years. In addition, Santos has signed a Memorandum of Understanding with the Timor-Leste regulator to consider repurposing Bayu-Undan facilities into a CCS project with capacity to store up to 10 million tonnes of CO_2 per annum. Santos is evaluating a third CCS opportunity in Western Australia using depleted reservoirs and existing infrastructure. Santos' CCS projects are potential enablers for the production of low or net zero emission hydrogen from natural gas.

Also in November 2021, Santos announced it was partnering with Australia's national science agency, CSIRO, to develop direct air capture technology which removes CO_2 directly from the atmosphere. The CO_2 can then be safely and stored in CCS projects. The technology will be trialled at Moomba in South Australia, from where the captured CO_2 will be transported to Santos' Moomba CCS project.

Santos' seven sustainability pillars underpin delivery of Santos' strategy and are essential to achieving its vision. The pillars provide a framework to reflect Santos' sustainability aspirations and targets, to guide Santos' performance and to manage issues that are material to Santos' business.

These pillars are economic sustainability, health and safety, climate change, environment, community and supply chain, indigenous partnership and people and culture.

Santos is committed to preventing harm to the environment as a result of its project and operational activities. Santos operates in diverse locations that have unique biodiversity and land features. Santos has set the following goals, to support this commitment, including:

– rehabilitate 100 per cent of our environment construction footprint within 12 months for production operations by 2030;

– zero waste to landfill by 2050; and

– 100 per cent background methane gas and baseline assessments across all onshore operations by 2030.

Santos has processes in place to identify and understand environmental values and mitigate potential risks. Subject matter experts are engaged to conduct ongoing measurement of water, waste, air and biodiversity indicators to ensure that Santos meets its high environmental standards.

Each year the Santos Board sets environmental targets that are specific, time-bound and mandatory. Regular progress updates are provided to the Board throughout the year.

Santos makes a significant contribution to the economy and its disciplined operating model makes this possible. Santos operates at a cost base that is sustainable in periods of lower oil prices. Santos works to support economic opportunities including employment, training, education and enterprise opportunities. Santos has a workforce of over 3000 people and in 2020, we spent approximately $3 billion on Australian goods and services with over 3700 businesses.

In terms of community contribution, Santos is committed to creating a sustainable future for the communities where it operates by providing benefits that have a positive impact. In 2020, Santos invested over $17 million in community partnerships and local infrastructure projects. Santos' community investment program aims to create social value by supporting organisations which deliver programs or initiatives that contribute to the following areas:

- environment and climate change;
- mental health and healthy living;
- science, technology, engineering and mathematics (**STEM**) training and education;
- strengthening local economies and communities; and
- indigenous communities, diversity and inclusion.

Santos partners with local businesses and organisation to actively listen to, support, invest, create jobs and build diverse skill sets. Hiring and procuring locally is important to Santos, and is a key enabler for economic, environmental, social and operational sustainability.

Santos is committed to building and maintaining mutually beneficial relationships with Indigenous communities. Santos has longstanding relationships with many Indigenous communities, some dating back over 30 years. Santos engages and works in partnership with Traditional Owner Groups and Land Councils for the lifecycle of our operations on matters relating to Native Title, consent and cultural heritage management.

Santos' strategy to '*Transform, Build and Grow*' is positioning the business to achieve its vision to be Australia's leading natural gas company by 2025. In order to deliver this vision, Santos intends to:

a) reduce emissions and improve air quality across Asia and Australia by displacing coal with natural gas and supporting the economic development of combined gas, cleaner fuels and carbon capture and storage solutions;
b) be the leading national supplier of domestic gas in Australia;
c) be a leading regional LNG supplier by increasing LNG sales to Santos' Asian customers to over 4.5 million tonnes per annum;
d) be a leading supplier of premium, low-sulphur crude and condensate to Australian and Asian customers;
e) be recognised as Australia's safest, most reliable and lowest cost developer and operator of upstream and midstream oil and gas facilities and infrastructure;
f) contribute positively to the communities Santos operates in by providing jobs and local partnerships; and
g) develop Santos' people and culture to deliver its vision.

On 14 April 2021, Santos published a sustainability report. A copy of this report is available from Santos' website (https://www.santos.com/sustainability/). As part of its annual reporting, Santos also published a climate change report on 18 February 2021. A copy of this report is available from Santos' website (https://www.santos.com/sustainability/climate-change/).

Santos has a dedicated Board sub-committee focused on governance of ESG matters. The Environment, Health, Safety and Sustainability Committee's duties comprise the governance and review of the Santos' activities in the areas of Environment, Health and Safety, Climate Change, Anti-Slavery, Land Access, Indigenous Engagement and Cultural Heritage and Community Engagement (EHS&S Remit).

5.6 Board of Directors and Senior Leadership Team

a) Santos' Managing Director and Chief Executive Officer

Mr Kevin Gallagher joined Santos as Managing Director and Chief Executive Officer on 1 February 2016. He is also a member of Santos' Environment, Health, Safety and Sustainability Committee and a Director of Santos Finance Limited.

Mr Gallagher has more than 25 years' experience in managing oil and gas operations. He is currently Chair of the Australian Petroleum Production and Exploration Association. He was previously Managing Director and Chief Executive Officer at Clough Limited where he oversaw the development of innovative programs to improve safety and drive productivity, executed an international expansion strategy, and led the sale of Clough Limited to their major shareholder Murray and Roberts Holdings Limited. He was also previously CEO of the North West Shelf Venture, where he was responsible for production from Australia's first LNG project, which underpinned a new domestic gas market.

Mr Gallagher has a Bachelor of Engineering (Mechanical) with Honours and is a Fellow of the Institution of Engineers Australia.

b) Santos Board

As at the Last Practicable Trading Date, the Santos Board comprises the following Santos Directors.

Name	Current Position
Keith Spence	Non-executive Director and Chairman
Kevin Gallagher	Managing Director and Chief Executive Officer
Yasmin Allen	Non-executive Director
Guy Cowan	Non-executive Director
Hock Goh	Non-executive Director
Vanessa Guthrie AO	Non-executive Director
Peter Hearl	Non-executive Director
Janine McArdle	Non-executive Director

c) Santos' Executive Leadership Team

As at the Last Practicable Trading Date, Santos' executive leadership team comprises the following individuals.

Name	Current Position
Kevin Gallagher	Managing Director and Chief Executive Officer
David Banks	Chief Technical and Marketing Officer
Brett Darley	Chief Operating Officer, Upstream Oil & Gas
Beverley East	Vice President People, Culture & Corporate Affairs
Jodie Hatherly	Vice President Environment, Social Responsibility and Governance and Legal
Angus Jaffray	Group Executive Transformation, Integration and Corporate Projects
Anthony Neilson	Chief Financial Officer
Jane Norman	Vice President Strategy & Business Development
Tracey Winters	Strategic Adviser External Affairs
Brett Woods	Chief Operating Officer, Midstream Infrastructure & Clean Fuels

5.7 Capital Structure

a) Capital Structure

As at the Last Practicable Trading Date, the capital structure of Santos is as follows:

Type of security	Number on issue
Santos Shares	2,083,066,041
Santos Share Acquisition Rights	15,459,842 share acquisition rights issued pursuant to the Santos Employee Equity Incentive Plan which are each capable of being converted into one Santos Share 2,435,890 issued pursuant to the ShareMatch Plan which are each capable of being converted into one Santos Share
Santos Executive Share Plan Shares	5000 "0" shares each paid to 1 cent 5000 "2" shares each paid to 1 cent

b) Santos Share Plans

Santos currently operates two general employee share plans, Share1000 and the ShareMatch Plan. Share1000 and ShareMatch Plan are governed by the rules of the Santos Employee Share Acquisition Plan and ShareMatch Plan respectively. Both plans were introduced in 2010 and provide a means for employees to acquire shares in Santos.

Santos currently has two executive share-based payment plans, Executive Long-Term Incentive Program (**Santos LTI Program**) and the Executive Short-Term Incentive Program (**Santos STI Program**). The Santos LTI Program provides for eligible executives selected by the Santos Board to receive Santos Share Acquisition Rights (**Santos SARs**). Each Santos SAR is a conditional entitlement to a fully paid ordinary share, subject to the satisfaction of performance or service conditions, on terms and conditions determined by the Santos Board. The Santos SARs have a four-year performance period. The Santos Board has the discretion to cash-settle Santos SARs granted under the amended SEEIP. The 2021 Santos LTI Program offers consisted only of Santos SARs.

Awards under the Santos STI Program are based on senior executive performance for a one-year period. Half (50%) of senior executives' STI award is delivered as cash following the end of the performance year. The other 50% is delivered in Santos Restricted Shares or Santos SARs, subject to a further two-year vesting period.

Further details are available in the Santos Annual Report for the year ended 31 December 2020.

c) Substantial Shareholders

As at the Last Practicable Trading Date, and based on filings released on the ASX on or before the Last Practicable Trading Date, so far as known to Santos, there are no substantial holders of Santos Shares other than as set out in the table below.

Substantial holder	Number of Santos Shares	Percentage of issued capital
United Faith Ventures	207,617,857	9.97%
BlackRock Group	129,704,766	6.23%
Mitsubishi UFJ Financial Group	108,927,265	5.23%
Challenger Limited	129,118,808	6.20%

The interests listed in this section 5.7(c) are as disclosed to Santos in substantial holder notices in accordance with the Australian Corporations Act. Information in respect of substantial holdings arising, changing or ceasing after this time or in respect of which the relevant announcement is not available on ASX's website is not included in this section 5.7(c).

5.8 Subsidiaries and Joint Venture Interests

a) Subsidiaries

As at the date of this Scheme Booklet, Santos was the ultimate holding company (as defined in the Australian Corporations Act) of the following Subsidiaries.

Name	Principal place of business/ country of incorporation	Ownership interest
Doce Pty Ltd	Australia	100%
Santos Timor Sea Pipeline Pty Ltd	Australia	100%
Santos International Holdings Pty Ltd	Australia	100%
Santos (N.T.) Pty Ltd	Australia	100%
Santos GLNG Pty Ltd	Australia	100%
Fairview Pipeline Pty Ltd	Australia	100%
Santos NA Darwin Pipeline Pty Ltd	Australia	100%
Santos NA Assets Pty Ltd	Australia	100%
Santos Darwin LNG Pty Ltd	Australia	100%
Santos WA PVG Pty Ltd	Australia	100%
Reef Oil Pty Ltd	Australia	100%
Santos Resources Pty Ltd	Australia	100%
Santos WA DC Pty Ltd	Australia	100%
Santos Direct Pty Ltd	Australia	100%
Bonaparte Gas & Oil Pty Ltd	Australia	100%
Vamgas Pty Ltd	Australia	100%
Santos Offshore Pty Ltd	Australia	100%
Santos WA (Exmouth) Pty Ltd	Australia	100%
Outback Energy Hunter Pty Ltd	Australia	100%
Santos WA East Spar Pty Limited	Australia	100%

a) Subsidiaries continued

Name	Principal place of business/ country of incorporation	Ownership interest
Santos KOTN Holdings Pty Ltd	Australia	100%
Santos NA Energy Pty Ltd	Australia	100%
Santos NA Barossa Pty Ltd	Australia	100%
Santos QNT (No. 1) Pty Ltd	Australia	100%
Bridgefield Pty Ltd	Australia	100%
Santos Petroleum Pty Ltd	Australia	100%
Santos WA Onshore Holdings Pty Ltd	Australia	100%
Santos Vietnam Pty Ltd	Australia	100%
Santos Wilga Park Pty Ltd	Australia	100%
Santos Browse Pty Ltd	Australia	100%
Santos WA Finance Holdings Pty Limited	Australia	100%
Santos WA Northwest Pty Ltd	Australia	100%
Santos WA Holdings Pty Ltd	Australia	100%
Santos NA Browse Basin Pty Ltd	Australia	100%
Santos CSG Pty Ltd	Australia	100%
Santos (NARNL Cooper) Pty Ltd	Australia	100%
Santos WA Varanus Island Pty Ltd	Australia	100%
Santos WA Management Pty Ltd	Australia	100%
Santos NSW (Pipeline) Pty Ltd	Australia	100%
Santos NA (19-13) Pty Ltd	Australia	100%
Santos WA Energy Holdings Pty Ltd	Australia	100%
Santos NA Emet Pty Ltd	Australia	100%
Santos WA AEC Pty Ltd	Australia	100%
Northwest Jetty Services Pty Ltd	Australia	100%
Santos WA Julimar Holdings Pty Ltd	Australia	100%
Santos QLD Upstream Developments Pty Ltd	Australia	100%
Bronco Energy Pty Ltd	Australia	100%
Santos NSW (Eastern) Pty Ltd	Australia	100%
Santos NSW (Hillgrove) Pty Ltd	Australia	100%
Santos WA Southwest Pty Limited	Australia	100%
Santos NSW (Betel) Pty Ltd	Australia	100%
Santos TOGA Pty Ltd	Australia	100%
SESAP Pty Ltd	Australia	100%
Santos WA PVG Holdings Pty Ltd	Australia	100%
Santos Finance Ltd	Australia	100%
Santos WA Kersail Pty Ltd	Australia	100%
Santos WA LNG Pty Ltd	Australia	100%
Moonie Pipeline Company Pty Ltd	Australia	100%
Petromin Pty Ltd	Australia	100%
Santos NA Energy Holdings Pty Ltd	Australia	100%
Santos QNT Pty Ltd	Australia	100%
Santos NSW (Narrabri Energy) Pty Ltd	Australia	100%
Santos NSW Pty Ltd	Australia	100%
Santos NSW (Narrabri Power) Pty Ltd	Australia	100%
Santos (TGR) Pty Ltd	Australia	100%
Santos Ventures Pty Ltd	Australia	100%
Santos NSW (LNGN) Pty Ltd	Australia	100%
Santos NSW (Holdings) Pty Ltd	Australia	100%
Santos WA Finance General Partnership	Australia	100%
Santos WA Asset Holdings Pty Ltd	Australia	100%
Bridge Oil Developments Pty Ltd	Australia	100%
Harriet (Onyx) Pty Ltd	Australia	100%
Santos NA (19-12) Pty Ltd	Australia	100%

5 Information about Santos

a) Subsidiaries continued

Name	Principal place of business/ country of incorporation	Ownership interest
Santos NA Asset Holdings Pty Ltd	Australia	100%
Santos WA Lowendal Pty Limited	Australia	100%
Santos Australian Hydrocarbons Pty Ltd	Australia	100%
Basin Oil Pty Ltd	Australia	100%
Santos (JPDA 91-12) Pty Ltd	Australia	100%
Santos Agency Pty Ltd	Australia	100%
Santos (BOL) Pty Ltd	Australia	100%
Santos Devil Creek Pty Ltd	Australia	100%
Santos NSW (Operations) Pty Ltd	Australia	100%
Alliance Petroleum Australia Pty Ltd	Australia	100%
Santos NA Timor Sea Pty Ltd	Australia	100%
Santos NA Timor Leste Pty Ltd	Australia	100%
Santos QNT (No. 2) Pty Ltd	Australia	100%
Santos NA Bayu Undan Pty Ltd	Australia	100%
Santos KOTN Pty Ltd	Australia	100%
Santos WA International Pty Ltd	Australia	100%
Santos WA Energy Limited	Australia	100%
Santos Midstream Holdings Pty Ltd	Australia	100%
Santos Midstream Asset Holdings Pty Ltd	Australia	100%
Santos Infrastructure Holdings Pty Ltd	Australia	100%
Santos Infrastructure West Holdings Pty Ltd	Australia	100%
Santos Infrastructure WAQ Holdings Pty Ltd	Australia	100%
Santos Infrastructure WAQ Assets Pty Ltd	Australia	100%
Santos Infrastructure WAQVIDC Pty Ltd	Australia	100%
Santos Infrastructure WASVIA Pty Ltd	Australia	100%
Santos Infrastructure WASDCA Pty Ltd	Australia	100%
Santos Northwest Natuna B.V.	Netherlands	100%
Santos P'nyang Ltd	Papua New Guinea	100%
Lavana Ltd	Papua New Guinea	100%
Barracuda Ltd	Papua New Guinea	100%
Santos Hides Ltd	Papua New Guinea	100%
Ningaloo Vision Holdings Pte. Ltd	Singapore	100%
Sanro Insurance Pte Ltd	Singapore	100%
Santos Singapore Management Pte Ltd	Singapore	100%
Santos (UK) Limited	United Kingdom	100%
Santos Bangladesh Ltd	United Kingdom	100%
Santos Sangu Field Ltd	United Kingdom	100%
Santos Queensland LLC	USA	100%
Santos Americas and Europe LLC	USA	100%
Santos TPY CSG LLC	USA	100%
Santos TOG LLC	USA	100%
Santos TPY LLC	USA	100%

b) Interests in joint operations

As at the date of this Scheme Booklet, Santos' interests in material joint operations are as follows.

	Principal place of business	Ownership interest
Exploration and evaluation assets		
Caldita/Barossa	Australia	62.5%
EP161, EP162 and EP189 (McArthur Basin)	Australia	75%
WA-435-P, WA-437-P (Bedout)	Australia	80%
WA-436-P, WA-438-P (Bedout)	Australia	70%
WA-58-R (WA-274-P) (Bonaparte)	Australia	30%
WA-80-R (Browse)	Australia	47.8%
WA-281-P (Browse)	Australia	70.5%
WA-90-R, WA-91-R, WA-92-R (Browse)	Australia	40%
Muruk 1	PNG	20%
Petrel	Australia	40%
Producing assets		
Arcadia	Australia	22.9 [1]
Barrow Island	Australia	28.6%
Bayu-Undan	Timor-Leste	43.4%
Combabula	Australia	7.3%
Fairview	Australia	22.8%
GLNG Downstream	Australia	30%
Macedon/Pyrenees	Australia	28.6%
PNG LNG	PNG	13.5%
Roma [2]	Australia	30%
SA Fixed Factor Area	Australia	66.6%
Scotia	Australia	30%
Spring Gully	Australia	24.6% [3]
SWQ Unit	Australia	60.1%

c) Interests in equity accounted associates and joint ventures

As at the date of this Scheme Booklet, Santos' interests in equity accounted associates and joint ventures are as follows.

	Principal place of business	Ownership interest
Darwin LNG Pty Ltd	Australia	43.4%
GLNG Operations Pty Ltd	Australia	30%
GLNG Property Pty Ltd	Australia	30%

1) Net of APLNG interest.

2) Santos' interest in Roma East is 24.6% given APLNG participation.

3) Net of APLNG interest

5.9 Recent Santos share price history

Santos Shares are listed on the ASX under the trading symbol 'STO'.

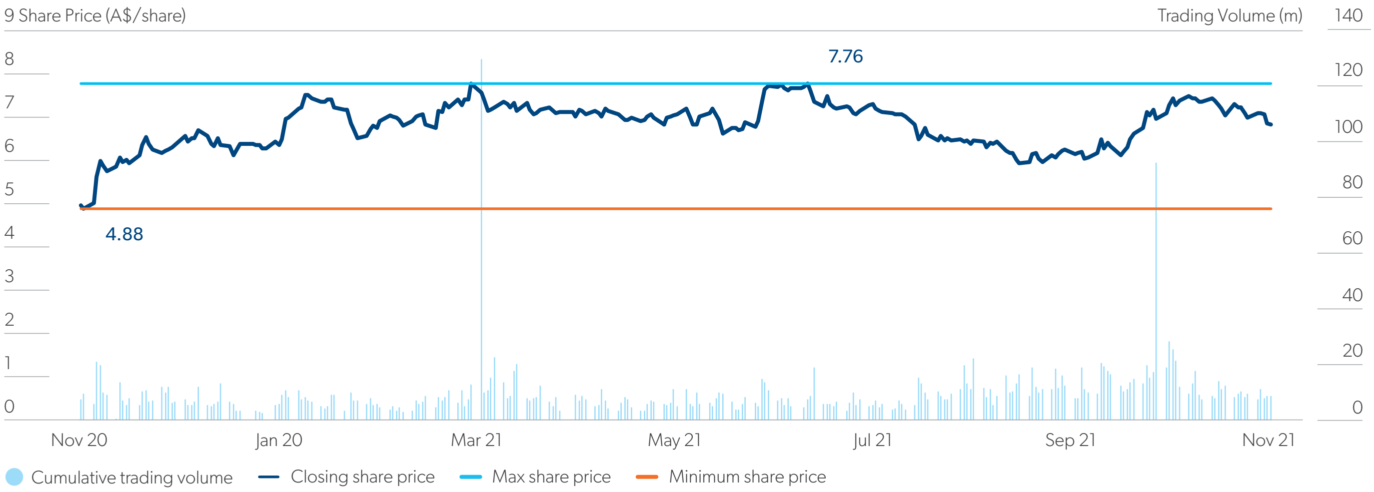
The closing price of Santos Shares on 19 July 2021 (being the last trading day prior to the announcement of Santos' non-binding indicative proposal on 20 July 2021) was A$6.83 per Santos Share.

The closing price of Santos Shares on 9 September 2021 (being the last trading day prior to the announcement of Oil Search and Santos' entry into the Merger Implementation Deed) was A$6.03 per Santos Share.

As at the Last Practicable Trading Date:
– the last recorded Santos share price on the ASX was A$6.83;
– the 1-month VWAP of Santos Shares was A$7.26;
– the 3-month VWAP of Santos Shares was A$6.67; and
– the lowest and highest Santos Share prices during the preceding three months was A$5.93 and A$7.49, respectively.

Figure 5 – Santos Last Twelve Months Share Price and Trading Volumes

The following chart shows the closing price and corresponding daily volume traded of Santos Shares over the last 12 months up to and including the Last Practicable Trading Date. Santos Shares' average daily trading volume over the last twelve months prior to and including the Last Practicable Trading Date was approximately 9.6 million shares per day.[1]



Data Source: IRESS as at market close on the Last Practicable Trading Date.

5.10 Rights and liabilities attaching to New Santos Shares

a) Introduction

The rights and liabilities attaching to the New Santos Shares which will be issued as Scheme Consideration are set out in Santos' constitution (**Santos Constitution**) and are also subject to the Australian Corporations Act and the ASX Listing Rules.

The following is a summary of the main rights and liabilities attaching to Santos Shares. This summary does not purport to be exhaustive or to constitute a definitive statement of all of the rights and liabilities attaching to Santos Shares. Such rights and liabilities involve complex questions of law arising from the interaction of the Santos Constitution and statutory and common law requirements. This summary must be read subject to the full text of the Santos Constitution, available from Santos' website (https://www.santos.com/about-us/corporate-governance/).

b) Overview

The New Santos Shares will be issued fully paid and will rank equally for dividends and other rights with existing Santos Shares, with effect from their date of issue.

Under the Australian Corporations Act, the Santos Constitution has effect as a contract between:
i) Santos and each Santos Shareholder;
ii) Santos and each director and company secretary of Santos; and
iii) a Santos Shareholder and each other Santos Shareholder.

Accordingly, if you receive New Santos Shares under the Scheme, you are taken to receive them subject to the terms of the Santos Constitution and you will be bound by the terms of the Santos Constitution.

1) The outliers in daily trading volumes, as illustrated in Figure 5 are: (i) Friday, 5 March 2021, where approximately 130 million Santos shares were traded as a result of ENN's approximate A$785m block trade, and (ii) Friday, 1 October 2021, where approximately 90 million Santos shares were traded as part of a share stock lending agreement between United Faith Ventures Limited and UBS AG, Australia Branch and Morgan Stanley & Co. International plc, and its affiliates.

c) Meeting of Santos Shareholders and notices

Santos Shareholders' rights to attend and vote at shareholder meetings are primarily prescribed by the Australian Corporations Act. Subject to certain exceptions, each Santos Shareholder is entitled to receive notice of, attend (whether or not entitled to vote) and vote at general meetings and to receive all notices and other documents required to be sent to Santos Shareholders under the Santos Constitution, the Australian Corporations Act and the ASX Listing Rules.

Santos may give a notice of meeting to Santos Shareholders by serving it personally or sending it by post, to the address shown in the Santos Register or such other address, or by sending it by fax or electronically to the address provided by the Santos Shareholder for the purpose of giving notices.

d) Voting rights

Subject to any rights or restrictions attached to Santos Shares and the terms of the Santos Constitution, at a general meeting of Santos Shareholders, every Santos Shareholder entitled to vote in person or by proxy, attorney or representative has:

i) one vote on a show of hands; and

ii) one vote on a poll for every Santos Share held.

If more than one joint holder of a Santos Share is present at a meeting in person or by proxy, attorney or representative and tenders a vote, the vote of the Santos Shareholder named first in the Santos Register will be accepted to the exclusion of others.

A person present at a general meeting who represents more than one Santos Shareholder (whether personally, or by proxy, attorney or representative) is entitled to only one vote only on a show of hands, even though he or she represents more than one Santos Shareholder.

A resolution at a general meeting must be decided on a show of hands unless a poll is demanded. A poll may be demanded (except a resolution concerning the election of the chair of the meeting) by:

i) the chair of the meeting; or

ii) Santos Shareholders in accordance with the Australian Corporations Act.

If votes on a proposed resolution are equal, the chair of the meeting has a casting vote, in addition to his or her deliberative vote.

e) Dividends

The directors may resolve to pay any interim and final ordinary dividends that, in their judgement, the financial position of Santos justifies.

Santos Directors may direct payment of a dividend from any available source permitted by law, including the distribution of specific assets (including paid-up shares of Santos or another body corporate) either generally or to specific Santos Shareholders. Santos Directors may, unless prevented by the ASX Listing Rules, direct payment of a dividend to particular Santos Shareholders wholly or partly from any particular fund or reserve or out of profits derived from any particular source.

f) Issue of further Santos Shares

Subject to the Australian Corporations Act, the ASX Listing Rules and the Santos Constitution, Santos Directors may issue and grant options for Santos Shares and decide the terms on which shares are issued or options are granted and the rights and restrictions attaching to those shares or options.

g) Transfer of Santos Shares

Subject to the Santos Constitution and the rights attached to Santos Shares under the ASX Listing Rules or the Australian Corporations Act or other applicable legislation, Santos Shareholders may transfer Santos Shares by a CHESS transfer or an instrument in writing in a form approved by the Santos Directors.

Santos Directors may request ASX Settlement Pty Limited to apply a holding lock or refuse to register a transfer of Santos Shares in circumstances set out in the Santos Constitution (including but not limited to where registration of the transfer may breach a law of Australia or where Santos is otherwise permitted or required to do so under the ASX Listing Rules or the terms of issue of the Santos Shares).

h) Variation of rights

The Australian Corporations Act provides that the rights attached to a class of shares may be varied or cancelled only:

i) with the written consent of members with at least 75% of the votes of the affected class; or

ii) by special resolution passed at a meeting of the holders of the issued shares of that class.

i) Number of directors

Santos must have at least five directors (excluding any managing directors). The maximum number of directors is fixed by the Santos Directors, but may not be more than ten except with the approval of Santos Shareholders in general meeting.

Subject to the Constitution, the Australian Corporations Act, and the maximum number of Santos directors, Santos Shareholders may be elect any natural person as a director at an annual general meeting of Santos.

j) Officer's indemnity

Santos must indemnity on a full indemnity basis and to the full extent permitted by law its current and former directors and secretaries, and such other officers or former officers of Santos or of its related bodies corporate as the Santos Directors determine, for all losses or liabilities incurred by the person as an officer of Santos, a related body corporate or trustee of a company superannuation fund.

k) Capitalising profits

Subject to the ASX Listing Rules, any rights or restrictions attached to any Santos shares or class of shares and any special resolution of Santos in general meeting, Santos Directors may capitalise and distribute among Santos Shareholders undivided profits and other amounts available for distribution. Santos Shareholders are entitled to participate in such capital distribution if entitled to receive dividends and in the same proportions.

l) Reduction of capital

Santos may reduce its share capital or alter its capital structure in any manner permitted by the Australian Corporations Act or the ASX Listing Rules.

m) Winding up

If Santos is wound up, a liquidator may (with the sanction of a special resolution) divide among Santos Shareholders the whole or any part of Santos' property and decide how the division is to be carried out as between the shareholders or different classes of shareholders.

Subject to the Constitution and the rights or restrictions attached to Santos Shares, if on a winding up, the assets available for distribution among the Santos Shareholders are more than sufficient to repay the whole of the capital paid up at the commencement of the winding up, the excess must be divided among Santos Shareholders in proportion to the number of shares they hold.

5.11 Historical financial information

This section contains the following historical financial information of Santos:

- historical income statements for the years ended 31 December 2019 and 31 December 2020 and for the half-year ended 30 June 2021 (**Santos Historical Income Statements**);
- historical statements of financial position as at 31 December 2019, 31 December 2020 and 30 June 2021 (**Santos Historical Statements of Financial Position**); and
- historical statements of cash flows for the years ended 31 December 2019 and 31 December 2020 and the half-year ended 30 June 2021 (**Santos Historical Statements of Cash Flows**),

(together, the **Santos Historical Financial Information**).

Further historical financial information can be found on Santos's website (www.santos.com). A number of figures, amounts, percentages prices, estimates, calculations of value and fractions are subject to the effect of rounding. Accordingly, totals in tables may not add due to rounding. Amounts in this section have been rounded to the nearest US$1 million.

a) Basis of presentation of Historical Financial Information

The Santos Historical Financial Information presented in this Scheme Booklet is in an abbreviated form and does not contain all presentation and disclosures that are usually provided in an annual report prepared in accordance with the Australian Corporations Act and should therefore be read in conjunction with the financial statements of Santos for the respective periods, including the description of the significant accounting policies contained in those financial statements and the notes to those financial statements. The Santos Historical Income Statements, Santos Historical Statements of Financial Position and Santos Historical Statements of Cash Flows are derived from Santos' consolidated financial statements for the years ended 31 December 2019 and 31 December 2020 and half year ended 30 June 2021, which have been lodged with ASIC and are available from Santos' website (www.santos.com) and the ASX website (www.asx.com.au). Santos' consolidated financial statements for the years ended 31 December 2019 and 31 December 2020 were audited by Ernst & Young in accordance with Australian Auditing Standards. Ernst & Young issued unqualified audit opinions on these financial statements. Santos' consolidated financial statements for the half-year ended 30 June 2021 were reviewed by Ernst & Young who issued an unmodified review conclusion in relation to Santos's Half-Year Financial Report.

The significant accounting policies used in the preparation of the Santos Historical Financial Information are consistent with those set out in Santos's Annual Report for the years ended 31 December 2019 and 31 December 2020. The Santos Historical Financial Information has been prepared in accordance with the recognition and measurement principles contained in the Australian Accounting Standards (**AAS**), including interpretations, adopted by the International Accounting Standards Board.

b) Santos Historical Statements of Financial Position

	Half-year 30 Jun 2021 US$million	31 Dec 2020 US$million	31 Dec 2019 US$million
Current assets			
Cash and cash equivalents	2,417	1,319	1,067
Trade and other receivables	684	560	554
Prepayments	22	39	40
Contract assets	19	23	23
Inventories	294	288	301
Other financial assets	1	29	195
Assets held for sale	259	438	—
Total current assets	**3,696**	**2,696**	**2,180**
Non-current assets			
Contract assets	97	106	130
Investments in associates and joint ventures	396	413	13
Other financial assets	17	24	29
Prepayments	38	2	—
Exploration and evaluation assets	1,013	1,818	1,187
Oil and gas assets	11,293	10,925	11,396
Other land, buildings, plant and equipment	262	248	223
Deferred tax assets	1,310	1,041	870
Goodwill	383	383	481
Total non-current assets	**14,809**	**14,960**	**14,329**
Total assets	**18,505**	**17,656**	**16,509**
Current liabilities			
Trade and other payables	825	558	719
Contract liabilities	117	64	125
Lease liabilities	130	121	114
Interest bearing loans and borrowings	243	233	196
Current tax liabilities	31	31	38
Provisions	155	177	122
Other financial liabilities	4	39	5
Liabilities directly associated with assets held for sale	7	312	—
Commodity derivatives (oil hedges)	196	—	—
Total current liabilities	**1,708**	**1,535**	**1,319**
Non-current liabilities			
Contract liabilities	249	281	233
Lease liabilities	287	336	311
Interest bearing loans and borrowings	4,977	4,309	3,800
Deferred tax liabilities	1,104	904	811
Provisions	2,853	3,039	2,329
Other liabilities	—	1	1
Other financial liabilities	24	24	29
Total non-current liabilities	**9,494**	**8,894**	**7,514**
Total liabilities	**11,202**	**10,429**	**8,833**
Net assets	**7,303**	**7,227**	**7,676**

b) Santos Historical Statements of Financial Position continued

	Half-year 30 Jun 2021 US$million	31 Dec 2020 US$million	31 Dec 2019 US$million
Equity			
Issued capital	9,001	9,013	9,010
Reserves	849	1,107	759
Accumulated losses	(2,547)	(2,893)	(2,093)
Equity attributable to owners of Santos Limited	**7,303**	**7,227**	**7,676**
Total equity	**7,303**	**7,227**	**7,676**

c) Santos Historical Income Statements of Profit and Loss and Other Comprehensive Income

	Half-year ended 30 Jun 2021 US$million	Year ended 31 Dec 2020 US$million	Year ended 31 Dec 2019 US$million
Revenue from contracts with customers — Product sales	2,040	3,387	4,033
Cost of sales	(1,483)	(2,642)	(2,714)
Gross profit	**557**	**745**	**1,319**
Revenue from contracts with customers – Other	72	125	153
Other income	72	65	109
Impairment of non-current assets	(8)	(895)	(61)
Other expenses	(119)	(145)	(233)
Finance income	2	15	37
Finance costs	(111)	(249)	(314)
Share of net profit of associates	14	33	8
(Profit/Loss) before tax	**479**	**(306)**	**1,018**
Income tax (expense)/benefit	(82)	63	(341)
Royalty-related tax expense	(43)	(114)	(3)
Total tax expense	**(125)**	**(51)**	**(344)**
Net profit/(loss) for the period attributable to owners of Santos Limited	**354**	**(357)**	**674**

c) Santos Historical Income Statements of Profit and Loss and Other Comprehensive Income continued

	Half-year ended 30 Jun 2021 US$million	Year ended 31 Dec 2020 US$million	Year ended 31 Dec 2019 US$million
Net profit/(loss) for the period	**354**	**(357)**	**674**
Other comprehensive (loss)/income, net of tax:			
Other comprehensive income to be reclassified to the income statement in subsequent periods:			
Exchange loss/gain on translation of foreign operations	(17)	55	—
	(17)	55	—
(Loss) on derivatives designated as cash flow hedges	(195)	(3)	(8)
Tax effect	59	1	2
	(136)	(2)	(6)
Net other comprehensive (loss)/income to be reclassified to the income statement in subsequent periods	(153)	53	(6)
Items not to be reclassified to the income statement in subsequent periods:			
Fair value changes on financial liabilities designated at fair value due to own credit risk	(1)	2	(6)
Tax effect	—	(1)	1
	(1)	1	(5)
Net other comprehensive (loss)/income that will not be reclassified to the income statement in subsequent periods	(1)	1	(5)
Other comprehensive (loss)/income, net of tax	(154)	54	(11)
Total comprehensive income/(loss) attributable to owners of Santos Limited	**200**	**(303)**	**663**
Earnings per share attributable to the equity holders of Santos Limited (¢)			
Basic profit/(loss) per share	17.0	(17.1)	32.4
Diluted profit/(loss) per share	16.9	(17.1)	32.1
Dividends per share (¢)			
Paid during the period	5.0	7.1	12.2
Declared in respect of the period	5.5	7.1	11.0

d) Santos Historical Statements of Cash Flows

	Half-year ended 30 Jun 2021 US$million	Full year 31 Dec 2020 US$million	Full year 31 Dec 2019 US$million
Cash flows from operating activities			
Receipts from customers	2,057	3,503	4,266
Interest received	2	15	37
Dividends received from associate	29	41	15
Pipeline tariffs and other receipts	94	218	146
Payments to suppliers and employees	(868)	(1,899)	(1,892)
Restoration expenditure	(14)	(37)	(24)
Exploration and evaluation seismic and studies	(34)	(48)	(83)
Royalty and excise paid	(28)	(59)	(90)
Payments for)/proceeds from commodity hedging	(66)	54	—
Borrowing costs paid	(84)	(176)	(227)
Income taxes paid	(23)	(5)	(30)
Royalty-related taxes paid	(114)	(154)	(97)
Insurance proceeds	—	13	28
Overriding royalty	(9)	10	(3)
Net cash provided by operating activities	**942**	**1,476**	**2,046**
Cash flows from investing activities			
Payments for:			
– Exploration and evaluation activities	(91)	(130)	(222)
– Oil and gas assets	(378)	(584)	(619)
– Other land, buildings, plant and equipment	(13)	(47)	(18)
– Acquisitions of exploration and evaluation assets	(10)	(9)	(18)
– Costs associated with acquisition of subsidiaries	(7)	(19)	(5)
– Acquisitions of a group of assets, net of cash acquired	—	(695)	(177)
Proceeds from disposal of non-current assets	186	—	10
Net (payments)/proceeds associated with disposal	—	(11)	18
Borrowing costs paid	(21)	(29)	(15)
Return of capital – Investments in associate	—	63	13
Net cash used in investing activities	**(334)**	**(1,461)**	**(1,033)**
Cash flows from financing activities			
Dividends paid	(104)	(136)	(251)
Drawdown of borrowings	996	1,492	592
Repayments of borrowings	(320)	(960)	(1,474)
Repayment of lease liabilities	(62)	(119)	(87)
Purchase of shares on-market (Treasury shares)	(31)	(31)	(31)
Net cash provided by financing activities	**479**	**246**	**(1,251)**
Net increase/(decrease) in cash and cash equivalents	1,087	261	(238)
Cash and cash equivalents at the beginning of the period	1,319	1,067	1,316
Effects of exchange rate changes on the balances of cash held in foreign currencies	11	(9)	(11)
Cash and cash equivalents at the end of the period	**2,417**	**1,319**	**1,067**

5.12 Material changes to Santos' financial position

As at the date of this Scheme Booklet, within the knowledge of the Santos Directors and other than as disclosed in this Scheme Booklet or announced on the ASX, there have been no material changes to the financial position of Santos since 30 June 2021, being the date of Santos' half year reviewed accounts for the year ended 31 December 2021, that would materially impact the information within this Scheme Booklet.

5.13 2021 production guidance

In its full year results announcement released to the ASX on 18 February 2021, Santos provided 2021 production guidance in the range of 84 to 91 mmboe. This guidance range was updated in Santos' second quarter report released to the ASX on 22 July 2021 to 87 to 91 mmboe. The guidance range was further updated in Santos' third quarter report released to the ASX on 21 October 2021 to 88 to 91 mmboe.

5.14 Santos Dividend History

Since the financial year ended 31 December 2020, the following dividends have been declared and paid by Santos.

- On 18 February 2021, Santos announced that the Santos Board had resolved to pay a fully franked final dividend of US$0.05 cents per fully paid ordinary share in relation to the financial year ended 31 December 2020. The record date for the dividend was 24 February 2021 and the payment date was 25 March 2021.
- On 17 August 2021, Santos announced that the Santos Board had resolved to pay a fully franked interim dividend of US$0.055 cents per fully paid ordinary share in relation to the half-year ended 30 June 2021 (**Santos Interim CY21 Dividend**). The record date for the dividend was 23 August 2021 and the payment date was 21 September 2021.

Under the Merger Implementation Deed, if Santos declares or determines to pay a CY21 Dividend or Interim CY22 Dividend prior to the Record Date, the number of New Santos Shares to be issued for each Scheme Share may be adjusted in accordance with the formula set out in clause 4.7 of the Merger Implementation Deed as set out in section 9.13.

Under the terms of the Merger Implementation Deed, between (and including) the date of the Merger Implementation Deed and 8:00am (Port Moresby time) on the Second Court Date, Santos is not permitted to declare, pay or distribute any dividend to Santos Shareholders other than the Santos Interim CY21 Dividend, a CY21 Dividend or an Interim CY22 Dividend provided that any such dividends are each declared and paid in the ordinary course and in accordance with Santos' existing dividend policy as at the date of the Merger Implementation Deed, all such dividends are declared before the Record Date and all such dividends are paid before the Implementation Date.

5.15 Material litigation

As at the Last Practicable Trading Date, the Santos Group is party to the following material litigation.

a) On 25 August 2021, the Australasian Centre for Corporate Responsibility (**ACCR**) filed proceedings against Santos in the Federal Court of Australia (case number NSD858/2021). The claim alleges misleading or deceptive conduct in relation to statements in Santos' 2020 Annual Report, being Santos':
   - net zero by 2040 Scope 1 and 2 emissions commitment; and
   - use of the terms 'clean energy' and 'clean fuel' in relation to Santos' business and the natural gas it produces.

   The ACCR seeks declarations that Santos' statements were misleading or deceptive and an injunction compelling a 'corrective' statement to the market and an injunction restraining Santos from publishing any further statements using the term "clean fuel" or "clean energy" or referring to Santos' "roadmap" to net zero emissions by 2040 as "clear" or "credible". No damages or financial relief are sought (other than ACCR's legal costs). Santos has rejected the allegations and is defending the claim.

b) On 13 December 2016, Santos issued proceedings against Fluor Australia Pty Ltd in the Supreme Court of Queensland for the recovery of approximately $1.5 billion for amounts claimed by Fluor and paid by Santos which Santos claimed Fluor were not entitled to claim under the terms of the contract for the design and construction of the upstream GLNG Project surface facilities. Fluor Corporation was subsequently included as a second defendant to the proceedings. As at the Last Practicable Trading Date, the hearing is scheduled to commence on 17 November 2021.

c) On 22 December 2020, an application for judicial review was filed in the NSW Land and Environment Court challenging the decision by the NSW Independent Planning Commission (**IPC**) to grant development consent to the Narrabri Gas Project. The application for judicial review was made by the Mullaley Gas and Pipeline Accord Incorporated (**MGPA**), seeking a declaration that the IPC development consent is invalid and of no effect. On 18 October 2021, the NSW Land and Environment Court determined that MGPA did not establish any grounds of review and dismissed the request for a declaration seeking that the IPC development consent is invalid and of no effect.

5.16 Interests of Santos Directors

a) Interests of Santos Directors in Santos Shares

The table below lists the Relevant Interests of Santos Directors in Santos Shares as at the date of this Scheme Booklet.

Santos Director	Interests in Santos Shares
Keith Spence	90,000 Santos Shares
Kevin Gallagher	1,930,224 Santos Shares / 2,924,210 Santos SARs
Yasmin Allen	48,883 Santos Shares
Guy Cowan	45,487 Santos Shares
Hock Goh	67,215 Santos Shares
Vanessa Guthrie	39,188 Santos Shares
Peter Hearl	48,808 Santos Shares
Janine McArdle	18,000 Santos Shares

No Santos Director acquired or disposed of a Relevant Interest in any Santos Shares during the four months before the date of this Scheme Booklet.

b) Marketable securities in Oil Search held by, or on behalf of, Santos Directors

As at the date of this Scheme Booklet, Santos' Chairman, Mr Keith Spence, indirectly holds 25,000 fully paid ordinary Oil Search Shares that were acquired during the period that Mr Spence served on the Oil Search Board.

Other than Mr Spence's holdings, no other marketable securities of Oil Search are held by, or on behalf of, Santos Directors as at the date of this Scheme Booklet. No Santos Director acquired or disposed of any marketable securities of Oil Search during the four months before the date of this Scheme Booklet.

c) Interests of Santos Directors in contracts of Oil Search

As at the date of this Scheme Booklet, Santos' Chairman, Mr Keith Spence, is still covered under Oil Search's directors' and officers' insurance policy (as a result of Mr Spence previously serving on the board of Oil Search).

Other than Mr Spence's interests, no Santos Director has an interest in any contract entered into by Oil Search.

d) Other interests of Santos Directors

Except as provided for in this Scheme Booklet, the Santos Directors have no interest in the outcome of the Scheme.

5.17 Disclosure of Interests

a) Santos' Relevant Interests in Oil Search Securities

As at the date of this Scheme Booklet, Santos does not have a Relevant Interest in Oil Search Securities.

Except for the consideration to be provided under the Scheme and as described in the Scheme Booklet, none of Santos nor any of its Controlled Entities (or any of their respective associates) has provided, or agreed to provide, consideration for any Oil Search Shares or other Oil Search securities under any transaction during the period of four months before the date of this Scheme Booklet.

Santos has not acquired or disposed of a Relevant Interest in any Oil Search security in the four months preceding the date of this Scheme Booklet.

b) Interests in connection with the issue of New Santos Shares

Except as otherwise provided in this Scheme Booklet, no:

- Santos Director or proposed director of Santos;
- person named in this Scheme Booklet as performing a function in a professional, advisory or other capacity in connection with the preparation or distribution of this Scheme Booklet for or on behalf of Santos; or
- promoter, stockbroker or underwriter of Santos or the Merged Group,

together, (the **Interested Persons**) holds, or held at any time during the two years before the date of this Scheme Booklet, any interests in:

- the formation or promotion of Santos or the Merged Group;
- property acquired or proposed to be acquired by Santos in connection with the formation or promotion of Santos or the Merged Group or the offer of Santos Shares under the Scheme; or
- the offer of New Santos Shares under the Scheme.

5.18 No pre-transaction benefits

a) Fees in connection with the Scheme

Except as otherwise disclosed in this Scheme Booklet, Santos has not paid or agreed to pay any fees, or provided or agreed to provide any benefit:

- to a director or proposed director of Santos to induce him or her to become or qualify as a director of Santos; or
- for services provided by any Interested Persons in connection with the formation or promotion of Santos or the Merged Group or the offer of the New Santos Shares under the Scheme.

b) Benefits in connection with the Scheme

During the period of four months prior to the date of this Scheme Booklet, neither Santos nor any Associate of Santos has given, or offered to give, or agreed to give, a benefit to another person which was likely to induce the other person, or an Associate of the other person, to vote in favour of the Scheme or dispose of Oil Search Shares, and which will not be provided to all Scheme Participants under the Scheme.

5.19 Publicly available information about Santos

As an ASX-listed company and disclosing entity for the purpose of the Australian Corporations Act, Santos is subject to regular reporting and disclosure obligations. Broadly, these obligations require Santos to announce price sensitive information to the ASX as soon as Santos becomes aware of that information, subject to certain exceptions including for confidential information.

The ASX maintains files containing publicly disclosed information about all entities listed on the ASX. Information disclosed to the ASX by Santos is available on ASX's website (www2.asx.com.au).

In addition, Santos is required to lodge various documents with ASIC. Copies of documents lodged with ASIC by Santos may be obtained using services provided by ASIC. Please note that ASIC may charge a fee in respect of such services.

Oil Search Shareholders may obtain a copy of Santos' 2020 Annual Report and its 2021 Half Year Report free of charge from ASX's website (www2.asx.com.au) or from the Santos website (www.santos.com.au).

5.20 No other material information

Except as otherwise disclosed in this Scheme Booklet, the Santos Board is not aware of any information, as at the date of this Scheme Booklet, that is material to the making of a decision in relation to the Scheme which has not been previously disclosed to Oil Search Shareholders.

6 Information about the Merged Group

6.1 Overview of the Merged Group

The Merger will bring together two highly complementary businesses and create a regional champion of size and scale with a diversified portfolio of high quality, long-life, low-cost oil and gas assets across Australia, Timor-Leste, Papua New Guinea and the United States of America.

The Merged Group is expected to have a pro-forma capitalisation of approximately A$23 billion.[1] The Merged Group is expected to be a S&P ASX20 company by free float market capitalisation,[2] and amongst the 20 largest global oil and gas companies by market capitalisation.[3]

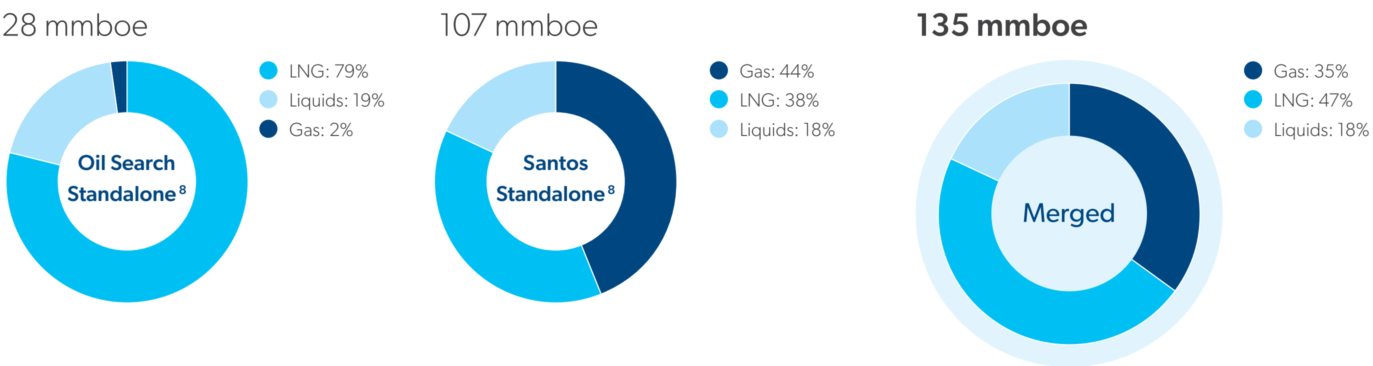
a) Overview of assets

Following completion of the Scheme, the Merged Group will have asset hubs across Australia, Timor Leste, Papua New Guinea and Alaska:

- (**Cooper Basin**) is one of Australia's largest conventional onshore oil and gas field developments producing sales gas, ethane, crude oil and gas liquids and the planned Moomba CCS project;
- (**Queensland and NSW**) includes GLNG (Gladstone, Queensland), which incorporates the development of onshore coal seam gas (**CSG**) fields, a 420 km gas transmission pipeline and a two-train liquefaction and storage facility (Santos 30% and upstream operator). Santos' Narrabri Gas Project in New South Wales is pre-FID in the design phase and 100% of the gas has been committed to the Australian domestic gas market;
- (**PNG**) includes a 42.5% stake in PNG LNG operated by a wholly-owned subsidiary of ExxonMobil, which incorporates 700 kilometres of onshore and offshore pipelines, the Hides gas conditioning plant and a two train liquefaction and storage facility, operated interests in a suite of PNG oil fields and a 22.8%[4] equity position in the pre-FID Papua LNG development;
- (**Northern Australia and Timor-Leste**) includes a 43.4% operating interest in the existing Bayu-Undan asset in Timor-Leste and the DLNG joint venture, as well as a 50%[5] interest in the Barossa development project located offshore Australia;
- (**Western Australia**) includes a low cost conventional domestic gas portfolio backed by medium to long term consumer price index linked contracts providing strong and stable cash flows. Santos also benefits from oil production from its 52.5% operated interest in the Van Gogh-Coniston-Novara project and has 28.6% non-operated position in the Pyrenees oil field. In addition to these producing assets, Santos has also entered into FEED for the proposed Dorado oil field development in which it has an 80% operated interest; and
- (**Alaska**) includes a 51% operated interest in the Alaskan oil assets, including the Pikka oil unit along with future development and exploration opportunities.

Across these asset hubs, the Merged Group had pro forma sales volumes of approximately 135 mmboe in calendar year 2020.[6] These volumes were diversified across gas, LNG and liquids (oil, condensate and LPG), and are segregated by product as illustrated in Figure 6 below.[7]

Figure 6 – Merged Group 2020 pro forma sales volumes by product (mmboe)



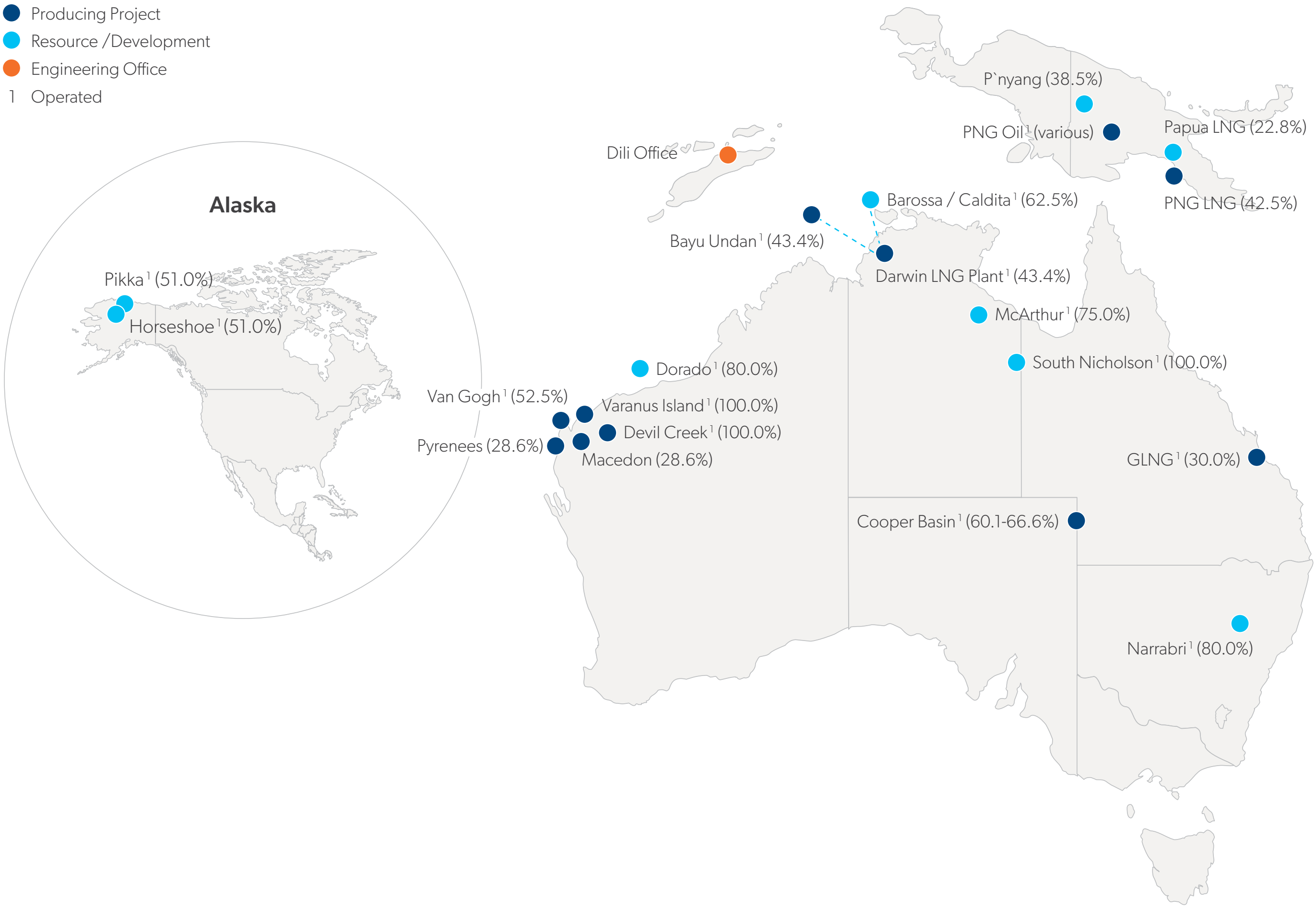
1) Based on closing price of $4.23 for Oil Search and $6.83 for Santos as at the Last Practicable Trading Date.
2) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.
3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.
4) The Merged Group's equity interest reduces to 17.7% assuming the State back-in rights of 22.5% are included.
5) Assuming Santos completes the planned 12.5% sell-down to JERA Co.
6) Based on 2020 annual sales volumes published by Santos on 21 January 2021 and Oil Search on 23 April 2021.
7) Liquids volumes are inclusive of oil, condensate, Naphtha and LPG volumes.

6 Information about the Merged Group

The Merged Group is expected to have strong cash flows, liquidity and balance sheet strength to fund its development projects and fund the transition to a low carbon future.

The Merged Group's producing and resource development assets are illustrated below in figure 7.

Figure 7 – Map of Merged Group producing and resource / development assets



b) Reserves and resources profile

The Merged Group will have pro forma combined 1P Reserves of 884 mmboe, 2P Reserves of 1,379 mmboe and 2C resources of 3,489 mmboe.[1] The Reserves and Resources are diversified across assets and products as set out in Table 1 and Table 2 below:

Table 1 – Reserves and Resources by Asset as of 31 December 2020

Category	1P Reserve (mmboe)	2P Reserves (mmboe)	2C Resources (mmboe)
PNG	504	620	768
Alaska	—	—	494
WA	147	254	401
QLD / NSW	164	328	434
Northern Australia	13	32	1,106
Cooper Basin	56	145	286
Total	**884**	**1,379**	**3,489**

1) Based on the aggregate of 1P, 2P reserves and 2C resources as of 31 December 2020 published by Santos on 18 February 2021 and Oil Search on 23 February 2021.

b) Reserves and resources profile continued

Table 2 – Reserves and Resources by Product

Category	1P Reserve (mmboe)	2P Reserves (mmboe)	2C Resources (mmboe)
Liquids[1]	88	141	876
Gas	796	1,237	2,613
Total	**884**	**1,379**	**3,489**

For more detail on Oil Search and Santos' reserves and resources by asset and by product, please refer to sections 4.4 and 5.4 of this Scheme Booklet. It is noted that Final Investment Decision was taken on the Barossa Project post 31 December 2020 and it is expected that the associated contingent resource volumes will be reclassified to reserves at 31 December 2021.

c) Production Guidance

The Merged Group's CY21 production guidance is set out in Table 3 below:

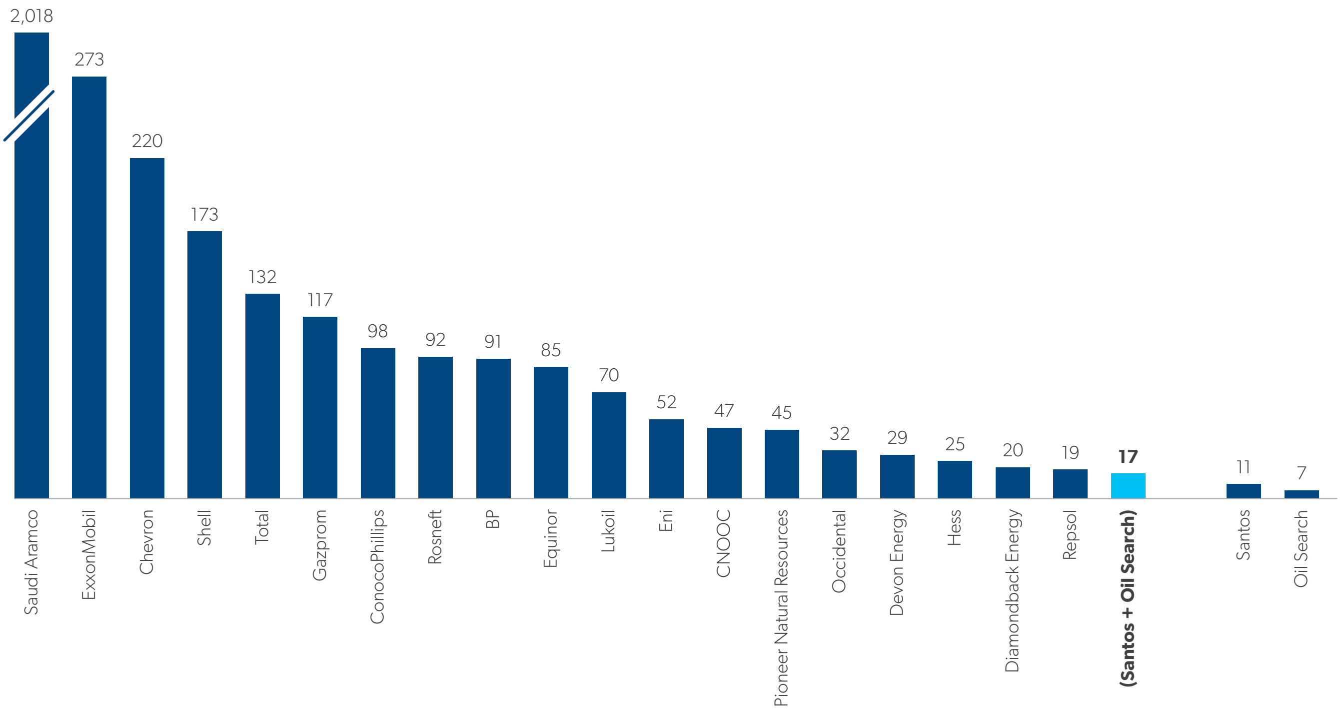
Table 3 – CY21 Production Guidance

Company	Production (mmboe)
Oil Search	26.0 – 28.0
Santos	88.0 – 91.0
Total	**114.0 – 119.0**

d) Market positioning

Following the completion of the Merger, the Merged Group is expected to be positioned within the S&P ASX20 index by market capitalisation[2] and the top 20 largest global oil and gas companies by market capitalisation,[3] as depicted in Figures 8 (below) and 9 (following page).

Figure 8 – Top 20 largest global Oil and Gas players by market capitalisation (US$bn)[4]



Source: FactSet data as at market close on the Last Practicable Trading Date, being 5 November 2021.

1) Liquids volumes are inclusive of oil, condensate and LPG volumes

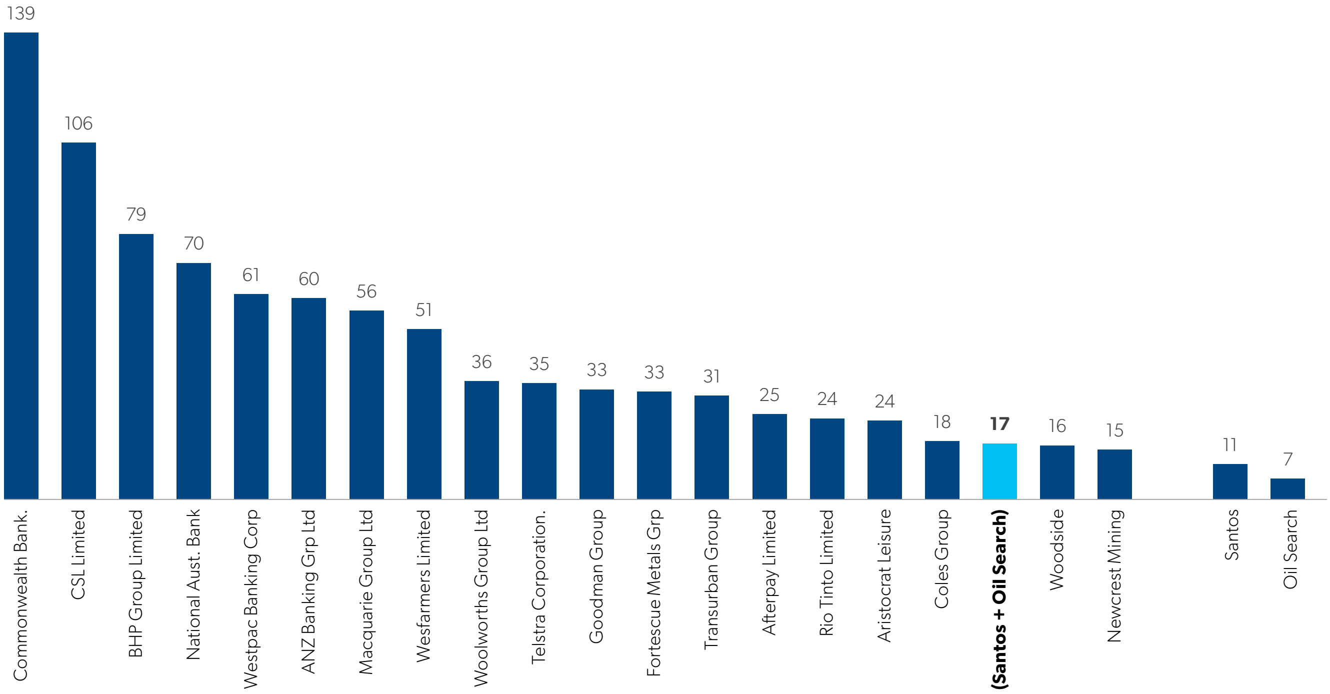
2) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.

3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.

4) On 17 August 2021, Woodside announced it is pursuing a merger with BHP's petroleum business. The market capitalisation of the combined entity is expected to be ~US$31 billion as at the date of announcement.

d) Market positioning continued

Figure 9 – S&P/ASX20 by market capitalisation (US$bn) [1]



Source: FactSet data as at market close on the Last Practicable Trading Date, being 5 November 2021.

6.2 Strategic rationale for Merger

The Merger will create a regional champion of size and scale, providing shareholders with the opportunity to participate in a new company with greater equity market relevance, broader diversification, and a stronger balance sheet and funding platform.

The strategic rationale of the Merger is summarised as follows.

a) Creates a regional champion of size and scale

The Merged Group will have a pro forma market capitalisation of approximately A$23 billion, [2] positioning it as an S&P ASX20 company by market capitalisation [3] and amongst the 20 largest global oil and gas companies by market capitalisation. [4] The Merged Group is expected to have the size and liquidity to benefit from greater indexation and subsequently attract investors across a broader spectrum of mandates by being well-positioned to provide sustainable returns throughout the cycle.

b) Diversified portfolio of long-life, low-cost assets

The Merged Group will consolidate a diversified portfolio of high quality, long-life, low-cost oil and gas assets across Australia, Timor-Leste, PNG and the United States of America. It is expected to have multiple independent sources of low-cost production reducing the risk of exogenous shocks, and have multiple pricing benchmarks with material contract diversification, making it more resilient throughout the oil price cycle. Additionally, the Merged Group will possess a robust pipeline of development assets.

c) Operatorship and control of key assets

The Merged Group will operate the majority of its key assets, which will enable it to exert control over the phasing and costs of project development and maintenance.

d) The Scheme is expected to unlock material pre-tax synergies

Santos has identified opportunities to deliver between US$90 and US$115 million per annum (excluding integration and other one-off costs) of synergies after full integration.

Section 6.3 of this Scheme Booklet contains further details of the expected synergies that may be realised in connection with the Merger.

1) Source: FactSet data as at market close 5 November 2021. S&P/ASX200 constituents as of 5 November 2021 as per IRESS. FactSet and IRESS have not consented to the use of this information in this Scheme Booklet.
2) Based on closing price of $4.23 for Oil Search and $6.83 for Santos as at the Last Practicable Trading Date.
3) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top-20 ASX-listed companies defined as the constituents of the S&P/ASX 20 index as at the Last Practicable Trading Date.
4) Based on pro-forma market capitalisation as at the Last Practicable Trading Date. Top 20 largest global oil and gas companies defined as the 20 largest upstream constituents of FactSet's "Oil & Gas Production" and "Integrated Oil" industries by market capitalisation. The following companies have been excluded given they have material exposures to other sectors outside of upstream oil and gas (i.e. petrochemicals, fertiliser, other commodities, and infrastructure): PetroChina, PTTEP, China Petroleum, EOG, Canadian Natural Resources, Ecopetrol, Imperial Oil, OMV AG, Petroleo Brasileiro SA, Suncor Energy and Surgutneftegas.

e) Creates a Merged Group with strong credentials in ESG

The Merged Group will have strong credentials in ESG across environmental, social and governance categories.

Santos has previously announced in its 2020 Annual Report and 2021 Climate Change Report that it intends to pursue a net zero Scope 1 and 2 emissions by 2040 target. Oil Search has previously announced in its 2020 Sustainability Report that it intends to set and pursue a net zero Scope 1 and 2 emissions by 2050 target. Santos' intentions for the Merged Group will be to set and pursue a net zero Scope 1 and 2 emissions by 2040 target for the combined assets, although the possible pathways to achieve that ambition will need to be determined following the incorporation of the Oil Search assets into the Merged Group.

The Merged Group will continue to pursue Santos' carbon capture and storage project focus and Oil Search's social and community investment in PNG and the United States of America. Santos considers a sustainable future depends on natural gas and is investing in the step-change technology of CCS, which will allow it to reduce emissions from its operations. Santos' existing capabilities and infrastructure support the large-scale production of cleaner fuels, including hydrogen, through the use of CCS.

In November 2021, Santos took the final investment decision on the Moomba CCS project in the Cooper Basin following the successful registration of the project with the Clean Energy Regulator. Moomba CCS is one of the largest and lowest-cost CCS projects globally and will have the capacity to capture and store underground approximately 1.7 million tonnes of CO_2 per annum. The Cooper Basin has the potential to store over 20 million tonnes of CO_2 per annum for more than 50 years and Santos is exploring new sources of CO_2, such as direct air capture. The CO_2 will be permanently stored in the depleted reservoirs which have held oil and gas in sealed structures for millions of years. In addition, Santos has signed a Memorandum of Understanding with the Timor-Leste regulator to consider repurposing Bayu-Undan facilities into a CCS project with capacity to store up to 10 million tonnes of CO_2 per annum. Santos is evaluating a third CCS opportunity in Western Australia using depleted reservoirs and existing infrastructure. Santos' CCS projects are potential enablers for the production of low or net zero emission hydrogen from natural gas.

Also in November 2021, Santos announced it was partnering with Australia's national science agency, CSIRO, to develop direct air capture technology which removes CO_2 directly from the atmosphere. The CO_2 can then be safely and stored in CCS projects. The technology will be trialled at Moomba in South Australia, from where the captured CO_2 will be transported to Santos' Moomba CCS project.

See sections 4.5 and 5.5 for a description of Oil Search's and Santos' existing programs.

f) Strong balance sheet and investment grade funding platform

The Merged Group is expected to have liquidity of approximately US$5.7 billion[1] and a strong balance sheet to fund the development of its growth projects, whilst maintaining optionality and flexibility to optimise its portfolio. The Merged Group intends to maintain an investment grade credit rating and a capital management and funding plan which addresses future requirements for the combined business, with the ability to:

- fund activities associated with the existing operations of the Merged Group across the core asset portfolio including associated exploration and appraisal activities;
- fund growth, including ESG projects that meet the Merged Group's investment criteria in accordance with the disciplined operating model; and
- pay sustainable dividends to shareholders.

g) Opportunity for alignment in PNG projects

The Merged Group will hold an increased position in the PNG LNG project. It will subsequently have the potential ability to improve alignment between the PNG LNG project, the development of the P'nyang Gas Project and Papua LNG, including State participation rights, which are expected to generate jobs growth and long term income for the Independent State of PNG and its people.

6.3 Overview of expected synergies and efficiencies

Santos expects the Merger to unlock pre-tax synergies of US$90 to US$115 million[2] per annum (excluding integration and other one-off costs).

The annual synergies are expected to be realised through a combination of operational and corporate efficiencies, including:

- integration of procurement, contracting and development;
- reduction of corporate overheads, listing, audit, Board, information technology, borrowing and insurance costs; and
- leveraging operations and maintenance capability across the portfolio.

Santos' track record of integration supports its ability to realise these expected synergies and unlock value in the Merged Group.

In 2018, Santos acquired Quadrant Energy. At the time of acquisition, guidance for pre-tax synergies was US$30 to US$50 million per annum, compared to delivered pre-tax synergies of US$60 million per annum.

1) Based on the arithmetic sum of Santos and Oil Search liquidity (comprising cash and committed undrawn debt facilities) as at 30 June 2021 as disclosed in Santos' and Oil Search's 2021 half year results and assuming the facilities currently available to Santos and Oil Search either remain in place or are replaced with facilities of equivalent or greater limits.

2) The following items have factored into the calculation of the expected pre-tax synergies (excluding integration and one-off costs) expected to be unlocked through the Merger: integration of procurement, contracting and development costs; reduced corporate overheads; reduced information technology and borrowing costs; efficiencies from organisational optimisation. The potential synergy numbers represent current expectations, and are subject to a number of assumptions, including as to future events which involve inherent uncertainties and contingencies. The final synergy value will only be determined following Implementation of the Scheme and completion of the Merged Group's detailed review of its operations. Further detail about the associated risks in relation to realisation of such synergies is detailed in section 7.2(f).

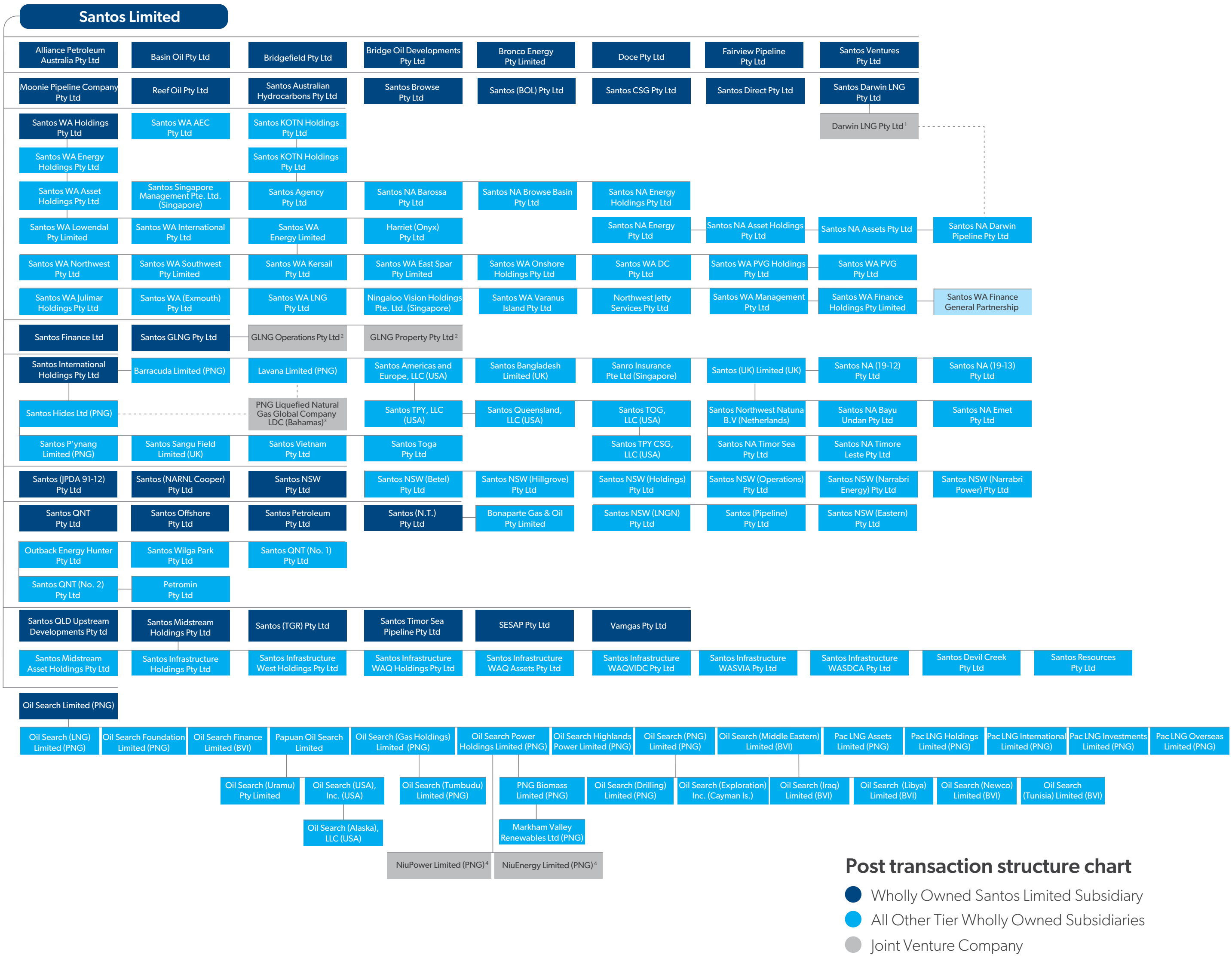
6.3 Overview of expected synergies and efficiencies continued

More recently, Santos acquired ConocoPhillips' Northern Territory and Timor-Leste business units, delivering more than US$100 million in pre-tax annual synergies, higher than original estimates. Combined, the Quadrant Energy and ConocoPhillips acquisitions have delivered more than US$160 million in pre-tax annual synergies.

Oil Search shareholders should note that the potential synergy numbers outlined above represent current expectations, and are subject to a number of assumptions, including as to future events (including the risks outlined in section 7.2(f) of the Scheme Booklet) which involve inherent uncertainties and contingencies. The final synergy value will only be able to be determined following Implementation of the Scheme and completion of the Merged Group's detailed review of its operations.

6.4 Corporate structure of the Merged Group

On implementation of the Scheme, Oil Search will be a wholly-owned Subsidiary of Santos, and each of the Subsidiaries of Oil Search will form part of the Santos Group. The structure of the Merged Group following implementation is illustrated in the diagram below.



1) 31.94% Santos NA Darwin Pipeline Pty Ltd/ 11.49% Santos Darwin LNG Pty Ltd.
2) 30% shareholding.
3) Combined 13.5% shareholding.
4) 50% shareholding.

6.5 Share capital and other securities of Merged Group

a) Share Capital

If the Scheme is implemented, Santos will issue approximately 1,303,851,292 New Santos Shares to Oil Search Shareholders.

The table below summarises the Santos Shares that will be on issue in the Merged Group on the Implementation Date:

Timing	Number of Santos Shares
On issue as at the Last Practicable Trading Date	2,083,066,041
To be issued under the Scheme	1,303,851,292[1]
Pro forma (post-implementation)	3,386,917,333[2]

ASX has granted Santos a waiver from ASX Listing Rule 7.1 to permit Santos to issue the New Santos Shares to Oil Search Shareholders under the Scheme without obtaining approval of Santos Shareholders.

b) Equity incentives

If the Scheme is implemented, it is expected that the Merged Group will have the following share acquisition rights, matching shares and share plan shares on issue, and no further share acquisition rights, matching shares or share plan shares will be issued as a result of the Scheme.

Timing	Share Acquisition Rights	Executive Share Plan Shares
On issue as at the date of this Scheme Booklet	15,459,842 under Equity Incentive Plan	5000 "0" shares
	2,435,980 under ShareMatch Plan	5000 "2" shares
Pro forma (post-implementation)	15,459,842 under Equity Incentive Plan	5000 "0" shares
	2,435,980 under ShareMatch Plan	5000 "2" shares

c) Merged Group Ownership Structure

On implementation of the Scheme, Santos Shareholders will own approximately 61.5% of the Merged Group and Oil Search Shareholders will own approximately 38.5% of the Merged Group.

6.6 Directors and Management of Merged Group following the Merger

If the Scheme is implemented, three existing non-executive directors from the Oil Search Board will be invited to join the Santos Board. The Santos Board will comprise 9 non-executive directors and the Chief Executive Officer and Managing Director of Santos. Santos intends to offer directorship to one Oil Search director who is a PNG national.

If Implementation of the Scheme occurs prior to the Santos 2022 Annual General Meeting (expected to be held in the second quarter of 2022), two of the three existing Oil Search directors will be invited to join the Santos Board upon Implementation, and one existing Oil Search director will be invited join the Santos Board on or around the date of Santos' 2022 Annual General Meeting in order to comply with Santos' Constitution and the Merger Implementation Deed. As at the date of this Scheme Booklet, the identities of the existing Oil Search directors who will be invited to join the Santos Board are still being determined. A final decision in relation to the identities of the Oil Search directors joining the Santos Board will be announced by Santos to the ASX prior to the Implementation of the Merger.

The Chairman of the Merged Group board will be the chairman of Santos, Mr Keith Spence.

The Chief Executive Officer and Managing Director of the Merged Group will be the current Santos Chief Executive Officer and Managing Director, Mr Kevin Gallagher. Section 5.6(a) contains further details of the qualifications and background of Mr Gallagher.

Members of the Merged Group's senior management team will be selected based on the principle that the best executive for the job will be offered the relevant role having regard to the skills, experience, knowledge and expertise required to manage the Merged Group and its assets.

1) This number is derived from the merger ratio of 0.6275 New Santos Shares for each Oil Search Share multiplied by 2,077,850,664 Oil Search Shares on issue. The exact number of New Santos Shares to be issued in connection with the Scheme will not be known until after the Record Date. In particular, if the Merger is not implemented until CY22 and either Santos or Oil Search declares or determines to pay a final CY21 dividend or interim CY22 dividend before the Record Date, the Scheme Consideration may be subject to adjustment for that dividend.

2) Sum of Santos Shares on issue as at the Last Practicable Trading Date of 2,083,066,041 and New Santos Shares to be issued under the Scheme of 1,303,851,292.

6.7 Merged Group intentions if the Scheme is implemented

This section 6.7 sets out the current intentions of Santos in relation to the Merged Group if the Scheme is implemented. The statements of intention are formed on the basis of facts and information known to Santos at the date of this Scheme Booklet.

Final decisions regarding the Merged Group's future operations will be made by the board of the Merged Group in light of material information and circumstances at the relevant time. Accordingly, the statements set out in this section are statements of current intentions only, which may vary as new information becomes available or circumstances change and the Merged Group further develops its strategic focus and outlook.

a) Continuation of business

If the Scheme is implemented, Santos intends to continue to operate the businesses of Santos and Oil Search in a similar manner as to how they are currently operating, while focusing on the realisation of the identified Merged Group expected pre-tax synergies which are estimated by Santos at US$90 to US$115 million per annum.[1] Notwithstanding this, Santos has and will continue to undertake a review of the Merged Group's operations covering strategic, financial, risk and commercial operating matters to determine and implement improvements to deliver the optimal outcomes for the Merged Group. In particular, Santos intends to continue with the exit from Oil Search's activities in the Middle East and Central Asia.

b) Corporate strategy

If the Scheme is implemented, the strategy of the Merged Group will be to:

- maintain strong base business operations and a disciplined operating model which would still have positive cash flow (excluding growth capital expenditure, acquisitions and divestments) provided that the oil price is above $35 per barrel (before the effects of hedging);
- maintain focus on safe, reliable and low cost development and operatorship of upstream and midstream oil & gas facilities and infrastructure;
- pursue targeted final investment decisions for material development projects;
- leverage operatorship across its growth portfolio to optimise capital allocation and project timing;
- leverage both Santos' and Oil Search's complementary skill sets to implement a best in class approach to the Merged Group's portfolio of assets;
- review the most efficient capital allocation to drive future growth in the Merged Group's portfolio, including continuing certain asset sell downs;
- conduct an evaluation of internal and external opportunities to maximise value for the Merged Group's shareholders;
- set and pursue a net zero Scope 1 and 2 emissions by 2040 target for the combined assets, although the possible pathways to achieve that ambition will need to be determined following the incorporation of the Oil Search assets into the Merged Group;
- continue to optimise the portfolio including the potential sale of project equity and the exit of Middle East and Central Asia positions;
- review opportunities to create greater alignment in PNG supporting the development of key projects including Papua LNG, deliver new jobs and help support the local economy; and
- continue to positively contribute to the communities in which the Merged Group operates by providing employment, local partnerships and sponsorship programmes.

c) Corporate Governance

It is intended that the Merged Group will continue to be governed by Santos' current corporate governance policies. In addition to Santos' 2020 Corporate Governance Statement lodged with ASX on 18 February 2021, available at http://www2.asx.com.au, a copy of Santos' core corporate governance policies can be accessed on Santos' website: https://www.santos.com/about-us/corporate-governance/.

d) Financing

Following implementation of the Scheme, a number of finance facilities currently held by Oil Search will be subject to review by lenders. The Merged Group intends to refinance these (in whole or part) with the objective to access more favourable terms. This refinancing activity will exclude the PNG LNG project finance facility.

Finance facilities currently held by Santos are unlikely to be adversely impacted by the Merger and no consents are required from lenders.

Following implementation of the Scheme, the Merged Group intends to maintain an investment grade credit rating and to maintain Santos' existing gearing policy, targeting gearing in the range of 20% to 30% pre major growth and up to approximately 35% following acquisitions and/or during periods of major growth expenditure.

1) The final synergy value will only be determined following Implementation of the Scheme and completion of the Merged Group's detailed review of its operations. Further information about the expected synergies are detailed in section 6.3 and further detail about the associated risks in relation to realisation of such synergies is detailed in section 7.2(f).

e) Key contracts

Santos anticipates the Merged Group may derive greater efficiencies and cost reductions in supply chain contracts as a result of greater volume/economy of scale post Implementation of the Scheme.

f) Dividend policy

Following implementation of the Scheme, Santos intends to maintain its existing policy to pay ordinary dividends that are sustainable through the oil price cycle, targeting a payout ratio in the range of 10% to 30% of free cash flow[1] generated per annum.[2]

g) Corporate matters in relation to Oil Search

In accordance with the Merger Implementation Deed, if the Scheme is implemented, Oil Search will apply for termination of official quotation of Oil Search Shares on the ASX and PNGX, and will apply to be removed from the official list of the ASX and PNGX. Oil Search will become a wholly-owned Subsidiary of Santos. The Oil Search Board will be reconstituted so that it comprises persons nominated by Santos.

h) Corporate office and trading name

The Merged Group will continue as Santos Limited, with its corporate office in Adelaide, South Australia, as well as maintaining Oil Search's office in Port Moresby. Santos Limited will continue to be listed on the ASX.

i) Listing on PNGX

On completion of the Merger, Santos will seek to establish a secondary listing on PNGX on standard terms and conditions for an exempt foreign entity and subject to the receipt of any exemptions for activities required by Santos from the ASX, ASIC, PNGX and the PNG Securities Commission.

6.8 Merged Group Pro Forma Historical Financial Information

This section contains pro forma historical financial information in relation to the Merged Group (the **Merged Group Pro Forma Historical Financial Information**) comprising the Merged Group historical statement of financial position as at 30 June 2021 (**Merged Group Pro Forma Historical Statement of Financial Position**).

Standalone historical consolidated income statement information for both the Oil Search Group and the Santos Group is set out in section 4.10(b) and section 5.11(c), respectively, in this Scheme Booklet.

In this Scheme Booklet (including in this section 6.8), references to "Merged Group Pro Forma Historical Financial Information" are references to the pro forma historical financial information of the Merged Group as at the relevant time, being the corporate group that will be formed as it will exist immediately following implementation of the Scheme.

The Merged Group Pro Forma Historical Financial Information should be read together with the:

- basis of preparation and pro forma adjustments as set out in section 6.8(a);
- subsequent events for Santos as set out in section 5.12 and subsequent events for Oil Search as set out in section 4.11;
- risk factors set out in section 7; and
- other information contained in this Scheme Booklet

Santos is responsible for the preparation and presentation of the Merged Group Pro Forma Historical Statement of Financial Position.

The Merged Group Pro Forma Historical Statement of Financial Position in this section is presented in an abbreviated form and does not contain all disclosures, presentations, statements or comparatives that are usually provided in an annual financial report prepared in accordance with the Australian Corporations Act.

The Investigating Accountant has prepared the Investigating Accountant's Report, in accordance with the Standard on Assurance Engagements ASAE 3450 involving Corporate Fundraisings and/or Prospective Financial Information, in respect of the Merged Group Pro Forma Historical Statement of Financial Position, a copy of which is included in Annexure B. Oil Search Shareholders should note the scope and limitations of the Investigating Accountant's Report.

Amounts in this section have been rounded to the nearest US$1 million. A number of figures, amounts, percentages prices, estimates, calculations of value and fractions are subject to the effect of rounding. Accordingly, totals in tables may not add due to rounding.

1) Free cash flow is a non-IFRS measure calculated as operating cash flow less investing cash flow net of acquisitions and disposals and major growth capex, less lease liability payments.

2) This differs from Oil Search's existing dividend policy which is a proportional dividend policy of 35-50% of core net profit after tax subject to Board discretion.

6 Information about the Merged Group

a) Basis of preparation

The Merged Group Pro Forma Historical Statement of Financial Position has been prepared for illustrative purposes, in order to give Oil Search Shareholders an indication of the financial position of the Merged Group as if the Scheme had been implemented as at 30 June 2021. By its nature, pro forma historical financial information is illustrative only. Consequently, it does not purport to reflect the actual financial position of the Merged Group as if it had operated on a combined basis for the relevant periods. Past performance is not a guide to future performance. It is likely that this information will differ from the actual financial information for the Merged Group as at the Effective Date.

The Merged Group Pro Forma Historical Statement of Financial Position for the period ended 30 June 2021 has been derived from the Santos historical financial statement position from the Half Year Report for the six months ended 30 June 2021 (adjusted for pro-forma adjustments as described in section 6.8(b) below).

The Santos Half-Year Financial Report for the six-month period ended 30 June 2021 was reviewed by Ernst & Young. Ernst & Young issued an unmodified review conclusion in relation to the Santos Half-Year Financial Report. Santos Annual and Half-Year Financial Reports are available from Santos's website (www.santos.com) and the ASX website (www.asx2.com.au).

The Merged Group Pro Forma Historical Statement of Financial Position has been prepared in accordance with the recognition and measurement principles contained in the AAS issued by the Australian Accounting Standards Board (**AASB**) and includes adjustments which have been prepared in a manner consistent with AAS, that reflect the impact of certain transactions as if they occurred as at 30 June 2021 in the Merged Group Pro Forma Historical Statement of Financial Position. Full compliance with AAS gives rise to IFRS compliance. The Merged Group Pro Forma Historical Statement of Financial Position has been prepared in accordance with and should be read in conjunction with the accounting policies detailed in the Santos Annual Report for the year ended 31 December 2020. An assessment has been undertaken by Santos to identify significant accounting policy differences where the impact is potentially material to the Merged Group and could be reliably estimated. No material differences have been identified.

b) Pro forma adjustments overview

The Merged Group Pro Forma Historical Statement of Financial Position includes the following pro forma adjustments to reflect the impact of certain transactions as if they occurred as at 30 June 2021 in the Merged Group Pro Forma Historical Statement of Financial Position:

- the acquisition of Oil Search and one-off transaction costs associated with the Scheme, including:
  - i) recognition of the assets and liabilities at provisional fair values at an indicative date, being 30 June 2021, and associated adjustments to the deferred tax based balances; and
  - ii) estimate of transaction costs payable as a result of the acquisition.

The Merged Group Pro Forma Historical Statement of Financial Position has been prepared using preliminary purchase price accounting estimates. The accounting standard AASB 3 Business Combinations (**AASB 3**) provides the acquirer (determined as Santos) up to one year from the acquisition date to finalise the identification and valuation process of all the assets and liabilities and record any resultant accounting adjustments to the initial acquisition date estimates based on new information obtained about facts and circumstances that existed at the acquisition date. Santos has not finalised the identification and valuation of Oil Search's assets and liabilities and this can only be done on implementation of the Scheme.

Accordingly, for the purposes of preparing the Merged Group Pro Forma Historical Statement of Financial Position, it has been assumed that:

- the assets and liabilities of Oil Search are recognised at provisional fair value in accordance with AASB 3 as at 30 June 2021; and
- an estimate of the associated adjustments to the deferred tax balances has been made.

The Merged Group Pro Forma Historical Statement of Financial Position is provided for illustrative purposes only. Due to its nature, the Merged Group Pro Forma Historical Statement of Financial Position does not represent Santos' or the Merged Group's actual or prospective financial position. A number of factors may impact the actual financial position of the Merged Group, including, but not limited to:

- successful implementation of the Scheme and the ultimate timing of that implementation;
- changes in the Santos share price of A$7.09 (closing Santos share price 30 June 2021) and AUD:USD exchange rate of 0.7513 will alter the value of the consideration for the transaction for accounting purposes, as the consideration will be calculated on the Implementation Date;
- impact of any dividends declared by Oil Search or Santos that would operate as an adjustment to the Scheme Consideration if they are not declared in accordance with the merger ratio implied by the Scheme Consideration as agreed in the Merger Implementation Deed (refer to section 9.13(b));
- differences between the estimated amount of transaction costs as set out in section 6.9 and the amount ultimately incurred;
- vesting of Oil Search Equity Incentives;
- finalisation of the acquisition accounting (in accordance with AASB 3), including determining appropriate purchase price allocations, such as the identification and valuation of all assets and liabilities acquired. Adjustments may include the allocation of purchase price notionally attributed to amortising assets (such as oil and gas properties), to non-amortising assets (such as indefinite life intangible assets, including goodwill) or between different amortising assets (for example a change in the allocation of value between different oil and gas properties). Changes in the amount and allocation of the purchase price could positively or negatively impact future reported earnings of the Merged Group;
- finalisation of the availability of tax losses and the recalculation and recognition of the deferred tax assets and liabilities, in accordance with AASB 112 Income Taxes; and
- the timing and realisation of expected synergies arising from the merger of Santos and Oil Search pursuant to the Scheme.

c) Pro forma adjustment acquisition accounting

The pro forma acquisition accounting reflects the provisional estimated accounting for the acquisition of Oil Search based on the provisional amounts shown in the following section. The estimated amount of the purchase consideration to be allocated has therefore been calculated as follows.

Number of new Santos Shares to be issued (#)	1,303,851,292[1]
Santos Share Price (A$)	7.09
Shares consideration to be allocated (A$'m)	9,244.3
Shares consideration to be allocated (US$'m)	6,945.2

The following table shows the sensitivity of the calculation of the purchase consideration to changes in the price of Santos Shares. This has been prepared assuming 1,303,851,292 new Santos Shares are issued in exchange for 2,077,850,664 Oil Search Shares.

Santos Share price on implementation date (A$)	6.50	7.00	7.09	7.50	8.00
Implied purchase consideration (US$'m)[2]	6,367	6,857	6,945	7,347	7,837

The initial estimates of the acquisition accounting undertaken for the purposes of the compilation of the Merged Group Pro Forma Historical Statement of Financial Position are discussed below. These estimates will be updated based on the actual assets and liabilities acquired on implementation of the Scheme.

The Merged Group Pro Forma Historical Statement of Financial Position, in section 6.8(d) below, includes the following purchase price accounting and other adjustments that have been included in the "Oil Search Pro Forma Value" column in the table as referenced by the "Note" column in the table:

i) recognition of Oil Search net assets acquired at fair value as at 30 June 2021;

ii) recognition of the estimated equity consideration of $6,945 million on the issuance of new Santos shares, excluding any impact of dividend adjustments as set out in section 9.13(b);

iii) recognition of the resulting estimated technical goodwill (refer below) on acquisition of Oil Search of $1,171 million as at 30 June 2021;

iv) recognition of the deferred tax assets and liabilities arising from the assets acquired and liabilities assumed; and

v) estimated Santos and Oil Search transaction costs (refer to section 6.9).

Technical Goodwill

The goodwill is attributable solely to the net deferred tax liability recognised on acquisition, in accordance with accounting standards (referred to as technical goodwill). Accounting for taxation at the acquisition date is within the scope of AASB 112 Income taxes. The general principle of AASB 112 is that deferred tax is recognised for all taxable temporary differences. In a business combination, there is no initial recognition exemption for deferred tax and the corresponding accounting entry for a deferred tax asset or liability forms part of the goodwill balance. A net deferred tax liability has been reflected of $1,171 million created primarily as a consequence of historical tax bases assumed in the merger being lower than the fair value of the assets acquired. The balance is offset by an amount booked as goodwill for $1,171 million. The goodwill recognized on acquisition is solely due to the net deferred tax liability recorded, referred to as technical goodwill.

1) This number is derived from the merger ratio of 0.6275 New Santos Shares for each Oil Search Share multiplied by 2,077,850,664 Oil Search Shares on issue. The exact number of New Santos Shares to be issued in connection with the Scheme will not be known until after the Record Date. In particular, if the Merger is not implemented until CY22 and either Santos or Oil Search declares or determines to pay a final CY21 dividend or interim CY22 dividend before the Record Date, the Scheme Consideration may be subject to adjustment for that dividend.

2) Assumes the 30/6/21 AUD/USD remains unchanged.

d) Merged Group Pro Forma Historical Statement of Financial Position

Set out in the following table is the Merged Group Pro Forma Historical Statement of Financial Position as at 30 June 2021. For the purposes of the Merged Group Pro Forma Historical Statement of Financial Position, fair values at an indicative date of 30 June 2021 have been assumed for the pro forma adjustments for the Scheme.

30 June 2021 US$m	Note	Santos	Oil Search (Pro-forma)	Merged Group (Pro-forma)
Cash and cash equivalents	(i)	2,417	504	2,921
Trade and other receivables	(i)	684	174	858
Inventories	(i)	294	130	424
Assets held for sale		259	—	259
Contract assets	(i)	19	143	162
Other assets	(i)	23	24	47
Total Current Assets		**3,696**	**975**	**4,671**
Investments in associates and joint ventures	(i)	396	11	407
Exploration and evaluation assets	(i)	1,013	2,727	3,740
Oil and gas assets	(i)	11,293	6,904	18,197
Other land, buildings, plant and equipment	(i)	262	553	815
Deferred tax assets	(iv)	1,310	945	2,255
Goodwill	(iii)	383	1,171	1,554
Contract assets	(i)	97	223	320
Other assets		55	—	55
Total Non-Current Assets		**14,809**	**12,534**	**27,343**
Total Assets		**18,505**	**13,509**	**32,014**
Trade and other payables	(i), (v)	825	269	1,094
Borrowings	(i)	373	483	856
Derivatives		196	—	196
Provisions	(i)	155	25	180
Current tax liabilities	(i)	31	71	102
Contract liabilities		117	—	117
Other liabilities		11	—	11
Total Current Liabilities		**1,708**	**848**	**2,556**
Borrowings	(i)	5,264	2,697	7,961
Deferred tax liabilities	(iv)	1,104	2,116	3,220
Provisions	(i)	2,853	984	3,837
Contract liabilities		249	—	249
Other liabilities	(i)	24	19	43
Total Non-Current Liabilities		**9,494**	**5,816**	**15,310**
Total Liabilities		**11,202**	**6,664**	**17,866**
Net Assets		**7,303**	**6,845**	**14,148**
Issued Capital	(ii)	9,001	6,944	15,945
Reserves		849	—	849
Retained earnings/(accumulated losses)		(2,547)	(99)	(2,646)
Total Equity		**7,303**	**6,845**	**14,148**

d) Merged Group Pro Forma Historical Statement of Financial Position continued

The Merged Group Pro Forma Historical Statement of Financial Position has not been adjusted to reflect:

- the performance and operation of Santos or Oil Search since 1 July 2021; or
- finalisation of the purchase price accounting for the Scheme, including identification and measurement of all purchase price allocations and the recalculation and recognition of associated deferred tax balances.

6.9 Merged Group transaction costs

Oil Search and Santos will incur external transaction costs in connection with the Scheme.

If the Scheme is implemented, the costs of the transaction to be paid by the Merged Group are expected to be approximately A$134 million (excluding GST). This amount reflects the total transactions costs payable by Oil Search and Santos in connection with the transaction, being A$89 million (excluding GST) and A$45 million (excluding GST) respectively. The transaction costs include financial advisory, legal, accounting, Independent Expert, Independent Technical Specialist, Investigating Accountant, tax and administrative fees, Scheme Booklet and printing, share registry, entry into D&O run-off arrangements and other expenses. It does not include any success-related or break fee-sharing fees which may be payable to either Oil Search's or Santos' financial advisers. The amount does not distinguish between amounts which may have already been paid by either Oil Search or Santos prior to the Implementation Date. The estimated transaction costs may differ from those currently expected to be incurred.

If the Scheme is not implemented, Oil Search's transaction costs will be borne by Oil Search alone. See section 9.22 for a summary of the external transaction costs of Oil Search.

The information relating to Oil Search contained in this section 6.9 is based on information provided or prepared by or on behalf of Oil Search. Neither Santos nor any of its affiliates, officers, directors, employees or advisers assumes any responsibility for the accuracy or completeness of such information.

7 Risks

7.1 Introduction

This section outlines:

- risks relating to the Scheme (refer to section 7.2);
- risks relating to the Merged Group (refer to section 7.3); and
- risks if the Scheme does not proceed and Oil Search remains a standalone entity (refer to section 7.4).

This section 7 is a summary only and does not purport to list every risk that may be associated with an investment in the Merged Group or Oil Search now or in the future. There may be additional risks and uncertainties not currently known to Oil Search which may also have a material adverse effect on the Merged Group's or Oil Search's financial and operational performance now or in the future.

In making your decision to vote on the Scheme Resolution, you should read this Scheme Booklet carefully. You should carefully consider the risk factors outlined below and your individual circumstances. This section 7 is general in nature only and does not take into account your individual objectives, financial situation, taxation position or particular needs.

7.2 Risks relating to the Scheme

a) The market value of the New Santos Shares issued in connection with the Scheme will depend on market conditions and the exact value of the Scheme Consideration is not certain

If the Scheme is implemented, Oil Search Shareholders (other than Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares) will receive the Scheme Consideration of 0.6275 New Santos Shares in respect of each Oil Search Share they hold on the Record Date. The exact value of this Scheme Consideration that would be realised by individual Scheme Shareholders will be dependent on the price at which the New Santos Shares trade on the ASX after the Effective Date.

Further, for Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt in to receive New Santos Shares, there is no guarantee as to the price at which Santos Shares may be sold by the Sale Agent as described in section 3.2 (or the timing).

Following implementation of the Scheme, the New Santos Shares listed on the ASX and/or PNGX (if Santos establishes a secondary listing on the PNGX) may rise or fall based on general market conditions and the Merged Group's financial and operational performance. If the Merged Group's share price falls, the value of those New Santos Shares received by Oil Search Shareholders as Scheme Consideration will decline in value. Conversely, the Scheme Consideration will increase in value if the Merged Group's share price rises.

Further, in circumstances where previous Oil Search Shareholders do not intend to continue to hold their New Santos Shares, there is a risk that a number of previous Oil Search Shareholders will seek to sell their New Santos Shares, which may adversely impact the price of Santos Shares.

b) Implementation of the Scheme is subject to various conditions that must be satisfied or waived

Implementation of the Scheme is subject to a number of conditions. There can be no certainty that these conditions will be satisfied or waived (where applicable), or if satisfied or waived (where applicable), when that will occur. In addition, there are a number of other conditions precedent to the Scheme which are outside the control of Oil Search and Santos, including, but not limited to, approval of the Scheme by Oil Search Shareholders and approval by the Court of the Scheme at the Court hearing to be held on the Second Court Date (as well as the approvals by regulatory authorities which are Conditions Precedent).

If for any reason the conditions to the Scheme are not satisfied or waived (where applicable) and the Scheme is not implemented, the market price of Oil Search Shares may be adversely affected.

c) The issue of New Santos Shares could adversely affect the market price of Santos Shares

If the Scheme is implemented, a number of additional Santos Shares will be available for trading on the ASX and/or PNGX (if Santos establishes a secondary listing on the PNGX). The increase in the number of Santos Shares (being the issued share capital of the Merged Group on implementation) may lead to sales of such shares or the perception that such sales may occur either of which may adversely affect the market for, and the market price of Santos Shares.

The sale by the Sale Agent of New Santos Shares issued to Ineligible Foreign Shareholders and Unmarketable Parcel Holders who do not opt-in to receive New Santos Shares may also place short-term downward pressure on the market price for Santos Shares by creating additional selling volumes and increased liquidity.

d) No guarantee that New Santos Shares will be listed on the PNGX

Oil Search Shares are listed on the ASX and PNGX. Currently, Santos Shares are only listed on the ASX. Subject to receipt of any exemptions for activities required by Santos from the ASX, ASIC, PNGX and the PNG Securities Commission and on completion of the Merger, Santos will seek to establish a secondary listing on PNGX on standard terms and conditions for an exempt foreign listing. However, there is no guarantee that Santos Shares will be listed on the PNGX and Oil Search Shareholders who receive New Santos Shares may not be able to trade their shares on the PNGX if Santos does not successfully establish a secondary listing on the PNGX. In these circumstances, there may be adverse consequences for Scheme Shareholders who previously traded Oil Search Shares on the PNGX and who will not be able to trade their New Scheme Shares on the PNGX, including foreign exchange restrictions, adverse taxation consequences and liquidity consequences.

e) Risks of trading during deferred settlement trading period

Due to rounding, Scheme Shareholders will not necessarily know the exact number of New Santos Shares that they will receive (if any) as Scheme Consideration until a number of days after those shares can be traded on ASX on a deferred settlement basis.

Scheme Shareholders who trade New Santos Shares on a deferred settlement basis without knowing the number of New Santos Shares they will receive as Scheme Consideration may risk adverse financial consequences if they purport to sell more New Santos Shares than they receive.

f) Failure to realise benefits of the Scheme including expected synergies

After implementation of the Scheme, the Merged Group will seek to pursue those strategies, operational objectives and benefits contemplated by this Scheme Booklet, including the estimated synergies detailed in section 6.3.

There is the risk that the Merged Group may be unable to realise these strategies, operational objectives and benefits including the synergies estimated by Santos and detailed in section 6.3 (in whole or in part) or that they will not materialise or will not materialise to the extent that the Merged Group anticipates (for whatever reason, including matters beyond the control of the Merged Group), or that the realisation of the strategies, operational objectives and benefits, including the estimated synergies detailed in section 6.3 are delayed, which could have an adverse impact on the Merged Group's operations, financial performance, financial position and prospects.

7.3 Risks relating to the Merged Group

Oil and gas industry and operational risks

a) The Merged Group is exposed to fluctuations in oil and gas prices and overall market conditions

The Merged Group's business and revenue will be heavily dependent on prevailing market prices for its products, primarily oil and gas. Changes in the prices of these commodities will impact the Merged Group's revenue, cash flows, profitability, and ability to service its debts.

The price of oil and gas decreased dramatically during the course of 2020 for a number of reasons, including the economic impact of the COVID-19 pandemic, an increase in supply from certain oil-producing countries resulting from geopolitical disagreements and other macroeconomic factors.

At the macro-level, oil and LNG demand growth may be impacted by an uncertain post-COVID-19 pandemic economic environment and broad energy transition concerns around the hydrocarbon industry. An economic slowdown combined with an increase in oil supply and decrease in LNG demand can also lead to a situation whereby the Merged Group or PNG LNG is unable to sell part or all of its products due to a lack of demand or available storage capacity, which will in turn materially adversely affect the Merged Group's revenue and cash flows. The Merged Group has no control over these events and it is not possible to predict future oil and gas price movements with certainty.

b) The Merged Group is subject to risks relating to exploration, development and decommissioning activities

To achieve its growth objectives, the Merged Group and its partners will commit significant capital to the initiation, development and delivery of major projects. The Merged Group's future production will also be highly dependent upon its success in the timely and cost-effective discovery and development of reserves and resources.

Oil and gas exploration and development involves a certain degree of risk. In the normal course of business, the Merged Group depends on factors such as successful exploration, appraisal of commercial oil and gas reserves, finding commercial solutions for the exploitation of reserves, ability to design and construct efficient producing, gathering and processing facilities, efficient transportation and marketing of hydrocarbons and sound management of operations.

In particular, oil and gas exploration is a speculative endeavour and the nature of the business carries a degree of risk associated with failure to find hydrocarbons with commercial characteristics.

At the end of field life, the Merged Group will also be required to undertake and incur expenditure in connection with decommissioning activities.

A number of factors influence the successful delivery and execution of such large-scale projects thereby rendering them exposed to commercial, political, engineering, execution, operational and legal risk amongst others.

Certain projects may also require the use of new and advanced technologies, which can be expensive to develop, purchase and implement, and may not function as expected. The risks associated with these factors could have a material adverse effect on the Merged Group's ability to commercially operate its business, which could in turn affect the Merged Group's financial condition.

c) The Merged Group may be subject to risks in production

Oil and gas producing assets may be exposed to production decreases or stoppages, which may be the result of facility shutdowns, mechanical or technical failure, well, reservoir or other subsurface impediments, safety breaches, natural disasters, interruption from the local community and other unforeseeable event. The risks associated with production are common across the oil and gas industry and are risks to which both Oil Search and Santos as separate businesses are currently exposed.

A significant failure to meet production targets could compromise the Merged Group's production and sales deliverability obligations, impact operating cash flows through loss of revenue and/or from incurring additional costs needed to reinstate production to required levels. Unplanned outages, particularly relating to LNG commitments, may have significant revenue and reputational impacts. The Merged Group's diversified asset portfolio means it will be well placed to mitigate and manage production risks and associated costs.

d) The Merged Group is subject to reserves depletion in excess of replacement

The Merged Group is subject to reserves depletion and its impact on organisational value. The Merged Group aims to replace and grow its reserves and resource base via exploration and commercial activities. The longer-term health of the business will depend on the quality and size of its current asset and opportunity portfolio and the investment decisions it makes over many years.

Oil and gas exploration is a speculative endeavour and each prospect/investment carries a degree of risk associated with the discovery of hydrocarbons in commercial quantities, which can be more challenging in a volatile commodity price environment. The value of exploration and development assets can be affected by a number of different factors including, amongst other things, macro-economic and socio-political conditions, changes to reserves estimates, the composition of oil and gas reserves, unforeseen project difficulties and other operational issues. Santos and Oil Search as separate businesses are currently exposed to risks associated with reserves depletion and replacement. Similarly, the economic value of the Merged Group's individual producing assets declines as oil and gas is produced and assets transition to abandonment. The Merged Group's future production profitability is subject to both subsurface and commodity price uncertainties but is also highly dependent on how the Merged Group manages and maximises the value of the production business over the life of the field. The Merged Group's diversified asset portfolio will assist the Merged Group to better mitigate the impacts of these risks.

Whether or not the Merged Group makes a final investment decision to develop a major project will depend on its ability to demonstrate the commercial viability of the development such that it will provide an appropriate return for shareholders. This will depend on multiple factors including but not limited to joint venture partner alignment, commodity prices, the availability of finance, the ability to enter into development contracts and offtake contracts on acceptable terms and the ability to obtain regulatory approvals on acceptable terms.

e) The Merged Group's oil and gas resource estimates involve a degree of uncertainty

Oil and gas resource estimates are expressions of judgement based on knowledge, experience and industry practice. Estimates, which are valid at a certain point in time, may alter significantly or become uncertain when new oil and gas reservoir information becomes available through additional drilling or reservoir engineering work over the life of the field, or if forward economic and commercial assumptions change materially. As resource estimates change, development and production plans may be altered in a way that may affect the Merged Group's operations and/or financial results.

Oil and gas resources are booked, in accordance with industry standards and according to the Merged Group's entitlement to the producible volumes. If that entitlement changes, the Merged Group's resource bookings will change.

Further, the Merged Group has provided certain estimates regarding oil and gas reserves and contingent resources in this Scheme Booklet. All reserves and contingent resource estimates and information derived therefrom are as of 31 December 2020. For further detail, please refer to the Important Notices section, section 4.4 and 5.4 of this Scheme Booklet. Oil Search and Santos both employ the appropriate internal expertise to prepare the Annual Reserves Statement in compliance with the ASX Listing Rules and the SPE Petroleum Resource Management System.

f) Risks related to potential acquisitions and divestments may adversely affect the Merged Group's business

The Merged Group may, from time to time, also acquire certain assets and businesses in order to expand its operations or divest or sell down its various interests and stakes in certain assets or businesses in line with the Merged Group's strategic objectives. However, there are a number of inherent risks associated with acquisitions or divestments, including overvaluation of an acquisition or investment or under-valuation of a divestment, or the ability to realise expected synergies, manage integration or separation of businesses, assets and/or processes, and restructuring costs. The Merged Group will be liable for all acquired businesses and properties, which may carry unforeseen costs and litigation issues.

The Merged Group may also divest or sell down its various interests and stakes. In addition, there are risks relating to the completion of any particular transaction including counterparty and settlement risk, or the non-satisfaction of any completion conditions (for example, relevant regulatory or third-party approvals and/or other completion conditions). Any of these factors may adversely affect the Merged Group's ability to conduct its business successfully and impact the Merged Group's operations or results.

The Merged Group may also have ongoing exposures to divested businesses or assets, including through the provision of continued services and infrastructure or an agreement to retain certain liabilities of the divested businesses or assets through warranties and indemnities, which may have an adverse impact on the Merged Group's business and financial performance and position.

g) The Merged Group is subject to joint venture risks

Much of the business of the Merged Group is carried on through joint ventures. The use of joint ventures is common in the oil and gas industry and serves to mitigate the risk and associated cost of exploration, development and production operations. However, failure of agreement or alignment with joint venture partners on the manner in which exploration, development and production operations are carried out could have a material effect on the Merged Group's business.

Additionally, the failure of a joint venture partner or joint venture operator to perform its obligations under the joint venture arrangements, particularly the obligation to meet its share of joint venture costs and liabilities, may result in the Merged Group having to make increased contributions to maintain joint venture operations.

h) The Merged Group is subject to counterparty risks

A dispute, or a breakdown in the relationship, between the Merged Group and governments, regulators, joint venture partners, suppliers or customers (**counterparties**), a failure to reach a suitable arrangement with a particular counterparty to pay or otherwise satisfy its contractual obligations (including as a result of insolvency or financial stress) or termination of an existing arrangement by a particular counterparty, could have an adverse effect on the reputation and/or the financial performance of the Merged Group. The Merged Group may also be adversely affected if a counterparty seeks to terminate or amend the terms (including pricing) of an existing contract, whether in anticipation of a potential breach of contract by such counterparty or otherwise. A breakdown in the relationship with a counterparty as a consequence of these or other factors may also adversely affect the Merged Group's future business prospects with that counterparty.

i) The Merged Group is exposed to force majeure events

Events may occur within or outside Australia, Timor Leste, PNG and the United States of America that negatively impact the above economies or other global or local economies relevant to the Merged Group's financial performance, the operations of the Merged Group and/or the price of ordinary shares.

These events may include, but are not limited to, acts of terrorism, an outbreak of international hostilities, fires, floods, earthquakes, labour strikes, civil wars, natural disasters, outbreaks of disease (including the COVID-19 pandemic) or other man-made or natural events or occurrences that may have a material adverse effect on the Merged Group's ability to perform its obligations.

j) The COVID-19 pandemic has materially adversely affected markets and global trade, and may adversely impact the Merged Group's business and financial performance for the foreseeable future

The COVID-19 pandemic has triggered global economic contraction, causing disruptions in demand and supply chains.

The ongoing COVID-19 pandemic has had a significant impact on the global economy and on the economies of those nations in which Oil Search and Santos operate or have interests and have affected the ability of businesses, individuals, and governments to operate.

A continuation or escalation of the COVID-19 pandemic could materially affect global demand for oil and gas and increase volatility in demand and pricing.

Supply chain disruption of suppliers, logistics partners, products, services/specialists and third-party providers due to the COVID-19 pandemic also has the potential to impact the Merged Group's operations and sales. A continuation or escalation of the COVID-19 pandemic could materially affect the ability of the Merged Group's suppliers (or suppliers to joint venture partners managing the Merged Group's assets) to provide products and services and threaten their ability to continue trading. If either the Merged Group or its joint venture partners are unable to source spare parts for machinery and operations or other products and services, including personnel, then the Merged Group and its joint venture partners may need to suspend certain projects or operations on a temporary or a prolonged basis.

These factors are beyond the Merged Group's control and there is no guarantee that the Merged Group's efforts to address the adverse impacts of the COVID-19 pandemic will be effective. This could have an adverse effect on the overall business sentiment and environment, causing material uncertainties in the regions where the Merged Group conducts its business, cause the Merged Group's business to suffer in ways that cannot be predicted with any reasonable certainty, and which may materially adversely impact the Merged Group's business, financial condition and results of operations.

k) The Merged Group is subject to risks relating to health, safety and environmental impacts

Oil and gas operations are exposed to industry operational safety risks including natural disasters, fire, drought, flood, earthquakes, infections, explosions, blow-outs, pipe failures, leaks, flaring as well as transport and occupational safety incidents. Major environmental risks include accidental spills or leakage of petroleum liquids, gas leaks, ruptures, or discharge of toxic gases. The occurrence of any of these risks and potential failure to manage these risks could result in substantial losses to the Merged Group due to injury or loss of life, damage to or destruction of property, natural resources or equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties or suspension of operations. Damages occurring to third parties as a result of such risks may also give rise to claims against the Merged Group. The Merged Group's ability to mitigate these risks and effectively respond to health and safety incidents may be also impaired by restrictions on the movement of products and personnel relating to the COVID-19 pandemic.

l) The Merged Group is dependent on its key management team and skilled employees

The Merged Group's operating and financial performance is in part dependent on the performance, efforts and expertise of its people. While the Merged Group will make every reasonable effort to retain and attract key employees, there can be no guarantee that it will be able to retain or attract key management, operating and technical staff. The loss of key employees or the delay in their replacement, or the inability to attract key employees with the requisite skills and experience, could adversely affect the Merged Group's ability to implement its business strategies.

m) The Merged Group may be subject to cyber security risks

The integrity, availability and reliability of data within the Merged Group's information technology systems may be subject to intentional or unintentional disruption. Given the increasing level of sophistication and scope of potential cyber-attacks, these attacks may lead to significant breaches of security that could jeopardise the sensitive information and financial transactions of the Merged Group (from a cyber perspective) and property and environmental damage (from a physical perspective). This risk may be elevated as a result of the COVID-19 pandemic and the increase in remote working by the Merged Group's staff and contractors.

Finance, accounting and insurance risks

n) Share market conditions may adversely affect the price of Santos Shares

The price at which Santos Shares are able to be bought and sold may increase or decrease due to a number of factors. These factors may cause the Santos Shares to trade at prices below the Santos Share price at the date of announcement of the Scheme. There is no assurance that the price of the Santos Shares will increase following implementation of the Scheme, even if the Merged Group's earnings increase.

Some of the factors which may adversely impact the price of the Santos Shares include fluctuations in the domestic and international market for listed securities, general economic conditions including interest rates, inflation rates, exchange rates, commodity and oil prices, changes to government fiscal, monetary or regulatory policies and settings, country trade and importation policies, changes in legislation or regulation, inclusion in or removal from market indices, the nature of the markets in which Santos operates and general operational and business risks including risks related to climate change.

There is no assurance that there will always be an active market for the Merged Group's shares.

o) Debt and equity funding

The Merged Group's continued ability to operate its business and effectively implement its business plan over time, particularly the development of growth projects, will depend in part on its ability to raise additional capital for future operations and to repay or refinance its debt. No assurance can be given that any such additional funding will be made available or that, if available, it will be available on terms acceptable to the Merged Group or its shareholders.

If additional funds are raised through the issue of equity securities, the capital raising may, in some circumstances, be dilutive to shareholders.

Santos and Oil Search each have existing debt facilities. In the future, the Merged Group may need to renegotiate or refinance the terms of these debt facilities or may seek further facilities or replacement facilities with alternative financiers to satisfy its capital requirements. The terms on which debt financiers are willing to offer finance may vary from time to time depending on a number of factors including macro-economic conditions, the performance of the Merged Group and an assessment of the risks and intended use of funds.

If the Scheme is implemented, the liabilities (including financial debt, whether assumed or refinanced) of Oil Search and Santos will become liabilities of Santos, which may increase the Merged Group's financial leverage and result in changes to other credit metrics.

There are a number of factors which could impact the credit rating of the Merged Group as issued by the relevant credit rating agencies, including the Merged Group's current and planned financial and business risk profile. The Merged Group intends to maintain a credit profile consistent with an investment grade credit rating however this is not guaranteed. Rating agencies may also revise or replace entirely the methodology applied to derive credit ratings. The Merged Group can give no assurances that its credit rating will remain for any period of time or that its credit rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant, or if a different methodology is applied to derive that credit rating.

Failure to maintain an investment grade credit rating could increase costs, impact the ability to obtain financing, increase future financing costs or impact access to capital markets for the Merged Group.

In addition, recently certain financial institutions, institutional investors and other sources of capital have begun to limit or eliminate their investment in oil and gas activities citing climate change concerns.

If sufficient funds are not available from either debt or equity markets to satisfy the Merged Group's short, medium or long-term capital requirements, when required, this may adversely impact the Merged Group's operations, financial performance and financial position.

p) Hedging risk

The Merged Group will enter into hedging transactions in accordance with its oil price hedging policy in order to mitigate the effect of commodity price volatility and support annual capital expenditure plans. The Merged Group will measure its oil price exposure and monitor commodity market conditions and will enter hedging transactions as appropriate. Notwithstanding the Merged Group's hedging policy, no assurance can be given that the Merged Group will be able to adequately protect itself from fluctuations in commodity prices. Furthermore, the Merged Group may incur losses as a result of the hedging positions it has adopted to protect it against commodity price risk.

There is also a risk associated with any derivative contracts that involve the possibility that counterparties may be unable to satisfy contractual obligations. If any counterparty to the Merged Group's derivative instruments were to default or seek bankruptcy protection, it could subject a larger percentage of the Merged Group's future oil and gas production to commodity price changes and could have a negative effect on the Merged Group's financial performance, including its ability to fund future projects. In addition, whether or not the Merged Group engages in hedging and other oil and gas derivative contracts on a limited basis or otherwise, the Merged Group will remain exposed to fluctuations in oil and gas prices and an extended decline in oil and gas prices could have a material adverse effect on the Merged Group's businesses.

q) The Merged Group will be subject to currency and PNG exchange control risks

Both Santos and Oil Search are US dollar reporting entities and the Merged Group will derive the majority of its revenue in US dollars. The Merged Group is therefore exposed to currency risk for transactions and valuations of assets and liabilities in any currency other than US dollars. Both Oil Search and Santos have most of their assets and liabilities denominated in United States dollars and therefore have residual currency exposure mainly in Australian dollars and, for Oil Search, PNG Kina.

The degree to which such exchange rates may vary is uncertain and presents a risk to the Merged Group's financial position.

The Merged Group will maintain a foreign currency hedging policy with the objective of reducing the effect of foreign currency exchange rate volatility and support annual capital expenditure plans. The Merged Group will enter hedging transactions as appropriate in accordance with this policy however no assurance can be given that the Merged Group will be able to successfully manage its exposure to foreign exchange risk. In addition, derivative contracts entered into under a hedging policy contain counterparty risk and may result in losses as a result of positions taken.

The Merged Group will be subject to PNG foreign exchange controls which could affect its ability to conduct business efficiently and effectively.

r) The Merged Group's insurance coverage may not be adequate

The Merged Group will seek to maintain appropriate policies of insurance that are consistent with those customarily carried by similar organisations in the energy sector. Any future increase in the cost of such insurance policies, or an inability to fully place, renew or claim against insurance policies could adversely affect the Merged Group's business, financial position and operational results.

Additionally, there is no assurance that the Merged Group's insurance coverage will be sufficient to compensate it against all losses it may suffer as a result of an incident affecting its assets or operations. There are certain types of risks which are not covered by insurance because they are either uninsurable or not economically insurable, including acts of war, acts of terrorism, civil unrest and business disruption caused by outbreaks of disease (including the COVID-19 pandemic). If such events were to occur, the Merged Group may have to bear the costs of any uninsured risk or uninsured amount, and this could have a material adverse effect on the Merged Group's business, financial position and operational results.

s) The Merged Group's assets may be subject to impairment risks

Many of the aforementioned risks and in particular the impact of extended low oil and gas prices may cause the Merged Group to reassess the carrying value of its assets. Indicators of impairment can exist for a number of reasons including where asset valuations are lower than their written down book values, certain activities are discontinued and deferred tax assets are not able to be recovered against future taxable income, amongst other things. The recognition of an impairment will result in a write-down of asset value and an equivalent non-cash charge to the income statement, thereby reducing the company's net assets and reported profits respectively. The Merged Group will assess for indicators of impairment at each reporting period.

t) Accounting risks

In accounting for the Merger, the Merged Group will perform a fair value assessment of all Oil Search assets, liabilities and contingent liabilities, which will include the identification and valuation of tangible and intangible assets. As a result of this fair value assessment, the Merged Group's Depreciation, Depletion and Amortisation (**DD&A**) may differ from the relevant DD&A of Santos and Oil Search as separate businesses and to that extent may impact the future earnings of the Merged Group.

The Merged Group must report and prepare financial statements in accordance with prevailing accounting standards and policies. There may be changes in these accounting standards and policies in the future which may have an adverse impact on the Merged Group.

u) The Merged Group is exposed to interest rate changes

Changes in interest rates will affect the cost of borrowings which bear interest at floating rates. Any material increase in interest rates will affect the Merged Group's costs of servicing existing floating rate borrowings and raising new borrowings which could materially and adversely affect the Merged Group's financial performance and position.

The Merged Group will maintain a policy of ensuring the majority of its exposure to changes in interest rates on borrowings is on a floating rate basis and may enter into derivative instruments to give effect to this policy from time to time.

ESG risks

v) The Merged Group is subject to risks from political, community and other stakeholders

The Merged Group will operate within complex and dynamic stakeholder environments with evolving societal norms and expectations that differ significantly across its operating jurisdictions. The countries in which the Merged Group has interests expose it to different degrees of political and commercial risk. The overall socio-political environment in which the Merged Group will operate, the profitability of particular operating assets and the safety of people may be adversely impacted by political instability, land ownership disputes, ongoing benefits delivery delays, discussions and disputes in respect of royalties and community issues as well as war, civil unrest and terrorism.

The Merged Group's ability to acquire, retain and gain full value from assets may also be affected by a number of political and social issues such as differing political agendas and decision making, environmental and social policy and the impact of bribery and corruption.

w) The Merged Group's operations may be subject to human rights, land access and native title claims

The Merged Group faces risks related to the potential impacts of actions of both public and private security forces, interactions with and the use of land associated with subsistence-based and/or indigenous communities and the work practices and supply chains of suppliers and contractors. The Merged Group may be required to obtain the consent of owners and occupiers of land within its licence areas and compensation may be required to be paid to the owners and occupiers of such land in order to carry out exploration and development or production activities. Additionally, there can be no assurance that native or indigenous title and land rights may also apply or be implemented in other jurisdictions in which the Merged Group would operate (including Australia, Alaska and PNG).

Potential claims by community members and landowners, who may have concerns over the social or environmental impacts of oil and gas operations or the distribution of oil and gas royalties and access to petroleum-related benefits, have the potential to affect land access or cause community unrest and activism, which may diminish the Merged Group's reputation.

Furthermore, the Merged Group is also subject to relevant laws and regulations relating to environment, social, human rights, modern slavery and health, safety and welfare laws. Any non-compliance with such laws and regulations may lead to third-party claims and penalties which may also diminish the Merged Group's reputation and in turn affect the Merged Group's financial condition.

x) The Merged Group may be subject to risks relating to climate change

The Merged Group is exposed to a number of climate change-related risks. Material climate-related risks include:

i) changes in demand for products due to change in regulation (such as emission reduction policies or additional GHG regulations) and technological changes as well as change in public sentiment due to climate change concerns and activism. National and international targets to reduce GHG emissions, including country level net zero targets, could also add additional costs to, or restrictions on, the Merged Group's operations. Additionally, detailed legislation and regulation to achieve net zero targets set by certain governments by 2050 have not yet been developed and there is a risk that they could adversely impact oil and gas assets and the business of the Merged Group;

ii) increases in operating costs of long-life assets due to carbon-pricing policies or other market mechanisms or regulations, for example, implementing GHG emissions reduction projects may increase operating or development costs which may have the effect of reducing rates of return to shares, return on equity and profitability of the Merged Group's portfolio;

iii) physical damage to assets or interruption to operations from climatic changes and extreme weather events;

iv) additional expenditure costs to develop technology to reduce GHG emissions and to engineer oil and gas projects in ways which reduce GHG emissions;

v) restrictions on capital deployment to carbon intensive industries including projects with higher GHG intensity and carbon emissions;

vi) reputational impacts and damage through increasing stakeholder activism and changing societal expectations, including exposure to the risk of reduced investor confidence and/or investor actions if the Merged Group fails to implement its strategy as part of the transition to a low carbon economy. Failure to deliver the Merged Group's climate actions or strategic goals may result in damage to reputation or give rise to adverse legal, regulatory or market consequences;

vii) certain financial institutions, institutional investors and other sources of capital have recently begun to limit or eliminate their investment in oil and gas activities citing climate change concerns; and

viii) climate change legal and litigation risks associated with historical, current, or future GHG emissions (Scope 1, 2, or 3), progress against targets, reporting or other statements made (including by Santos, the Merged Group, or externally set targets and reporting requirements). Climate change-related litigation or legal claims could result in additional costs, penalties, reputational damage or impose new restrictions on the Merged Group's operations.

The occurrence of any of these risks could result in asset impairment, decreased revenue and diminished brand value, amongst other things. Any adverse or extreme climatic conditions could also affect the Merged Group's operations through delaying exploration, development and production activities, resulting in additional expenditure and impacting production levels.

Legal and regulatory risks

y) The Merged Group is subject to legislative and regulatory risk including a change in applicable tax law

The Merged Group will have interests in Australia and in international jurisdictions and the business is subject to various national, federal, state and local laws and regulations in those jurisdictions. Non-compliance can lead to regulatory or legal actions and can impact the status of licences or operatorship or granting of governmental regulatory approvals for certain operations. Retention of licences can also be impacted when government development expectations are not met, or in the event of non-compliance with respective licence commitments.

Changes in governments, government policy, fiscal regime, regulatory regime, legislative framework or policy positions held by government regulators could impact the Merged Group's business, results from operations, asset valuations or financial condition and performance, including regimes which may seek to impose a cost on carbon (whether through a carbon tax, carbon trading scheme or otherwise).

Companies in the oil and gas industry such as the Merged Group may be subject to paying direct and indirect taxes, royalties and other imposts in addition to normal company taxes. The Merged Group's profitability may be affected by changes in government taxation and royalty policies.

In addition to changes in existing tax laws, risk also arises in relation to changes in interpretation or application of the law by courts or taxation authorities, especially where specific guidance is unavailable or has not been tested in the relevant tax jurisdiction.

The Merged Group may from time-to-time be subject to reviews, audits or investigations from, or disputes with, relevant tax authorities, the outcome of which may impact the amount of tax payable by the Merged Group and impact the financial performance of the Merged Group.

z) Sanctions risks

Sanctions laws, including but not limited to those of Australia, the United States of America, the European Union and the United Kingdom, prohibit dealings with certain designated persons or entities that are identified from time to time on sanctions lists or engaged in prohibited activities in sanctioned jurisdictions. Organisations operating in the oil and gas sector may become exposed to sanctions related issues if, for example, an existing joint venture partner or other contract counterparty is identified on or added to a sanctions list or if an existing sanctioned person or entity sought to participate in an asset or business in which the Merged Group had dealings or if an activity in which the Merged Group engaged in was sanctioned. The Merged Group will have in place compliance policies and procedures which prevent dealings with sanctioned persons or entities or in sanctioned activities. In the event that a potential dealing with a sanctioned person or entity is identified in connection with an asset, or in the event that sanctions laws prohibit dealings in a particular activity, the Merged Group may need to withdraw from that asset or cease engaging in that activity in order to comply with the relevant sanctions laws.

aa) Dependence on licences and permits

The Merged Group's operations and projects will require the retention of relevant licences, permits, authorisations, concessions and other approvals in connection with its activities (**Operating Approvals**).

Obtaining and complying with the necessary Operating Approvals (and other relevant approvals) or governmental regulations can be complex, costly and time-consuming and is not assured.

The duration, cost and success of applications for Operating Approvals are contingent on many factors, including those outside the control of the Merged Group. Delay in obtaining or renewing, or failure to obtain or renew, a material and necessary permit could mean that the Merged Group may be delayed or, in a worst-case scenario, unable to proceed with the development or continued operation of a project or asset. The Operating Approvals that the Merged Group requires may not be issued, maintained or renewed either in a timely fashion or at all, which may constrain the ability of the Merged Group to conduct its operations and activities, which in turn may impact the Merged Group's operations, financial performance and financial position.

bb) The Merged Group is subject to the risk of investigations, disputes and legal proceedings

The risk of litigation and claims is a general risk that applies across the Merged Group's business. The Merged Group may be subject to litigation, arbitration, expert determination, class actions and other claims and disputes in the course of its business, including employment disputes, contractual disputes, indemnity claims, occupational and personal claims. The Merged Group is also subject to environmental regulatory compliance and may incur substantial fines, civil or criminal actions or third-party claims if held liable under environmental laws and regulations. Any litigation, class actions, claims or disputes, including employment disputes, price review disputes and environmental disputes, including the costs of settling claims, or a negative outcome from litigation and operational impacts, could materially adversely affect the Merged Group's business, operating and financial performance.

Under the Merger Implementation Deed, the Merger is conditional on the approval of the ICCC, the PNG competition regulator, and is not subject to any other competition clearances. The competition laws of various countries may, in certain circumstances, seek to regulate transactions that occur outside of those countries. It is possible that a competition regulator of a foreign country from outside the jurisdiction of PNG may take the view that the Merger required clearance under the law of that country. Should a foreign competition regulator take that view in circumstances where clearance was not obtained, the regulator may raise an issue or attempt to take action against Santos, Oil Search or the Merged Group, such as imposing a fine.

Not obtaining clearance in these circumstances may also impact on the capacity of the Merged Group to conduct business in that foreign country in the future and to obtain approvals that may be sought for other transactions.

Other

cc) Other risks

Additional risks and uncertainties not currently known to Oil Search and Santos may also have a material adverse effect on the Merged Group if the Merger is implemented. The information set out above does not purport to be, nor should it be construed as representing, an exhaustive list of all of the risks that may affect the Merged Group.

7.4 Risks if the Scheme does not proceed

In addition, a number of the risks relating to the Merged Group in section 7.3 are risks of investing in an oil and gas company and will also apply, albeit to a differing extent, to an ongoing investment in Oil Search if the Scheme does not proceed.

a) If the Scheme does not proceed, the price of an Oil Search Share may fall below its recent trading price

If the Scheme does not proceed, the trading price of Oil Search Shares could fall to below the level at which it has been trading since the Scheme was announced (although this is difficult to predict with any degree of certainty). The trading price of an Oil Search Share rose by 10.1% over the two days following the announcement of Santos' first non-binding indicative offer (based on the closing price of Oil Search Shares on the ASX on the date prior to the announcement and the closing price of Oil Search Shares on the ASX on the date after the announcement).

b) Oil Search may require access to additional funding for future growth

The oil and gas business involves significant capital expenditure, including in exploration and development, production, processing and transportation. Oil Search relies on cash flows from operating activities and on external sources, including bank facilities and offerings of debt or equity securities in the Australian and international capital markets, to finance capital expenditures, operating costs and/or refinance its existing debt obligations.

Unexpected changes to future cost profiles and additional costs required to meet future ongoing work programs could result in Oil Search's cash requirements being over and above its liquidity. To the extent that Oil Search's operating cash flows and debt facilities are insufficient to meet its requirements for ongoing operations and capital expenditure, Oil Search may need to seek additional funding, sell assets, defer capital expenditure or refinance its existing debt obligations. There can be no assurance that sufficient equity or debt funding, or any refinancing, will be available to Oil Search on favourable terms or at all. If Oil Search is unable to obtain additional funding or refinancing on acceptable terms in these circumstances, there may be a reduction in planned capital expenditure which could have a material adverse effect on Oil Search's ability to expand its business and/or maintain operations at current levels, which could in turn affect Oil Search's financial condition.

If the Scheme does not proceed, the Oil Search Group will continue to be exposed to additional regulatory approval requirements involved in capital and liquidity management that are associated with being a PNG incorporated company.

c) Oil Search is subject to product demand and market risks

Oil Search operates in a mature oil market. Potential demand and market risks are limited in the near-term due to highly liquid trading conditions for crude. At a macro-level, the timing and level of oil demand growth is challenged by the uncertainty of the post-COVID-19 pandemic economic outlook and the energy transition pressures on oil as a key component of the global energy mix.

Oil Search operates in a growing but competitive LNG market with diverse buyers and sellers. Oil Search's Papua LNG expansion project depends on successfully placing volumes under long-term contracts with creditworthy counterparties on terms that underpin project economics.

During the next several years, multiple competing LNG projects are scheduled to reach FID. These competing suppliers, which include the Qatar expansion, and proposed new LNG projects in Australia, Mozambique and North America, are targeting an expected shortfall in LNG supply against demand in the late 2020s.

d) Any consequential downgrading of PNG's sovereign credit rating by an international rating agency could have a negative impact on Oil Search's business and the trading price of Oil Search Shares

Oil Search would continue to have a significant presence in PNG and as at 31 December 2020, 84% of Oil Search's assets are located in PNG. On 19 April 2021, Moody's Investors Service ("Moody's") changed the outlook for PNG's rating to negative from stable but reaffirmed its rating at "B2". This change in outlook reflects the risks relating to the weakening in PNG's fiscal strength due to macroeconomic conditions and its debt position. On 28 April 2020, Standard & Poor's Ratings Services ("S&P") downgraded PNG from "B" to "B-" and on 30 April 2021, S&P placed PNG on negative CreditWatch.

There can be no assurance that these ratings will not be further revised or changed by Moody's, Fitch or S&P or that any of the other global rating agencies will not downgrade PNG's sovereign credit rating. Any adverse revisions to PNG's credit ratings by international rating agencies may adversely impact Oil Search's access to capital markets, ability to raise additional financing and the interest rates and other commercial terms at which such financing is available. Any of these developments may materially and adversely affect Oil Search's business, financial condition and results of operations.

e) Other risks

In the event the Scheme is not implemented, an investment in Oil Search Shares will continue to be exposed to various further risk factors, including those which currently apply to a shareholding in Oil Search. Many of the risk factors described as applicable to the Merged Group in section 7.3 also apply to a continuing investment in Oil Search as a stand-alone entity.

1) This number represents non-current assets excluding deferred tax assets in PNG.

8 Taxation implications

8.1 Australian taxation implications

a) Scope of tax comments

This is a general overview of the Australian income tax (including CGT), GST and stamp duty implications for certain Australian and non-Australian resident Scheme Shareholders on implementation of the Scheme.

The categories of Scheme Shareholders considered in this summary are limited to individuals, companies (other than life insurance companies), trusts and complying superannuation funds that hold their Scheme Shares on capital account for Australian income tax purposes. The tax comments outlined in this summary are not applicable to all Scheme Shareholders and do not cover Scheme Shareholders who:

- hold their Scheme Shares as a revenue asset (ie, trading entities or entities who acquired their Scheme Shares for the purposes of resale at a profit) or as trading stock;
- hold or are entitled to acquire, either alone or together with associates, 10% or more of the Scheme Shares;
- are partnerships or individuals who are partners of such partnerships;
- hold their shares as an asset in a business that is carried on through a permanent establishment in Australia;
- acquired their Scheme Shares pursuant to an employee share plan;
- are under a legal disability;
- are exempt from Australian income tax;
- are Ineligible Foreign Shareholders;
- are subject to the taxation of financial arrangements rules in Division 230 of the *Income Tax Assessment Act 1997* (Cth) in relation to gains and losses on their Scheme Shares;
- are subject to the Investment Manager Regime under Subdivision 842-I of the *Income Tax Assessment Act 1997* (Cth) in respect of their Scheme Shares;
- may be subject to special rules, such as banks, insurance companies, tax exempt organisations, certain trusts, superannuation funds (unless otherwise stated) or dealers in shares;
- are 'temporary residents' as that term is defined in section 995-1(1) of the *Income Tax Assessment Act 1997* (Cth); or
- change their tax residence whilst holding Scheme Shares.

This summary is based on the Australian tax law, and the practice of the tax authorities, at the time of issue of this Scheme Booklet. The laws are complex and subject to change periodically as is their interpretation by the courts and the tax authorities. This summary is general in nature and is not intended to be an authoritative or complete statement of the applicable law. This summary does not take into account the tax law of countries other than Australia. The precise implications of ownership or disposal of their Scheme Shares will depend upon each Scheme Shareholder's specific circumstances.

These comments should not be a substitute for advice from an appropriate professional advisor having regard to each Scheme Shareholder's individual circumstances. All Scheme Shareholders are strongly advised to obtain and rely only on their own professional advice on the tax implications based on their own specific circumstances.

Oil Search is in the process of applying for a class ruling from the ATO regarding the income tax implications for Scheme Shareholders of participating in the Scheme, and confirming the availability of CGT scrip-for-scrip roll-over relief in respect of the Scheme Consideration to be received by Scheme Shareholders, if the Scheme is implemented. The income tax comments provided below are consistent with the positions taken in the class ruling application lodged with the ATO.

The class ruling is not expected to be issued by the ATO until after the Implementation Date, which is currently estimated to be Friday, 17 December 2021. However, Oil Search expects to receive a draft of the class ruling prior to the Scheme Meeting, which is currently estimated to be held on Tuesday, 7 December 2021.

Scheme Shareholders should refer to the final class ruling once it is published on www.ato.gov.au and on Oil Search's Website.

b) Australian resident shareholders

This section applies to Scheme Shareholders who are residents of Australia for income tax purposes.

i) CGT Event on disposal of Scheme Shares to Santos

Scheme Shareholders will dispose of their Scheme Shares to Santos in exchange for the Scheme Consideration, comprising 0.6275 New Santos Shares in respect of each Oil Search Share held by a Scheme Shareholder as at the Record Date.

The disposal of the Scheme Shares to Santos under the Scheme will give rise to a CGT event for Scheme Shareholders. The timing of the CGT event for Scheme Shareholders should be the date the Scheme Shares are disposed of under the Scheme, being the Implementation Date.

b) Australian resident shareholders continued

i) CGT Event on disposal of Scheme Shares to Santos continued

In the absence of CGT roll-over relief (discussed below), the following tax consequences are expected to arise for the Scheme Shareholders that acquired (or are deemed to have acquired) their Scheme Shares on or after 20 September 1985:

– a capital gain will be realised to the extent the capital proceeds received by the Scheme Shareholder from the disposal of their Scheme Shares exceed the cost base of those shares; or

– a capital loss will be realised to the extent the capital proceeds received by the Scheme Shareholder from the disposal of their Scheme Shares are less than the reduced cost base of those shares.

Capital losses can only be offset against capital gains derived in the same income year or later income years. Specific loss recoupment rules apply to companies which must be satisfied if those tax losses are to be used in current or future years. Scheme Shareholders should seek their own tax advice in relation to the operation of these rules.

ii) Capital proceeds received by Scheme Shareholders

The capital proceeds on disposal of the Scheme Shares should be equal to the Scheme Consideration received by the Scheme Shareholders. Therefore, the capital proceeds for Scheme Shares disposed of by the Scheme Shareholders should be equal to the market value of New Santos Shares received by the Scheme Shareholders under the Scheme.

Further information regarding the determination of the market value of New Santos Shares received by Scheme Shareholders is expected to be available on Santos' website after the Implementation Date.

iii) Cost base and reduced cost base of a Scheme Share

The cost base of a Scheme Share will generally be equal to the cost of acquiring that Scheme Share, plus any incidental costs of acquisition and disposal, such as brokerage fees and legal costs.

The reduced cost base of a Scheme Share is determined in a manner similar to the cost base although some differences in the calculation of reduced cost base do exist depending on the Scheme Shareholder's individual circumstances. The cost base and reduced cost base of each Scheme Share will depend on the individual circumstances of each Scheme Shareholder.

iv) CGT Discount

The CGT discount may apply to Scheme Shareholders that are individuals, complying superannuation funds or trusts, who have held, or are taken to have held, their Scheme Shares for at least 12 months (not including the date of acquisition or the date of disposal) at the time of the disposal of their Scheme Shares to Santos. The CGT discount is:

– 50% if the Scheme Shareholder is an individual or trustee: meaning only 50% of the capital gain will be included in assessable income; and

– 33⅓% if the Scheme Shareholder is a trustee of a complying superannuation entity: meaning only two-thirds of the capital gain will be included in assessable income.

The CGT discount is not available to Scheme Shareholders that are companies.

If a Scheme Shareholder makes a discounted capital gain, any current year and/or carried forward capital losses will be applied to reduce the undiscounted capital gain before the relevant CGT discount is applied. The resulting amount is then included in the Scheme Shareholder's net capital gain for the income year and included in assessable income.

The CGT discount rules relating to trusts are complex. We recommend trustees seek their own independent advice on how the CGT discount applies to them and the trust's beneficiaries.

v) CGT Scrip-for-scrip roll-over relief

Scheme Shareholders who make a capital gain from the disposal of their Scheme Shares may be eligible to choose CGT scrip-for-scrip roll-over relief (provided certain conditions are met). Broadly, CGT scrip-for-scrip roll-over relief enables Scheme Shareholders to disregard the capital gain they make from the disposal of their Scheme Shares under the Scheme.

If a capital loss arises, CGT scrip-for-scrip roll-over relief is not available.

Scheme Shareholders do not need to inform the ATO, or document their choice to claim CGT scrip-for-scrip roll-over relief in any particular way, other than to complete their income tax return in a manner consistent with their choice.

vi) Consequences for choosing CGT scrip-for-scrip roll-over relief

If a Scheme Shareholder chooses to obtain CGT scrip-for-scrip roll-over relief, the capital gain arising on the disposal of their Scheme Shares under the Scheme should be disregarded.

The first element of the cost base for their New Santos Shares is then determined by attributing, on a reasonable basis, the existing cost base of the Scheme Shares exchanged under the Scheme. The first element of the reduced cost base is determined similarly.

For the purposes of determining future eligibility for the CGT discount, the acquisition date of the New Santos Shares is taken to be the date when the Scheme Shareholder originally acquired their Scheme Shares.

b) Australian resident shareholders continued

vii) Consequences if CGT scrip-for-scrip roll-over relief is not available or not chosen

If a Scheme Shareholder does not qualify for CGT scrip-for-scrip roll-over relief, or the Scheme Shareholder chooses not to obtain CGT scrip-for-scrip roll-over relief, the general CGT treatment outlined at paragraph 8.1(b)(i) will apply.

If a Scheme Shareholder makes a capital loss from the disposal of their Scheme shares, this loss may be used to offset capital gains in the same or subsequent years of income (subject to satisfying certain conditions). The capital loss cannot be offset against ordinary income or carried back to offset net capital gains arising in earlier income years.

c) Non-Australian resident shareholders

This section applies to Scheme Shareholders that are not residents of Australia for Australian income tax purposes.

Non-Australian tax resident Scheme Shareholders who hold their Scheme Shares on capital account should not be subject to the CGT rules in Australia on the disposal of their Scheme Shares on the basis that they and their associates hold, or are entitled to acquire, less than 10% of the Scheme shares.

d) Foreign resident CGT withholding rules

Australia's foreign resident capital gains withholding tax regime applies to transactions involving the acquisition of certain indirect interests in Australian real property from relevant foreign residents. The withholding rate is 12.5%.

On the basis that the Scheme Shares held by Scheme Shareholders should not be considered 'taxable Australian property' under section 855-15 of the *Income Tax Assessment Act 1997* (Cth), the foreign resident capital gains withholding tax regime should not apply. Accordingly, the regime should not operate to require Santos to withhold an amount of the Scheme Consideration that is to be paid to the Scheme Shareholders that are not tax residents of Australia.

e) Stamp Duty

No stamp duty should be payable by the Scheme Shareholders on the acquisition by Santos of their Scheme Shares under the Scheme or on the receipt by Scheme Shareholders of the New Santos Shares as Scheme Consideration.

f) GST

No GST should be payable by Scheme Shareholders on the acquisition by Santos of their Scheme Shares under the Scheme, or on the receipt by Scheme Shareholders of the New Santos Shares as Scheme Consideration.

Scheme Shareholders who are registered for GST may not be entitled to input tax credits (or only entitled to reduced input tax credits) for any GST incurred on costs associated with the disposal of their Scheme Shares.

g) Disclaimer

To persons receiving this document in Australia:

The information contained in this section does not constitute 'financial product advice' within the meaning of the Australian Corporations Act. To the extent that this document contains any information about a 'financial product' within the meaning of the Australian Corporations Act, taxation is only one of the matters that must be considered when making a decision about the relevant financial product. This material has been prepared for general circulation and does not take into account the objectives, financial situation or needs of any recipient. Accordingly, any recipient should, before acting on this material, consider taking advice from a person who is licensed to provide financial product advice under the Australian Corporations Act. Any recipient should, before acting on this material, also consider the appropriateness of this material having regard to their objectives, financial situation and needs and consider obtaining independent financial advice.

8.2 PNG taxation implications

a) Scope of tax comments

This is a general overview of the PNG income tax, stamp duty and GST consequences for certain Scheme Shareholders on disposal of their Scheme Shares in exchange for the Scheme Consideration under the Scheme.

This summary is applicable to both PNG residents (or deemed PNG residents) for tax purposes (**PNG Resident**) and non-PNG residents for tax purposes (**Non-PNG Resident**).

This summary is based upon PNG taxation law and administrative practice in effect as at the date of this Scheme Booklet. It is not intended to be an authoritative or comprehensive analysis of the taxation laws of PNG applicable to the particular circumstances of a Scheme Shareholder.

This summary applies to Scheme Shareholders who hold their Scheme Shares on capital account for PNG tax purposes. It does not deal with the taxation consequences of disposing Scheme Shares which are:

- held by banks, insurance companies or financial institutions;
- held in the course of carrying on a business;
- acquired for the purpose of profit making by sale or as part of the carrying out of a profit making undertaking or plan; or
- otherwise held by a Scheme Shareholder on revenue account.

This summary also does not apply to Scheme Shareholders who hold their shares in Oil Search through a branch or permanent establishment in PNG. Scheme Shareholders who may be in this position should consult their own tax advisers.

This summary does not constitute tax advice and is intended only as a general guide to the PNG tax implications of participating in the Scheme. It does not consider any specific facts or circumstances that may apply to a particular Scheme Shareholder. As the tax consequences to Scheme Shareholders of participating in the Scheme will depend on the individual circumstances of each Scheme Shareholder, all Scheme Shareholders are advised to seek independent professional advice regarding the PNG tax consequences of disposing of their Scheme Shares according to their own circumstances.

b) Disposal of Oil Search Shares

There is currently no capital gains tax in PNG. As a consequence, if a Scheme Shareholder holds Scheme Shares on capital account, no PNG income tax will be payable on any capital gain realised by the Scheme Shareholder (whether a PNG Resident or Non-PNG Resident) on the disposal of their Scheme Shares as a result of participating in the Scheme, and no deduction will be available in respect of any capital loss.

c) Ongoing ownership of Santos Shares

i) PNG Residents

In the case of an individual PNG Resident Scheme Shareholder who has participated in the Scheme and is holding shares in Santos, the gross amount of dividends received or deemed to be received (calculated before deduction of withholding tax) on the New Santos Shares will be included in computing the individual's assessable income. A credit will be allowed for any Australian withholding tax (if any) deducted from the dividend on their behalf, subject to limitations as set out in the *Income Tax Act 1959* (PNG).

In the case of a PNG Resident that is a corporation which has participated in the Scheme and is holding shares in Santos, the gross amount of all dividends received or deemed to be received (calculated before deduction of withholding tax if applicable) from the Santos Shares will be included in computing the corporation's assessable income. PNG Residents who hold shares in Santos and who are corporations are generally entitled to a rebate against the tax payable on dividends received. PNG Residents to whom these rules may be relevant should consult their own tax advisers.

ii) Non-PNG Residents

Non-PNG Residents should not be subject to PNG tax on dividends received on their New Santos Shares.

d) Stamp Duty

Scheme Shareholders will not be liable to PNG stamp duty on the transfer of their shares to Santos under the Scheme, and PNG stamp duty will not apply to the issue of New Santos Shares to Scheme Shareholders.

e) GST

The transfer and issue of shares is the supply of a financial service which is treated as an exempt supply for GST purposes. Deductions for input tax (such as GST on adviser's fees) are not available to the extent that the input tax is incurred in relation to exempt supplies.

9 Additional Information

9.1 Interests of Oil Search Directors in Oil Search securities

The table below lists the relevant interests of Oil Search Directors in Oil Search Shares as at the date of this Scheme Booklet.

Oil Search Director	Position	Relevant Interest in Oil Search Shares
Mr Richard Lee AM	Chairman, Non-executive Director	131,433 Oil Search Shares
Ms Susan Cunningham	Non-executive Director	42,404 Oil Search Shares[1]
Dr Eileen Doyle	Non-executive Director	53,494 Oil Search Shares
Ms Fiona Harris AM	Non-executive Director	35,956 Oil Search Shares
Dr Agu Kantsler	Non-executive Director	62,704 Oil Search Shares
Mr Musje Werror	Non-executive Director	Nil
Mr Michael Utsler	Non-executive Director	Nil

No Oil Search Director acquired or disposed of a Relevant Interest in any Oil Search Shares during the four months before the date of this Scheme Booklet.

Oil Search Directors who hold Oil Search Shares will be entitled to vote at the Scheme Meeting and receive the Scheme Consideration along with the other Oil Search Shareholders.

Each Oil Search Director intends to vote all the Oil Search Shares they hold or control in Oil Search in favour of the Scheme, in the absence of a Superior Proposal.

9.2 Interests of Oil Search Directors in Oil Search Equity Incentives

Except in respect of the 42,240 Oil Search NED Restricted Shares and 22,971 Oil Search NED Rights referred to below, none of the Oil Search Directors have any interest in any Oil Search Equity Incentives.

As detailed in Oil Search's 2020 Annual Report, Oil Search operates the Oil Search NED Share Plan, under which Oil Search Directors may elect to receive a portion of their director's fees in the form of Oil Search NED Rights, which then convert into Oil Search NED Restricted Shares once the relevant shares are issued or purchased to satisfy the rights. The Oil Search NED Share Plan is intended to facilitate share ownership for Oil Search Directors to reach minimum share ownership requirements. Oil Search NED Rights and Oil Search NED Restricted Shares which are issued under the Oil Search NED Share Plan are subject to certain disposal restrictions prior to vesting.

Two of the Oil Search Directors (being the Chairman and Non-executive Director, Mr Richard Lee, and Non-Executive Director, Dr Agu Kantsler) have previously been issued Oil Search NED Restricted Shares under the Oil Search NED Share Plan. Mr Lee holds 27,525 Oil Search NED Restricted Shares and Dr Kantsler holds 14,715 Oil Search NED Restricted Shares.

Under the terms that govern the Oil Search NED Share Plan, in the event of a proposed change of control of Oil Search, the Oil Search Board has a discretion to determine the treatment of any unvested Oil Search NED Rights and Oil Search NED Restricted Shares and the timing of such treatment. Further, unless the Oil Search Board determines otherwise, the unvested Oil Search NED Rights will automatically vest and any restrictions on disposal of the Oil Search NED Restricted Shares will be released on a change of control. The Oil Search Board has also determined that if the Scheme becomes Effective, all 42,240 unvested Oil Search NED Restricted Shares will have any restrictions on their disposal released prior to the Record Date. This means that if the Scheme is implemented, those shares will be acquired by Santos in the ordinary course of the Scheme for the Scheme Consideration (provided they are still held by the relevant participant as at the Record Date).

The Oil Search NED Rights were issued in March 2021, Mr Lee holds 13,636 Oil Search NED Rights and Dr Kantsler holds 9,335 Oil Search NED Rights. Rather than have those Oil Search NED Rights automatically convert into Oil Search NED Restricted Shares, the Oil Search Board has determined that, if the Scheme becomes Effective, those Oil Search NED Rights will be unwound and the fees previously sacrificed will be paid to those two directors.

1) In addition to holding 12,404 ordinary shares, Ms Susan Cunningham holds 6,000 Oil Search ADRs which are equivalent to 30,000 Oil Search Shares.

9.3 Treatment of Oil Search Equity Incentives in connection with the Scheme

a) Overview of arrangements

As detailed in Oil Search's 2020 Annual Report, Oil Search offers its executives and employees participation in the Oil Search Long Term Incentive Plan under which they are awarded Oil Search Equity Incentives as an incentive, recognition of performance and to align the interests of participants with those of Oil Search Shareholders.

As at the Last Practicable Trading Date, Oil Search had the following Oil Search Equity Incentives on issue:

i) 11,534,728 unvested Oil Search Equity Incentives on issue granted under the Oil Search Long Term Incentive Plan, comprised of:
  a) 356,611 Oil Search Alignment Rights;
  b) 6,396,647 Oil Search Share Rights; and
  c) 4,781,470 Oil Search Performance Rights.

ii) 1,329,081 unvested Oil Search Restricted Shares on issue granted under the Oil Search Long Term Incentive Plan, comprised of:
  a) 476,769 Oil Search 2020 Restricted Shares; and
  b) 852,312 Oil Search 2021 Restricted Shares.

The Oil Search Equity Incentives referred to above entitle the holder to be issued one Oil Search Share for nil consideration subject to various vesting conditions. The Oil Search Long Term Incentive Plan also allows for cash settlement, instead of the incentives being satisfied by the issue of Oil Search Shares. In summary:

i) Oil Search Alignment Rights were granted in 2021 and are subject to a vesting condition of a minimum standard of performance over a three-year period including in relation to resilience (production costs), sustainability, environment, health & safety factors, regulatory compliance and leadership;

ii) Oil Search Share Rights are subject to a time-based continuity of service vesting condition;

iii) Oil Search Performance Rights comprise a 2019 grant, a 2020 grant and a 2021 grant, and are subject to the satisfaction of performance conditions within defined time restrictions related to total shareholder return and, in relation to certain grants, return on capital employed; and

iv) Oil Search 2020 Restricted Shares and Oil Search 2021 Restricted Shares are a form of short term incentive deferral award and are subject to a trading restriction until at least the first trading window following the second anniversary of the short-term incentive performance period end.

Further information about Oil Search's Long Term Incentive Plan and the Oil Search Equity Incentives can be found in announcements lodged by Oil Search with the ASX and PNGX, including in Oil Search's 2020 Remuneration Report in the 2020 Annual Report and the Notice of 2021 Annual Meeting and Proxy Form which can be obtained from Oil Search's Website, the ASX website at www.asx.com.au or the PNGX website at https://www.pngx.com.pg.

Oil Search does not have any options over any Oil Search Shares on issue as at the date of this Scheme Booklet.

b) Intended treatment of Oil Search Equity Incentives in connection with the Scheme

Under the terms that govern the Oil Search Long Term Incentive Plan, in the event of a proposed change of control of Oil Search, the Oil Search Board has discretion to accelerate the vesting of some or all of an Oil Search Long Term Incentive Plan participant's unvested Oil Search Equity Incentives. Once the discretion arises, the decision regarding the extent to which rights should vest must take into account all relevant circumstances, including whether performance is in line with any applicable performance conditions to the date of the relevant event. If the Oil Search Board does not make a determination or determines that only some of a participant's Oil Search Equity Incentives will vest, all unvested Oil Search Equity Incentives will lapse or be deemed to be forfeited.

The Oil Search Board has resolved, in accordance with the terms of the Oil Search Long Term Incentive Plan, to treat the Oil Search Equity Incentives as detailed in sections 9.3(b)(i) to 9.3(b)(iv) below.

The number of Oil Search Equity Incentives set out to vest or lapse as detailed in sections 9.3(b)(i) to 9.3(b)(iv) below are forecast for 31 December 2021 and are subject to change if the Effective Date occurs after 31 December 2021.[1] The Oil Search Board intends to apply the treatment outlined below at the Effective Date.

1) The pro-rata calculations for the treatment of Oil Search Performance Rights are of the total number of Oil Search Performance Rights granted under the 2019 Oil Search Long Term Incentive Plan, 2020 Oil Search Long Term Incentive Plan and 2021 Oil Search Long Term Incentive Plan, rather than calculated individually for each participant. Where the calculation of vested Oil Search Performance Rights for each individual participant would result in a fraction of an Oil Search Share, the number will be rounded down to the nearest whole number of Oil Search Share with fractions of 0.5 or more being rounded up.

b) Intended treatment of Oil Search Equity Incentives in connection with the Scheme continued

i) Oil Search Alignment Rights

The Oil Search Board has resolved that, subject to the Scheme becoming Effective, all 356,611 Oil Search Alignment Rights which remain outstanding at the time will vest in full (ie, any vesting conditions which remain to be satisfied on those Oil Search Alignment Rights will be waived) before the Record Date. These rights will be cash settled in accordance with the terms of the Oil Search Long Term Incentive Plan at that time.

ii) Oil Search Performance Rights

a) **2019 Oil Search Long Term Incentive Plan**

The Oil Search Board has resolved that, subject to the Scheme becoming Effective, all 1,131,826 Oil Search Performance Rights granted under the 2019 Oil Search Long Term Incentive Plan will lapse and be cancelled for no consideration.

b) **2020 Oil Search Long Term Incentive Plan**

The Oil Search Board has resolved that, subject to the Scheme becoming Effective:

1) 50% of each individual participant's Oil Search Performance Rights granted under the 2020 Oil Search Long Term Incentive Plan will lapse and be cancelled for no consideration in accordance with the terms of the Oil Search Long Term Incentive Plan; and
2) for each individual participant's remaining Oil Search Performance Rights granted under the 2020 Oil Search Long Term Incentive Plan, Oil Search will waive performance conditions for all participants and allow for time-based vesting for participants who are currently Oil Search employees (ie, the remaining proportion of 2020 Oil Search Long Term Incentive Plan Oil Search Performance Rights will vest in proportion with the percentage of the time hurdle that would have been reached on the Effective Date).[1]

This is equivalent to 524,028 of the 1,777,637 Oil Search Performance Rights granted under the 2020 Oil Search Long Term Incentive Plan converting into an equivalent number of Oil Search Shares to be cash settled in accordance with the terms of the Oil Search Long Term Incentive Plan. The remaining 1,253,609 Oil Search Performance Rights will lapse in accordance with the terms of the Oil Search Long Term Incentive Plan.

c) **2021 Oil Search Long Term Incentive Plan**

The Oil Search Board has resolved that, subject to the Scheme becoming Effective, it will waive the performance conditions and allow for time-based vesting of the 1,872,007 Oil Search Performance Rights granted under the 2021 Oil Search Long Term Incentive Plan.[1] This is equivalent to 406,529 Oil Search Performance Rights converting into an equivalent number of Oil Search Shares to be cash settled in accordance with the terms of the Oil Search Long Term Incentive Plan. The remaining 1,465,478 Oil Search Performance Rights granted under the 2021 Oil Search Long Term Incentive Plan will lapse in accordance with the terms of the Oil Search Long Term Incentive Plan.

iii) Oil Search Share Rights

The Oil Search Board has resolved that, subject to the Scheme becoming Effective, all 6,451,300 Oil Search Share Rights which remain outstanding at the time will vest in full (ie, any time-based vesting conditions which remain to be satisfied on those Oil Search Share Rights will be waived) before the Record Date and be cash settled in accordance with the terms of the Oil Search Long Term Incentive Plan.

iv) Oil Search Restricted Shares

The Oil Search Board has resolved that, subject to the Scheme becoming Effective, all 1,329,081 unvested Oil Search Restricted Shares will have any restrictions on their disposal released prior to the Record Date. This means that if the Scheme is implemented, those shares will be acquired by Santos in the ordinary course of the Scheme for the Scheme Consideration (provided they are still held by the relevant participant as at the Record Date).

9.4 Marketable securities in Santos held by, or on behalf of, Oil Search Directors

No marketable securities of Santos are held by, or on behalf of, Oil Search Directors as at the date of this Scheme Booklet.

9.5 Interests of Oil Search Directors in contracts of Santos

No Oil Search Director has an interest in any contract entered into by Santos.

9.6 Other interests of Oil Search Directors

Other than as noted in section 9.1 above and as set out in section 9.7, no Oil Search Director has any other interest, whether as a director, member or creditor of Santos or otherwise, which is material to the Scheme, other than in their capacity as a holder of Oil Search Shares, being their entitlement to receive the Scheme Consideration for the Oil Search Shares they hold.

1) For completeness, 'good leavers' under the Oil Search Long Term Incentive Plan had time-based pro-rating applied to their holdings of Oil Search Performance Rights at the time they ceased employment with Oil Search.

9.7 Agreements or arrangements with Oil Search Directors

As noted in section 9.2, two of the Oil Search Directors (being the Chairman and Non-executive Director, Mr Richard Lee, and Non-Executive Director, Dr Agu Kantsler) have previously been issued Oil Search NED Restricted Shares under the Oil Search NED Share Plan.

Other than this, there is no agreement or arrangement made between any Oil Search Director and any other person, including a member of the Oil Search Group, in connection with or conditional upon the outcome of the Scheme.

9.8 Deeds of indemnity, insurance and access

Oil Search has entered into deeds of indemnity, insurance and access with the directors of Oil Search, on customary terms. Such deeds of indemnity, insurance and access include terms that provide for each Oil Search Group Member to indemnify each of its directors against any liability incurred by such persons in their capacity as a director of the company to any person other than an Oil Search Group Member. This obligation extends for a period of seven years from the time that an individual ceases being a director.

Oil Search also pays insurance premiums for the benefit of the directors and officers of the Oil Search Group. Pursuant to clause 6.4(b) of the Merger Implementation Deed, Oil Search may prior to implementation of the Scheme, enter into an arrangement to provide insurance coverage for all current directors and officers of the Oil Search Group for a period of up to seven years from the Implementation Date. As at the date of the Scheme Booklet Oil Search has not obtained such insurance coverage.

9.9 Payments and other benefits to directors, secretaries or executive officers of Oil Search

Other than as described in this Scheme Booklet, no payment or other benefit is proposed to be made or given to a director, secretary or executive officer of Oil Search or any member of the Oil Search Group as compensation for loss of, or as consideration for or in connection with their retirement from, office in Oil Search or any member of the Oil Search Group as a result of the Scheme.

9.10 Suspension of trading of Oil Search securities

If the Court approves the Scheme, Oil Search will notify the ASX and PNGX. It is expected that suspension of trading on the ASX and PNGX in Oil Search Shares will occur from close of trading on the Effective Date. This is expected to occur on Friday, 10 December 2021.

Oil Search intends to give notice to BNY Mellon directing it to terminate the Oil Search Deposit Agreement if the Scheme becomes Effective. Oil Search ADR Holders will receive notice of termination from BNY Mellon, and the termination will be effective 90 days from the date of that notice or the date on which there are no Oil Search ADRs outstanding, whichever is earlier. If Oil Search ADR Holders have any questions, they should contact BNY Mellon at 101 Barclay Street, New York, NY 10286 United States of America or +1 888 269 2377 (within the United States of America) or +1 201 680 6825 (outside United States of America).

9.11 Deed Poll

Santos has executed the Deed Poll pursuant to which it has undertaken in favour of each Scheme Shareholder that it will observe and perform the obligations contemplated of it under the Scheme, including to procure that each Scheme Shareholder is provided the Scheme Consideration to which they are entitled to under the Scheme, in accordance with the terms of the Scheme and the Deed Poll, and subject to the Scheme becoming Effective.

A copy of the Deed Poll is contained in Annexure D.

9.12 Warranties by Scheme Shareholders

The Scheme provides that each Scheme Shareholder is deemed to have warranted to Santos, and to the extent enforceable, to have appointed and authorised Oil Search as that Scheme Shareholder's agent and attorney to warrant to Santos, that all of their Scheme Shares (including all rights and entitlements attaching to those Scheme Shares) will, at the time of the transfer of them to Santos pursuant to the Scheme, be fully paid and free from all mortgages, charges, liens, encumbrances, pledges, security interests and other interests of third parties of any kind, and restrictions on transfer of any kind, and that they have full power and capacity to sell and transfer their Scheme Shares (together with all rights and entitlements attaching to such Scheme Shares) to Santos pursuant to the Scheme, and as at the Record Date, they have no existing right to be issued any other Scheme Shares or any other form of securities in Oil Search. Oil Search undertakes in favour of each Scheme Shareholder that it will provide such warranty, to the extent enforceable, to Santos on behalf of that Scheme Shareholder.

9.13 Summary of the Merger Implementation Deed

On 10 September 2021, Oil Search and Santos entered into a binding Merger Implementation Deed under which Oil Search agreed to propose and implement the Scheme and Santos agreed to assist Oil Search to propose and implement the Scheme.

A summary of the key elements of the Merger Implementation Deed is set out below. A full copy of the Merger Implementation Deed was lodged with the ASX and PNGX on 10 September 2021 and can be obtained from Oil Search's Website, the ASX website at www.asx.com.au or the PNGX website at https://www.pngx.com.pg.

a) Conditions

Implementation of the Scheme is subject to satisfaction or waiver (where capable of waiver) of the Conditions Precedent set out in clause 3.1 of the Merger Implementation Deed. In summary, these conditions include:

i) (**Oil Search Shareholder approval**) Oil Search Shareholders approve the Scheme by the Requisite Majority;

ii) (**Court approval**) the Court approves the Scheme;

iii) (**No restraints**) at 8:00am on the Second Court Date, no court of competent jurisdiction in any part of the world or Government Agency has issued a ruling, regulation or law that prevents, makes illegal or prohibits the implementation of the Scheme;

iv) (**PNG Securities Commission**) before 8:00am on the Second Court Date, the PNG Securities Commission providing all approvals, waivers or exemptions (if required) necessary to implement the Scheme (unconditionally or subject to conditions acceptable to Santos, acting reasonably);

v) (**ICCC Clearance**) before 8:00am on the Second Court Date, the ICCC providing written confirmation that it has cleared the Scheme under section 81 of the *Independent Consumer and Commission Act 2002* (unconditionally or subject to conditions acceptable to Santos, acting reasonably);

vi) (**CFIUS Clearance)** before 8:00am on the Second Court Date, the parties obtaining from CFIUS clearance of the Transaction or confirmation from CFIUS that it will take no action on the Transaction (unconditionally or subject to conditions acceptable to Santos, acting reasonably). As at the date of this Scheme Booklet, the parties have received CFIUS clearance for the Merger;

vii) (**Other regulatory approvals**) before 8:00am on the Second Court Date, all other regulatory approvals agreed by Santos and Oil Search (each acting reasonably) necessary or desirable to implement the Merger are obtained (unconditionally or subject to conditions acceptable to Santos, acting reasonably);

viii) (**ASX approvals and waivers**) Santos obtaining a waiver from ASX Listing Rule 7.1 to the extent necessary to permit Santos to validly issue the New Santos Shares and ASX approval for the official quotation of New Santos Shares by 8:00am on the Second Court Date. As at the date of this Scheme Booklet, Santos has obtained the required waiver from the ASX from ASX Listing Rule 7.1 and confirmation that official quotation of the New Santos Shares will be granted by the ASX;

ix) (**Prescribed occurrence**) no Oil Search Prescribed Occurrence or Santos Prescribed Occurrence occurs between (and including) the date of the Merger Implementation Deed and 8:00am on the Second Court Date;

x) (**Material adverse change**) no Oil Search Material Adverse Change or Santos Material Adverse Change occurs between (and including) the date of the Merger Implementation Deed and 8:00am on the Second Court Date; and

xi) (**Regulated events**) subject to clause 3.9 of the Merger Implementation Deed, no Oil Search Regulated Event or Santos Regulated Event occurs between (and including) the date of the Merger Implementation Deed and 8:00am on the Second Court Date.

The Conditions Precedent are set out in full in clause 3.1 of the Merger Implementation Deed.

Subject to the terms of the Merger Implementation Deed, the Scheme will not proceed unless all the Conditions Precedent are satisfied (or waived, if applicable) before 10 June 2022 (or such later date as Oil Search and Santos may agree) in accordance with the Merger Implementation Deed.

b) Adjustment to Scheme Consideration if any dividends paid in calendar year 2022 in respect of calendar year 2021

If either party pays a CY21 Dividend or an Interim CY22 Dividend prior to the Implementation Date, the Scheme Consideration will be adjusted such that the number of New Santos Shares for each Scheme Share to be provided to Scheme Shareholders will be determined in accordance with the following formulas.

b) Adjustment to Scheme Consideration if any dividends paid in calendar year 2022 in respect of calendar year 2021 continued

CY21 Dividend

Adjusted Ratio #1

$$= \left(0.6275 * \left(1 + \frac{\text{Santos CY21 Dividend}}{\text{Santos Ref Price}_1 - \text{Santos CY21 Dividend}}\right)\right) - \left(\frac{\text{Oil Search CY21 Dividend}}{\text{Santos Ref Price}_1 - \text{Santos CY21 Dividend}}\right)\Bigg)$$

where:

Adjusted Ratio #1 = Number of New Santos Shares for each Scheme Share following the declaration by either party of a CY21 Dividend.

Santos Ref Price 1 = the volume weighted average share price of Santos Shares for the 10 trading days up to (but excluding) the CY21 dividend declaration date of Santos or Oil Search (whichever comes first).

Santos CY21 Dividend = the amount of any Santos CY21 Dividend declared by Santos in accordance with clause 4.7(a) of the Merger Implementation Deed (in Australian dollars per share as at the record date for the Santos CY21 Dividend).

Oil Search CY21 Dividend = the amount of any Oil Search CY21 Dividend declared by Oil Search in accordance with clause 4.7(a) of the Merger Implementation Deed (in Australian dollars per share).

Interim CY22 Dividend

Adjusted Ratio #2

$$= \left(X* \left(1 + \frac{\text{Santos Interim CY22 Dividend}}{\text{Santos Ref Price}_1 - \text{Santos Interim CY22 Dividend}}\right)\right) - \left(\frac{\text{Oil Search Interim CY22 Dividend}}{\text{Santos Ref Price}_1 - \text{Oil Search Interim CY22 Dividend}}\right)\Bigg)$$

where:

X = Adjustment Ratio 1 (if there has been a Santos or Oil Search CY21 Dividend declared and paid) or 0.6275 otherwise.

Adjusted Ratio #2 = Number of New Santos Shares for each Scheme Share following the declaration by either party of an Interim CY22 Dividend.

Santos Ref Price 1 = the volume weighted average share price of Santos Shares for the 10 trading days up to (but excluding) the Interim CY22 Dividend declaration date of Santos or Oil Search (whichever comes first).

Santos Interim CY22 Dividend = the amount of any Santos Interim CY22 Dividend declared by Santos accordance with clause 4.7(a) of the Merger Implementation Deed (in Australian dollars per share as at the record date for the Santos Interim CY22 Dividend).

Oil Search Interim CY22 Dividend = the amount of any Oil Search Interim CY22 Dividend declared by Oil Search in accordance with clause 4.7(a) of the Merger Implementation Deed (in Australian dollars per share).

c) Oil Search Board recommendation

Oil Search must procure that:

i) the Oil Search Board unanimously recommends to Oil Search Shareholders that they vote in favour of the Scheme (the **Recommendation**);

ii) each Oil Search Director will vote the voting rights attached to all Oil Search Shares over which he or she has control in favour of any Oil Search Shareholder resolutions to implement the Scheme and any related or ancillary transactions (the **Voting Statement**);

iii) Oil Search and Santos must include the Recommendation and Voting Statement in the ASX and PNGX (as applicable) announcements to be issued following execution of the Merger Implementation Deed and any subsequent public announcement made to the ASX and PNGX (as applicable) in relation to the Transaction;

iv) each director of Oil Search does not:
   a) adversely change, withdraw or adversely modify or qualify the Recommendation or Voting Statement; or
   b) support or endorse a Competing Proposal in respect of Oil Search or recommend that Oil Search Shareholders accept or vote in favour of a Competing Proposal in respect of Oil Search;

v) this Scheme Booklet includes a statement by the directors of Oil Search to the effect that each such director of Oil Search:
   a) recommends to Oil Search Shareholders that they vote in favour of the Scheme; and
   b) will vote (or procure the voting of) all Oil Search Shares held or controlled by him or her in favour of the Scheme at the Scheme Meeting,

in each case other than,

vi) if the Independent Expert concludes in the Independent Expert's Report (or any update of, or any revision, amendment or supplement to, that report) that the Merger is not in the best interests of Scheme Shareholders;

vii) if Oil Search has received a Competing Proposal which is a Superior Proposal;

c) Oil Search Board recommendation continued

viii) in response to a requirement from the court or a Government Agency that any director of Oil Search abstain from making his or her Recommendation; or

ix) where a Government Agency imposes a condition in connection with the grant of a regulatory approval the subject of a Condition Precedent and the Oil Search Board has determined, acting in good faith, that failing to withdraw, adversely change, modify or qualify their Recommendation or Voting Statement directly as a result of the imposing of such condition constitutes a breach of the fiduciary or statutory duties of the Oil Search Board.

d) Exclusivity

The Merger Implementation Deed contains reciprocal exclusivity arrangements in favour of both Oil Search and Santos. These obligations may be summarised as follows.

i) (**No Current discussions regarding a Competing Proposal**) Each of Oil Search and Santos represents and warrants to the other that, as at the time of execution of the Merger Implementation Deed, it is not in any negotiations or discussions in respect of any Competing Proposal in respect of that party with any person.

ii) (**No Shop**) Each party must not, and must ensure that each of its Representatives does not, solicit, invite, encourage or initiate (including by the provision of non-public information to any Third Party) any actual, proposed or potential Competing Proposal in respect of that party (or any approach, discussion or inquiry which could reasonably be expected to lead to the same) or communicate to any person an intention to do any of those things.

iii) (**No Talk**) Each party must not, and must ensure that each of its Representatives does not:

a) facilitate, participate in or continue any negotiations or discussions, or enter into any agreement or understanding with any Third Party in relation to any actual, proposed or potential Competing Proposal in respect of that party;

b) negotiate, accept or enter into, or offer or agree to negotiate, accept or enter into, any agreement, arrangement or understanding regarding any actual, proposed or potential Competing Proposal in respect of that party; or

c) communicate to any person an intention to do any of those things.

iv) (**No Due Diligence**) Each party must not, and must ensure that each of its Representatives does not, disclose or otherwise provide or make available any non-public information about the business or affairs of it or any of its Controlled Entities to a Third Party in connection with, with a view to obtaining, or which would reasonably be expected to encourage or lead to the formulation, development, finalisation, receipt or announcement of any actual, proposed or potential Competing Proposal in respect of that party whether by that Third Party or another person or communicate to any person an intention to do any of those things.

v) (**Notification**) Each party must as soon as reasonably practicable (and in any event within 24 hours) notify the other party in writing if it, or any of its Representatives:

a) has received any actual, proposed or potential Competing Proposal in respect of that party, or any approach or inquiry which could reasonably be expected to lead to any actual, proposed or potential Competing Proposal in respect of that party; or

b) any request made by a Third Party for, or provision to a Third Party of, any non-public information in connection with such Third Party formulating, developing or finalising, or assisting in the formation, development or finalisation of, any actual, proposed or potential Competing Proposal in respect of that party,

whether direct or indirect, solicited or unsolicited, and in writing or otherwise (each, a **Notifiable Proposal**). Such notice must include all material terms and conditions of the Notifiable Proposal and the identity of the Third Party making the Competing Proposal.

vi) (**Santos matching right**) Before Oil Search or any Oil Search Group Member enter:

a) into any definitive agreement pursuant to give effect to an actual, proposed or potential Competing Proposal; and

b) any Oil Search Director:

1) withdraws or adversely changes, modifies or qualifies their Recommendation or Voting Statement;

2) supports or endorses a Competing Proposal in respect of Oil Search; or

3) recommends that Oil Search Shareholders accept or vote in favour of a Competing Proposal in respect of Oil Search,

the following conditions must be satisfied:

c) the Oil Search Board acting in good faith and in order to satisfy what the Oil Search Board consider to be their statutory or fiduciary duties determines that the actual, proposed or potential Competing Proposal is, would be or would be reasonably likely to be, a Superior Proposal;

d) Oil Search has provided Santos with the material details of the actual, proposed or potential Competing Proposal;

e) Oil Search has given Santos at least five Business Days from the date Oil Search notifies Santos for the purposes of Santos' matching right to provide a matching or superior proposal to the terms of the actual, proposed or potential Competing Proposal (**Santos Counterproposal**); and

d) Exclusivity continued

f) Santos has not provided to Oil Search a matching or superior proposal to the terms of the actual, proposed or potential Competing Proposal within 5 Business Days.

If Santos submits a Santos Counterproposal to Oil Search within five Business Days, Oil Search must use reasonable endeavours to procure that the Oil Search Board considers the Santos Counterproposal. If the Oil Search Board determines that the Santos Counterproposal would provide an equivalent or superior outcome for Oil Search Shareholders, then:

a) Oil Search and Santos must use their best endeavours to agree the amendments to the Merger Implementation Deed, the Scheme and the Deed Poll (as applicable) that are reasonably necessary to give effect to and implement the Santos Counterproposal; and

b) Oil Search must procure that each Oil Search Director continues to recommend the Transaction (as modified by the Santos Counterproposal) to Oil Search Shareholders.

However, each of Oil Search and Santos is not required to comply with its obligations under the 'No Talk' and 'No Due Diligence' provisions in the Merger Implementation Deed in relation to a bona fide actual, proposed or potential Competing Proposal in respect of that party if the Oil Search Board or Santos Board (as applicable), acting in good faith, has determined:

a) after consultation with its financial advisers and external legal advisers, that such Competing Proposal is, or may reasonably be expected to lead to a Superior Proposal; and

b) after receiving written legal advice from its external legal advisers, that compliance with those clauses would, or would be reasonably likely to, constitute a breach of any of the fiduciary or statutory duties of the directors of Oil Search or Santos (as applicable).

e) Break Fee payable to Santos

Oil Search has agreed to pay Santos a Break Fee of A$80 million if certain specified events occur, including:

i) (**Change in recommendation**) at any time before the Merger Implementation Deed is terminated, any Oil Search Director:

a) fails to make the Recommendation or Voting Statement;

b) withdraws or adversely changes, modifies or qualifies their Recommendation or Voting Statement; or

c) supports or endorses a Competing Proposal in respect of Oil Search or recommends that Oil Search Shareholders accept or vote in favour of a Competing Proposal in respect of Oil Search,

unless:

d) the Independent Expert concludes in the Independent Expert's Report (or any update of, or revision, amendment or supplement to, that report) that the Merger is not in the best interests of Oil Search Shareholders (except where the reason for that conclusion is the announcement of a Competing Proposal in respect of Oil Search);

e) if any director of Oil Search withdraws or adversely changes, modifies or qualifies their Recommendation or Voting Statement, where this is directly as a result of a Government Agency imposing a condition in connection with the grant of a regulatory approval the subject of a Condition Precedent and the Oil Search Board has determined, acting in good faith, that failing to withdraw, adversely change, modify or qualify their Recommendation or Voting Statement constitutes a breach of the fiduciary or statutory duties of the Oil Search Board; or

f) Oil Search is (or would have been) entitled to terminate the Merger Implementation Deed for material breach by Santos;

ii) (**Competing Proposal announced and transaction subsequently completed**) at any time before the Merger Implementation Deed is terminated, a Competing Proposal in respect of Oil Search is announced by a Third Party (whether or not such proposal is stated to be subject to pre-conditions) and, within 12 months after that occurring, the Third Party or an associate of the Third Party completes in all material respects a Competing Proposal in relation to Oil Search; or

iii) (**Material breach**) Santos validly terminates the Merger Implementation Deed for material breach by Oil Search.

Except in relation to a wilful or intentional breach by Oil Search of the Merger Implementation Deed, Oil Search's liability to Santos under the Merger Implementation Deed is capped at the amount of the Break Fee.

f) Break Fee payable to Oil Search

Santos has agreed to pay Oil Search a Break Fee of A$80 million if certain specified events occur, including:

i) (**Superior Proposal in respect of Santos**) at any time before the Merger Implementation Deed, a Superior Proposal in respect of Santos is received or announced and:

a) the Superior Proposal requires as a condition, that the Scheme not be implemented; and

b) any Santos director makes a public statement that they no longer support the Transaction and recommend such Superior Proposal, unless Santos is entitled to terminate the Merger Implementation Deed for material breach by Oil Search; or

ii) (**Material breach**) Oil Search validly terminates the Merger Implementation Deed for a material breach of the Merger Implementation Deed by Santos.

Except in relation to a wilful or intentional breach by Santos of the Merger Implementation Deed, Santos' liability to Oil Search under the Merger Implementation Deed is capped at the amount of the Break Fee.

g) Termination rights

Broadly, each of Oil Search or Santos may terminate the Merger Implementation Deed by written notice to the other party if:

i) at any time before 8:00am on the Second Court Date if the other party is in material breach of any provision of the Merger Implementation Deed (including a representation and warranty given by either Oil Search or Santos where such breach is material in the context of the Transaction as a whole) and the relevant circumstances continue to exist for five Business Days from the time of the non-breaching party's written notice of intention to terminate is given;

ii) in certain circumstances where:

   a) within the earlier of five Business Days after the date on which a consultation notice is given in accordance with clause 3.4(b) of the Merger Implementation Deed, unless the relevant occurrence or the failure of the Condition Precedent to be satisfied, or the failure of the Scheme to become Effective, arises out of a breach by the terminating party of the Merger Implementation Deed or the relevant Condition Precedent for the sole benefit of the other party;

   b) if at any time before the End Date (being the date that is nine months after the date of the Merger Implementation Deed or such later date as Oil Search and Santos may agree in writing), after consulting in good faith, Oil Search and Santos agree that any Condition Precedent is unable to be satisfied before the End Date; or

iii) if the Effective Date for the Scheme has not occurred, or will not occur, on or before the End Date other than as a result of any breach of the Merger Implementation Deed by the party purporting to terminate.

Broadly, Santos may terminate the Merger Implementation Deed by written notice to Oil Search at any time before 8:00am on the Second Court Date, if:

iv) any Oil Search Director fails to make the Recommendation or Voting Statement, or adversely changes, withdraws or adversely modifies or qualifies their Recommendation or Voting Statement, or supports or endorses a Competing Proposal in respect of Oil Search or recommends that Oil Search Shareholders accept or vote in favour of a Competing Proposal in respect of Oil Search;

v) an Oil Search Group Member accepts or enters into a definitive agreement, arrangement or understanding to undertake or implement or otherwise give effect to an actual, proposed or potential Competing Proposal; or

vi) a Superior Proposal in respect of Santos is received or announced and the Superior Proposal requires as a condition, that the Scheme not be implemented and a majority of Santos Directors make a public statement that they no longer support the Transaction and recommend such Superior Proposal, and if required to do so under the Merger Implementation Deed, Santos has paid the Break Free to Oil Search.

Broadly, Oil Search may terminate the Merger Implementation Deed by written notice to Santos at any time before 8:00am on the Second Court Date, if:

i) a majority of Oil Search Directors fails to make the Recommendation or Voting Statement, or adversely changes, withdraws or adversely modifies or qualifies their Recommendation or Voting Statement, or supports or endorses a Competing Proposal in respect of Oil Search or recommends that Oil Search Shareholders accept or vote in favour of a Competing Proposal in respect of Oil Search, and if required to do so under the Merger Implementation Deed, Oil Search has paid the Break Fee to Santos; or

ii) a Superior Proposal in respect of Santos is announced and the Superior Proposal requires as a condition, that the Scheme not be implemented and any Santos Director makes a public statement that they no longer support the Transaction and recommend such Superior Proposal.

The Merger Implementation Deed will terminate automatically if, at the Scheme Meeting, Oil Search Shareholders do not pass the Scheme Resolution.

9.14 Status of Conditions Precedent

As at the date of this Scheme Booklet, Oil Search is not aware of anything that would cause the Conditions Precedent not to be satisfied.

As at the date of this Scheme Booklet, Santos is not aware of anything that would cause the Conditions Precedent not to be satisfied.

A summary of the status of certain regulatory applications which are Conditions Precedent is provided below. An update on the status of the Conditions Precedent will be provided at the Scheme Meeting.

While Oil Search is not aware of any circumstances which would cause the regulatory conditions and relief outlined in section 9.15 not to be satisfied or provided as at the date of this Scheme Booklet, it is possible that the requirement for approval from PNG Securities Commission, ICCC or CFIUS for the Scheme to proceed may be delayed and that this may result in a delay to the date of the Scheme Meeting. All Conditions Precedent must be satisfied or waived in order for the Scheme to proceed.

9.15 Regulatory conditions and relief

a) ASX waivers

ASX has granted Santos a waiver from ASX Listing Rule 7.1 to permit Santos to issue New Santos Shares under the Scheme without obtaining the approval of Santos Shareholders.

b) ASX application for quotation of New Santos Shares

ASX has confirmed to Santos that official quotation of the New Santos Shares will be granted by the ASX, subject to Santos complying with the ASX Listing Rules (including lodging an Appendix 2A and Appendix 3B).

c) ASIC relief

ASIC has granted the following relief:

i) an exemption from section 911A(1) of the Australian Corporations Act exempting Santos and Oil Search from the requirement to hold an Australian financial services licence for the provision or giving of financial product advice in the Scheme Booklet;

ii) an exemption from the requirements in Division 5A of Part 7.9 of the Australian Corporations Act, in relation to offers to purchase Oil Search Shares in connection with the Scheme; and

iii) an exemption from and declarations in relation to Parts 6D.2 and 6D.3 of the Australian Corporations Act, allowing Santos to issue New Santos Shares to Scheme Shareholders under the Scheme without a prospectus and allowing the on-sale of the New Santos Shares (including those issued to the Sale Agent) within the first 12 months after the Scheme without further disclosure requirements.

d) PNG Securities Commission exemptions

Santos has sought the following exemptions and confirmations from the PNG Securities Commission:

i) exemption from compliance with the operation of section 278 of the PNG Capital Market Act relating to the operation of the Papua New Guinea Take-Overs and Mergers Code as there is currently no such code in effect under section 277 of the PNG Capital Market Act;

ii) exemption from the compliance with the operation of section 138 of the PNG Capital Market Act to permit Scheme Shareholders who are issued New Santos Shares to on-sell those New Santos Shares without the need for Santos to comply with the prospectus style disclosure obligations in the PNG Capital Market Act that would otherwise apply;

iii) confirmation that it will not take any action under section 116(5) of the PNG Capital Market Act to require further approvals in relation to the implementation of the Merger; and

iv) confirmation under section 277(6) of the PNG Capital Market Act confirms that it has no objection to the Merger on the grounds that it is contrary to the national interest of PNG and that it does not propose to issue any restraining orders.

e) ICCC

Santos has filed a submission to seek clearance under section 81 of the Independent *Consumer and Competition Commission Act 2002* (**ICCC Act**) from the ICCC.

f) CFIUS

CFIUS provided Santos and Oil Search clearance for the Transaction under the *Defence Production Act of 1950* (as amended) and confirmation that there are no unresolved national security concerns related to the implementation of the Scheme.

9.16 Foreign selling restrictions

No action has been taken to register or qualify the New Santos Shares or otherwise permit a public offer of such securities in any jurisdiction outside Australia and PNG.

Based on the information available to Oil Search, Scheme Shareholders whose addresses are shown in the Oil Search Share Register on the Record Date as being in the following jurisdictions will be entitled to have New Santos Shares issued to them under the Scheme subject to any qualifications set out below in respect of that jurisdiction:

- PNG;
- Australia;
- Hong Kong;
- Ireland, where (i) the Oil Search shareholder is a "qualified investor" (as defined in Article 2(e) of the Prospectus Regulation) or (ii) the number of other Oil Search shareholders is less than 150;
- Malaysia;
- New Zealand;
- Singapore;
- United Kingdom;
- United States of America; and
- any other jurisdiction in respect of which Santos is satisfied that the laws of that place permit the allotment and issue of New Santos Shares to a Scheme Shareholder whose address shown in the Oil Search Share Register is in that place under the Scheme, either unconditionally or after compliance with conditions that Santos regards as acceptable and not unduly onerous or impracticable.

Nominees, custodians and other Scheme Shareholders who hold Oil Search Shares on behalf of a beneficial owner resident outside PNG; Australia, Hong Kong, Malaysia, New Zealand, Singapore and the United Kingdom and United States of America may not forward this Scheme Booklet (or any accompanying document) to anyone without the consent of Oil Search, except to "qualified investors" in Ireland.

9.17 Comparison of corporations regulation (other than takeovers regulation) in PNG and Australia

While the regime in Australia in relation to the regulation of corporations is generally similar to the equivalent regime in PNG, there are some differences (for example, the Australian regime is generally more detailed). Some of the key elements of corporations regulation are summarised in the table below. Notably, part of the relevant regulatory regime that applies to Oil Search are the ASX Listing Rules, as Oil Search has a primary listing on the ASX. Similarly, Santos also has a primary listing on the ASX and therefore these same protections will continue to apply in relation to New Santos Shares issued as Scheme Consideration.

The comparison below is not an exhaustive statement of all relevant laws, rules and regulations and is intended as a general guide only. Oil Search Shareholders should consult with their own legal adviser if they require further information. Oil Search Shareholders should also note that the relevant laws, rules and regulations below are current as at the date of this Scheme Booklet, but are subject to change.

Note that a comparison of takeovers regulation to which the acquisition of shares in Oil Search is subject as a PNG incorporated company, and the takeovers regulation to which the acquisition of shares in Santos is subject as an Australian incorporated company, is set out in section 9.18.

	Australia	**PNG**
Source of corporate regulation	The Australian Corporations Act, and the Australian Corporations Regulations, are the core of regulation of companies in Australia.	Corporations are regulated by the PNG Companies Act, the issue of any dealings in securities of corporations are regulated by the PNG Capital Market Act, and both companies and the issue of and dealing in securities are regulated by the underlying law of PNG.
Regulatory supervision of corporations	The relevant regulatory agency in Australia is ASIC, which administers the Australian Corporations Act and has broad supervisory powers over corporations and dealings in securities.	The relevant regulatory agency in PNG is the PNG Registrar of Companies (which administers the PNG Companies Act) and the PNG Securities Commission (which administers the PNG Capital Market Act and the *Securities Commission Act 2015* (PNG)).
Calling shareholder meetings	Directors of a company must call a meeting within 21 days after a request is given to the company by members with at least 5% of the votes that may be cast at the general meeting or at least 100 members who are entitled to vote at the general meeting.	The PNG Companies Act provides that shareholders with at least 5% voting rights may require the board to call a special meeting. The required notice period to shareholders to call a general meeting is 14 days.
Voting requirements	Unless required by the Australian Corporations Act or a company's constitution, resolutions of a company generally require a simple majority of votes cast on the resolution. The Australian Corporations Act requires certain matters to be resolved by special resolution, (which requires 75% of the votes cast on the resolution), including: – adoption of a constitution after the registration of the company; – change of company name; – change of company type; – variation of rights attached to shares in a class of shares where a company does not have a constitution, or has a constitution that does not set out the procedure for varying those rights; – a selective capital reduction; – a selective buy-back of shares; and – the giving of financial assistance by a company for the acquisition of its shares. Where the company directors have exceeded their powers in the conduct of the company's affairs, the shareholders may resolve to approve the conduct (approval by ordinary resolution is required in less serious circumstances and unanimous assent of all shareholders is required in more serious circumstances).	As a general rule, the PNG Companies Act provides that power reserved to shareholders is to be exercised by ordinary resolution, which is a simple majority of those shareholders entitled to vote. For certain matters voting on the question is by special resolution (which is a majority of 75% of votes cast on the resolution – unless a company's constitution requires a higher majority) including: – the adoption, alteration or revocation of a company's constitution; – a Major Transaction (see below); – change of company name; – an amalgamation of a company under the PNG Companies Act (other than by scheme of arrangement); and – the placement of a company into liquidation.

9 Additional Information

	Australia	PNG
Major transactions	Shareholders are not required to vote on a major transaction entered into by the company unless, if the company is listed, there is a significant change to the nature or scale of that company's activities or the transaction is with a 'person of influence' (in which case, approval by ordinary resolution of shareholders may be required under the ASX Listing Rules) or if the significant change involves the company disposing of its main undertaking (in which case, approval by ordinary resolution of shareholders is required).	Shareholders are required to vote on 'Major Transactions' (which are broadly defined under the PNG Companies Act to include an acquisition, disposal or other transaction with a value that is more than half the value of the assets of the company), which require approval by special resolution of shareholders (being a resolution approved by a majority of 75% or more of shares voted).
Appraisal rights	Shareholders who vote against a transaction which requires approval of shareholders have no statutory right to have their shares acquired by the company.	Where shareholders have approved a Major Transaction (as described above) or an amalgamation transaction (under which two or more PNG companies are merged), a shareholder who has voted all its shares against that resolution has a right to require the company to purchase all that person's shares at a fair and reasonable price (as agreed between the parties or determined by the National Court of PNG).
Shareholder proceedings	Shareholders of a company may bring an action in cases where the conduct of the company's affairs, an act or a resolution, is contrary to the interests of shareholders as a whole, or oppressive to, unfairly prejudicial to, or unfairly discriminatory against, any shareholder or shareholders, whether in their capacity as a shareholder or any other capacity. Shareholders or former shareholders may also bring an action on behalf of the company if permission is given by the court. Such permission is likely to be granted where the court is satisfied that: – the company will not itself bring the proceedings or properly take responsibility for such actions; – the applicant is acting in good faith; – it is in the best interests of the company that the applicant be granted leave or given permission; – there is a serious question to be tried; and – either at least 14 days before making application, the applicant gave notice to the company of its intention to apply for leave and of its reasons, or it is appropriate to grant leave.	Shareholders or former shareholders may bring an action against a director for breach of a duty owed to that person as a shareholder, but may not recover any loss relating to the value of shares by reason only of a loss suffered or a gain forgone by the company. Shareholders or former shareholders of a company may also bring an action if they consider the affairs of the company have been, or are being, or are likely to be, conducted in a manner that is, or is likely to be, oppressive, unfairly discriminatory, or unfairly prejudicial to them as shareholders or in any other capacity. A shareholder or director of a company may bring an action on behalf of the company or may intervene in action to which the company is a party for the purposes of continuing, defending or discontinuing the proceedings if leave is granted by the court. In determining whether to grant leave, the court must have regard to: – the likelihood of the proceedings succeeding; – the costs of the proceedings in relation to the relief likely to be obtained; – any action already taken by the company to obtain the relief; and – the interests of the company in the proceedings. Leave may be granted only where the court is satisfied that either: – the company does not intend to bring, diligently continue or defend, or discontinue the proceedings; or – it is in the interests of the company that the conduct of the proceedings should not be left to the directors or to the determination of shareholders as a whole.

9 Additional Information

	Australia	PNG
Dividends	Australian companies are not limited by law to paying dividends from the profits of the company – they can pay any amount as a dividend, provided the company has a sufficient surplus of assets over liabilities, the payment is fair and reasonable to the shareholders as a whole and the payment does not prejudice the company's ability to pay its creditors.	The board of directors of a company must authorise the making of all dividends and other distributions to shareholders. Directors need to be satisfied that the company is solvent immediately following the making of dividends or distributions. The board of a company must not authorise a dividend: – in respect of some but not all the shares in a class; or – that is of a greater value per share in respect of some shares of a class than it is in respect of other shares of that class, unless the amount of the dividend in respect of a share of that class is in proportion to the amount paid to the company in satisfaction of the liability of the shareholder under the constitution of the company or under the terms of issue of the share.
Directors' duties	Directors (and other statutory officers) in Australia have duties imposed upon them by the Australian Corporations Act, the common law and particular statutes. Broadly, these duties include to: – act in the good faith and for a proper purpose; – act in the best interests of the company; – to act with the care and diligence of a reasonable person; – to avoid conflicts of interest; – to disclose any material personal interest; – to not improperly use position; – to not improperly use information; – to prevent insolvent trading; and – duties around financial reporting and disclosure.	Pursuant to the PNG Companies Act and applicable common law, directors of the company are subject to substantially similar duties to those under Australian law.
Remuneration of directors and officers	Under the ASX Listing Rules, the maximum amount to be paid to directors for their services as directors (other than the salary of an executive director) is not to exceed the amount approved by shareholders at a general meeting. Shareholders of listed companies have the right under the Australian Corporations Act to participate in a non-binding vote, to be held at an annual general meeting, on the adoption of the remuneration report of a company. The remuneration report is included in the directors' report and is required to contain a discussion of the board of directors' policy in relation to remuneration of key management personnel of the company.	The PNGX Listing Rules contain substantially the same restrictions on payments to directors as the ASX Listing Rules. Under the PNG Companies Act, shareholders have a general right to pass a resolution at a meeting relating to the management of the company, which would extend to the remuneration of directors and officers. That resolution is not binding on the board of the company unless the company's constitution provides otherwise. Pursuant to the PNG Companies Act, if shareholders unanimously agree to an action that is or has been taken by the company, such action is deemed to be validly authorised by the company notwithstanding any provisions of the company's constitution. In addition, certain prescribed provisions of the PNG Companies Act will not apply in relation to that action including provisions of the PNG Companies Act regarding payments to directors, such as remuneration.

9 Additional Information

	Australia	PNG
Directors' declarations of interest	A director who has a material personal interest in a matter that relates to the affairs of the company may be required under the Australian Corporations Act to give the other directors notice of that interest. That director must not be present at a meeting where the matter is being considered or vote on the matter unless the other directors or ASIC approve, or the matter is not one which requires disclosure under the Australian Corporations Act. The failure of a director to disclose a material personal interest, or voting despite a material personal interest, does not affect the validity of any act in which the director has an interest.	A director of a company is 'interested in a transaction' to which the company is a party if that director may derive a material financial benefit from the transaction, has a material financial interest in, or is a director, officer or trustee of a party to the transaction, is the parent, child or spouse of another party to the transaction, or is otherwise directly or indirectly materially interested in that transaction. The director must give notice of the interest to the company and the other directors but may vote on the transaction if permitted by the constitution. The failure of a director to disclose their interest in a transaction does not affect the validity of a transaction entered into by the company or the director. The transaction may be avoided by the company within three months of disclosure to shareholders unless the company receives fair value from the transaction.
Related party transactions	A public company is prohibited under the Australian Corporations Act from giving a related party (which includes any entity which controls that company, a director of that company, directors of any entity which controls that company and, in each case, spouses and certain relatives of such persons) a financial benefit, unless it obtains the approval of shareholders and gives the benefit within 15 months after approval. If the giving of the benefit is required by a contract and the making of the contract was approved by the members as a financial benefit given to a related party, the benefit need not be given within 15 months after the approval of members if the contract was made within 15 months after the approval or, before that approval, if the contract was conditional on the approval being obtained. The ASX Listing Rules prohibit a listed company from acquiring a substantial asset (an asset the value of or consideration for which is 5% or more of the entity's equity interests) from, or disposing of a substantial asset to, certain related parties of the company, unless it obtains the approval of shareholders. The related parties include a director, a person who has or has had in the prior six month period an interest in 10% or more of the shares in the company and, in each case, any of their associates. The provisions apply even where the transaction may be on arm's length terms. The ASX Listing Rules also prohibit a listed company from issuing, or agreeing to issue, shares to a director or a related party unless it obtains the approval of shareholders or the share issue is one of the specified exceptions set out in ASX Listing Rule 7.2.	The PNG Companies Act does not contain such restrictions, except to the extent contained in the 'interested director' provisions described above. The PNGX Listing Rules contain substantially the same restrictions on related party transactions as the ASX Listing Rules, except that the approval required for an issue of securities to a related party under the PNGX Listing Rules must be made by special resolution. However, in the event of liquidation, there is specific provision which allows the liquidator to recover an amount from a related company or party to the extent that the company has paid an excessive amount for or disposed of for, an inadequate amount, any business property or services, within five years before the commencement of the liquidation.
Issue of new shares	Subject to specified exceptions set out in ASX Listing Rule 7.2, the ASX Listing Rules set an aggregate limit on the number of equity securities an entity can issue over any 12 month period without shareholder approval broadly equivalent to 15% of its fully paid ordinary issued capital. Up to that limit, and subject to this power being exercised in a manner that is consistent with the ASX Listing Rules, the entity is free to issue equity securities at whatever price and whatever terms its board considers appropriate. Once that limit is reached, the holders of the entity's ordinary securities must approve the issue.	The PNGX Listing Rules contain substantially the same restrictions as the ASX Listing Rules.

9 Additional Information

	Australia	PNG
Winding up	Under the Australian Corporations Act, an insolvent company may be wound up by a liquidator appointed by either creditors or the court. Directors cannot use their powers after a liquidator has been appointed. If there are funds left over after payment of the costs of the liquidation, and payment to other priority creditors, including employees, the liquidator will pay these to unsecured creditors as a dividend. The shareholders rank behind the creditors and are, therefore, unlikely to receive any dividend in an insolvent liquidation. Under the Australian Corporations Act, shareholders of a solvent company may decide to wind up the company if the directors are able to form the view that the company will be able to pay its debts in full within 12 months after the commencement of the winding up. A meeting at which a decision is made to wind up a solvent company requires at least 75% of votes cast by the shareholders present and voting.	Under the PNG Companies Act, a company may be put into liquidation by appointing a person as liquidator. A liquidator may be appointed by a special resolution of shareholders, on the occurrence of an event specified in the constitution, or by the Court on application of the company, a director or shareholder, other entitled person, a creditor or the PNG Registrar of Companies. The Court has a discretion to appoint a liquidator where it is satisfied that: – the company is unable to pay its debts when they fall due; – the company or the board has persistently or seriously failed to comply with the PNG Companies Act; – the company no longer complies with the essential requirements for being a company under the PNG Companies Act, such as having one or more shareholders or one or more directors; or – it is just and equitable that the company be put in liquidation. The PNG Companies Act contains provisions equivalent to those in the Australian Corporations Act regarding payment of creditors' claims and returns of any surplus to shareholders.

9.18 Comparison of Australian and PNG Takeover Regulation

The takeovers regulation which applies to the acquisition of shares in Oil Search as a PNG incorporated company, and the takeovers regulation which applies to the acquisition of shares in Santos (and therefore any future acquisition of shares in the Merged Group) as an Australian incorporated company, is materially different.

At present, there is no Takeovers Code applying to the acquisition of shares in Oil Search. While the PNG Capital Market Act provides for the adoption of a Takeovers Code, no such code has been adopted since the commencement of that Act. This means that while a person seeking to acquire control of Oil Search as a PNG company must obtain certain approvals from the PNG Securities Commission, there is no requirement (as there is for an Australian company under Australian takeover laws) for that person to make an offer to all shareholders on the same terms and conditions.

The PNG Securities Commission has the power to issue rulings on the practice and conduct of persons involved in or affected by any takeover offer, merger or compulsory acquisition including to prescribe that an offer to all shareholders must be on the same terms and conditions. However, as at the date of this Scheme Booklet, the PNG Securities Commission has not issued any ruling regulating takeover offers or mergers.

In contrast, the acquisition of shares in an Australian company such as Santos is subject to extensive regulation under a combination of the Australian Corporations Act, Australian Corporations Regulations, policies published by ASIC and guidance published by the Australian Takeovers Panel, with the objective of ensuring that:

- the acquisition of control of a company such as Santos takes place in an efficient, competitive and informed market;
- shareholders have a reasonable time to consider a proposed acquisition and are given enough information to enable them to assess the merits of the proposal;
- shareholders have an equal opportunity to participate in the benefits of a change of control of a company; and
- an appropriate procedure is followed prior to compulsory acquisition of the entity's securities under the Australian Corporations Act.

Under those provisions, a person cannot acquire a 'relevant interest' in voting securities of an Australian listed company if that would result in any person's 'voting power' exceeding 20%, except via a specified exception (such as a takeover bid or scheme of arrangement) (the **20% rule**). The concept of 'relevant interest' is extremely broad, covering almost all situations where a person has direct or indirect control over the voting or disposal of a security. A person's 'voting power' in an entity is the aggregate of that person's 'relevant interests' in voting securities and the 'relevant interests' of that person's associates, expressed as a percentage of all issued voting securities. The concept of 'association' seeks to ascertain all persons who should be considered as belonging to a single security holding bloc in relation to an entity. It covers all entities within the same corporate group, and persons who are deemed to be working together for the purpose of influencing the composition of the relevant entity's board of directors or its management, or working together in relation to the relevant entity's affairs.

There are various exceptions to the 20% rule. These exceptions include acquisitions of relevant interests under a takeover bid, under a scheme of arrangement, with target shareholder approval, under a creep acquisition (ie, 3% every six months), under a downstream acquisition (ie, acquisitions of shares in listed entities which hold shares in a target), under a rights issue, or as a result of exercising a security interest.

9 Additional Information

a) Takeover bids

A takeover bid involves the making of individual offers to purchase target securities at a specified bid price (which can be cash, securities such as shares, or a combination of both). There are two types of takeover bid: an off-market bid and a market bid. Virtually all takeover bids are off-market bids because of the ability to include conditions. Takeover bids are subject to the following key rules that:

i) all offers must be the same;

ii) the bid price cannot be lower than the price which the bidder paid for a target security within the previous four months;

iii) the offer period to be no less than one month and no more than 12 months;

iv) the bidder must issue a 'bidder's statement' containing the offer terms and all information known to the bidder which is material to a decision by a target securityholder whether or not to accept the offer. It is also required to contain a range of statutory disclosures, including:

   a) a statement of the bidder's intentions regarding the continuation of and any major changes to be made to the target's business, and the future employment of present employees;

   b) where cash is offered as consideration, the funding sources of that cash; and

   c) where securities are offered as consideration, information to prospectus disclosure standard regarding the assets, liabilities, profits and prospects of the issuer and particulars of the securities being offered;

v) the target must issue a 'target's statement' containing the target board's recommendation and all information known to any target director that target shareholders and their professional advisers would reasonably require to make an informed assessment whether to accept the bid; and

vi) the bidder is entitled to compulsory acquisition of remaining shares (on the same terms as proposed under the takeover offer) if it obtains a relevant interest in at least 90% of the target securities (and has acquired at least 75% of the securities it offered to acquire).

b) Schemes of arrangement

A members scheme of arrangement is usually used for an acquisition of a company where the proposal is recommended by the company's directors and is frequently used to effect 100% acquisitions. A scheme of arrangement is a shareholder and court-approved statutory arrangement between a company and its shareholders that becomes binding on all shareholders by operation of law. It is a process similar to the that proposed by the Merger which is described in this Scheme Booklet.

An Australian scheme of arrangement for companies usually involves:

i) execution of a scheme implementation agreement between the bidder and the target (which commonly contains terms similar to those in the Merger Implementation Deed);

ii) the preparation by the target, with input from the bidder, of a draft 'scheme booklet' (similar to this Scheme Booklet) which is given to ASIC for review;

iii) the target seeking court approval for the despatch of the scheme booklet to target shareholders and court orders for the convening of the shareholders' meeting to vote on the scheme (ie, the scheme meeting);

iv) the target holding the scheme meeting (at which each class of shareholders whose shares are to be acquired under the scheme must vote to approve the scheme by a 'special majority' which is a majority in number representing at least 75% of shares voted);

v) the target seeking court approval for the implementation of the scheme;

vi) implementing the scheme; and

vii) delisting the target from ASX.

9.19 Consents and disclaimers

a) The following parties have given, and have not withdrawn before the date of this Scheme Booklet, their consent to be named in this Scheme Booklet in the form and context in which they are named:

   i) Goldman Sachs, Macquarie Capital and Rothschild & Co as financial advisers to Oil Search;

   ii) Computershare as the manager of the Oil Search Share Register;

   iii) Allens as Australian and PNG legal adviser to Oil Search in relation to the Scheme;

   iv) Deloitte Touche Tohmatsu as the auditor of Oil Search;

   v) Ernst & Young as the auditor of Santos; and

   vi) Boardroom as the manager of the Santos Share Register.

b) The Independent Expert and Independent Technical Expert have given and have not withdrawn their consent to be named in this Scheme Booklet and to the inclusion of the Independent Expert's Report (including the Independent Technical Expert's Report) in Annexure A to this Scheme Booklet and to the references to the Independent Expert's Report (including the Independent Technical Expert's Report) in this Scheme Booklet being made in the form and context in which each such reference is included.

c) The Investigating Accountant has given, and has not withdrawn their consent to be named in this Scheme Booklet and to the inclusion of the Investigating Accountant's Report in Annexure B to this Scheme Booklet and to the references to the Investigating Accountant's Report in this Scheme Booklet being made in the form and context in which that information is included.

d) Santos has given, and has not withdrawn, its consent in relation to the inclusion of the Santos Information in this Scheme Booklet and to the references to that information in this Scheme Booklet in the form and context in which that information is included.

e) Paul Lyford has given, and has not withdrawn his consent to be named in this Scheme Booklet in relation to the compilation of Santos' estimates of petroleum reserves and resources in the Important Notices in this Scheme Booklet in the form and context in which that information is included.

f) Andrei Judzewitsch has given, and has not withdrawn his consent to be named in this Scheme Booklet in relation to the compilation of Oil Search's estimates of petroleum reserves and resources in the Important Notices in this Scheme Booklet in the form and context in which that information is included.

g) GaffneyCline, Netherland, Sewell & Associates, Inc and RISC Advisory Pty Ltd have given, and have not withdrawn their consent to be named in this Scheme Booklet as Santos' independent expert in relation to Santos' estimates and reserves in the Important Notices in this Scheme Booklet in the form and context in which that information is included.

h) Netherland, Sewell & Associates, Inc has given, and has not withdrawn its consent to be named in this Scheme Booklet as Oil Search's independent expert in relation to Oil Search's estimates and reserves in the Important Notices in this Scheme Booklet in the form and context in which that information is included.

i) Ryder Scott has given, and has not withdrawn its consent to be named in this Scheme Booklet as Oil Search's independent expert that audits and/or evaluates a portion of the hydrocarbon resources of Oil Search in the state of Alaska on an annual basis in the Scheme Booklet in the form and context in which it is named.

j) Each person named in this section 9.19:

   i) has not authorised or caused the issue of this Scheme Booklet;

   ii) does not make, or purport to make, any statement in this Scheme Booklet or any statement on which a statement in this Scheme Booklet is based, other than as specified in this section 9.19; and

   iii) to the maximum extent permitted by law, expressly disclaims all liability in respect of, makes no representation regarding, and takes no responsibility for, any part of this Scheme Booklet, other than a reference to its name and the statement (if any) included in this Scheme Booklet with the consent of that party as specified in this section 9.19.

9.20 No other material information to the making of a decision in relation to the Scheme

Otherwise than as contained or referred to in this Scheme Booklet, including the Independent Expert's Report and the information that is contained in the Annexures to this Scheme Booklet, there is no other information that is material to the making of a decision by an Oil Search Shareholder whether or not to vote in favour of the Scheme Resolution to approve the Scheme, being information that is known to any Oil Search Director and which has not previously been disclosed to Oil Search Shareholders.

9.21 Supplementary information

If Oil Search becomes aware of any of the following between the date of this Scheme Booklet and the Effective Date:

- a material statement in this Scheme Booklet is false or misleading;
- a material omission from this Scheme Booklet;
- a significant change affecting a matter in this Scheme Booklet; or
- a significant new matter has arisen and it would have been required to be included in this Scheme Booklet if it had arisen before the date of this Scheme Booklet,

depending on the nature and timing of the changed circumstances, and subject to obtaining any relevant approvals, Oil Search may circulate and publish any supplementary document by:

- making an announcement to the ASX and PNGX;
- placing an advertisement in a prominently published newspaper which is circulated generally throughout PNG and Australia;
- posting the supplementary document to Oil Search Shareholders at their registered address as shown in the Oil Search Share Register; or
- posting a statement on Oil Search's Website,

as Oil Search in its absolute discretion considers appropriate.

9.22 Oil Search transaction costs

Oil Search will incur external transaction costs in connection with the Scheme. If the Scheme is not implemented, Oil Search's transaction costs will be borne by Oil Search alone. Oil Search may also be required to pay a Break Fee to Santos, depending on the circumstances in which the Scheme does not proceed (see section 9.13(e) for information on the circumstances in which a Break Fee may be payable by Oil Search).

If the Scheme is not implemented, the costs of the transaction to be paid by Oil Search are expected to be approximately A$29.1 million (excluding GST). This is broadly in line with costs it will have incurred or committed prior to the Scheme Meeting. This includes financial advisory, legal, accounting, Independent Expert, Independent Technical Specialist, Investigating Accountant, tax and administrative fees, Scheme Booklet and printing, share registry and other expenses. It does not include costs that may be payable by Santos or success-related or break fee-sharing fees which may be payable to Oil Search's financial advisers.

See section 6.9 for a summary of the external transaction costs of Oil Search and Santos payable by the Merged Group in connection with the Scheme.

9.23 Other information for Oil Search ADR Holders

Pursuant to the terms of the Oil Search ADS Deposit Agreement and at the request of Oil Search, BNY Mellon will provide each registered Oil Search ADR Holder with this Scheme Booklet and such other information related to the Scheme distributed to Oil Search Shareholders. BNY Mellon will also arrange to provide copies of this Scheme Booklet to brokers and other securities intermediaries that hold Oil Search ADRs through The Depository Trust Company ("DTC") on behalf of customers, for distribution by them to those customers. BNY Mellon will provide each Oil Search ADR Holder with a voting instruction card by which the Oil Search ADR Holder may instruct BNY Mellon how to vote the Oil Search Shares represented by the Oil Search ADR Holder's Oil Search ADRs (in the manner, and prior to the time, advised by BNY Mellon). Oil Search ADR Holders should contact BNY Mellon for any additional information. Persons holding Oil Search ADRs in accounts with brokers and other securities intermediaries should receive instructions from their securities intermediaries as to how they can give voting instructions and the applicable cut-off dates and times for receipt of those instructions.

Oil Search ADR Holders who wish to attend or vote at the Scheme Meeting or be represented at the Second Court Hearing should take steps to surrender their Oil Search ADRs to BNY Mellon for the withdrawal of those Oil Search Shares, and take delivery of those Oil Search Shares so as to become Oil Search Shareholders before the record date for voting at the Scheme Meeting. An Oil Search ADR Holder wishing to do this would need to have a securities account to which Australia or Papua New Guinea-listed shares can be delivered. It is uncertain how long it would take to become a direct Oil Search Shareholder. Therefore, Oil Search ADR Holders wishing to do so should take action as soon as possible.

10 Glossary and interpretation

10.1 Glossary

Term	Meaning
ASIC	the Australian Securities and Investments Commission.
ASX	ASX Limited (ABN 98 008 624 691) and, where the context requires, the financial market that it operates.
ASX Listing Rules	the official listing rules of the ASX.
Australian Corporations Act	the *Corporations Act 2001* (Cth), as modified or varied by any applicable ASIC class order,ASIC legislative instrument or ASIC relief.
Australian Corporations Regulations	the *Corporations Regulations 2001* (Cth).
BNY Mellon	The Bank of New York Mellon.
Break Fee	A$80 million.
Business Day	any day that is each of the following: – a Business Day within the meaning given in the ASX Listing Rules and PNGX Listing Rules; and – a day that banks are open for business in Sydney, Australia, Adelaide, Australia and Port Moresby, PNG.
CCS	carbon capture and storage.
CFIUS	the Committee on Foreign Investment in the United States and each member agency thereof, acting in such capacity.
Competing Proposal	any proposal, offer, expression of interest, agreement, arrangement or transaction, which, if entered into or completed substantially in accordance with its terms, would result in a Third Party (either alone or together with any Associate): – directly or indirectly acquiring or having the right to acquire (a) a Relevant Interest in; (b) a legal, beneficial or economic interest (including by way of an equity swap, contract for difference or similar transaction or arrangement) in; or (c) control of, 20% or more of a party's shares; – acquiring control (as determined in accordance with section 50AA of the Australian Corporations Act, but disregarding sub-section 50AA(4)) of a party; – directly or indirectly acquiring or becoming the holder of, or otherwise acquiring or having a right to acquire, a legal, beneficial or economic interest in, or control of, all or a substantial part of a party's business or assets; – otherwise directly or indirectly acquiring or merging with a party; or – requiring a party to abandon, or otherwise fail to proceed with, the Transaction, whether by way of takeover bid, members' or creditors' scheme of arrangement, reverse takeover, shareholder approved acquisition, capital reduction, buy back, sale or purchase of shares, other securities or assets, assignment of assets and liabilities, incorporated or unincorporated joint venture, dual-listed company (or other synthetic merger), deed of company arrangement, any debt for equity arrangement, recapitalisation, refinancing or other transaction or arrangement.
Conditions Precedent	each of the conditions set out in clause 3.1 of the Merger Implementation Deed.
Controlled Entity	means, in relation to a party: – a related body corporate of that party; or – an entity, fund or partnership over which a party (or a related body corporate of a party) exercises control, or by which a party is controlled, within the meaning of section 50AA of the Australian Corporations Act (but read as though section 50AA(4) were omitted).
Court	the National Court of Justice of Papua New Guinea or such other court of competent jurisdiction as Oil Search and Santos may agree in writing.
COVID-19 pandemic or Coronavirus	the Novel Coronavirus (COVID-19) pandemic.
CY21	the calendar year ending 31 December 2021.
CY22	the calendar year ending 31 December 2022.
Deed Poll	a deed poll to be executed by Santos in favour of Scheme Shareholders substantially in the form of Annexure D to this Scheme Booklet.
EBITDAX	earnings before interest, tax, depreciation (or depletion), amortisation, impairment, exploration and evaluation expense.

10 Glossary and interpretation

Term	Meaning
Effective	when used in relation to the Scheme, the coming into effect, pursuant to section 250 of the PNG Companies Act, of the orders of the Court under section 250(1) of the PNG Companies Act in relation to the Scheme, but in any event at no time before a certified copy of the orders of the Court are lodged with the PNG Registrar of Companies.
Effective Date	the date on which the Scheme becomes Effective.
End Date	10 June 2022 (being nine months after the date of the Merger Implementation Deed) or such later date as Oil Search and Santos may agree in writing.
Exclusivity Period	the period commencing on the date of the Merger Implementation Deed and ending on the earlier of: – the termination of the Merger Implementation Deed in accordance with its terms; – the End Date; and – the Effective Date.
First Court Date	the first day of hearing of an application made to the Court by Oil Search for the First Court Order or, if the hearing of such application is adjourned for any reason, means the first day of the adjourned hearing.
First Court Order	an order pursuant to section 250(2)(b) of the PNG Companies Act convening the Scheme Meeting.
FY19	the financial year ended 31 December 2019.
FY20	the financial year ended 31 December 2020.
FY21	the financial year ending 31 December 2021.
FY22	the financial year ending 31 December 2022.
GHG	Greenhouse Gas.
Gobe	the Gobe Oil Project comprises two producing oil fields, namely the South East (SE) Gobe oil field and the Gobe Main oil field.
Goldman Sachs	Goldman Sachs Australia Pty Ltd (ACN 006 797 897).
Government Agency	includes any government or representative of a government or any governmental, semi-governmental, administrative, fiscal, regulatory or judicial body, department, commission, authority, tribunal, agency or similar entity or organisation in any part of the world.
GST	goods and services tax or similar value added tax levied or imposed in Australia or PNG (as applicable) under the GST Law or otherwise on a supply.
GST Act	the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) and the *Goods and Services Tax Act 2003* (PNG).
GST Law	has the same meaning as in the GST Act.
H1FY21	the half year ended 30 June 2021.
Hides	the Hides gas field, located in PDL 1, was discovered in 1987. The majority of gas production from the Hides field is dedicated to the PNG LNG Project.
IASB	International Accounting Standards Board.
ICCC	the Independent Consumer and Competition Commission of Papua New Guinea.
IFRS	the International Financial Reporting Standards.
Implementation Date	the date that is three Business Days after the Record Date.
Independent Expert or Grant Samuel	Grant Samuel & Associates Pty Limited ABN 28 050 036 372.
Independent Expert's Report	the report of the Independent Expert, including the Independent Technical Expert's Report, as set out in Annexure A.
Independent Technical Expert	Gaffney, Cline & Associates.
Independent Technical Expert's Report	the report of the Independent Technical Expert prepared for inclusion in the Independent Expert's Report.

10 Glossary and interpretation

Term	Meaning
Ineligible Foreign Shareholder	a Scheme Shareholder whose address as shown in the Oil Search Share Register is a place outside Australia and its external territories, New Zealand, PNG, Hong Kong, Malaysia, Singapore, the United Kingdom, Ireland and the United States of America.
Instruction Cut-off Date	the last date designated by BNY Mellon to receive instructions from Oil Search ADR Holders with respect to voting in respect of the Scheme.
Investigating Accountant	Ernst & Young.
Investigating Accountant Report	the report of the Investigating Accountant, as set out in Annexure B in respect to the Pro forma Historical Statement of Financial Position.
Last Practicable Trading Date	5 November 2021.
LNG	Liquefied Natural Gas.
Macquarie Capital	Macquarie Capital (Australia) Limited (ACN 123 199 548).
Merged Group	Santos and its Subsidiaries following implementation of the Scheme.
Merger	the proposed all-scrip merger of Oil Search and Santos, pursuant to the Scheme.
Merger Implementation Deed	the Merger Implementation Deed dated 10 September 2021 between Oil Search and Santos. A summary is set out in section 9.13, and a full copy can be obtained from Oil Search's Website.
New Santos Shares	the Santos Shares to be issued to Scheme Shareholders under the terms of the Scheme.
Notice of Meeting	the Notice of Meeting, as set out in Annexure E, together with the proxy form the Scheme Meeting.
Officer	in relation to an entity, any of its directors, officers and employees.
Oil Search ADR	the Oil Search American Depositary Shares, each representing rights with respect to five Oil Search Shares.
Oil Search ADS Deposit Agreement	the Amended and Restated Deposit Agreement among Oil Search, BNY Mellon and Owners and Holders of Oil Search ADRs in the form filed with the U.S. Securities and Exchange Commission on 19 December 2018.
Oil Search ADR Holder	each person who is registered as the holder of an Oil Search ADR in the Oil Search ADR Register maintained by BNY Mellon.
Oil Search Alignment Right	an alignment right in respect of an Oil Search Share granted under the Oil Search Long Term Incentive Plan.
Oil Search Board	the board of directors of Oil Search.
Oil Search Director	a member of the Oil Search Board.
Oil Search Equity Incentives	the Oil Search Alignment Rights, Oil Search Share Rights and Oil Search Performance Rights.
Oil Search Group	Oil Search and its Controlled Entities.
Oil Search Group Member	a member of the Oil Search Group.
Oil Search Information	all information in this Scheme Booklet, excluding the Santos Information, the Independent Expert's Report and the Investigating Accountant's Report.
Oil Search Long Term Incentive Plan	the Oil Search Long Term Incentive Plan Rules, as amended prior to the date of the Merger Implementation Deed.

10 Glossary and interpretation

Term	Meaning

Oil Search Material Adverse Change	has the meaning given to it in the Merger Implementation Deed and includes (subject to certain exceptions) any event, occurrence or matter (whether occurring before, on or after the date of the Merger Implementation Deed) which has resulted in, or is reasonably likely to result in, when aggregated, with all such events, occurrences or matters:
	– a diminution in:
	  – the consolidated net assets of the Oil Search Group by an amount equal to US$225 million or more; or
	  – the consolidated EBITDAX for the financial year ending 31 December 2021 or the financial year ending 31 December 2022 or both being reduced by an amount equal to US$70 million or more; or
	– the Oil Search Group being unable to carry on its business or operations with respect to the PNG LNG Project in substantially the same manner as carried on as at the date of the Merger Implementation Deed and such inability is reasonably likely to continue for at least 60 days (whether or not that 60 days would go beyond the Second Court Date); or
	– an Oil Search Group Member resigning or being removed as joint venture operator, or any notice of resignation is given or there is a successful vote to remove any Oil Search Group Member as operator, in each case of any of the PNG oil assets or the Pikka Unit, which is reasonably likely to have effect for at least 60 days (whether or not that 60 days would go beyond the Second Court Date).

Oil Search NED Share Plan	the Oil Search Non-Executive Director Fee Sacrifice Share Acquisition Plan, adopted by the Oil Search Board on 20 February 2020.
Oil Search NED Restricted Share	a NED restricted share granted under the Oil Search NED Share Plan rules dated 20 February 2020.
Oil Search NED Right	a NED right granted under the Oil Search NED Share Plan rules dated 20 February 2020.
Oil Search Performance Right	a performance right in respect of an Oil Search Share granted under the Oil Search Long Term Incentive Plan.
Oil Search Prescribed Occurrence	has the meaning given to it in the Merger Implementation Deed and includes a range of corporate activities primarily related to capital which Oil Search is prohibited from undertaking from the date of the Merger Implementation Deed to either implementation or termination of the Merger Deed without the prior written consent of Santos.
Oil Search Share Register	the register of members of Oil Search maintained in accordance with the PNG Companies Act.
Oil Search Share Registry or Computershare	Computershare Investor Services Pty Limited (ABN 48 078 279 277).
Oil Search Regulated Event	has the meaning given in the Merger Implementation Deed and includes a number of restrictions on the corporate activities of the Oil Search Group without the consent of Santos (subject to relevant materiality and financial thresholds).
Oil Search 2020 Restricted Shares	a restricted Oil Search Share granted in calendar year 2020 under the Oil Search Long Term Incentive Plan as a deferred short term incentive award and held in the Oil Search Employee Share Trust on behalf of the employee with a scheduled vesting date in the months following the end of the financial year ending 31 December 2021.
Oil Search 2021 Restricted Shares	a restricted Oil Search Share granted in calendar year 2021 under the Oil Search Long Term Incentive Plan as a deferred short term incentive award and held in the Oil Search Employee Share Trust on behalf of the employee with a scheduled vesting date in the months following the end of the financial year ending 31 December 2022.
Oil Search Restricted Shares	the Oil Search 2020 Restricted Shares and Oil Search 2021 Restricted Shares.
Oil Search Share	a fully paid ordinary share in Oil Search.
Oil Search Shareholder	each person who is registered as the holder of an Oil Search Share in the Oil Search Share Register.
Oil Search Share Right	an Oil Search Performance Right granted under the Oil Search Long Term Incentive Plan where the only performance condition is a requirement for a continuous period of service.
Oil Search's Website	https://www.oilsearch.com/investors.
Opt-in Notice	a notice by an Unmarketable Parcel Shareholder requesting to receive the Scheme Consideration as New Santos Shares.
Opt-in Notice Date	6:00pm (Sydney time) / 5:00pm (Port Moresby time) on Monday, 13 December 2021, which is the Business Day prior to the Record Date (expected to be Tuesday, 14 December 2021).
Papua LNG Project	is a liquified natural gas project that will target the production of the Elk and Antelope gas fields.

10 Glossary and interpretation

Term	Meaning
PNG	Papua New Guinea.
PNG Companies Act	the *Companies Act 1997* (PNG).
PNG Capital Market Act	the *PNG Capital Market Act 2015* (PNG).
PNG LNG Project	is an integrated development that includes gas production and processing facilities that extend from Hela, Southern Highlands, Western and Gulf provinces to Port Moresby in Central Province.
PNG Registrar of Companies	the Registrar of Companies appointed under section 394(1) of the PNG Companies Act.
PNG Securities Commission	the Securities Commission of Papua New Guinea.
PNGX	PNGX Markets Limited or, as the context requires, the financial market operated by it.
PNGX Listing Rules	the official listing rules of the PNGX.
Record Date	7:00pm (Sydney time) / 6:00pm (Port Moresby time) on the date that is two Business Days after the Effective Date.
Related Company	the meaning given in the PNG Companies Act, except that references to 'subsidiary' have the meaning given to 'Subsidiary' in the Merger Implementation Deed.
Relevant Interest	the meaning given in sections 608 and 609 of the Australian Corporations Act.
Representative	in relation to a person: – a Controlled Entity of the person; – an Officer of the person or any of the person's Controlled Entities; or – an adviser (as defined in the Merger Implementation Deed) to the person or any of the person's Controlled Entities.
Requisite Majority	in relation to the Scheme Resolution to be put to the Scheme Meeting, at least 75% of the votes cast on the Scheme Resolution by eligible Oil Search Shareholders.
Rothschild & Co	Rothschild & Co Australia Limited (ACN 008 591 768).
Ryder Scott	Ryder Scott Company Petroleum Consultants.
Sale Agent	a person appointed by Santos to sell the New Santos Shares that are attributable to Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders do not opt-in to receive New Santos Shares under the Scheme.
Sale Proceeds	has the meaning given to it in section 3.3.
Santos Board	the board of directors of Santos.
Santos Executive Share Plan Shares	Plan 2 and Plan 0 shares issued pursuant to the Santos Executive Share Plan Rules.
Santos Group	Santos and its Controlled Entities.
Santos Group Member	a member of the Santos Group.
Santos Information	all information regarding the Santos Group and the Merged Group (including the prospects, synergies and risks of the Merged Group) prepared for and provided on or behalf of Santos in writing for inclusion in the Scheme Booklet, which comprises the information in the sections as follows: – 'Santos estimates and reserves' in the 'Important Notices'; – the Letter from the Chairman of Santos; – information about Santos and the Merged Group in section 2 (Frequently asked questions); – section 5 (Information about Santos); – section 6 (Information about the Merged Group), excluding any information expressed to be the belief of the Oil Search Directors; – section 7.3 (Risks relating to the Merged Group); – section 9.15 (Regulatory conditions and relief); – any reference to the belief of the Santos Directors in the Scheme Booklet; and – any other reference to the information listed above where such information is replicated in full, except, in each case, to the extent that information is based on information provided or prepared by or on behalf of Oil Search.

10 Glossary and interpretation

Term	Meaning
Santos Material Adverse Change	has the meaning given to it in the Merger Implementation Deed and includes (subject to certain exceptions) any event, occurrence or matter (whether occurring before, on or after the date of the Merger Implementation Deed) which has resulted in, or is reasonably likely to result in, when aggregated, with all such events, occurrences or matters: – a diminution in: – the consolidated net assets of the Santos Group by an amount equal to US$360 million or more; or – the consolidated EBITDAX of the Santos Group for the financial year ending 31 December 2021 or the financial year ending 31 December 2022 or both being reduced by an amount equal to US$190 million or more; – the Santos Group being unable to carry on its business or operations in respect of the Gladstone LNG Project or Cooper Basin assets of the Santos Group in substantially the same manner as carried on as at the date of the Merger Implementation Deed and such inability is reasonably likely to continue for at least 60 days (whether or not that 60 days would go beyond the Second Court Date); or – a Santos Group Member resigning or being removed as joint venture operator, or any notice of resignation is given or there is a successful vote to remove any Santos Group Member as operator, in each case of the Gladstone LNG Project or Cooper Basin assets of the Santos Group, which is reasonably likely to have effect for at least 60 days (whether or not that 60 days would go beyond the Second Court Date).
Santos Prescribed Occurrence	has the meaning given to it in the Merger Implementation Deed and includes a range of corporate activities primarily related to capital which Santos is prohibited from undertaking from the date of the Merger Implementation Deed to either implementation or termination of the Merger Implementation Deed without the prior consent of Oil Search.
Santos Regulated Event	has the meaning given in the Merger Implementation Deed and includes a number of restrictions on the corporate activities of the Santos Group without the consent of Oil Search (subject to relevant materiality and financial thresholds).
Santos Share	a fully paid ordinary share issued in the capital of Santos.
Santos Share Acquisition Right	a performance right in respect of a Santos Share granted under the Santos Employee Equity Incentive Plan.
Santos Share Register	the register of members of Santos maintained in accordance with the Australian Corporations Act.
Santos Share Registry or Boardroom	Boardroom Pty Limited (ACN 003 209 836).
Santos Shareholder	a person entered into the register of members of Santos as a holder of a Santos Share.
Scheme	a scheme of arrangement under Part XVI of the PNG Companies Act between Oil Search and Oil Search Shareholders substantially in the form of Annexure C, or in such other form as Oil Search and Santos may agree in writing (each acting reasonably).
Scheme Booklet	this document dated 11 November 2021, including all of the Annexures to and the forms which accompany this document.
Scheme Consideration	the consideration payable to Scheme Shareholders under the terms of the Scheme, being 0.6275 New Santos Shares for each Oil Search Share held by the Scheme Shareholder as at the Record Date (or, in respect of Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who do not opt-in to receive New Santos Shares, their respective pro rata proportion of the Sale Proceeds).
Scheme Meeting	the meeting of Oil Search Shareholders to be ordered by the Court to be convened under section 250(2)(b) of the PNG Companies Act in relation to the Scheme, and includes any adjournment of that meeting.
Scheme Shareholder	means each person who is registered in the Oil Search Share Register as a holder of Scheme Shares as at the Record Date.
Scheme Shares	means the Oil Search Shares on issue as at the Record Date.
Second CourtDate	the first day of hearing of an application made to the Court by Oil Search for orders for the Second Court Order or, if the hearing of such application is adjourned for any reason, means the first day of the adjourned hearing.
Second Court Order	an order, pursuant to section 250(1) of the PNG Companies Act, approving the Scheme.

10 Glossary and interpretation

Term	Meaning
Subsidiary	has the meaning given in the PNG Companies Act, provided that an entity will also be taken to be a Subsidiary of another entity if it is controlled by that entity (as 'control' is defined in section 6 of the PNG Companies Act) and, without limitation: – a trust may be a Subsidiary, for the purposes of which a unit or other beneficial interest will be regarded as a share; – an entity may be a Subsidiary of a trust if it would have been a Subsidiary if that trust were a corporation; and – an entity will also be deemed to be a Subsidiary of an entity if that entity is required by the accounting standards to be consolidated with that entity.

Superior Proposal	a bona fide written Competing Proposal in respect of a party:
	– of the kind referred to in limbs two, three, four or five of the definition of Competing Proposal; and
	– not resulting from a breach by the party of any of its obligations under clause 12 of the Merger Implementation Deed,
	that the Oil Search Board (in the case of Oil Search) or Santos Board (in the case of Santos), acting in good faith and in order to satisfy what the Oil Search Board (in the case of Oil Search) or Santos Board (in the case of Santos) considers to be the Oil Search Board's (in the case of Oil Search) or the Santos Board's (in the case of Santos) statutory or fiduciary duties (after having obtained advice from their external legal and financial advisers) determines:
	– is reasonably capable of being valued, and completed in a reasonable timeframe, taking into account all terms, conditions and other aspects of the Competing Proposal in respect of that party, including, but not limited to:
	  – the identity, reputation and financial condition of the party making the Competing Proposal in respect of that party;
	  – the ability of the party making the Competing Proposal in respect of that party to consummate the transactions contemplated by the Competing Proposal in respect of that party; and
	  – all relevant legal, financial, regulatory and other matters; and
	– would, if completed substantially in accordance with its terms, be more favourable to Oil Search Shareholders or Santos Shareholders (as applicable) (as a whole) than the Transaction (and, if applicable, than the Transaction as amended or varied following application of the matching right set out in clause 12.5 of the Merger Implementation Deed), taking into account all terms, conditions and other aspects of the Competing Proposal in respect of that party and all terms, conditions and other aspects of the Transaction.

Third Party	in relation to Oil Search, any of the following: – a person other than any Santos Group Member; or – a consortium, partnership, limited partnership, syndicate or other group in which no Santos Group Member has agreed in writing to be a participant; and in relation to Santos, means any of the following: – a person other than any Oil Search Group Member; or – a consortium, partnership, limited partnership, syndicate or other group in which no Oil Search Group Member has agreed in writing to be a participant, and includes a Government Agency.
Transaction	the proposed transaction under which Santos will acquire the Scheme Shares under the Scheme, in consideration for the provision of the Scheme Consideration.
Unmarketable Parcel Shareholder	a Scheme Shareholder (other than an Ineligible Foreign Shareholder) who, based on their holding of Scheme Shares on the Record Date, would, on the Implementation Date, be entitled to receive less than a marketable parcel (as that term is defined in the ASX Listing Rules) of New Santos Shares (assessed by reference to price of Santos Shares on the ASX as the close of trade on the trading day prior to the Record Date) as Scheme Consideration.

10.2 Interpretation

In this Scheme Booklet:

a) words of any gender include all genders;
b) words importing the singular include the plural and vice versa;
c) an expression importing a person includes any company, partnership, joint venture, association, corporation or other body corporate and vice versa;
d) a reference to a section or annexure, is a reference to a section of or annexure of, this Scheme Booklet as relevant;
e) a reference to any legislation includes all delegated legislation made under it and amendments, consolidations, replacements or re-enactments of any of them;
f) headings and bold type are for convenience only and do not affect the interpretation of this Scheme Booklet;
g) a reference to time is a reference to Port Moresby, PNG time unless otherwise specified;
h) a reference to dollars and $ is to Australian currency unless otherwise specified;
i) an accounting term is a reference to that term as it is used in accounting standards under the PNG Companies Act, or, if not inconsistent with those standards, in accounting principles and practices generally accepted in PNG; and
j) the words 'include', 'including', 'for example' or 'such as' when introducing an example, do not limit the meaning of the words to which the example relates to that example or examples of a similar kind.

GRANT SAMUEL

9 November 2021

The Directors
Oil Search Limited
Ground Floor, Harbourside East Building
Stanley Esplanade, National Capital District
Port Moresby
PAPUA NEW GUINEA

Dear Directors

Merger of Oil Search and Santos

1 Introduction

On 10 September 2021, Oil Search Limited ("Oil Search") announced that it had entered into a Merger Implementation Deed ("MID") with Santos Limited ("Santos"), under which Santos would acquire all the shares in Oil Search in exchange for 0.6275 Santos shares for each Oil Search share via a scheme of arrangement ("the Merger"). The announcement followed:

- an initial non-binding proposal submitted by Santos in June 2021 (offering 0.589 Santos shares for each Oil Search share) that was rejected by Oil Search;
- public disclosure of the earlier Santos proposal on 20 July 2021;
- a period of negotiation that led to agreed terms being announced on 2 August 2021; and
- a period of mutual due diligence.

Upon completion of the Merger, Oil Search shareholders will own approximately 38.5% of the Merged Group and Santos shareholders will own approximately 61.5%.

Established in 1929, Oil Search is the largest oil and gas company incorporated in Papua New Guinea (also referred to as PNG). It is listed on the Australian Securities Exchange ("ASX") and on the PNG Exchange ("PNGX")[1]. Santos is one of Australia's largest oil and gas companies and is an ASX top 50 company. The Merged Group is expected to be included within the S&P/ASX 20 index and to be amongst the top 20 largest oil and gas companies in the world, with a pro forma market capitalisation of approximately A$25 billion[2].

The current Chief Executive Officer ("CEO") and Chairman of Santos, Mr Kevin Gallagher and Mr Keith Spence, will remain in those roles for the Merged Group. Following completion of the Merger, three non-executive directors from Oil Search will join the Santos Board. The composition of senior management (other than the CEO) will be determined by a committee established by both parties.

Key conditions of the Merger include:

- Oil Search shareholder approval;
- approval by the National Court of Papua New Guinea;
- regulatory approval; and
- no material adverse change, prescribed occurrences or regulated events (each as defined in the MID) occurring in relation to either Santos or Oil Search.

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1 Market operated by PNGX Markets Limited.
2 All references to $ in this report are references to United States dollars unless stated otherwise (e.g. A$).

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The Oil Search Board of Directors has unanimously recommended that Oil Search shareholders vote in favour of the Merger in the absence of a superior proposal and subject to an independent expert concluding that the Merger is in the best interests of the Oil Search shareholders.

The directors of Oil Search have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report. The Companies Act 1997 (PNG) does not specify the form of any report or opinion. The directors have requested Grant Samuel to provide an opinion as to whether the Merger is in the best interests of shareholders. A copy of the report (including this letter) will accompany the Scheme Booklet to be sent to Oil Search shareholders. This letter contains a summary of Grant Samuel's opinion and main conclusions.

2 Summary

Evaluation of the Merger requires an assessment of both value related considerations and broader issues relating to strategy, commercial imperatives and funding and other synergies.

The Merger comprehensively addresses the significant capital constraints facing Oil Search. In particular, the Merged Group would have the funding capacity to progress the development of Oil Search's Pikka project or otherwise realise value for Pikka on an optimal basis. In addition to the explicit synergies expected to be achieved (cost savings estimated at $90-115 million), the Merger is likely to deliver other synergistic benefits. The potential for improved alignment of interests between the participants in the PNG LNG and Papua LNG projects could facilitate an optimised development of the extensive PNG gas resource base. The Merged Group's Australian domicile, its access to global capital markets and its size, share liquidity and enhanced index ranking all suggest that it would enjoy a lower cost of capital than a standalone Oil Search, with shares likely to trade closer to underlying value. The Merger would also resolve the question of future management and leadership that would otherwise need to be addressed by a standalone Oil Search. While these benefits cannot be quantified with any precision, there is no doubt that they are collectively material.

At the same time, PNG LNG is a world class project and Papua LNG is an attractive expansion option. There is a credible standalone path forward that might involve sub-optimal outcomes for Pikka but would ultimately see value created as Oil Search's funding issues were resolved and Papua LNG progressed through development.

Grant Samuel's analysis suggests that the financial terms of the Merger are not reflective of the relative contributions of underlying value by Oil Search and Santos. Oil Search shareholders are contributing around 43-44% of the aggregate estimated underlying value of the Merged Group compared to the 38.5% of the Merged Group that they will receive. Even after taking into account the value of the cost savings expected to be realised, the analysis indicates that the Merger will result in a reduction in the underlying value attributable to Oil Search shareholders.

These relativities do not correspond with those based on share market values. On one view, underlying value is in any event of limited relevance, since shareholders could only access underlying value through a fully priced cash takeover offer for Oil Search. Parties who might be interested in bidding for Oil Search will have had ample opportunity to do so prior to the Scheme meeting to approve the Merger. In the absence of such an offer, shareholders could justifiably attribute more significance to share market values. The Merger terms provided a premium to Oil Search shareholders of around 16% at the time of announcement of the Merger.

A relative weighting of the valuation issues against the broader benefits of the Merger is not straightforward. The dilution of underlying value implied by the Merger terms is material. There is clearly a risk that the funding and other strategic benefits do not fully compensate shareholders for this dilution. On the other hand:

- **the options to maximise the value realised for Pikka and, over time, to optimise the development of its PNG interests are significant benefits of the Merger that are not available to Oil Search on a standalone basis;**
- **any estimates of underlying value are inherently uncertain, particularly in the current environment; and**
- **Oil Search faces real challenges in funding its growth opportunities on a standalone basis.**

In the circumstances, an overall judgement on the merits of the Merger is finely balanced. At a minimum, Grant Samuel believes that it is appropriate for the Merger to be put before shareholders for their consideration. Grant Samuel's view is that Oil Search shareholders are likely to be better off if the Merger proceeds than if it does not. Accordingly, the Merger is in the best interests of shareholders, in the absence of a superior proposal.

However, the judgement is highly subjective and shareholders could reasonably weigh these factors differently, attributing less weight to the strategic, funding and other benefits and voting against the Merger. In doing so, they should be aware that if the Merger did not proceed it is likely that the Oil Search share price would fall (assuming continuation of current oil prices and broader market conditions). More importantly, shareholders would need to recognise the risks inherent in such a decision, including the real possibility that a standalone Oil Search would require equity support from its shareholders to maximise the value of its future development projects. A decision by shareholders as to whether to vote in favour of the Merger would depend on factors including their views on value, their willingness to support the funding required by a standalone Oil Search, their views on future oil prices, appetite for PNG risk, the strategic benefits available from the Merger and other matters.

3 Key Conclusions

- **The Merger is being proposed against the backdrop of accelerating structural changes in global energy markets.**

  The Merger is being proposed against the backdrop of profound changes in global energy markets. A focus on reductions in carbon emissions has resulted in a growing emphasis on renewable energy and increasing uncertainty about the future role of traditional carbon-based energy sources. Oil and gas producers have reduced investment in exploration and new production, while challenges associated with integrating intermittent renewable energy sources into traditional energy systems have not been resolved. Capital and bank markets have responded to ESG concerns by reducing the flow of funding to the oil and gas sectors. Global energy demand is expected to continue to grow, largely reflecting ongoing energy intensive economic growth in China, India and other Asian nations. In this context, supply side pressures have exacerbated price volatility. The increasing integration of energy markets has meant that regional demand and supply mismatches are no longer contained but instead have global impacts.

  The result has been a fundamental change in the challenges facing oil and gas sector participants. The most obvious and pressing impact relates to access to capital. Given the growing funding constraints faced by oil and gas sector participants, financial strength (in terms of capital structure, liquidity, access to capital markets and underlying cash flow generation underpinned by high quality assets) is increasingly a key competitive advantage. It allows participants to fund asset developments on a value-maximising basis, while minimising their vulnerability to price volatility and other risks.

- **The commercial and strategic logic of the Merger is compelling.**

  Oil Search faces a number of real challenges on a standalone basis. In particular, it faces significant funding constraints which bear on its ability to develop its growth assets in a manner that maximises value for shareholders:

- free cash flow is severely constrained until after 2026 when PNG LNG will have fully repaid its project debt facility and will begin distributing its operating cash flows;
- bank debt markets are becoming more fickle and harder to access particularly as ESG pressures on lenders continue to mount; and
- Oil Search is unlikely to be able to secure an investment grade credit rating given its asset concentration (and incorporation) in PNG and therefore cannot access debt capital markets on attractive terms.

Oil Search faces major potential funding commitments in the short term, both in relation to the Papua LNG project and to the Pikka Phase 1 development on the Alaskan North Slope. The challenge is most acute in relation to Pikka, which is approaching FID. In February 2021, Oil Search announced that it intended to sell down a 15% interest in the project (i.e. reducing its stake to 36%). Such a sale would provide funding capacity, reduce Oil Search's funding obligation and provide commercial and technical validation of the project. However, to date no divestment has been announced.

Deferring development reduces the potential value creation substantially while other forms of less conventional finance would be expensive. In any event, an early sale would be suboptimal as full value recognition is unlikely until the project is close to, or has commenced, production.

By contrast, the Merged Group will have both scale and a strong funding platform as a result of:

- the expected maintenance of Santos' "investment grade" credit rating[3]. This rating enables Santos to access debt capital markets on attractive terms (as demonstrated in April 2021);
- the combined liquidity. At 30 June 2021, pro forma cash was $2.9 billion and undrawn facilities were $2.8 billion;
- the relatively modest gearing levels (proforma 2021 net debt/EBITDAX of 1.5 times);
- the combined cashflows from the two businesses;
- the flexibility to sell down a significant part of the combined 42.5% interest in PNG LNG to, say, around 30% while still maintaining a clear position as the second largest investor behind ExxonMobil (the operator), potentially releasing over $3 billion;
- the diversified asset base (across geographies, products and lifecycles) but anchored by a world class, long life, low cost asset (PNG LNG); and
- the reduced average carbon intensity (compared to Santos standalone).

The Merged Group should therefore be able to optimise its development portfolio. In particular, it will have strategic flexibility to "carry" developments on its own balance sheet to the point where selldown makes most economic sense. It will not be forced to sell down prematurely (at least to the same extent) to secure development funding. In other words, it will be able to pursue development funding from a position of strength. Specifically, it could readily commit to developments such as Pikka or Papua LNG.

Another important benefit of the Merger is the potential for better alignment of interests in PNG. At present, Santos is an investor in PNG LNG but has no interest in either P'nyang or the planned Papua LNG project, while Total Energies SE (the main proponent of the project Papua LNG) has no interest in PNG LNG or P'nyang. The Merged Group will have flexibility to sell down part of its 42.5% interest in PNG LNG, therefore potentially facilitating a realignment of interests across PNG LNG, P'nyang and Papua LNG. Such a realignment would improve co-ordination across these projects and, more importantly, help accelerate the development of P'nyang and Papua LNG as well as additional capacity

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[3] Standard & Poor's has expressed some concern about the substantial increase in exposure to PNG as a result of the Merger but notes Santos' track record with acquisitions and the scope to rebalance the combined portfolio following implementation. No decisions have yet been made by either Standard & Poor's or Fitch regarding changes, if any, to the credit ratings.

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in PNG LNG. This has the potential to deliver significant value accretion for the benefit of all participants. In this scenario, the Merged Group would obviously have funds available to meet any funding obligations.

In addition:

- Santos has estimated annual cost savings of $90-115 million. The expected cost savings encompass corporate overheads, employees (predominantly in Australia), information systems and borrowing costs. If realised, the synergies are worth approximately 30 US cents per share (A$0.40); and
- the Merger would also avoid the need to appoint a new permanent CEO and CFO and to continue Oil Search's board renewal process.

- **Underlying valuation analysis suggests that Oil Search shareholders will have a disproportionately low shareholding in the Merged Group.**

  Comparison of their value contribution to the Merged Group with the share of the Merged Group to be held by Oil Search shareholders provides an important framework for assessing the Merger.

  For the purpose of assessing the underlying value of Oil Search and Santos, Grant Samuel has estimated the market value of each of the assets or businesses of the two entities, subtracting debt and allowing for any other assets and liabilities. The underlying value is notionally the price that could be realised for each asset or business in an orderly sale and is estimated irrespective of the capital structure of the vendor. The estimated underlying values do not take into account the synergies that might be available to acquirers of each of the companies.

  Grant Samuel has estimated the underlying value of equity in Oil Search to be $6,766 – 8,341 million and the underlying value of equity in Santos to be $8,728 – 10,903 million by aggregating individual asset values. These have been estimated having principal regard to the results of discounted cash flow ("DCF") analysis.

  Cash flow models for each of the oil and gas assets were prepared based on scenarios developed in conjunction with the technical specialist, Gaffney, Cline & Associates Pty Ltd ("GaffneyCline"). Gaffney Cline reviewed technical assumptions relating to Oil Search's and Santos' operating and development projects, including those regarding reserve and resource estimates, production profiles, operating costs, capital and abandonment costs and the potential for reserve extensions, and made adjustments as necessary to develop scenarios that were appropriate for valuation purposes. GaffneyCline also valued the exploration interests of both companies. Grant Samuel determined the economic and financial assumptions used in the cash flow models and applied an overall commercial overlay taking into account factors such as sovereign risk (particularly for assets in PNG) and other factors such as development risks, funding and ESG issues and other relevant matters. Discount rates were applied to ungeared after tax cash flows to estimate net present values. While Grant Samuel has estimated NPVs using, as a starting point, discount rates in the range 8.5-9.5%, the valuation ranges selected imply a variety of discount rates. In particular:

  - Grant Samuel's valuations of the interests of Oil Search and Santos in PNG LNG have been risked such that the valuations imply discount rates in the approximate range of 10-11%, reflecting sovereign and other risks associated with the project's PNG location. Higher risk factors have been applied to other longer date development assets in PNG;
  - the value attributed to Oil Search's interest in the Alaskan Assets implies much higher discount rates, approaching 15%; and, conversely

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- Grant Samuel has had regard to the low risk nature (in some cases approaching infrastructure like characteristics) of some parts of the Santos business, particularly in relation to the revenues derived from domestic gas delivered into fixed price or inflation-linked contracts on the East Coast of Australia or in Western Australia.

Alternative valuation methodologies have been considered as secondary evidence of value, where appropriate (e.g. multiples of reserves and resources).

The valuations are summarised below:

OIL SEARCH – VALUE ANALYSIS SUMMARY (US$ MILLIONS)

	SECTION REFERENCE	VALUE RANGE	
		LOW	HIGH
PNG LNG	5.3.2	7,350	8,250
P'nyang and Muruk	5.3.3	100	150
Papua LNG	5.3.4	600	800
Operated Oil & Gas Assets	5.3.5	350	400
Alaskan Assets	5.3.6	700	800
PNG Exploration Assets	5.3.7	400	600
Other Assets and Liabilities	5.3.8	25	50
Corporate Overheads	5.3.9	(450)	(400)
Enterprise Value		**9,075**	**10,650**
Adjusted Net Borrowings	5.3.10	(2,309)	(2,309)
Equity Value		**6,766**	**8,341**

SANTOS – VALUE ANALYSIS SUMMARY (US$ MILLIONS)

	REPORT SECTION REFERENCE	VALUE RANGE	
		LOW	HIGH
Western Australia	5.4.2	2,700	3,100
Queensland and New South Wales	5.4.3 / 5.4.4	3,180	3,700
Cooper Basin	5.4.5	1,600	1,900
Northern Australia and Timor-Leste	5.4.6	1,200	1,450
Papua New Guinea	5.4.7	3,200	3,600
Exploration interests not included in individual asset values	5.4.8	200	400
Other	5.4.9	(5)	55
Corporate overheads	5.4.10	(440)	(395)
Enterprise value		**11,635**	**13,810**
Adjusted net borrowings	5.4.11	(2,907)	(2,907)
Value of equity		**8,728**	**10,903**

The valuations are set out in detail in Section 5 of Grant Samuel's report. They represent overall judgements as to underlying value, having regard to DCF analysis, other valuation evidence and GaffneyCline estimates of the value of exploration interests. GaffneyCline has attributed total value to Santos' exploration interests in the range $1.1 – 1.5 billion. Of this, approximately $700 million relates to the value of exploration interests offshore Western Australia, and has been included in the valuation of Santos' Western Australian business. A further $230-350 million relates to the value of Santos' exploration interests in the Cooper Basin and has been included in the overall valuation of the Cooper Basin.

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On the basis of the valuations set out above, Oil Search shareholders are contributing 43-44% of the value but are receiving a 38.5% shareholding in the Merged Group:

RELATIVE CONTRIBUTION – UNDERLYING VALUE (US$ MILLIONS)

		UNDERLYING VALUE RANGES	
		LOW	HIGH
Oil Search (Equity Value)	A	6,766	8,341
Santos (Equity Value)	B	8,728	10,903
Combined group (aggregate)	C = A+B	**15,494**	**19,244**
Relative value contributed			
Oil Search shareholders	***A/C***	***43.7%***	***43.3%***
Santos shareholders	B/C	56.3%	56.7%

Source: Grant Samuel analysis

An alternative approach is to compare the aggregate underlying value contributed by Oil Search shareholders with the aggregate value that they will hold in the Merged Group (i.e. in absolute rather than proportionate terms). The potential synergies of $90-115 million per annum are a significant factor in the Merger. Consideration of the value of these synergies allows a comparison of the "value in" with the "value out":

VALUE IN/OUT ANALYSIS (US$ MILLIONS)

	UNDERLYING VALUE RANGES	
	LOW	HIGH
Oil Search Equity Value In	**6,766**	**8,341**
Oil Search Equity Value Out		
Oil Search	6,766	8,341
Santos	8,728	10,903
Synergies (excluding associated implementation costs)[4]	950	1,050
Total	**16,444**	**20,294**
Oil Search Share (38.5%)	**6,331**	**7,813**
Change	***-6%***	***-6%***

This analysis indicates that Oil Search shareholders will suffer a reduction in the underlying value of their shares even including synergies. However:

- that reduction may not be reflected in market values, depending on the relative discounts to underlying value at which shares in the Merged Group could trade. Grant Samuel would expect shares in the Merged Group to trade at a lower discount to underlying value than shares in a standalone Oil Search, reflecting factors including a lower cost of capital; and
- the underlying value could strengthen over time relative to a standalone Oil Search if the Merger benefits are realised.

▪ **However, there are other perspectives on the value equation for shareholders.**

Merger analysis based on estimated underlying value is, at best, an incomplete approach in the circumstances of the Merger:

- estimates of value for oil and gas businesses are inherently uncertain. This uncertainty is exacerbated in the current market. Estimates of future oil and gas prices fall within a wide range,

[4] Indicative estimate based on Santos' estimate of annual cost savings of $90-115 million.

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given the wide range of views about the likely trajectory of global energy markets. In general, Oil Search is more leveraged to higher oil prices, while Santos' significant domestic gas business provides price protection in softer markets. In the face of rapidly mounting ESG pressures, the cost of capital for oil and gas assets (and therefore the discount rates to apply in estimating underlying values) are not clear. To the extent that costs of capital have risen (or are likely to rise in the future), these higher costs are likely to be more significant for Oil Search, given the long dated nature of its cash flows relative to those of Santos. The reality is that, while estimates of underlying value appear precise, such precision is spurious. Judgements regarding underlying value are subjective;

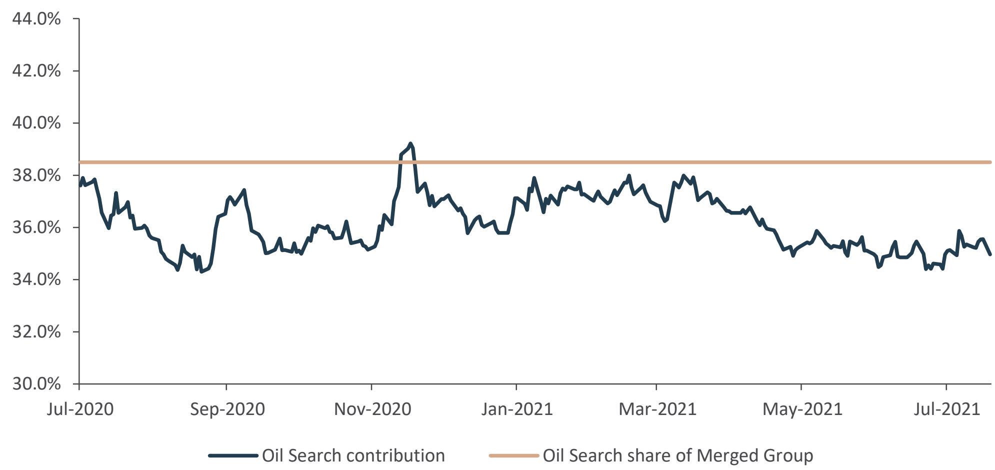
- the underlying value of Santos estimated above is below its market value. The market price may reflect:
  - different views on the value of Santos' asset portfolio (e.g. through different assumptions as to life extensions, exploration success or the timing and quantum of capital and abandonment expenditures); and/or
  - other factors that would contribute to value, including plans for future initiatives (of which Santos has several);
- underlying value is essentially a theoretical construct. It is based on an estimate of the market value of individual assets that does not take into account the particular capital structure of the company in question. Given the funding constraints facing Oil Search and their possible impact on shareholder value, analysis based on underlying value should be treated with some caution; and
- individual shareholders cannot "access" the underlying value of a company's assets except in the context of a cash takeover offer. Rather, the interests of minority investors in Oil Search are intermediated through the corporate and capital structure of company. In this regard, there is no doubt that the "true" equity value contributed by Oil Search shareholders is less than indicated by the underlying value analysis. Oil Search is a PNG incorporated entity that generates over 90% of its cash flows from a single (non-operated) asset, the PNG LNG joint venture. It incurs a higher cost of debt than Santos because of this structural risk. Additionally, Oil Search is capital constrained and has limited capacity to fund its growth program (on an efficient basis) over the next few years (at least until 2026). Intuitively, its cost of equity is also almost certainly higher than for a company like Santos, because of its concentration risk and the sovereign risk associated with its assets (although this is difficult to measure reliably). In contrast, Santos has a diversified asset portfolio (mostly in Australia) and a stronger balance sheet. Accordingly, Oil Search shares are likely to trade at a larger discount to underlying value than Santos shares and any proper test of relative contribution should reflect this differential, because that will be reflected in market values that shareholders can realise in the ordinary course.

Having regard to these factors, it is appropriate to incorporate in the analysis estimates of the relative contributions of market value made by Oil Search and Santos shareholders. Market values are volatile but they are at least objective (and the analysis is consistent over several months).

Oil Search's contribution to the aggregate sharemarket value of the two companies (based on daily closing prices) compared to the share of the Merged Group received by Oil Search shareholders over the period from 1 July 2020 to 19 July 2021, the last trading date prior to public confirmation of the potential merger is shown in the following chart:

OIL SEARCH – SHARE OF COMBINED MARKET VALUE

1 JULY 2020 TO 19 JULY 2021



Source: IRESS and Grant Samuel analysis

The following table shows the relative contributions based on VWAPs compared to the relative values received under the Merger terms by the shareholders of each company across different periods prior to 19 July 2021:

RELATIVE CONTRIBUTION – SHAREMARKET VALUE

		19 JULY 2021		PERIOD TO 19 JULY 2021 (VWAP)				
		LAST PRICE	VWAP[4] FOR THE DAY	ONE WEEK	ONE MONTH	THREE MONTHS	SIX MONTHS	TWELVE MONTHS
Oil Search								
Price (A$)		3.67	3.72	3.82	3.86	3.87	4.00	3.64
Market capitalisation (A$ millions)	A	7,626	7,719	7,946	8,025	8,039	8,316	7,553
Santos								
Price (A$)		6.83	6.85	7.03	7.17	7.15	7.17	6.40
Market capitalisation (A$ millions)	B	14,227	14,269	14,634	14,925	14,902	14,944	13,338
Combined sharemarket value (A$ millions)	***C=A+B***	***21,853***	***21,988***	***22,579***	***22,950***	***22,941***	***23,259***	***20,891***
Oil Search % contribution	***A/C***	***34.9%***	***35.1%***	***35.2%***	***35.0%***	***35.0%***	***35.8%***	***36.2%***
Santos % contribution	*B/C*	*65.1%*	*64.9%*	*64.8%*	*65.0%*	*65.0%*	*64.2%*	*63.8%*

Source: IRESS and Grant Samuel analysis

The analysis demonstrates that, based on sharemarket prices up to 12 months prior to the announcement, Oil Search shareholders are contributing a consistently lower share (of around 35%) of the combined sharemarket value than they are receiving (38.5%). On one view, analysis of relative contributions of market value better reflect the realities of the situation facing shareholders, because it captures the funding and other issues facing Oil Search.

Other parameters also suggest Oil Search shareholders' contribution is materially less than their share of the Merged Group:

RELATIVE CONTRIBUTIONS – OTHER PARAMETERS

	PARAMETER		*CONTRIBUTION (%)*	
	OIL SEARCH	SANTOS	*OIL SEARCH*	*SANTOS*
Reserves and Resources at 31 December 2020 (mmboe) [5]				
2P	445	933	***32.3***	*67.7*
2P + 2C	1,768	3,215	***35.5***	*64.5*
Production (mmboe)				
2020 (actual)	29	89	***24.6***	*75.4*
2021 (forecast)	27	89	***23.3***	*76.7*
Earnings ($ millions)				
1HY21 (actual)				
EBITDAX	491	1,231	***28.5***	*71.5*
EBIT (normalised[6])	279	588	***32.2***	*67.8*
NPAT (normalised[6])	139	317	***30.5***	*69.5*
2021 (broker consensus forecast)				
EBITDAX	1,175	2,805	***29.5***	*70.5*
EBIT	770	1,558	***33.1***	*66.9*
NPAT	419	852	***33.0***	*67.0*

Source: Oil Search, Santos, S&P Global Market Intelligence and Grant Samuel analysis

This is a relatively crude and incomplete analysis. It does not reflect factors including the relative profitability of production, the quantum of and risks associated with growth projects, differing capital expenditure and abandonment expenditure profiles and other matters. Nonetheless, it is clear that Oil Search shareholders will be receiving a share in the Merged Group greater than their contribution of reserves, resources, production and profitability.

- **There should be an uplift in earnings per share for Oil Search shareholders.**

  The impact on attributable earnings per share and dividends per share for Oil Search shareholders is difficult to determine largely because of the inherent volatility of earnings (driven by oil prices) as well as the different bases for the respective dividend policies.

  An illustration of the potential impact on earnings per share is set out in the table below using consensus broker forecasts for the full 2021 year and for 2022:

PRO FORMA EPS IMPACT PER EQUIVALENT OIL SEARCH SHARE[7]

	OIL SEARCH STANDALONE	MERGED GROUP	EQUIVALENT OIL SEARCH SHARE	CHANGE	
				ABSOLUTE	%
2021 Earnings per share (before significant items)					
- before cost synergies	20.2c	37.5c	23.5c	3.4c	16.8%
- after cost synergies	20.2c	39.6c	24.9c	4.7c	23.4%
2022 Earnings per share (before significant items)					
- before cost synergies	30.8c	53.4c	33.5c	2.7c	8.7%
- after cost synergies	30.8c	55.5c	34.8c	4.0c	13.0%

Source: S&P Global Market Intelligence and Grant Samuel analysis

5 As reported by each company in their respective Annual Reports.

6 Normalised EBIT and NPAT are before impairment charges and other significant items. Only Santos' EBIT and NPAT have been normalised for other significant items in 1HY21 as Oil Search did not report any other significant items.

7 Based on a simple addition of Oil Search and Santos earnings. No proforma adjustments have been made (except for synergies). In particular, no allowance has been made for transaction assets or costs to achieve the synergies.

On this basis, it is reasonable to conclude that Oil Search shareholders should benefit from a meaningful uplift in earnings per share, at least in the short to medium term.

The impact on dividends for Oil Search shareholders is less clear. The two companies have different policy bases:

- Oil Search targets a payout ratio of 35-50% of NPAT; while
- Santos targets a payment of 10-30% of free cash flow which is defined as operating cash flow less investing cash flow (including capital expenditure, exploration expenditure and interest) but with discretion to exclude material growth projects.

Shareholders should note that:

- the primary driver of earnings (and therefore dividends) will be external factors such as oil prices;
- future dividend decisions will be determined by the board of the Merged Group having regard to financial and other circumstances at the time and the Santos policy provides a wide range of outcomes; and
- the dividend policy could be changed at any time.

Additionally, for Australian resident shareholders there should be a further benefit in terms of dividend franking. As a PNG incorporated entity with operations in PNG, Oil Search's dividends have historically not been franked and (assuming the asset composition does not change) will not be in future. In contrast, Santos dividends have been 100% franked because of its significant proportion of Australian based assets. Future dividends of the Merged Group should be able to be at least partially franked.

- **There are standalone alternatives to the Merger, but these are not without risk.**

  A standalone Oil Search does have a viable future.

  While a standalone Oil Search may face challenges in funding Pikka, the Company is under no direct or broader funding pressure. PNG LNG is a world class project and should generate strong positive cash flows at current oil prices. An outcome that saw Pikka divested or otherwise dealt with would see Oil Search able to focus on the funding of Papua LNG. A successful Papua LNG development would offer the potential for real value uplift over time for Oil Search.

  On the other hand:

  - a sale of Pikka in the short term may result in a significant loss of value. Similarly, any significant development deferral would result in value diminution;
  - a decision to reject the Merger and proceed on a standalone basis would not be without risk. It is likely that the Oil Search share price would fall, at least in the short term. The way forward for Pikka is unclear and could involve more value loss than implied in Grant Samuel's estimate of current value. Shareholders should expect that they would be required to support the Company's future funding via some significant equity raising; and
  - Oil Search has an Acting CEO and CFO, having suffered several unplanned management changes over the past twelve months. The previous CEO left the Company immediately prior to the announcement of the proposed Merger. If shareholders were to vote against the Merger, that would likely result in an acceleration of the Board renewal process already underway, with Oil Search potentially facing the need to appoint a number of new directors.

  Shareholders who would prefer not to be exposed to these uncertainties or to address Oil Search's funding challenges via direct equity support would be justified in preferring to pursue the Merger.

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- **There are some disadvantages, risks and costs which are not trivial.**

  Change in Mix of Assets

  Oil Search shareholders will have a much lower exposure to Oil Search's assets (e.g. from collective ownership of a 29% interest in PNG LNG to a little over 16%). While these assets do carry some degree of sovereign risk, the PNG LNG joint venture has been in operation since 2014, largely without incident, and the assets are considered world class with long life resources, low operating costs and quality (rich) gas with low CO_2 content.

  Correspondingly, they will have a significant exposure (over half of the value of their investment) to Santos' assets. In broad terms, those assets can be regarded as lower quality than PNG LNG, with an overall faster anticipated decline in production over time, lower margins and higher emissions intensity.

  Some shareholders may not welcome this diversification and reduced exposure to the PNG assets. If they are already shareholders in Oil Search they are presumably comfortable with the highly concentrated exposure to LNG projects in Papua New Guinea. Shareholders seeking exposure to Santos assets could easily buy Santos shares. Diversification is more efficiently achieved by shareholders themselves rather than through being locked into a specific mix of assets within a corporate entity.

  At the same time, it should be recognised that:

  - asset "quality" differences should be reflected in the relative valuations. In addition, the merger terms indicate Oil Search shareholders are receiving a premium, in the order of 16% (based on the share prices at the time of announcement of the Merger);
  - other aspects of the diversification may be of value to shareholders, in particular the increased exposure to domestic gas markets which tend to have more stable pricing than LNG and oil; and
  - some of Santos' assets offer a lower risk profile than Oil Search (e.g. some domestic gas sales and midstream assets that could be considered to have some infrastructure type characteristics, at least to the extent they derive "tolling" revenues from third parties).

  Santos Share Price Risk

  The underlying value analysis would suggest that there is a risk that the Santos share price could fall in future (even if oil prices remained stable). At the same time, Santos is a liquid share that provides detailed disclosures and is followed by over ten analysts. Market prices may reflect factors other than underlying value which may prove sustainable over time.

  Reduced Likelihood of Takeover Premium

  Oil Search in its current form has an open share register, an attractive asset base and is of a size that means that it would be a meaningful acquisition for any interested party. The Merger, if implemented, is evidence that an acquisition of Oil Search (at least in a technical sense) is achievable. The concerns of the PNG government are likely to be that:

  - the owners are committed to fully exploiting the resource to provide the maximum economic benefit to the PNG population; and
  - that PNG citizens have a readily available opportunity to invest (even if indirectly) in these assets.

  By contrast, a takeover of the Merged Group may be more problematic. The Merged Group will have a relatively open share register, with no single shareholder holding more than 6%. Accordingly, there is at least a theoretical possibility of a third party making a takeover offer, including a full control premium, at some future date. However:

  - at a proforma enterprise value of almost $25 billion the field of potential suitors with the financial capacity to make a fully priced offer is more limited;

- the highly diversified asset base of the Merged Group may be less attractive than one narrowly focussed on a single world class asset; and
- the acquirer, if foreign, may face issues in obtaining approval under Australia's Foreign Acquisitions and Takeovers Act.

Overall, it is reasonable to conclude that the Merger will reduce the prospects of Oil Search shareholders ever realising a full takeover premium through a cash or cash equivalent offer.

On the other hand, there is probably only a handful of possible acquirers of a standalone Oil Search. All will already have good insights into Oil Search and its assets. By the time of the shareholders' meeting to approve the Merger, any potential counter-bidders will have had over four months to formulate an alternative proposal. In the absence of any alternative offer, Oil Search shareholders could conclude that their prospects of realising a full takeover premium are remote.

Accordingly, while the Merger may theoretically reduce the likelihood of Oil Search shareholders realising a takeover premium, any real world disadvantage is unlikely to be material.

Transaction and Integration Costs

Oil Search and Santos will each incur transaction costs in relation to the Merger. Transaction costs are estimated to total approximately A$124 million (A$79 million for Oil Search and A$45 million for Santos). The Merged Group will also incur integration costs associated with achieving the cost savings which have not been quantified. However, these integration costs are one off and unlikely to be material in the context of the Merged Group.

Oil Search shareholders will, in aggregate, bear 38.5% of these costs (as well as 38.5% of the integration costs). The transaction costs represent less than 0.5% of the pro forma market capitalisation of the Merged Group.

Integration Risks

Realisation of the expected benefits will not be an automatic consequence of the Merger but will require the successful integration and ongoing management of the Merged Group. Business integrations are inherently risky. There may be unanticipated issues or costs that arise on integration of the Merged Group. Anticipated savings may not be able to be achieved to the extent expected. On the other hand, Santos has a strong track record from acquisitions and integrations implemented over the last three years.

- **The question of whether the Merger is in the best interests of shareholders involves a weighing up of the value considerations with the broader strategic and funding benefits and any downside factors. This judgement is inherently subjective.**

  A relative weighting of the valuation issues against the broader benefits of the Merger is not straightforward. There is clearly a risk that the funding and other strategic benefits do not fully compensate for the dilution of underlying value implied by the Merger terms. On the other hand, the options to maximise the value realised for Pikka and, over time, to optimise the development of its PNG interests are significant benefits of the Merger that are not available to Oil Search on a standalone basis. In the circumstances, the judgement is finely balanced. At a minimum, having regard to the challenges for Oil Search posed by its current circumstances and the inherent uncertainties attached to valuation, Grant Samuel believes that it is appropriate for the Merger to be put before shareholders for their consideration. Grant Samuel's view is that Oil Search shareholders are likely to be better off if the Merger proceeds than if it does not. Accordingly, the Merger is in the best interests of shareholders, in the absence of a superior proposal.

  However, the judgement is highly subjective and shareholders could reasonably weigh these factors differently, attributing less weight to the strategic, funding and other benefits and voting against the

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Merger. In doing so, they should be aware that if the Merger did not proceed it is likely that the Oil Search share price would fall (assuming continuation of current oil prices and broader market conditions). More importantly, shareholders would need to recognise the risks inherent in such a decision, including the real possibility that a standalone Oil Search would require equity support from its shareholders to maximise the value of its future development projects. A decision by shareholders as to whether to vote in favour of the Merger would depend on factors including their views on value, their willingness to support the funding required by a standalone Oil Search, their views on future oil prices, appetite for PNG risk, the strategic benefits available from the Merger and other matters.

4 Other Matters

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual Oil Search shareholders. Accordingly, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Scheme Booklet issued by Oil Search in relation to the Merger.

Grant Samuel has not been engaged to provide a recommendation to shareholders in relation to the Merger, the responsibility for which lies with the directors of Oil Search. In any event, the decision whether to vote for or against the Merger is a matter for individual shareholders, based on their own views as to value and business strategy, their expectations about future economic and market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. Shareholders who are in doubt as to the action they should take in relation to the Scheme should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell shares in Oil Search, Santos or the Merged Group. These are investment decisions upon which Grant Samuel does not offer an opinion and are independent of a decision on whether to vote for or against the Merger. Shareholders should consult their own professional adviser in this regard.

Grant Samuel has prepared a Financial Services Guide which is included at the beginning of the full report.

This letter is a summary of Grant Samuel's opinion. The full report from which this summary has been extracted is attached and should be read in conjunction with this summary.

The opinion is made as at the date of this letter and reflects circumstances and conditions as at that date.

Yours faithfully
GRANT SAMUEL & ASSOCIATES PTY LIMITED

Grant Samuel & Associates

FINANCIAL SERVICES GUIDE
AND
INDEPENDENT EXPERT'S REPORT
IN RELATION TO THE PROPOSED MERGER BETWEEN
OIL SEARCH LIMITED
AND
SANTOS LIMITED

GRANT SAMUEL & ASSOCIATES PTY LIMITED
ABN 28 050 036 372

9 NOVEMBER 2021

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FINANCIAL SERVICES GUIDE

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Grant Samuel is providing this Financial Services Guide ("FSG") in connection with its provision of an independent expert's report ("Report") which is included in a document provided to members by the entity ("Entity") for which Grant Samuel prepares the Report.

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When providing Reports, Grant Samuel's client is the Entity to which it provides the Report. Grant Samuel receives its remuneration from the Entity. In respect of the Report for Oil Search Limited ("Oil Search") in relation to the proposed merger with Santos Limited ("Santos") ("the Oil Search Report"), Grant Samuel will receive a fixed fee plus reimbursement of out-of-pocket expenses for the preparation of the Report (as stated in Section 7 of the Oil Search Report).

No related body corporate of Grant Samuel, or any of the directors or employees of Grant Samuel or of any of those related bodies or any associate receives any remuneration or other benefit directly attributable to the preparation and provision of the Oil Search Report.

The following information in relation to the independence of Grant Samuel is stated in Section 7.3 of the Oil Search Report:

> ***"Grant Samuel considers itself to be independent of Oil Search and Santos.***
>
> ***Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any business or professional relationship with Oil Search or Santos, or any financial or other interest that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Merger.***
>
> ***Grant Samuel had no part in the formulation of the Merger. Its only role has been the preparation of this report.***
>
> ***Grant Samuel will receive a fixed fee for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Merger. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report."***

Grant Samuel has internal complaints-handling mechanisms and is a member of the Australian Financial Complaints Authority, No. 11929. If you have any concerns regarding the Oil Search Report, please contact the Compliance Officer in writing at Level 19, Governor Macquarie Tower, 1 Farrer Place, Sydney NSW 2000. If you are not satisfied with how we respond, you may contact the Australian Financial Complaints Authority at GPO Box 3 Melbourne VIC 3001 or 1800 931 678. This service is provided free of charge.

Grant Samuel holds professional indemnity insurance which satisfies the compensation requirements of the Corporations Act.

Grant Samuel is only responsible for the Oil Search Report and this FSG. Complaints or questions about the Scheme Booklet should not be directed to Grant Samuel which is not responsible for that document. Grant Samuel will not respond in any way that might involve any provision of financial product advice to any retail investor.

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SELECTED GLOSSARY

The following terms used in this report (including the summary letter and appendices) have the meanings set out below:

GLOSSARY OF TECHNICAL TERMS

ABBREVIATION	DESCRIPTION
bbl / BBL	barrel of oil (42 US gallons or approximately 159 litres)
boe / BOE	barrel of oil equivalent (by energy value)
bopd	barrels of oil per day
kbbl	thousand barrels of oil
mmbbl / MMBBL	million barrels of oil
mmboe / MMBOE	million barrels of oil equivalent
Mt / MT	million tonnes
Mtpa /MTPA	million tonnes per annum
scf	standard cubic feet
mmscf / MMSCF	million standard cubic feet
bcf / BCF	billion cubic feet
tcf / TCF	trillion cubic feet
btu / BTU	british thermal unit
mmbtu / MMBTU	million british thermal units
tbtu	trillion british thermal units
GJ	gigajoules of energy
PJ	petajoules of energy
TJ	terrajoules of energy
1P	Proven reserves based on 90% probability (P90)
2P	Probable reserves based on 50% probability (P50)
1C	Contingent resources based on 90% probability (P90)
2C	Contingent resources based on 50% probability (P50)
km	kilometre(s)
kL	thousand litres
ML	million litres
MW	megawatts

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ABBREVIATION	DESCRIPTION
FID	Final Investment Decision
FEED	Front End Engineering and Design
CYXX	Calendar year end 31 December 20XX (i.e. CY20 is the year ended 31 December 2020)
1HYXX	Six months ended 30 June 20XX
2HYXX	Six months ended 31 December 20XX
EBITDAX	Earnings before net interest, tax, depreciation and amortisation, exploration costs written-off share of profits of equity accounted associates, investment income and significant and non-recurring items
EBITDA	Earnings before net interest, tax, depreciation and amortisation, share of profits of equity accounted associates, investment income and significant and non-recurring items
EBIT	Earnings before net interest, tax, share of profits of equity accounted associates, investment income and significant and non-recurring items
NPAT	Net profit after tax
NPV	Net present value
VWAP	Volume weighted average share price
EMV	Expected Monetary Value, a valuation methodology applied to the valuation of (in particular) prospective resources. The methodology essentially involves estimating an NPV for a hypothetical development assuming that the estimated hydrocarbon volumes are discovered, and then risking that NPV by applying a probabilty of success reflecting an estimate of the probability that a proposed exploration drilling program will prove up the estimated volumes
ESG	The common term for the range of concerns falling under Environment, Social and Governance issues

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1 Details of the Merger

On 20 July 2021, Oil Search Limited ("Oil Search") announced that it had received and rejected a confidential non-binding and indicative change of control proposal. On the same date, Santos Limited ("Santos") confirmed that it was the company that had submitted the proposal to the Oil Search Board. Under the all-scrip merger proposal (submitted on 25 June 2021), Oil Search shareholders would have received 0.589 new Santos shares for each Oil Search share held, with Oil Search shareholders owning 36.9% of the Merged Group.

On 2 August 2021, Oil Search announced that it had received an improved merger proposal from Santos under which Santos would acquire all of the shares in Oil Search for 0.6275 new Santos shares for each Oil Search share held and that the parties had decided to grant mutual due diligence access ("Revised Proposal"). Following completion of due diligence, Oil Search and Santos announced on 10 September 2021 that they had entered into a Merger Implementation Deed ("MID"), under which it is proposed that the two companies merge via an Oil Search scheme of arrangement ("Merger") on the terms agreed and released to the Australian Securities Exchange ("ASX") and PNG Exchange ("PNGX")[1] on 2 August 2021.

Upon completion of the Merger, Oil Search shareholders will own approximately 38.5% of the Merged Group and Santos shareholders will own approximately 61.5%.

Established in 1929, Oil Search is the largest oil and gas exploration and development company incorporated in Papua New Guinea (also referred to as PNG). It is listed on the ASX and the PNGX[2]. Santos is one of Australia's largest oil and gas companies and is an ASX top 50 company. The Merged Group is expected to be included within the S&P/ ASX 20 index and to be amongst the top 20 largest oil and gas companies in the world, with a pro forma market capitalisation of approximately A$25 billion[3].

The current Chief Executive Officer ("CEO") and Chairman of Santos, Mr Kevin Gallagher and Mr Keith Spence, will remain in those roles for the Merged Group. Following completion of the Merger, three non-executive directors from Oil Search will join the Santos Board. The composition of senior management (other than the CEO) will be determined following completion of the Merger.

The Merger is expected to realise annualised pre-tax synergies (cost savings) of $90-115 million per annum (excluding integration and other one-off costs).

Key conditions of the Merger include:

- Oil Search shareholder approval;
- approval by the National Court of Papua New Guinea ("PNG Court");
- regulatory approval; and
- no material adverse change, prescribed occurrences or regulated events (each as defined in the MID) occurring in relation to either Santos or Oil Search.

The MID includes reciprocal exclusivity arrangements during the exclusivity period[4] including "no shop", "no talk" and "no due diligence" restrictions (each subject to a fiduciary carve out) and notification obligations, matching rights for Santos on market standard terms and reciprocal break fees of A$80 million payable in certain circumstances.

The Oil Search Board of Directors has unanimously recommended that Oil Search shareholders vote in favour of the Merger in the absence of a superior proposal and subject to an independent expert concluding that the Merger is in the best interests of the Oil Search shareholders.

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1 Market operated by PNGX Markets Limited.

2 Oil Search shares are also listed in the United States via American Depository Receipts.

3 All reference to $ in this report are reference to United States dollars unless stated otherwise (e.g. A$)

4 Means the period from 10 September 2021 to the earlier of the termination of the MID, 10 June 2022 (or such other date as agreed by Oil Search and Santos) or the date the Scheme becomes effective

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2 Scope of the Report

2.1 Purpose of the Report

The Merger is to be implemented by way of a scheme of arrangement under Section 250 of the *Companies Act 1997* of PNG ("PNG Companies Act") between Oil Search and its shareholders ("Scheme"). The Scheme must be approved by the requisite majority being at least 75% of the votes cast. The Scheme will also require PNG Court approval. The PNG Companies Act does not specifically require the preparation of an independent expert's report in relation to a scheme effected under the PNG Companies Act, nor does it specify the opinion to be given. Grant Samuel understands that there is no other statutory or listing rule requirements for such a report. However, under Section 250 of the PNG Companies Act, the Court may make an order requiring that a report on the Scheme be prepared for the Court by a person specified by the Court and provided to shareholders. Past experience indicates that the Court will require an independent expert's report.

Accordingly, the directors of Oil Search have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report. The directors have requested that Grant Samuel state whether, in its opinion, the Merger is in the best interests of Oil Search shareholders and to state reasons for that opinion.

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual Oil Search shareholders. Accordingly, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Scheme Booklet issued by Oil Search in relation to the Merger.

Voting for or against the Scheme is a matter for individual shareholders based on their views as to value and business strategy, their expectations about future economic and market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. Shareholders who are in doubt as to the action they should take in relation to the Merger should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell securities in Oil Search, Santos or the Merged Group. These are investment decisions upon which Grant Samuel does not offer an opinion and are independent of a decision on whether to vote for or against the Scheme. Shareholders should consult their own professional adviser in this regard.

2.2 Basis of Evaluation

The PNG Companies Act and the PNG regulatory regime generally do not prescribe the preparation of a "best interests" opinion and so accordingly there is no relevant legal definition of the expression "in the best interests". Given that the Scheme is proceeding under PNG law and regulation, Australian regulation is not applicable.

In this context, Grant Samuel has assumed that the Merger will be in the best interests of Oil Search shareholders if they are likely to be better off if the Merger proceeds than if it does not. In particular, in Grant Samuel's view, assessment of whether the Merger is in the best interests of Oil Search shareholders requires consideration of the overall commercial effect of the proposed Merger, the circumstances that have led to the proposal and the alternatives available. The expert must weigh up the advantages and disadvantages of the Merger and form an overall view as to whether Oil Search shareholders are likely to be better off if the Merger is implemented than if it is not. If the advantages outweigh the disadvantages and shareholders are likely to be better off, then the Merger will be in the best interests of Oil Search shareholders.

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In assessing whether the Merger is in shareholders' best interests, Grant Samuel has had regard to the economic substance of the transaction.

From the perspective of Oil Search shareholders, there are factors that suggest that there is a "change of control" in favour of Santos under the Scheme:

- upon implementation of the Scheme, Oil Search shareholders will, in aggregate, own only 38.5% of the Merged Group;
- the agreed terms implied a premium for Oil Search shareholders of 16% compared to the price at which Oil Search shares closed on 19 July 2021 ($3.67), the day before the market was advised of Santos' initial proposal;
- only three Oil Search directors will be appointed to the Santos board (which has eight existing members); and
- the current Chairman and CEO of Santos will remain in those roles for the Merged Group.

On the other hand:

- the Scheme is a full scrip offer (with no cash alternative) so shareholders are in a different situation than in a cash offer where they are clearly selling "control" and will not retain any exposure going forward;
- a change of control at a board and management level should not be confused with a change of control from the perspective of a shareholder. The board serves at the behest of shareholders and former Oil Search shareholders will, collectively, have a significant vote. In turn, management is appointed by the board; and
- from a shareholder perspective the critical issue for control is shareholdings. Post implementation, there will be no shareholders with more than a 6% interest in the Merged Group. Oil Search shareholders will therefore retain the opportunity to receive a control premium at some time in the future.

While the Merger does not precisely fit the "merger of equals" construct, in Grant Samuel's opinion, the better view, on balance, is that merger analysis is the appropriate basis on which to assess the Merger.

Grant Samuel has assessed the Merger both in terms of "merger value analysis" and by considering the broader strategic, commercial and funding benefits that the Merger will potentially deliver.

The "merger value analysis" involves comparison of the exchange ratio with the relative contributions of the two sets of shareholders across a range of parameters. Put another way, it compares the share of value of the Merged Group received by Oil Search shareholders with the value contributed by Oil Search shareholders to that entity. For this purpose, Grant Samuel has had regard to relative contributions by Oil Search shareholders measured by reference to:

- Grant Samuel's estimate of the fundamental (underlying) value of both businesses, estimated on the same basis for both businesses;
- sharemarket value; and
- key parameters such as earnings and reserves/resources.

Nevertheless, as the relative shares (38.5%/61.5%) are on the outer bounds of what might be considered a "merger", Grant Samuel has also considered the terms of the Merger from the perspective of a takeover/change of control transaction for the sake of completeness.

In assessing the broader advantages and disadvantages of the Merger, Grant Samuel has considered:

- the impact of changes in energy markets and financial markets of a growing investor focus on ESG issues and the consequences for investor and corporate appetites for oil and gas exposures;

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- the funding constraints faced by Oil Search on a standalone basis;
- in particular, the funding and other challenges faced by Oil Search in relation to the optimal development of its Alaskan asset (the Pikka project) and the potential loss of value if in the absence of funding the project development could not be taken forward in a timely and optimal fashion;
- the improved funding position of the Merged Group and its impact on the funding and development of Oil Search's growth prospects;
- other positive aspects of the Merged Group, including its market rating, likely cost of capital and other relevant factors;
- the direct synergies expected to be realised as a result of the Merger;
- indirect synergies, including the potential benefits of an improved alignment of interests in relation to Oil Search's PNG operations including PNG LNG, Papua LNG, P'nyang and others;
- the impact of the Merger on the strategic positioning of the Merged Group and the longer term benefits that might flow from that positioning;
- the impact of the Merger on key investment metrics for Oil Search shareholders (e.g. earnings, distributions);
- the investment characteristics of the Merged Group compared to Oil Search on a standalone basis;
- the impact on the composition of the share register and sharemarket liquidity;
- the likelihood of an alternative offer and the opportunity for alternative transactions in the future;
- other benefits and advantages of the Merger for Oil Search shareholders; and
- other costs, disadvantages and risks of the Merger for Oil Search shareholders.

2.3 Sources of Information

The following information was utilised and relied upon, without independent verification, in preparing this report:

- the Scheme Booklet (including earlier drafts);
- annual reports of Oil Search and Santos for the five years ended 31 December 2020;
- half year announcement of Oil Search and Santos for the six months ended 30 June 2021;
- press releases, public announcements, media and analyst presentation material and other public filings by Oil Search and Santos including information available on its website;
- brokers' reports and recent press articles on Oil Search and Santos and the energy industry;
- sharemarket data and related information on Australian and international listed companies engaged in the oil and gas sector and on acquisitions of companies and businesses in this industry;
- information relating to the Australian and international energy sectors including supply/demand forecasts and regulatory decisions and pronouncements (as appropriate); and
- other confidential documents, board papers, presentations, working papers and detailed cash flow models for the business operations of Oil Search and Santos.

In preparing this report, Grant Samuel has held discussions with, and obtained information from, senior management of Oil Search and its advisers and senior management of Santos and its advisers.

2.4 Limitations and Reliance on Information

Grant Samuel believes that its opinion must be considered as a whole and that selecting portions of the analysis or factors considered by it, without considering all factors and analyses together, could create a misleading view of the process employed and the conclusions reached. Any attempt to do so could lead to

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undue emphasis on a particular factor or analysis. The preparation of an opinion is a complex process and is not necessarily susceptible to partial analysis or summary.

Grant Samuel's opinion is based on economic, sharemarket, business trading, financial and other conditions and expectations prevailing at the date of this report. These conditions can change significantly over relatively short periods. If they did change materially, subsequent to the date of this report, the opinion could be different in these changed circumstances.

This report is also based upon financial and other information provided by Oil Search and its advisers and Santos and its advisers. Grant Samuel has considered and relied upon this information. Oil Search and Santos have represented in writing to Grant Samuel that to their knowledge the information provided by them was then, and is now, complete and not incorrect or misleading in any material respect. Grant Samuel has no reason to believe that any material facts have been withheld.

The information provided to Grant Samuel has been evaluated through analysis, inquiry and review to the extent that it considers necessary or appropriate for the purposes of forming an opinion as to whether the Merger is in the best interests of Oil Search shareholders. However, Grant Samuel does not warrant that its inquiries have identified or verified all of the matters that an audit, extensive examination or "due diligence" investigation might disclose. While Grant Samuel has made what it considers to be appropriate inquiries for the purposes of forming its opinion, "due diligence" of the type undertaken by companies and their advisers in relation to, for example, prospectuses or profit forecasts, is beyond the scope of an independent expert.

Accordingly, this report and the opinions expressed in it should be considered more in the nature of an overall review of the anticipated commercial and financial implications rather than a comprehensive audit or investigation of detailed matters.

An important part of the information used in forming an opinion of the kind expressed in this report is comprised of the opinions and judgement of management. This type of information was also evaluated through analysis, inquiry and review to the extent practical. However, such information is often not capable of external verification or validation.

Preparation of this report does not imply that Grant Samuel has audited in any way the management accounts or other records of Oil Search or Santos. It is understood that the accounting information that was provided was prepared in accordance with generally accepted accounting principles and in a manner consistent with the method of accounting in previous years (except where noted).

Gaffney, Cline & Associates Pty Ltd ("GaffneyCline") was appointed technical specialist to provide advice to Grant Samuel and prepare a technical specialist report. In particular, for each of Oil Search and Santos, GaffneyCline reviewed estimates of reserves and resources, capital costs, production profiles and operating costs for each significant producing and development asset. GaffneyCline used this information (amended as appropriate) as the basis of valuation scenarios that it prepared for each of the assets of Oil Search and Santos. GaffneyCline also prepared valuations of the exploration interests of Oil Search and Santos. The report prepared by GaffneyCline is attached to and forms part of this report (see Appendix 7).

The information provided to Grant Samuel and GaffneyCline included development plans and forecasts for the key assets of Oil Search and Santos and detailed cash flow models including financial projections for each of their assets (the "forward looking information"). Oil Search and Santos are responsible for the forward looking information. Grant Samuel and GaffneyCline have considered and, to the extent deemed appropriate, relied on this information for the purposes of its analysis. For valuation purposes, GaffneyCline has recommended various changes to the information provided by Oil Search and Santos. Grant Samuel has also made its own assumption regarding various key variables (in particular commodity prices).

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Subject to these changes, on the basis of the information provided to Grant Samuel and GaffneyCline, and the review conducted by Grant Samuel and GaffneyCline of such information, Grant Samuel and GaffneyCline have concluded that the forward looking information was prepared appropriately and accurately based on the information available to management at the time and within the practical constraints and limitations of such forward looking information. However, the achievability of the forward looking information is not warranted or guaranteed by Grant Samuel. Future profits and cash flows are inherently uncertain. They are predictions by management of future events that cannot be assured and are necessarily based on assumptions, many of which are beyond the control of the company or its management. Actual results may be significantly more or less favourable.

The detailed valuation scenarios developed by GaffneyCline included assumptions relating to annual production, operating costs, capital costs and abandonment expenditures ("Detailed Information"). In the ordinary course, it would be expected that the Detailed Information would be included in Grant Samuel's report. Santos has advised Grant Samuel that some of the Detailed Information is or may be confidential or commercially sensitive to it and others and has declined to provide the releases required for Grant Samuel to include the Detailed Information in its report. Accordingly, Grant Samuel has removed or aggregated the Detailed Information.

While Oil Search and Santos have provided outlook statements for 2021, including certain production and cost parameters, the Directors of both companies have decided not to include the forward looking information in the Scheme Booklet and therefore this information has not been disclosed in this report.

To provide an indication of the expected financial performance of Oil Search and Santos, Grant Samuel has considered brokers' forecasts. Grant Samuel has used consensus estimates of brokers' forecasts to review the parameters implied by its valuations. These consensus forecasts are considered useful for analytical purposes although it should be noted that the forecasts are heavily dependent on the oil price (and associated energy prices) assumptions adopted by each broker at the time the forecast was made.

As part of its analysis, Grant Samuel has developed cash flow models on the basis of the technical valuation assumptions deemed appropriate by GaffneyCline. Grant Samuel has reviewed the sensitivity of net present values to changes in key variables. The sensitivity analysis isolates a limited number of assumptions and shows the impact of the expressed variations to those assumptions. No opinion is expressed as to the probability or otherwise of those expressed variations occurring. Actual variations may be greater or less than those modelled. In addition to not representing best and worst case outcomes, the sensitivity analysis does not, and does not purport to, show all the possible variations to the business model. The actual performance of the business may be negatively or positively impacted by a range of factors including, but not limited to:

- changes to the assumptions other than those considered in the sensitivity analysis;
- greater or lesser variations to the assumptions considered in the sensitivity analysis than those modelled; and
- combinations of different assumptions may produce outcomes different to those modelled.

In forming its opinion, Grant Samuel has also assumed that:

- matters such as title, compliance with laws and regulations and contracts in place are in good standing and will remain so and that there are no material legal proceedings, other than as publicly disclosed;
- the assessments by Oil Search and Santos and its advisers with regard to legal, regulatory, tax and accounting matters relating to the Merger are accurate and complete;
- the information set out in the Scheme Booklet sent by Oil Search to its shareholders is complete, accurate and fairly presented in all material respects;

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- the publicly available information relied on by Grant Samuel in its analysis was accurate and not misleading;
- the Merger will be implemented in accordance with its terms; and
- the legal mechanisms to implement the Merger are correct and will be effective.

To the extent that there are legal issues relating to assets, properties, or business interests or issues relating to compliance with applicable laws, regulations, and policies, Grant Samuel assumes no responsibility and offers no legal opinion or interpretation on any issue.

3 Profile of Oil Search

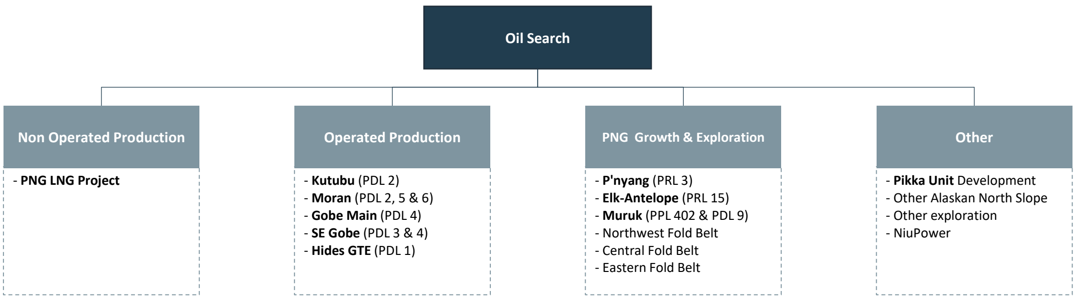
3.1 Background

Oil Search was incorporated in Papua New Guinea in 1929 with a focus on oil and gas exploration in PNG. It listed on the ASX in December 1980 and on the PNGX in December 2001. Oil Search is an ASX top 100 company with a market capitalisation of approximately A$9.5 billion as at 15 October 2021.

Oil Search transitioned from an exploration company to a production company when first gas was produced from the Hides field in 1991 and first oil from the Kutubu oil field in 1992. Since then, Oil Search has added to its asset portfolio in PNG through a number of acquisitions, including its acquisition of the upstream PNG assets of British Petroleum Limited in 1998, its merger with the PNG-government controlled Orogen Minerals Limited ("Orogen") in 2002, its acquisition of Chevron Niugini's PNG assets in 2003 and its acquisition of the Pac LNG Group companies in 2014. Although Oil Search had previously made various investments outside PNG (principally in the Middle East), its $400 million acquisition of interests in the Alaskan North Slope in 2018 was the first material acquisition outside PNG. Oil Search has since approximately doubled its interests in Alaska.

Oil Search owns a 29% stake in the ExxonMobil-operated PNG LNG Project, interests in various Oil Search-operated producing oil and gas fields in PNG that also supply gas to PNG LNG, stakes in oil and gas fields at various stages of development or exploration in PNG and its Alaskan North Slope interests. The asset portfolio can be summarised as follows:

OIL SEARCH ASSET PORTFOLIO



Source: Oil Search

A detailed profile of Oil Search's asset portfolio is set out in Appendix 3.

A key transformational event for Oil Search was the commencement of production at its 29% owned PNG LNG Project in April 2014. The project, which shipped its first cargo of LNG in May 2014, transformed Oil Search into an LNG producer and resulted in a step change increase in Oil Search's production. The PNG LNG Project has consistently operated at above its nameplate capacity of 6.9 Mtpa, producing 8.8 Mt of LNG in 2020 and operating at an annualised rate of 8.2 Mtpa in 1HY21. Oil Search produced a total of 29.0 mmboe from the PNG LNG Project and its operated PNG oil and gas assets in 2020, and expects to produce 26-28 mmboe in 2021.

Oil Search has significant growth options through the expansion and life extension of its LNG operations in PNG and the development of oil operations on the Alaskan North Slope. Oil Search and its partners in the PRL 15 (Papua LNG) joint venture plan to develop an additional two LNG trains in PNG with feedstock sourced from the Elk-Antelope fields, as well as from other surrounding discoveries and prospects, with first gas expected in 2027. Oil Search and its partners in the PRL 3 and PNG LNG joint ventures intend to develop the P'nyang gas field to provide material backfill volumes to the two existing LNG trains. In Alaska, Oil Search plans to commercialise the conventional Nanushuk oil reservoir by developing the Pikka Unit.

Oil Search commenced FEED studies for Phase 1 of the Pikka Project in February 2021, for a development planned to produce 80,000 bopd, with first oil planned for 2025.

Oil Search's head office is located in Port Moresby, PNG. It also has a substantial administration and engineering support office in Sydney, an office in Anchorage to provide regional support to Oil Search's Alaskan activities and a marketing office in Tokyo.

Key events in the development of Oil Search since January 2014 include:

DATE	EVENT
March 2014	Placement of Oil Search shares to the PNG Government equating to an approximate 10% stake
March 2014	Acquisition of Pac LNG Group, giving Oil Search a 22.8% interest in PRL 15 (Elk-Antelope)
April 2014	First production from the PNG LNG Project
September 2015	Woodside proposal to acquire Oil Search, ultimately withdrawn in December 2015
February 2018	Acquisition of oil interests on the Alaska North Slope for $400 million
February 2018	Highlands earthquake, significantly affecting Oil Search operations
April 2019	Signing of Papua LNG Gas Agreement
June 2019	Acquisition of further interests on the Alaska North Slope for $450 million
September 2019	Endorsement of Papua LNG Gas Agreement by new PNG administration
April to May 2020	Raising of A$1.14 billion of new equity (net of transaction costs) through a placement and entitlement offer
February 2021	Execution of Fiscal Stability Agreement regarding Papua LNG. Five year PRL15 licence extension awarded
February 2021	Commencement of FEED in relation to Phase 1 of the Pikka Unit development
September 2021	Execution of implementation deed for merger of Oil Search and Santos via scheme of arrangement

Source: Oil Search

3.2 Reserves and Contingent Resources

Oil Search's reserves and contingent resources as at 31 December 2020 are summarised as follows:

OIL SEARCH – RESERVES AS AT 31 DECEMBER 2020 (NET TO OIL SEARCH)

	PROVEN (1P)		PROVEN & PROBABLE (2P)	
	LIQUIDS (MMBBL)	GAS (BCF)	LIQUIDS (MMBBL)	GAS (BCF)
RESERVES				
Kutubu (PDL 2)	8.3	-	13.7	-
Moran Unit (PDL 2, 5 & 6)	4.9	-	8.5	-
Gobe Main (PDL 4)	0.01	-	0.0	-
SE Gobe (PDL 3 & 4)	-	-	0.0	5.4
Hides GTE (PDL 1)	-	-	-	-
Oil fields and Hides GTE	**13.2**	**-**	**22.2**	**5.4**
PNG LNG [5]	34.7	1,735.9	38.8	1,955.0
Total reserves	**48.0**	**1,735.9**	**61.0**	**1,960.4**

Source: Oil Search 2020 Annual Report
Note: Numbers may not add due to rounding

[5] PNG LNG Project Reserves comprise the Kutubu, Moran, Gobe Main, SE Hedinia, Hides, Angore and Juha fields.

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OIL SEARCH – CONTINGENT RESOURCES AS AT 31 DECEMBER 2020 (NET TO OIL SEARCH)

	1C		2C	
	LIQUIDS (MMBBL)	GAS (BCF)	LIQUIDS (MMBBL)	GAS (BCF)
CONTINGENT RESOURCES				
PNG LNG	-	-	2.1	142.0
Other PNG [6]	-	-	51.5	3,814.4
Pikka Project [7]	-	-	391.5	-
Other Alaska [7]	-	-	102.1	-
Total resources	-	-	**547.2**	**3,956.4**

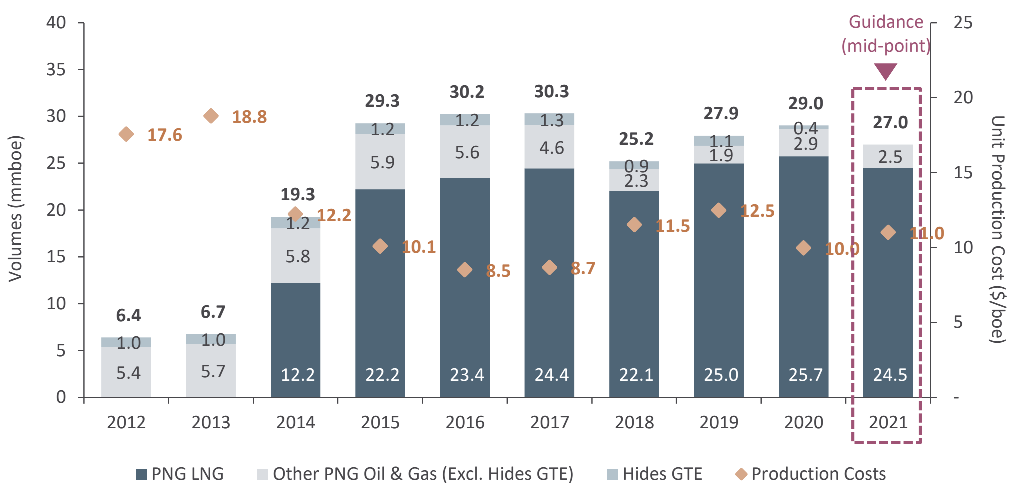
Source: Oil Search 2020 Annual Report
Note: Numbers may not add due to rounding

Reserves as at 31 December 2020 declined relative to 2019 reserves, primarily due to natural depletion, although there were also minor variations due to changes in price forecasts and project timing. The 2020 contingent resource estimates include a material increase in Alaskan oil volumes. The drilling of the Stirrup-1 and Mitquq-1 vertical and side-track wells, combined with reprocessed and merged 3D seismic data, resulted in the booking of 102.1 mmbbl attributable to the Horseshoe and Quokka trends, and 20.4 mmbbl attributable to the Pikka Unit. The contingent resource estimates also reflect a decline in PNG gas by 695.5 bcf, primarily due to Oil Search discontinuing its ownership of the licences relating to the Kimu, Uramu, Barikewa and Mananda gas and oil discoveries. The development concepts relating to these discoveries were internally assessed as commercially non-viable.

3.3 Production

Oil Search's annual production volumes and unit production costs from 2012 to 2020 are presented in the chart below, together with updated company guidance for 2021:

PRODUCTION VOLUMES (MMBOE NET TO OIL SEARCH) AND COSTS ($ PER BOE)



Source: Oil Search

The commencement of the PNG LNG project resulted in a step change in gas production from 5.5 bcf in 2013 to 57.9 bcf in 2014, and then to 103.8 bcf in 2015. While oil production trended down from 2016,

[6] Comprises Oil Search's other PNG fields including Elk-Antelope, SE Mananda, Juha North, P'nyang, Iehi, Cobra, Flinders and Muruk.
[7] Comprises Oil Search's 51% working interest before royalties in the Alaskan assets, incorporating the Nanushuk and satellite reservoirs.

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reflecting the natural decline of Oil Search's maturing oil fields in PNG, total annual production rose to, and was maintained at around 30 mmboe as the PNG LNG project produced at increasing rates.

Production fell in 2018 due to the 7.5 magnitude earthquake that struck the PNG Highlands in February 2018, causing material damage to well flow lines, processing facilities and other infrastructure. The PNG LNG Project recovered relatively quickly with production resuming in April 2018. It exceeded pre-earthquake throughput rates in the second half of 2018 and produced 25.0 mmboe in 2019.[8] The earthquake's impact on oil production was more significant, with production halving from 4.0 mmbbl in 2017 to 2.0 mmbbl in 2018. Oil production fell further to 1.6 mmbbl in 2019, due both to the impact of the earthquake and to unscheduled repairs at Oil Search's offshore liquids loading facility, restricting the level of liquids storage.

The PNG LNG Project produced 25.7 mmboe in 2020, a record since coming onstream, despite the impact on operations of COVID due to deferral of some maintenance expenditures. Operated oil production also increased from 1.6 mmbbl in 2019 to 2.6 mmbbl in 2020, reflecting the contribution of new development wells at Moran and Kutubu, in addition to well workovers and improved reliability at the Agogo Processing Facility.

Oil Search has released updated net production guidance of 26.0 – 28.0 mmboe for 2021, comprising 24 – 25 mmboe from the PNG LNG project and 2 – 3 mmboe from the operated fields. PNG LNG production in 2021 is expected to be lower than in 2020 due to the completion of scheduled maintenance at the Hides gas conditioning plant and the liquefaction plant in Port Moresby.

3.4 Financial Performance

Oil Search's operating performance for the five years ended 31 December 2020 and for the six months to June 2021 (summarised below) reflects relatively steady production from the PNG LNG Project, the natural decline in production at the oil fields, the effects of the PNG earthquake and repairs to the offshore loading facility, as well as material movements in realised oil, gas and LNG prices:

OIL SEARCH – PRODUCTION AND SALES SUMMARY

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
PRODUCTION VOLUMES						
Oil and condensate (mmbbl)	8.6	7.6	5.0	4.8	5.7	2.8
Gas (bcf)	110.5	116.0	102.9	117.9	117.4	54.5
Total (mmboe)	30.2	30.3	25.2	27.9	29.0	13.5
SALES VOLUMES						
Oil and condensate (mmbbl)	8.9	7.5	4.9	5.1	5.4	3.0
Gas (billion btu)	124,586	129,505	115,294	130,049	131,622	59,770
Total (mmboe)	30.6	30.0	25.0	27.8	28.4	13.4
REALISED PRICES						
Oil and condensate ($/bbl)	45.0	55.7	70.7	62.9	37.2	64.7
LNG and gas ($/mmbtu)	6.4	7.7	10.1	9.6	6.5	7.9
UNIT PRODUCTION COSTS						
Total production cost ($/boe)	8.50	8.67	11.50	12.48	9.97	10.63

Source: Oil Search Annual Reports

8 The PNG LNG Project achieved an annualised production rate of 8.8 Mtpa for 2HY18, which compares to 8.5 Mtpa for 2HY17 and nameplate capacity of 6.9 Mtpa.

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Oil and Condensate

Average realised oil and condensate prices increased by 24% in 2017 and 27% in 2018, offsetting a decline in oil and condensate sales volumes of 16% in 2017, due to lower production at Kutubu and Moran, and 34% in 2018, due to the effects of the PNG earthquake on well flowlines, production facilities and other relevant infrastructure. Oil and condensate sales volumes recovered modestly in 2019 and 2020, while average realised prices declined by 11% in 2019 and 41% in 2020, reflecting lower global energy prices and, in particular, Russia-Saudi Arabia oil supply and price competition and the impact of COVID on oil demand.

LNG and Gas

LNG and gas sales volumes increased by 4% from 2016 to 2017, largely reflecting the strong performance of the PNG LNG Project. Increased volumes, combined with a material recovery in global energy prices, resulted in an increase of 25% in LNG and gas sales revenues in 2017. An 11% fall in gas sales volumes in 2018 due to the PNG earthquake was more than offset by a 31% increase in realised prices, resulting in a net revenue uplift of 17%. Gas sales volumes returned to pre-earthquake levels in 2019, increasing by approximately 13%, which was followed by a marginal increase in 2020. The increased sales volumes in 2019 were offset in part by a 5% reduction in the realised LNG and gas price, resulting in a net increase of 7% in gas and LNG revenues for 2019. The small increase in volumes in 2020 was more than offset by a 32% reduction in realised LNG prices, resulting in a net decline of 31% in gas and LNG revenues. Production and sales volumes are expected to decline marginally in 2021 relative to 2020 levels, as a result of scheduled maintenance at the Hides gas conditioning plant and the LNG liquefaction plant.

Production Costs

Unit production costs increased slightly from 2016 to 2017 which included higher field maintenance costs and the commencement of the Moran-4 workover. Unit production costs in 2018 and 2019 were considerably higher than preceding years and were affected by the remediation costs associated with the Highlands earthquake and repairs to the offshore liquids loading facility. Unit production costs in 2020 fell due to the combination of higher production volumes, lower earthquake remediation expenditures, cost reduction initiatives and the deferral of discretionary expenditures.

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Oil Search's financial performance over the period is summarised as follows:

OIL SEARCH – FINANCIAL PERFORMANCE ($ MILLIONS)[9]

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
FINANCIALS						
LNG sales	759.0	952.6	1,124.9	1,201.4	835.9	467.4
Oil and condensate sales	383.1	394.9	326.0	295.5	188.7	180.9
Gas sales	33.8	40.4	35.1	45.0	18.9	1.8
Other revenue [10]	59.9	58.0	49.7	43.0	30.6	17.6
Total revenue	**1,235.9**	**1,446.0**	**1,535.8**	**1,584.8**	**1,074.2**	**667.7**
EBITDAX	**852.2**	**1,052.1**	**1,110.0**	**1,145.9**	**721.0**	**488.8**
Exploration costs expensed	(53.2)	(35.9)	(66.7)	(47.3)	(103.3)	(9.8)
EBITDA	**799.0**	**1,016.2**	**1,043.3**	**1,098.6**	**617.7**	**479.0**
Depreciation and amortisation	(436.7)	(380.6)	(326.1)	(413.7)	(423.8)	(202.0)
Share of net profits from joint ventures	-	-	-	0.6	5.1	1.9
Other	-	-	-	4.4	21.6	-
Core EBIT[11]	**362.3**	**635.6**	**717.2**	**689.9**	**220.5**	**278.8**
Net interest expense	(196.0)	(194.7)	(209.9)	(230.9)	(190.4)	(80.1)
Core profit before tax	**166.3**	**440.9**	**507.4**	**459.0**	**30.1**	**198.8**
Core income tax expense	(59.6)	(138.8)	(166.2)	(138.1)	(8.1)	(59.8)
Core NPAT before significant items[12]	**106.7**	**302.1**	**341.2**	**320.9**	**22.0**	**139.0**
Impairment expenses (post tax)	-	-	-	(4.1)	(260.2)	-
InterOil break-fee (post tax)	18.7	-	-	-	-	-
Other signficant items (post tax)	(35.6)	-	-	(4.4)	(82.5)	-
NPAT after significant items – As Reported	**89.8**	**302.1**	**341.2**	**312.4**	**(320.7)**	**139.0**
STATISTICS						
Sales revenue growth (%)	*(22.1)%*	*17.0%*	*6.2%*	*3.2%*	*(32.2)%*	*n.a.*
EBITDAX margin (%)	*69.0%*	*72.8%*	*72.3%*	*72.3%*	*67.1%*	*73.2%*
EBITDA margin (%)	*64.6%*	*70.3%*	*67.9%*	*69.3%*	*57.5%*	*71.7%*
Core EBIT margin (%)	*29.3%*	*44.0%*	*46.7%*	*43.5%*	*20.5%*	*41.8%*
Core effective tax rate (%)	*35.8%*	*31.5%*	*32.8%*	*30.1%*	*26.9%*	*30.1%*

Source: Oil Search Annual Reports and Grant Samuel analysis and calculation

Oil Search's financial performance reflects the movements in oil, gas and LNG sales volumes, oil and gas prices and production costs outlined above, as well as the following:

- **Exploration Costs Expensed**: exploration costs expensed in 2020 include the unsuccessful Gobe Footwall well in PNG and exploration activity in Alaska predominantly relating to the acquisition of Kuukpik 3D seismic data. Approximately $65.2 million is attributable to PNG, with the remaining $38.1 million attributable to Alaska;

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9 Financial information shown below has been prepared by Grant Samuel from published financial statements but is not presented in the same format as the statutory accounts. Some of the key statistics and metrics included in these tables have been calculated by Grant Samuel and are not reported by Oil Search.

10 Other revenue consists of infrastructure tariffs, rig lease income, shipping revenue, marketing fees, and electricity and naphtha sales.

11 Core EBIT excludes Interoil fee, impairment, site restoration costs and significant items.

12 Core NPAT is net profit excluding significant, non-recurring and other one-off items.

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- **Depreciation and Amortisation**: depreciation and amortisation ("D&A") reached its lowest point in 2018, largely reflecting the curtailment of production following the PNG earthquake. D&A expense increased by $88 million in 2019, primarily due to higher production volumes and higher D&A for right-of-use assets recognised in line with the adoption of the IFRS 16 *Leases* accounting standard. D&A further increased by $10 million in 2020, consistent with higher production volumes;
- **Share of Net Profits from Joint Ventures**: Oil Search's share of net profits from joint ventures ($0.6 million in 2019 and $5.1 million in 2020) relates to its 50% interest in NiuPower and NiuEnergy, the owner and operator of the Port Moresby gas-fired power station. The power station currently has capacity to deliver 58 MW to the Port Moresby grid;
- **Significant Items (Post Tax)**: the charge of $35.6 million in 2016 related to a one-off, non-cash restatement of deferred tax balances as a consequence of changes in PNG tax legislation. The impairment charge of $4.1 million in 2019 relates to both the PNG and Alaska business units. The post tax impairment expense of $260.2 million in 2020 relates to exploration assets in PNG and Alaska that were assessed as non-prospective or non-economic and the Hides GTE project which is currently in care and maintenance. The other item of $82.5 million in 2020 comprises site restoration cost increases for previously impaired assets and the derecognition of net deferred tax assets ($61.5 million); and
- **Income Tax**: the effective tax rate in 2016 was approximately 50% as oil fields attracted an income tax rate of 50%, as opposed to the current income tax rate of 30%. The legislative changes aligned the tax rate levied on oil proceeds with that levied on gas proceeds. From 1 January 2017 effective tax rates remained relatively consistent with the current income tax rate of 30%.

Oil Search's earnings per share (before significant items) have predominantly trended in line with core net profit after tax. For the period 2016 to 2019, the marginal increases in the number of Oil Search shares on issue were the result of small issues pursuant to its dividend reinvestment plan or to satisfy the vesting and exercise of share and performance rights. In April and May 2020, Oil Search issued approximately 553 million new shares to raise A$1.14 billion (net of transaction costs) through an accelerated pro-rata non-renounceable entitlement offer, an institutional placement, and an offer to its PNG shareholders. This equity raise was undertaken to strengthen Oil Search's balance sheet and improve its liquidity position, given the material fall in oil prices and adverse market conditions that resulted from the COVID pandemic.

Following the commencement of production at the PNG LNG Project, Oil Search reassessed its dividend policy and now seeks to pay out between 35% and 50% of NPAT before significant items. All dividends are unfranked as Oil Search does not pay tax in Australia.

OIL SEARCH – EARNINGS AND DIVIDENDS PER SHARE[9]

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
Basic EPS before significant items (cents)	7.0	19.8	22.4	21.1	1.1	6.7
Basic EPS after significant items (cents)	5.9	19.8	22.4	20.5	(16.6)	6.7
Dividends per share (cents)	3.5	9.5	10.5	9.5	0.5	3.3
Percentage of dividends franked (%)	-	-	-	-	-	-
Effective payout ratio (%)	49.9%	47.9%	46.9%	45.1%	47.2%	49.3%
Weighted average no. shares (millions)	1,522.7	1,523.3	1,523.6	1,524.3	1,929.3	2,077.9

Source: Oil Search Annual Reports and Grant Samuel analysis and calculations

Outlook

Oil Search provides guidance in relation to future production, operating costs, D&A and investment expenditure.

Oil Search's third quarter guidance for 2021 production is expected to be 26 – 28 mmboe, comprising 24 – 25 mmboe from the PNG LNG Project and 2 - 3 mmboe from other oil and gas fields. 2021 production guidance is below 2020 realised production levels, reflecting the impact of scheduled maintenance at the Hides gas conditioning plant and the liquefaction plant for PNG LNG.

Oil Search is expecting total unit production costs to be in the range $10.5 – 11.5/boe in 2021.

Oil Search is also expecting total investment expenditure for 2021 to be in the range $185-275 million, approximately 50% of which relates to exploration and evaluation, including FEED costs relating to Phase 1 of the Pikka Unit development and pre-FEED costs for the LNG expansion project in PNG.

Oil Search does not provide guidance in relation to sales revenue or earnings. To provide an indication of the expected future financial performance of Oil Search, Grant Samuel has considered broker forecasts for Oil Search (which are sensitive to assumptions as to future oil prices) summarised as follows:

OIL SEARCH – FINANCIAL PERFORMANCE ($ MILLIONS)

	YEAR ENDING 31 DECEMBER			
	ACTUAL	BROKER CONSENSUS		
	2020	2021	2022	2023
Production (mmboe)	29.0	27.5	28.5	28.7
Revenue	1,074.2	1,566.0	1,824.6	1,660.2
EBITDAX	721.0	1,175.0	1,476.0	1,291.5
EBITDA	617.7	1,146.8	1,435.3	1,246.3
Core EBIT	220.5	770.0	1,051.0	863.5
Core NPAT before significant items	22.0	419.0	640.0	514.0
EPS before significant items (cents)[13]	1.1	20.2	30.8	24.7
Dividends per share (cents)[13]	0.5	9.0	13.5	11.5

Source: Broker reports and Grant Samuel analysis.

[13] Some broker estimates have been converted from Australian dollars to United States dollars using either the broker's own forecast exchange rates or the spot rate.

3.5 Financial Position

The financial position of Oil Search at year end for each of the five years ended 31 December 2020 and at 30 June 2021 is summarised below:

OIL SEARCH - FINANCIAL POSITION ($ MILLIONS)[9]

	31 DECEMBER					30 JUNE 2021
	2016	2017	2018	2019	2020	
Receivables	152.7	156.3	228.7	272.1	169.4	186.2
Inventories	106.8	95.0	90.4	104.0	127.8	131.4
Prepayments	11.8	20.8	12.3	19.9	30.0	21.4
Creditors and provisions	(236.0)	(292.6)	(414.2)	(466.2)	(244.1)	(264.3)
Net working capital	**35.3**	**(20.5)**	**(82.8)**	**(70.2)**	**83.1**	**74.7**
Oil and gas assets	6,646.3	6,535.7	6,240.6	6,124.4	6,020.6	5,717.9
Exploration and evaluation assets	1,521.4	1,672.4	2,344.8	2,998.0	2,740.8	2,788.2
Other property, plant and equipment	186.7	205.7	248.8	488.3	472.9	448.4
Investment in joint ventures	-	-	4.0	54.4	59.5	61.4
Other non-current assets	117.0	133.2	142.8	149.4	155.4	158.1
Non-current payables and provisions	(404.0)	(609.5)	(593.1)	(698.7)	(868.1)	(717.8)
Deferred tax assets/(liabilities) (net)	(165.3)	(235.5)	(315.2)	(388.8)	(328.0)	(351.4)
Net capital employed	**7,937.3**	**7,681.4**	**7,989.8**	**8,656.8**	**8,336.3**	**8,179.6**
Cash and deposits	862.7	1,015.2	600.6	396.2	540.8	503.6
Bank loans, other loans and finance leases	(4,074.8)	(3,758.9)	(3,424.8)	(3,794.6)	(3,306.8)	(2,999.5)
Net borrowings	**(3,212.0)**	**(2,743.7)**	**(2,824.2)**	**(3,398.4)**	**(2,766.0)**	**(2,495.9)**
Net assets	**4,725.3**	**4,937.8**	**5,165.6**	**5,258.4**	**5,570.3**	**5,683.7**
Equity attributable to Oil Search shareholders	**4,725.3**	**4,937.8**	**5,165.6**	**5,258.4**	**5,570.3**	**5,683.7**
STATISTICS						
Shares on issue at period end (million)	*1,522.7*	*1,523.6*	*1,523.6*	*1,524.7*	*2,077.9*	*2,077.9*
Net asset per share	*3.10*	*3.24*	*3.39*	*3.45*	*2.68*	*2.74*
Gearing [14]	*40.5%*	*37.0%*	*35.3%*	*36.2%*	*29.9%*	*27.2%*

Source: Oil Search Annual Reports and Grant Samuel analysis

Oil and gas assets generally relate to producing assets. Exploration and evaluation assets mostly comprise licence acquisition costs, which are classified as intangible assets and account for approximately 65% of the total, and capitalised drilling and well evaluation costs.[15] Transport, logistics and rigs account for approximately 50% of other property, plant and equipment, with the balance comprising corporate assets. Provisions mostly relate to site restoration obligations and employee entitlements. The material uplift in exploration and evaluation assets from 2017 to 2019 is largely attributable to Oil Search's acquisition of licence interests in Alaska, while the step-up in other property, plant and equipment from 2018 to 2019 principally reflects the adoption of the IFRS 16 *Leases* accounting standard. The decline in exploration and evaluation assets from 2019 to 2020 is in large part related to the impairment of various licences in PNG and Alaska.

[14] Gearing is calculated as net borrowings (excluding finance leases) divided by net assets plus net borrowings (excluding finance leases) in accordance with Oil Search practice.

[15] Upon approval for development, an asset's accumulated exploration and evaluation costs are transferred to oil and gas assets.

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Oil Search's debt balance of $2,999.5 million as at 30 June 2021 consists of the company's share of the PNG LNG Project financing of $2,425.8 million (a reduction of $191.2 million relative to 31 December 2020), $200.0 million of bilateral revolving corporate facilities and $373.7 million of finance leases.

The PNG LNG Project borrowing entity is a separate company in which each of the PNG LNG equity participants has an interest equal to its interest in the project. The PNG LNG Project debt is secured against the PNG LNG Project assets and cash flows, with no recourse to the PNG LNG Project sponsors. Interest and principal is payable semi-annually, and commenced in June 2015, with the principal being repayable over 11.5 years based on a customised repayment profile. As at 30 June 2021, there were five years remaining until the debt is fully repaid. A minimum cash balance equal to the next six months' of scheduled interest and principal payments is maintained within the PNG LNG Project accounts. There are no financial covenants, although PNG LNG distributions are subject to meeting historic and forecast debt service cover ratios.

In December 2018, Oil Search replaced two $125 million bilateral facilities with three separate $100 million bilateral revolving credit facilities with expiration in December 2023. $200 million was drawn on these facilities as at 30 June 2021. In September 2019, Oil Search arranged an additional $300 million of unsecured bilateral facilities with expiration in September 2020, to partially fund its $450 million acquisition of additional interests in Alaska. In May 2020, the expiry date for these facilities was extended to 30 June 2021 and secured, and they were repaid and cancelled during 1HY21. In September 2021, Oil Search entered into a $565 million non-amortising revolving credit facility with maturity in December 2026. This replaced an undrawn $600 million debt facility that was due to expire in June 2022. There are several financial covenants that apply to the corporate facilities, including a 3.0x EBITDAX to interest cover ratio (increasing to 4.0x in 2025) calculated biannually over the prior and future twelve months. In September 2021, the limit on the bilateral revolving credit facilities with an expiration in December 2023 was reduced from $300 million to $260 million.

As at 30 June 2021, Oil Search had a cash balance of $504 million, including $316 million in PNG LNG escrow accounts, resulting in total liquidity of $1.2 billion.

OIL SEARCH – NET BORROWINGS AT 30 JUNE 2021 ($ MILLIONS)

FACILITY	FACILITY SIZE	AMOUNT DRAWN	MATURITY
PNG LNG Project finance facility	2,425.8	2,425.8	June 2026
Finance leases		373.7	
Syndicated revolving facility [16]	600.0	-	June 2022
Bilateral revolving facilities | 5 Year	300.0	200.0	December 2023
Total interest bearing liabilities	**3,325.8**	**2,999.5**	
Cash and short term deposits		503.6	
Net borrowings		**2,495.9**	

Source: Oil Search

[16] This facility was replaced in September 2021 with a $565 million non-amortisation revolving credit facility expiring in December 2026.

3.6 Cash Flows

Oil Search's cash flows for the five years ended 31 December 2020 and for the six months to June 2021 are summarised below:

OIL SEARCH – CASH FLOWS ($ MILLIONS)[9]

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
NPAT	89.8	302.1	341.2	312.4	(320.7)	139.0
Exploration costs expensed	32.2	21.9	-	-	44.5	-
D&A	436.7	380.6	326.1	413.7	423.8	202.0
Impairment	-	-	-	5.9	374.2	-
Share of net profit from joint ventures	-	-	-	(0.6)	(5.1)	(1.9)
Other non-cash items	17.2	26.2	28.0	28.1	12.0	11.9
Net working capital & other adjustments	(20.8)	112.7	159.3	(4.9)	(122.7)	2.9
Operating cash flows	**555.1**	**843.6**	**854.6**	**754.6**	**406.1**	**353.9**
Payments for producing assets	(35.7)	(38.2)	(26.2)	(78.6)	(49.5)	(12.6)
Payments for oil & gas development assets	(34.8)	(21.1)	(36.9)	(39.5)	(139.3)	(6.0)
Payments for exploration & evaluation assets	(142.9)	(157.3)	(647.6)	(650.7)	(167.0)	(39.8)
Payments for power assets	-	(10.2)	(41.7)	(6.3)	-	-
Payments for other plant & equipment	(12.0)	(38.1)	(56.4)	(36.4)	(36.1)	(10.5)
Loans or advances to third parties	(3.5)	(2.3)	(2.2)	(1.8)	(1.2)	(0.5)
Investing cash flows	**(228.9)**	**(267.3)**	**(811.0)**	**(813.3)**	**(393.2)**	**(69.5)**
Dividends	(76.1)	(99.0)	(114.3)	(205.7)	(68.6)	(10.4)
Net proceeds from share issues	-	-	-	-	698.7	-
Proceeds from borrowings	-	-	-	1,150.0	275.0	330.0
Repayment of borrowings	(289.3)	(313.9)	(331.9)	(1,064.2)	(737.4)	(621.2)
Finance lease payments	(1.5)	(2.0)	(2.2)	(24.0)	(31.8)	(14.8)
Other [17]	(7.1)	(8.9)	(10.0)	(1.8)	(4.1)	(5.2)
Financing cash flows	**(374.0)**	**(423.8)**	**(458.3)**	**(145.7)**	**131.8**	**(321.6)**
Opening cash balance	910.5	862.7	1,015.2	600.6	396.2	540.8
Net cash flows	(47.7)	152.5	(414.7)	(204.3)	144.6	(37.2)
Closing cash balance	**862.7**	**1,015.2**	**600.6**	**396.2**	**540.8**	**503.6**

Source: Oil Search and Grant Samuel analysis and calculations

Oil Search generated substantial cash flows from operations during the 2017, 2018 and 2019 financial years, reflecting high levels of profitability. However, the low oil price environment in 2020, combined with an increase in net working capital, led to a 46.0% reduction in operating cash flows from 2019 to 2020. Operating cash flows over the past five years have been applied primarily to fund ongoing operations, support exploration and developments, make debt repayments and pay dividends to the Oil Search shareholders.

Expenditure on producing assets predominantly relates to the completion of additional wells in PNG, as well as sustaining capital expenditure for the PNG LNG Project and the operated PNG oil and gas assets. Development expenditure relates primarily to civil works, engineering and optimisation studies in relation to the development of the Pikka Unit in Alaska and the Oil Search share of PNG LNG Project development

17 Comprises the purchase of treasury shares, establishment fees on credit facilities and loans to third parties.

costs for Angore. Exploration and evaluation expenditure relates principally to the drilling of appraisal wells in PNG and Alaska, the acquisition of seismic data in PNG across the Eastern Foldbelt, pre-FEED activities for Papua LNG, P'nyang and the Pikka Unit, and the acquisition of licence interests, including more than $950 million for the Alaskan North Slope interests in 2018 and 2019. Payments for power assets from 2017 to 2019 relate to the PNG Biomass project and the NiuPower gas-fired power station in Port Moresby. Expenditure on other plant and equipment relates to Oil Search's enterprise resource planning system.

Oil Search has a proportional dividend policy of 35-50% of NPAT before significant items and it has consistently paid near the top of that range over the past five years. Oil Search announced total unfranked dividends of $0.005 per share for the 2020 financial year and distributed $10.4 million in the form of dividend payments to its shareholders in March 2021. A dividend of $68.6 million was paid to shareholders in September 2021 in respect of profits for the half year to 30 June 2021.

The $698.7 million raised in 2020 (net of transaction costs) was via the institutional placement and entitlement offer described in Section 3.4.

Oil Search has reduced its level of borrowings in each financial year from 2016 to 2020, with the exception of 2019 in which it drew down $85.8 million in excess of its repayments to partially fund the acquisition of further Alaskan assets. Debt movements generally relate to scheduled amortisation of the PNG LNG project debt and the establishment, refinancing or maturation of various corporate facilities as described in Section 3.5.

The cash balance of $504 million as at 30 June 2021 includes $316 million escrowed in the PNG LNG Project accounts. Sales proceeds for the PNG LNG Project are paid into the PNG LNG Project account and used for agreed expenditures and debt servicing, with the surplus then distributed to the project participants if the debt service cover ratio tests are met.

3.7 Taxation Position

At 30 June 2021, Oil Search had a deferred tax asset of $1,038.3 million which is expected to be recovered against future revenues from exploration, development and production, including the following:

- carried forward PNG income tax losses of approximately $69.6 million, of which $64.9 million were recognised;
- carried forward Australian income tax losses of approximately $6.3 million;
- carried forward US net operating losses of approximately $122.5 million; and
- infrastructure tax credits of approximately $225.5 million available for offset against future PNG income tax liabilities;

Oil Search has no franking credits for distribution to shareholders.

3.8 Capital Structure

As at 22 September 2021, Oil Search had the following securities on issue:

- 2,077,850,664 ordinary fully paid shares;
- 6,426,300 share rights;
- 4,781,470 performance rights;
- 374,442 LNG expansion rights;
- 356,611 alignment rights;
- 1,329,081 restricted shares;
- 42,240 non-executive director restricted shares; and
- 22,971 non-executive director rights.

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The employee share rights are granted for nil consideration and are subject to continued employment at the vesting date. Upon vesting, share rights will be automatically exercised and may be converted to ordinary shares in Oil Search or may be settled in cash of equivalent value, at the Board's discretion. As at 22 September 2021, there were 6,426,300 share rights on issue, held by 968 employees, exercisable at nil cost and in 16 tranches across the period to 20 May 2024.

Each performance right is granted for nil consideration and represents a right to an ordinary share provided specified performance hurdles are met within defined time periods. Examples of the performance hurdles that apply to performance rights include the achievement of total shareholder return benchmarks over three years. Shareholder return is tracked relative to a peer group. 2019 and 2020 grants are measured relative to the ASX50, excluding property trusts and non-standard listings, as well as particular constituents of the S&P Global Energy Index. The two performance criteria for the vesting of performance rights grants made in 2021 are total shareholder return measured relative to the constituents of 14 upstream oil and gas peer companies and Oil Search Return on Capital Employed performance measured in the 2023 financial year.

Upon vesting, Performance Rights may be converted to ordinary shares in Oil Search or may be settled in cash of equivalent value, at the Board's discretion. As at 22 September 2021, there were 4,781,470 performance rights on issue, held by 77 current and former employees, exercisable at nil cost and in 9 tranches across the period to 20 May 2024.

The LNG expansion projects incentive was granted in 2018 as a separate incentive for the achievement of investment sanction for the Papua LNG development project and the PNG LNG expansion project. Vesting is contingent on achieving investment sanction for the Projects within a defined period with a vesting period that ends two years after investment sanction is achieved (provided that date is before a certain date determined by the Board). As at 22 September 2021 there were 374,442 LNG Expansion Rights held by 8 current and former employees.

Awards of alignment rights were introduced in 2021 and are structured as rights to acquire ordinary shares in the Company for nil consideration, provided the Board is satisfied during its vesting assessment that the minimum standards of performance are met over the three-year assessment period. Upon vesting, alignment rights may be converted to ordinary shares in Oil Search or may be settled in cash of equivalent value, at the Board's discretion. As at 22 September 2021, there were 356,611 alignment rights on issue, held by 47 current and former employees, exercisable at nil cost and in 2 tranches across the period to 20 May 2024.

Restricted shares are granted as a deferral of a portion of a participant's short-term incentive award. Restricted shares are held on trust on behalf of the participants until the terms of the Plan are satisfied. As at 22 September 2021, there were 1,329,081 restricted shares on issue, held by eight current and former employees.

The Non-Executive Director Fee Sacrifice Share Acquisition Plan is intended to facilitate share ownership and to support Board members to reach minimum share ownership requirements. The Plan operates through a biannual grant of NED rights to the value of a portion of fees sacrificed by individual Directors. NED rights when vested convert into NED restricted shares, which are restricted from sale for a period nominated by the Director when electing to participate in the Plan for the relevant year. The restriction period will end earlier than the elected period if the director retires from the Board. As at 22 September 2021, there were 22,971 NED rights on issue held by two Directors and 42,240 NED restricted shares held by two Directors.

The vesting of the securities issued pursuant to the employee incentive plans and the Non-Executive Director Fee Sacrifice Share Acquisition Plan is not automatic in the event of a change of control transaction. Vesting is at the Board's discretion.

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3.9 Ownership

At 22 September 2021, there were approximately 66,000 registered shareholders in Oil Search. The top twenty registered shareholders account for approximately 85% of the shares on issue and are principally institutional nominee or custodian companies.

Oil Search has received substantial holder notices from the following parties:

OIL SEARCH – SUBSTANTIAL SHAREHOLDERS

	NUMBER OF SHARES	PERCENTAGE
BlackRock Inc	126,212,734	6.07%
UBS Group AG	134,404,202	6.47%
Total		**12.54%**

Source: BlackRock – Oil Source Annual Report January 2021, UBS – Notice of change in interest October 2021

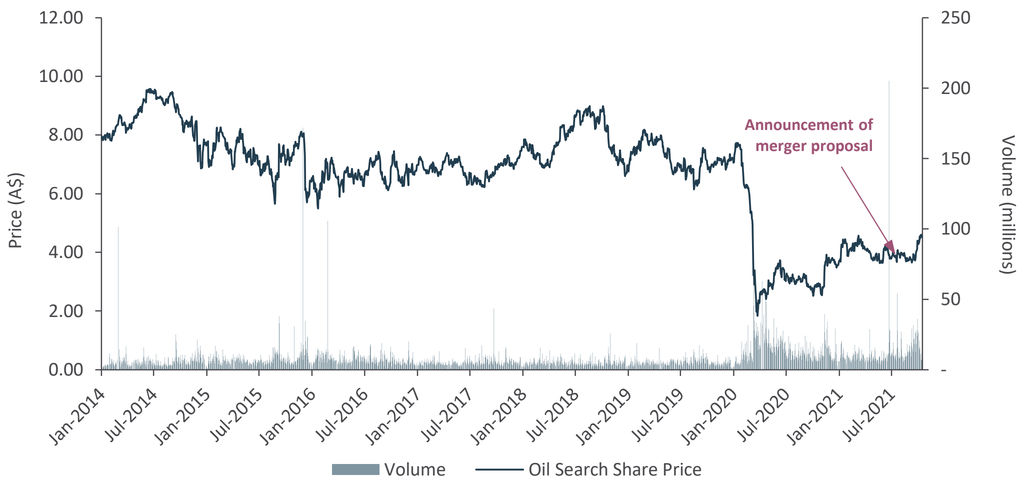
The Independent State of Papua New Guinea ("State of PNG"), through the Independent Public Business Corporation ("IPBC") as trustee of The General Business Trust of Papua New Guinea, became a shareholder in Oil Search in 2002 through the merger of Oil Search and Orogen, as it had a 51% interest in Orogen. In 2008, IPBC used its interest in Oil Search to secure funding for the State of PNG's share of the capital costs in the PNG LNG Project, through the issue of exchangeable bonds to the International Petroleum Investment Company ("IPIC"), an investment vehicle wholly owned by the Abu Dhabi Government. The bonds matured in March 2014 at which time IPIC issued a Mandatory Exchange Notice to IPBC, which resulted in IPBC transferring its shareholding in Oil Search to IPIC. IPIC merged with Mubadala Development Company in 2017 to create Mubadala Investment Company. Mubadala sold approximately half of its stake in June 2021, reducing its equity interest in Oil Search from 9.46% to 4.94%.

In March 2014, Oil Search issued 149 million shares to an entity controlled by the State of PNG, to fund Oil Search's acquisition of the Pac LNG Group companies. The funds received by the share issue were used by Oil Search to acquire its interest in PRL 15 (Elk-Antelope). The State of PNG sold its shares in September 2017 to fund health, education, infrastructure and other initiatives, and as a result, no longer has a shareholding in Oil Search.

3.10 Share Price Performance

A summary of the share trading history of Oil Search shares from 1 January 2014 to 15 October 2021 is set out in the chart below:

OIL SEARCH – SHARE PRICE AND TRADING VOLUME



Source: IRESS

Oil Search's share price trended upward for the first half of 2014, in part due to the progressive de-risking of the PNG LNG Project as it approached first production in April 2014. Oil Search's share price reached a high of A$9.88 on 19 June 2014, subsequently weakening through to early 2016 and reaching a low of A$5.56 on 21 January 2016. From then until March 2020 the share price was relatively stable, trading in the range of A$6.00-8.00 (apart from a brief surge in August 2018).

The emergence of COVID-19 saw a sharp decline in March 2021, including a massive fall of 35% on 9 March 2020. The shares fell to around $2.00 with the collapse reflecting the plunging oil price, in turn the result of a significant decline in energy demand and global economic and social uncertainty caused by the COVID-19 pandemic. In April and May 2020, Oil Search conducted an institutional placement and entitlement offer to raise approximately A$1.16 billion. Both the placement and the entitlement offer were priced at $2.10 per share. The share price has since trended upwards, with Oil Search shares stabilising at around A$4.00 for most of 2021. The share price closed at A$3.67 on 19 July 2021, immediately before the announcement that Oil Search and Santos had been engaged in merger discussions. Since then Oil Search shares have traded at prices reflecting the terms of the Merger. The closing price on 5 November 2021 was A$4.23.

Trading volumes over the 12 months to 31 August 2021 represent approximately 145% of the share register. Spikes in trading volumes have generally related to block trades or the establishment and subsequent unwinding of derivative and hedging positions relating to funding arrangements originally put in place in March 2014 for the benefit of the State of PNG.

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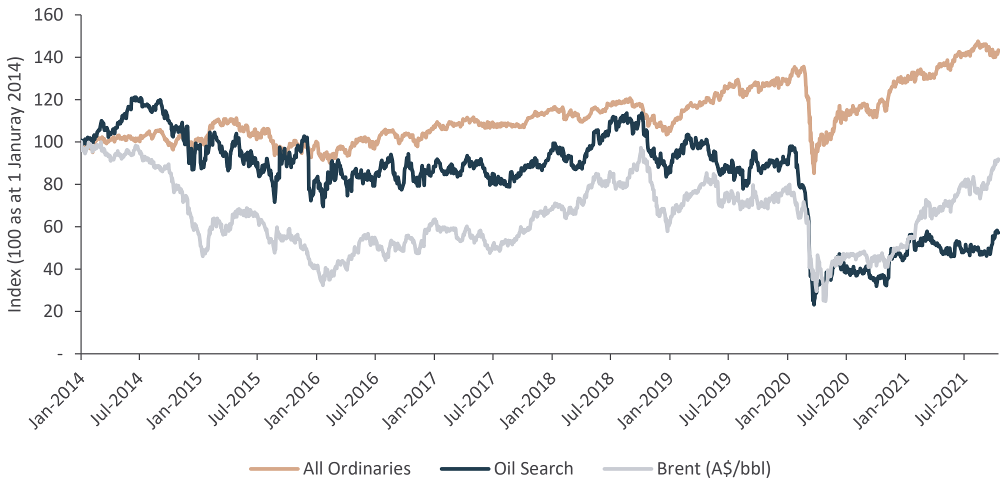
Oil Search is a member of various ASX indices including the All Ordinaries, S&P/ASX 100 and S&P/ASX 100 Resources. At 22 September 2021, its weighting in these indices was, respectively, 0.33%, 0.41% and 2.29%. The following graph illustrates the performance of Oil Search shares since 1 January 2014 relative to the All Ordinaries Index and to the Brent oil price, measured in Australian dollars:

OIL SEARCH – RELATIVE ADJUSTED SHARE PRICE PERFORMANCE



Source: IRESS

Oil Search's share price was relatively stable across the January 2014 to March 2020 period despite the oil price declining significantly and then recovering. By March 2020 it was still ahead of the oil price. This probably reflected the growing but stable volumes at PNG LNG and LNG pricing mechanisms that provided some insulation from oil price fluctuations. Both the oil price and Oil Search's share price fell dramatically with the initial COVID-19 outbreak. While the Oil Search share price recovered in line with the rising oil price through 2020, it has under-performed during 2021, which may reflect market expectations that current oil prices are not sustainable over the longer term, or growing ESG-related impacts on investor demand for oil exposures.

With the exception of 2014 and 2018, Oil Search's share price has underperformed the All Ordinaries index, particularly since 2019.

4 Profile of Santos

4.1 Background

Santos (which is an acronym for "South Australia Northern Territory Oil Search") is one of Australia's largest oil and gas companies. Incorporated in 1954 and listed on the ASX in 1984, it is an ASX top 50 company with a market capitalisation as at 15 October 2021 of approximately A$15.3 billion.

Santos made its first two major natural gas discoveries in the Cooper Basin and Moomba in the 1960s. These gas discoveries provided Santos with commercially viable reserves of gas to develop gas processing infrastructure to service Adelaide and New South Wales. Over the next three decades, Santos expanded its operations and by the 1990s held oil and gas interests across Australia and Asia including in Indonesia, Malaysia, Vietnam and Papua New Guinea.

Following the 2014-2016 oil price downturn, Santos implemented a new Transform, Build and Grow strategy in 2016 to simplify the business by focusing on core asset hubs and divesting non-core businesses, including its Asian assets. This strategy prioritised the pursuit of high margin scalable growth and development of new gas supplies to drive long-term value from its core assets, and underpinned the recent acquisitions of Quadrant Energy's Western Australia oil and gas interests (2018) and ConocoPhillips' northern Australia and Timor-Leste interests (2020).

Key events in Santos' development since 2008 include:

SANTOS – SUMMARY OF KEY EVENTS SINCE 2008

DATE	EVENT
May 2008	Establishment of Gladstone LNG project joint venture with Petronas
December 2009	Development approval for PNG LNG project
July 2011	Acquisition of Eastern Star Gas, including the Narrabri Gas Project
April 2014	First production from PNG LNG project
September 2015	First production from the GLNG project
December 2016	Implementation of new strategy to focus on core asset hubs
August 2017	Receipt of first takeover offer from Harbour Energy
May 2018	Rejection of "best and final" offer from Harbour Energy and termination of discussions
May 2018	Divestment of non-core Asian assets
November 2018	Completion of the acquisition of Quadrant Energy for $2.15 billion plus contingent payments
May 2020	Completion of the acquisition of ConocoPhillips' northern Australia and Timor-Leste assets, including majority interest in the Darwin LNG project, Bayu-Undan project and Barossa project, for a purchase price of $1.265 billion plus a contingent payment of $200 million
March 2021	Announcement of Barossa project FID
April 2021	Completion of sell-down of 25% interests in the Bayu-Undan and Darwin LNG projects to SK E&S for approximately $190 million net funds to Santos.
June 2021	Launch of Dorado project FEED

Source: Santos

Today, Santos operates a diversified energy portfolio of natural gas, LNG, oil and associated oil and gas infrastructure assets in Australia, Papua New Guinea and Timor-Leste. The company is the largest domestic gas supplier in Australia, with significant positions in South Australia, New South Wales, Western Australia, and Queensland. It also produces and exports LNG into the Asia Pacific region. A map showing the location of its Australian and PNG operations is set out below:

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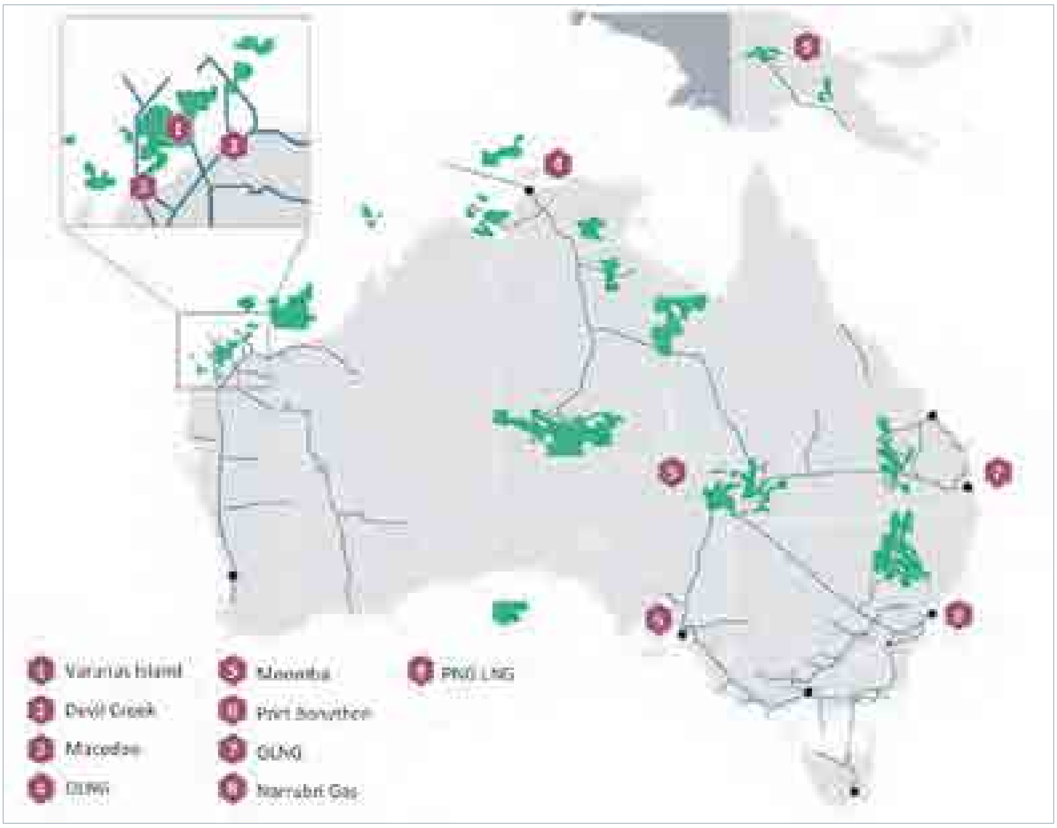
SANTOS – MAP OF CORE ASSETS AND KEY INFRASTRUCTURE ASSETS



Source: Santos

Santos' strategy is underpinned by its five core asset hubs:

- **Cooper Basin**, which produces natural gas for domestic retailers, industrial users and LNG feed gas supply and gas liquids and crude oil for domestic and export markets. Production is primarily sourced from the Cooper and Eromanga Basins, which are the largest onshore oil and gas field developments in Australia. The operation is supported by extensive infrastructure including the Moomba plant, Port Bonython plant and gas and oil transport pipelines;
- **Queensland and New South Wales**, which includes Santos' upstream gas production assets in the Surat and Bowen Basins, as well as its 30% interest in the Gladstone LNG ("GLNG") project. Santos is the upstream operator of the GLNG project, which exports LNG under long-term offtake agreements with Petronas and KOGAS. This segment also includes the 80% owned undeveloped Narrabri domestic gas project in New South Wales;
- **Northern Australia and Timor-Leste**, which primarily comprises Santos' 43.4% interest in the Darwin LNG ("DLNG") project and the Bayu-Undan gas field. The vertically integrated operation includes offshore processing facilities at Bayu-Undan. Gas produced at Bayu-Undan is transported by sub-sea pipeline to DLNG facilities for liquefaction and export. In March 2021, Santos confirmed FID to develop the Barossa Project, which is expected to extend the operating life of the DLNG project after the Bayu-Undan field ceases production;
- **Papua New Guinea**. Santos holds a 13.5% interest in the PNG LNG joint venture, in which Oil Search holds a 29% interest. Separately, Santos has interests in exploration acreage in the Gulf of Papua, Eastern Fold Belt and PNG Forelands; and

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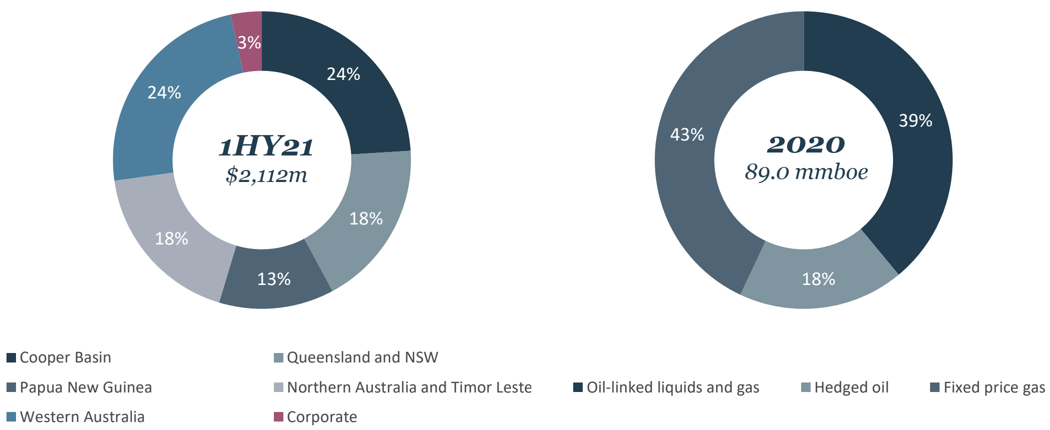
- **Western Australia.** Santos is the largest domestic gas producer in Western Australia, particularly in the Carnarvon Basin. Santos sources gas from a number of offshore gas fields to support domestic gas production through its wholly owned Varanus Island and Devil Creek gas plants and the Macedon gas plant, in which it has a 28.6% interest. Santos is progressing the development of the Dorado oil and gas project in the Bedout Basin, which also contains a number of other prospective development and exploration targets.

A detailed profile of Santos' asset portfolio is set out in Appendix 4 (except for PNG LNG – see Appendix 4).

While Santos is primarily a gas producer, more than 95% of LNG revenues are based on oil price-linked contracts. In 2020, circa 57% of Santos' production was sold under terms linked to global oil prices (including most of its oil, condensate and LPG production, which is primarily sold in spot markets). The remainder of its sales are under inflation-linked or, to a lesser extent, fixed price contracts.

SANTOS – REVENUE AND PRODUCTION CONTRIBUTION

BY SEGMENT | **NATURE OF CONTRACTS**



Source: Santos

Santos' exploration strategy is focussed on brownfield development opportunities to maximise the value of the infrastructure in place at its core asset hubs. This includes identifying low-cost and short payback opportunities for backfill of its existing upstream reserves.

Santos has over 2,700 employees across its global locations. Its head office is located in Adelaide, South Australia. The company also maintains two corporate offices, one for its offshore upstream operations in Perth, Western Australia and one for its onshore upstream operations in Brisbane, Queensland.

4.2 Reserves and Contingent Resources

Santos' reserves and contingent resources as at 31 December 2020 are summarised as follows:

SANTOS – RESERVES AS AT 31 DECEMBER 2020 (NET TO SANTOS)

	PROVEN (1P)					PROVEN & PROBABLE (2P)				
	SALES GAS (PJ)	CRUDE OIL (MMBOE)	CONDENSATE (MMBOE)	LPG (000 TONNES)	TOTAL (MMBOE)	SALES GAS (PJ)	CRUDE OIL (MMBOE)	CONDENSATE MMBOE)	LPG (000 TONNES)	TOTAL (MMBOE)
RESERVES										
Cooper Basin	243	7	3	441	**56**	652	16	8	1,084	**145**
Queensland and NSW	956	--	--	--	**164**	1,906	--	--	--	**328**
Papua New Guinea	647	0	5	--	**117**	964	0	9	--	**174**
Northern Australia & Timor-Leste	72	--	0	25	**13**	162	--	3	186	**32**
Western Australia	733	15	7	--	**148**	1,277	23	12	--	**254**
Total reserves	**2,650**	**22**	**16**	**466**	**496**	**4,961**	**39**	**33**	**1,270**	**933**

Source: Santos

SANTOS – CONTINGENT RESOURCES AS AT 31 DECEMBER 2020[18] (NET TO SANTOS)

	2C				
	SALES GAS (PJ)	CRUDE OIL (MMBOE)	CONDENSATE MMBOE)	LPG (000 TONNES)	TOTAL (MMBOE)
RESOURCES					
Cooper Basin	1,291	31	19	1,839	286
Queensland and NSW	2,523	0	0	--	434
Papua New Guinea	293	--	5	--	55
Northern Australia & Timor-Leste	5,979	--	83	4	1,106
Western Australia	1,275	134	41	1,171	401
Total resources	**11,361**	**165**	**148**	**3,014**	**2,282**

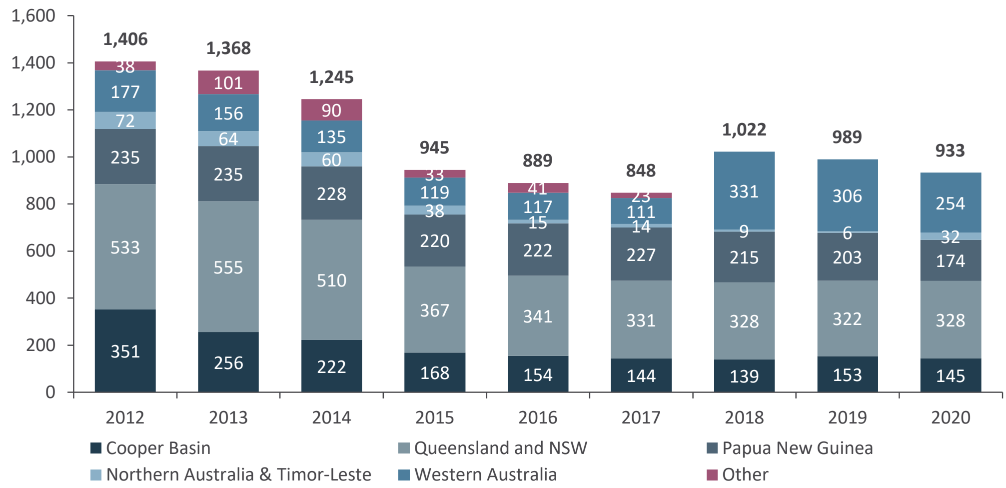
Source: Santos

As of 31 December 2020, more than 90% of Santos' reserves (on a mmboe basis) comprised sales gas. Crude oil constituted only approximately 4% of total reserves, with condensate and LPG representing the balance.

A steady decline in Santos' reserves across the period 2012-2014 accelerated in 2015, reflecting the weak oil price environment, a write-down in reserves for the Cooper Basin, the reclassification of Narrabri reserves to contingent resources and non-core asset divestments. While 2020 reserves had recovered to 2015 levels, this was primarily due to the new reserves acquired in the Quadrant Energy (2018) and the ConocoPhillips northern Australia and Timor-Leste (2020) transactions.

[18] Santos does not disclose 1C contingent resources.

2P RESERVES (IN MMBOE, NET TO SANTOS) (MMBOE)



Source: Santos

Reserves as at 31 December 2020 were 56 mmboe lower than the prior year. The completion of the acquisition of ConocoPhillips' assets in Northern Australia and Timor-Leste and new infill drilling at Bayu-Undan contributed an additional 41 mmboe to 2P reserves, and there were reserve upgrades at the Cooper Basin and GLNG's Fairview, Roma and Arcadia fields. These additions were more than offset by production depletion (89 mmboe) and reserve reductions in Papua New Guinea (15 mmboe) and Western Australia's Reindeer gas field (20 mmboe). These reductions were due to reclassification to contingent resources (PNG) and water ingress occurring earlier than previously modelled (Reindeer).

The Barossa FID in March 2021 is expected to contribute up to 380 mmboe of additional 2P reserves at Santos' expected ultimate project interest. These additional 2P reserves are not reflected in the above chart.

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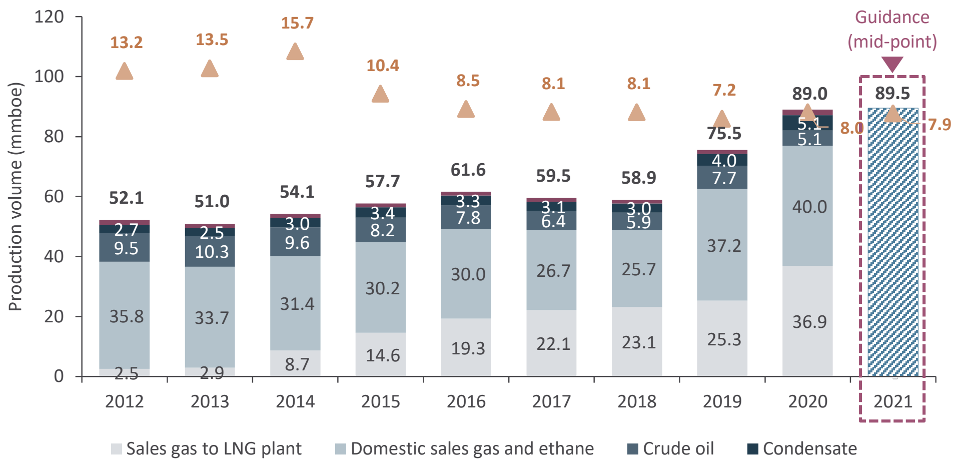
4.3 Production

Santos' annual production volumes and unit production costs from 2012 to 2020 are presented in the chart below, together with company guidance for 2021.

PRODUCTION VOLUMES (NET TO SANTOS) (MMBOE)



Source: Santos

Since 2012, growth in production volumes has been driven by higher LNG production and acquisitions. Aggregate production has grown by nearly 70%, as LNG has emerged as a core component of Santos' portfolio. Cooper Basin production declined significantly over the period to 2015, but has since been relatively consistent, while Western Australian gas production tripled between 2017 and 2019 as a result of the Quadrant Energy acquisition

In summary, the past ten years can be divided into three discrete phases:

- **Ramp-up in LNG portfolio (2012-2016).** This period saw the start-up of two major LNG projects in PNG and Queensland. The PNG LNG project was the primary contributor of growth in production volumes between 2013 and 2016, as production ramped up to produce approximately 12 mmboe within three years of the commencement of operations in 2014. The GLNG project commenced production shortly afterwards in 2015 and delivered more than 5 mmboe in 2016. The ramp-up in LNG production was partly offset by declining domestic gas production over the same period;
- **Portfolio simplification (2016-2018).** The reduction in production resulting from the sale of Santos' Asian portfolio and non-core Australian assets was largely offset by continued growth in Santos' core LNG portfolio. As a result, production for the period 2016 to 2018 was flat to marginally negative; and
- **Growth through acquisitions (2018-2020).** This period saw Santos increase production by over 50% in just two years, as a result of the 2018 acquisition of Quadrant energy and the 2020 acquisition of ConocoPhillips' northern Australian and Timor-Leste assets. The latter included an incremental 56.9% interest in the mature gas-liquids Bayu-Undan[19] field, which was producing approximately 40 mmboe per year (on a 100% basis).

In October 2021, Santos released revised production guidance of 88 to 91 mmboe and unit production costs of $7.7- 8.00/boe for FY21. Based on its earnings announcement of 17 August 2021 and third quarter results announcement on 21 October 2021, the company remains on track to meet its guidance as it delivered record first half production in 1HY21.

[19] Santos sold a 25% interest in Bayu Undan to SK E&S in April 2021.

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4.4 Financial Performance

Santos' operating performance for the five years ended 31 December 2020 and for the six months to 30 June 2021 is set out below:

SANTOS – PRODUCTION AND SALES SUMMARY

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE
	2016	2017	2018	2019	2020	
PRODUCTION VOLUMES						
LNG (PJ)	112.0	125.7	116.7	129.6	198.0	123.5
Domestic gas (PJ)	174.4	158.0	167.1	233.7	249.6	117.4
Crude oil (mmbbl)	7.8	6.4	5.9	7.7	5.1	2.4
Condensate (mmbbl)	3.5	3.4	3.2	4.3	5.5	2.7
LPG (000 tonnes)	147.2	145.2	145.7	151.0	220.9	109.3
SALES VOLUMES						
LNG (000 t)	2,799.5	3,066.9	2,791.1	2,951.0	4,278.8	2,392.5
Domestic gas (PJ)	232.5	224.4	211.9	272.4	275.1	130.1
Crude oil (mmbbl)	12.4	10.0	10.1	12.9	11.1	4.5
Condensate (mmbbl)	4.2	4.3	4.2	5.5	6.3	3.2
LPG (000 tonnes)	137.4	183.9	158.2	182.0	235.7	132.1
REALISED PRICES						
LNG ($/mmbtu)	6.03	7.31	9.91	9.77	6.39	6.74
Domestic gas ($/GJ)	3.86	4.57	5.03	4.30	3.88	4.65
Crude oil ($/bbl)	46.43	57.85	75.05	71.99	47.70	69.57
Condensate ($/bbl)	43.22	54.59	71.87	61.09	40.50	63.61
LPG ($/tonne)	375.56	479.78	537.61	464.54	401.52	548.28
UNIT PRODUCTION COSTS						
Upstream unit production costs ($/boe)	8.5	8.1	8.1	7.2	8.0	8.00

Source: Santos

Approximately 85% of Santos' attributable LNG sales from 2020 are delivered into mid-to-long term oil-linked contracts. Consequently, realised LNG prices have closely tracked movements in oil prices. Between 2016 and 2018, realised LNG and oil prices rose by over 60% as oil prices staged a strong recovery from the lows experienced in 2015 and 2016. The precipitous COVID-related fall in oil prices in the second quarter of 2020 saw average oil and LNG prices decline by approximately 35% for the year. Oil prices recovered strongly in the first half of 2021, although the recovery in LNG pricing was more muted, reflecting the lagged linkage between LNG pricing and Japan Crude Cocktail ("JCC"). After essentially flat LNG production over the period 2016 – 2019, the ConocoPhillips acquisition and resultant increase in Santos' DLNG interest resulted in a material increase in LNG production for 2020 and 2021.

The majority of Santos' domestic gas sales are under short to medium term sales contracts at fixed prices or prices indexed to inflation. Western Australia domestic gas prices skew more heavily towards long-term agreements rather than to short-term sales contracts, with 85% of volumes contracted under long-term fixed price arrangements with retailers and large industrial users such as Alcoa. Notwithstanding the acquisition of Quadrant Energy and its portfolio of favourably priced long-term gas supply contracts (average domestic sales gas prices for Quadrant Energy were approximately 7% higher than for Santos prior to the acquisition), domestic gas prices declined in 2019 and 2020 due to the impact of the significant fall in oil prices on pricing under oil-linked contracts. Sales volumes of domestic gas declined gradually between 2016 and 2018, before increasing in 2019 following the Quadrant Energy acquisition.

Overall, Santos' revenues grew strongly in 2017 and 2018 on the back of the commodity price recovery and then showed further growth in 2019, driven by the growth in domestic gas sale volumes and crude oil sales following the Quadrant Energy acquisition. Revenue fell sharply in 2020, despite the increased production that resulted from the acquisition of ConocoPhillips' interests in DLNG and Bayu-Undan, impacted by a substantial COVID-related fall in oil prices that was reflected in reduced realised prices for all of Santos' products.

Santos delivered unit production costs in the range of A$13.00-13.50/boe in 2012 and 2013 and A$15.70/boe in 2014. In response to the downturn in market prices in 2015 and 2016, Santos implemented a range of cost saving and operating efficiency initiatives. Together with the divestment of non-core assets and its increase in lower cost LNG and domestic production (in part through acquisition), this has allowed Santos to reduce its upstream production cost base to approximately $7-8/boe over the last five years.

Santos' financial performance for the five years to 31 December 2020 and the six months to 30 June 2021 is summarised as follows:

SANTOS – FINANCIAL PERFORMANCE ($ MILLIONS)

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
FINANCIALS[20]						
LNG sales	887	1,178	1,453	1,514	1,437	848
Domestic sales gas & ethane	897	1,020	1,065	1,172	1,068	604
Crude oil sales	575	579	757	927	531	312
Condensate sales	183	235	300	335	256	203
LPG sales	52	88	85	85	95	73
Total revenue	**2,594**	**3,100**	**3,660**	**4,033**	**3,387**	**2,040**
EBITDAX	**1,281**	**1,398**	**2,175**	**2,455**	**1,862**	**1,264**
Exploration costs expensed	(138)	(94)	(105)	(103)	(59)	(41)
EBITDA	**1,143**	**1,304**	**2,070**	**2,352**	**1,803**	**1,223**
Depreciation and other amortisation	(741)	(742)	(667)	(1,000)	(1,015)	(614)
Change in future restoration assumptions	37	31	46	2	(1)	20
EBIT	**439**	**593**	**1,449**	**1,354**	**787**	**629**
Net interest expense	(281)	(270)	(228)	(277)	(234)	(109)
Core profit before tax	**158**	**323**	**1,221**	**1,077**	**553**	**520**
Core income tax expense	(48)	(19)	(457)	(355)	(152)	(160)
Royalty-related tax expense	(7)	14	(37)	(3)	(114)	(43)
NPAT before significant items - Core	**103**	**318**	**727**	**719**	**287**	**317**
Significant items (net of tax)	(1,150)	(678)	(97)	(45)	(644)	37
NPAT after significant items – As reported	**(1,047)**	**(360)**	**630**	**674**	**(357)**	**354**
STATISTICS						
Sales revenue growth (%) (pcp)	*6.2%*	*19.5%*	*18.1%*	*10.2%*	*(16.0%)*	*22.3%*
EBITDAX margin (%)	*49.4%*	*45.1%*	*59.4%*	*60.9%*	*55.0%*	*62.0%*
EBITDA margin (%)	*44.1%*	*42.1%*	*56.6%*	*58.3%*	*53.2%*	*60.0%*
EBIT margin (%)	*16.9%*	*19.1%*	*39.6%*	*33.6%*	*23.2%*	*30.8%*
Core effective tax rate (%)	*30.4%*	*5.9%*	*37.4%*	*33.0%*	*27.5%*	*30.8%*

Source: Santos and Grant Samuel analysis

20 Includes Santos' proportional interest in DLNG and GLNG.

Santos' financial performance has largely reflected the movements in production volumes and realised product prices described above. In addition, it has been affected by the following factors:

- improved operating leverage through increased scale. The Quadrant Energy and ConocoPhillips transactions have delivered more than $160 million in cost synergies to date. These include reduced corporate costs (e.g., consolidation of Western Australian corporate offices, IT costs, insurance), optimised maintenance costs and reduced marketing and operational costs;
- exploration costs, which were approximately $100 million per annum between 2016 and 2019 but were reduced sharply to $59 million in 2020 in response to the fall in oil prices; and
- depreciation charges, of which the majority are depletion charges recognised as hydrocarbon reserves are produced. The $334 million increase in depreciation expenses in 2019 was largely due to the higher production rates and new cost base resulting from the Quadrant Energy acquisition.

Santos has also recognised pre-tax impairment charges of approximately $3.5 billion over the past five years. This included a circa $2,700 million impairment (pre-tax) of the GLNG project in 2016 and 2017 resulting from a ramp-up of production at rates slower than expected, higher input gas prices and lower oil prices. The net impairment expense in 2017 was partly offset by a $480 million pre-tax write-back of Cooper Basin assets due to cost reductions and strong drilling and development results. In 2020, Santos recognised approximately $895 million in pre-tax impairments due to a write-down of reserves in Western Australia, reflecting in part lower oil prices amidst the COVID-19 pandemic.

Santos' earnings per share have moved in line with net profit after tax. Due to the challenging operating environment in 2016 and 2017, Santos did not declare any dividends in those years. Dividends were reinstated in 2018. Excluding impairments, the effective dividend payout ratio ranged between approximately 30% and 40% of underlying NPAT.

SANTOS – EARNINGS AND DIVIDENDS PER SHARE ($ MILLIONS)

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE
	2016	2017	2018	2019	2020	2021
STATISTICS						
Basic EPS before significant items (cents)	2.6	11.5	33.1	34.3	17.0	17.3
Basic EPS after significant items (cents)	(58.2)	(17.3)	30.2	32.4	(17.1)	17.0
Dividends per share (cents)	--	--	9.7	11.0	7.1	5.5
Dividend franking percentage (%)	--	--	100%	100%	100%	100%
Effective payout ratio (%)[21]	--	--	29%	32%	42%	32%
Basic weighted average number of shares (millions)	1,798	2,079	2,083	2,083	2,083	2,083

Source: Santos and Grant Samuel analysis

[21] Dividends per share divided by earnings per share before significant items.

4.4.1 Outlook

Santos has provided guidance on key financial and operational metrics for FY21. The guidance includes:

- production volumes of 88-91 mmboe and sales volumes of 100-105 mmboe. Santos achieved record production volumes in 1HY21;
- upstream production costs of $7.70 – 8.00/boe. This reflects increased COVID-related costs to enhance employee safety across its operations. For example, health orders require increased quarantine periods for its offshore Bayu-Undan operations; and
- capital expenditures of $1.3-1.5 billion, comprising $800-900million in sustaining capex and $500-600 million in major growth capex. The majority of growth capex is in relation to the Barossa project, which was approved for development in March 2021.

Santos does not provide guidance in relation to sales revenue or earnings. In the absence of publicly released detailed earnings forecasts for 2021 and subsequent years, Grant Samuel has considered brokers' forecasts (which are sensitive to assumptions as to future oil prices) to provide an indication of the expected future financial performance of Santos:

SANTOS – FINANCIAL PERFORMANCE ($ MILLIONS)

	YEAR ENDING 31 DECEMBER			
	2020 ACTUAL	BROKER CONSENSUS		
		2021	2022	2023
Production (mmboe)	89.0	91.0	88.0	82.5
Revenue	3,387	4,639	4,953	4,540
EBITDAX	1,862	2,805	3,127	2,818
EBITDA	1,803	2,737	3,082	2,791
EBIT	787	1,558	1,987	1,773
NPAT before significant items	287	852	1,167	984
EPS before significant items ($ cents)	17.0	40.9	56.0	47.2
Dividends per share ($ cents)	7.1	11.9	13.0	10.7

Source: Capital IQ and Grant Samuel analysis.

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4.5 Financial Position

The financial position of Santos at year end for each of the five years ended 31 December 2020, and at 30 June 2021, is summarised below:

SANTOS - FINANCIAL POSITION ($ MILLIONS)

	31 DECEMBER					30 JUNE 2021
	2016	2017	2018	2019	2020	
Receivables	367	440	521	554	560	684
Inventory	321	266	288	301	288	294
Payables	(523)	(512)	(724)	(757)	(589)	(856)
Other operating assets / (liabilities)	51	45	48	40	41	60
Net working capital	**216**	**239**	**133**	**138**	**300**	**182**
Oil and gas assets	10,398	9,536	11,224	11,396	10,925	11,293
Exploration and evaluation assets	495	459	1,004	1,187	1,818	1,013
Other property, plant and equipment	135	126	119	223	248	262
Contract assets / (liabilities)	0	(121)	(163)	(205)	(216)	(250)
Investment in joint ventures	56	43	31	13	413	396
Goodwill	0	0	628	481	383	383
Assets held for sale	92	7	13	0	126	252
Provisions	(1,585)	(1,636)	(2,263)	(2,451)	(3,216)	(3,008)
Other assets / (liabilities)	(65)	49	(29)	161	(27)	(28)
Deferred tax assets/(liabilities) (net)	833	1,179	132	59	137	206
Net capital employed	**10,575**	**9,881**	**10,829**	**11,002**	**10,891**	**10,701**
Cash and deposits	2,026	1,231	1,316	1,067	1,319	2,417
Bank loans, other loans and finance leases	(5,239)	(3,943)	(4,919)	(4,421)	(4,999)	(5,637)
Derivatives	(282)	(18)	53	28	16	(178)
Net borrowings	**(3,495)**	**(2,730)**	**(3,550)**	**(3,326)**	**(3,664)**	**(3,398)**
Net assets	**7,080**	**7,151**	**7,279**	**7,676**	**7,227**	**7,303**
Equity attributable to Santos shareholders	**7,080**	**7,151**	**7,279**	**7,676**	**7,227**	**7,303**
STATISTICS						
Shares on issue at period end (million)	*1,798*	*2,079*	*2,083*	*2,083*	*2,083*	*2,083*
Net asset per share	*3.94*	*3.44*	*3.49*	*3.69*	*3.47*	*3.51*
Gearing	*33.0%*	*27.6%*	*32.8%*	*30.2%*	*33.6%*	*31.8%*

Source: Santos and Grant Samuel analysis

Due to the capital-intensive nature of Santos' operations, the majority of its capital is deployed in long-term fixed assets and liabilities. These include:

- oil and gas assets, which represent nearly all the capital employed. These assets represent Santos' investment in development and producing assets including its share of joint operations (such as PNG LNG);
- exploration and evaluation assets, which account for the second largest share of capital employed. These assets reflect deferred expenditure incurred in the search for resources (e.g., seismic acquisition and drilling programs), feasibility assessments and commercial viability studies for identified resources. The reduction as at 30 June 2021 reflects the upgrade of the Barossa project to "assets in development", which are included under oil and gas assets;

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- provisions primarily comprise restoration obligations in relation to future removal and environmental rehabilitation costs. The increase in 2019 was largely due to the acquisition of ConocoPhillips' northern Australia assets and their associated rehabilitation obligations and revised restoration cost estimates; and
- investments in joint ventures, which are equity accounted, primarily comprises Santos' 43.4% interest in DLNG. While the acquisition of ConocoPhillips' interest in the joint venture increased Santos' interest to 68.4% as of 31 December 2020, the planned sale of a 25% interest meant that it was still appropriate to treat it as an equity accounted investment in an associate, due to Santos' limited voting and decision making rights.

Assets held for sale at 31 December 2020 comprised a 25% interest in the Bayu-Undan and DLNG joint ventures (sold to SK E&S in April 2021). At 30 June 2021, assets held for sale consisted principally of a 12.5% interest in the Barossa Project that Santos intends to sell to Jera. The signing of a binding Sale and Purchase Agreement is expected shortly.

Santos' net borrowings are diversified across different markets and instruments, including bank debt, revolving facilities, US capital markets bonds and export credit agency facilities. Prior to 2016, Santos carried a more leveraged balance sheet with gearing ratios of approximately 40%. Since the 2014-2016 oil price downturn, the company has focused on strengthening its balance sheet and has reduced its debt balance from approximately $4,750 million to $3,398 million by 30 June 2021. Santos continues to target a gearing ratio of up to 35% and has remained well within this threshold since 2016.

The Company enjoys a strong liquidity position of $4.5 billion with undrawn debt facilities of $2.1 billion and cash of $2.4 billion at 30 June 2021. While the Company has historically maintained approximately $3 billion in available liquidity, the higher liquidity levels are expected to support the funding of its growth investments, including the Barossa gas project and, potentially, the Moomba CCS project. Most recently, Santos issued a $1.0 billion senior unsecured fixed rate 10-year bond in the US144A/Reg-S market in April 2021.

Santos has received credit ratings (prior to the Merger) of BBB- (S&P) and BBB (Fitch).

SANTOS – NET BORROWINGS AT 30 JUNE 2021 ($ MILLIONS)

FACILITY	AMOUNT DRAWN	MATURITY
Export credit agency facilities	252	2021 to 2026
Bank term loan facilities	1,242	2024 and 2026
US Private Placements	246	2022 and 2027
144A and Reg-S bonds	2,378	2027 to 2031
PNG LNG project finance	1,102	2024 and 2026
Finance leases	417	--
Derivatives	178	--
Total interest bearing liabilities	**5,815**	
Cash and short term deposits	(2,417)	
Net borrowings	**3,398**	

Source: Santos

4.6 Cash Flow

Santos' cash flows for the five years ended 31 December 2020 and for the six months to 30 June 21 are summarised below:

SANTOS – CASH FLOW ($ MILLIONS)

	YEAR ENDED 31 DECEMBER					SIX MONTHS ENDED 30 JUNE 2021
	2016	2017	2018	2019	2020	
EBITDA	1,061	1,334	2,055	2,354	1,839	1,190
Changes in working capital	65	293	(86)	111	(52)	59
Net interest received (paid)	(226)	(254)	(194)	(190)	(107)	(148)
Tax paid	(17)	(28)	(69)	(30)	(5)	(23)
Royalties and royalty-related taxes	(38)	(72)	(98)	(190)	(203)	(151)
Operating cash flows	**845**	**1,273**	**1,608**	**2,055**	**1,472**	**927**
Restoration expenditure	0	(37)	(36)	(24)	(37)	(14)
Capital expenditures (net)	(649)	(634)	(566)	(859)	(761)	(482)
Acquisitions	(18)	(49)	(1,953)	(200)	(723)	(17)
Investments (net)	0	0	0	13	63	0
Other (incl. disposals)	465	155	152	28	(11)	186
Free cash flows	**643**	**708**	**(795)**	**1,013**	**3**	**600**
Share issuance / (buybacks)	733	(8)	(10)	(31)	(31)	(31)
Dividends (net)	(31)	12	(67)	(236)	(95)	(75)
Proceeds from / (repayments of) borrowings	(167)	(1,516)	967	(984)	384	593
Net cash generated (used)	**1,178**	**(804)**	**95**	**(238)**	**261**	**1,087**
Cash - opening	*839*	*2,026*	*1,231*	*1,316*	*1,067*	*1,319*
Exchange rate impacts	*9*	*9*	*(10)*	*(11)*	*(9)*	*11*
Cash - ending	*2,026*	*1,231*	*1,316*	*1,067*	*1,319*	*2,417*

Source: Santos and Grant Samuel analysis

Operating cash flows peaked in 2018 and 2019, reflecting strong commodity prices. Apart from 2018, when Santos part debt-funded the $1.93 billion Quadrant Energy acquisition[22], operating cash flows have been sufficient to fund capital expenditure, investments and acquisitions. Acquisitions in 2020 included the $1.265 billion acquisition of ConocoPhillips' northern Australia assets[23], net of the concurrent sell down of a 25% interest in Bayu-Undan and DLNG to SK E&S for $390 million.

Disposals of non-core assets in 2016 through 2018 provided additional cash to finance these investments. Santos is currently engaged in a process to sell a 12.5% interest in the Barossa Project.

[22] The net cash paid at completion was $1.93 billion, comprising the headline purchase price of $2.15 billion less completion adjustments and cash acquired.

[23] The total consideration was an upfront "face value" payment of $1.265 billion plus a payment contingent on Barossa FID of $200 million. As the effective date of the transaction was 1 January 2019, the actual net settlement amount was $655 million, after adjusting for net cash generated from the effective date and other settlement adjustments. Between the announcement date and completion date, Brent oil prices declined by nearly 40%

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4.7 Taxation Position

Santos together with each of its wholly owned Australian subsidiaries is a consolidated tax group for income tax purposes, the effect of which is for the Australian group to be taxed as a single entity.

As at 31 December 2020, Santos had:

- total carried forward income tax losses of approximately $626 million, which were recognised on the balance sheet;
- unrecognised tax losses of $132 million. These losses had not been accounted for due to the uncertainties relating to their future utilisation; and
- accumulated franking credits of $194 million.

4.8 Capital Structure

As at 22 October 2021, Santos had the following securities on issue:

- 2,083,066,041 ordinary fully paid shares;
- 10,000 partially paid unlisted Plan 0 and Plan 2 shares[24]; and
- 17,895,732 share acquisition rights ("SARs").

Santos operates:

- a short term incentive ("STI") plan under which certain senior executives may receive up to 50% of the STI in cash and the remaining 50% in equity subject to a two-year restriction period; and
- long term incentive plans under which certain senior executives may receive SARs for the achievement of certain performance targets. These are administered under the Santos Employee Equity Incentive Plan and the Santos Employee Share Purchase Plan. Vesting of long-term incentives is contingent on achieving performance metrics over a four year period.

The SARs are granted for nil consideration and subject to continued employment at the vesting date. On the vesting date, the number of share rights that have vested will be automatically exercised and converted to ordinary shares in Santos. Performance metrics for SARs are assessed over a four year period and include shareholder return targets, returns on capital employed and stable through-the-cycle cash flow generation performance targets.

Santos also operates two general employee share plans. The Share1000 Plan provides for grants of fully paid ordinary shares up to a value determined by the Board. The ShareMatch Plan allows for the purchase of up to A$5,000 in value under an employee loan.

4.9 Ownership

As at 22 October 2021, there were approximately 125,000 registered shareholders in Santos. The top twenty registered shareholders account for approximately 74% of the shares on issue.

Other than the interests held by the ENN Group, the other top 20 registered shareholders are principally investment managers, institutional nominees or custodian companies.

As at the date of this report, Santos had received substantial holder notices from the following parties:

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24 Plan 0 and Plan 2 shares are legacy executive share plans that were in place between 1987 and 1997. There are no further issues of share under this plan.

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SANTOS – SUBSTANTIAL SHAREHOLDERS

	NUMBER OF SHARES	PERCENTAGE
ENN Group[25] (held by United Faith Ventures)	207,617,857	9.97%
BlackRock Group	129,704,766	6.23%
Mitsubishi UFJ Financial Group	108,480,725	5.21%
Challenger Limited	129,118,808	6.20%
Total	**574,922,156**	**27.61%**

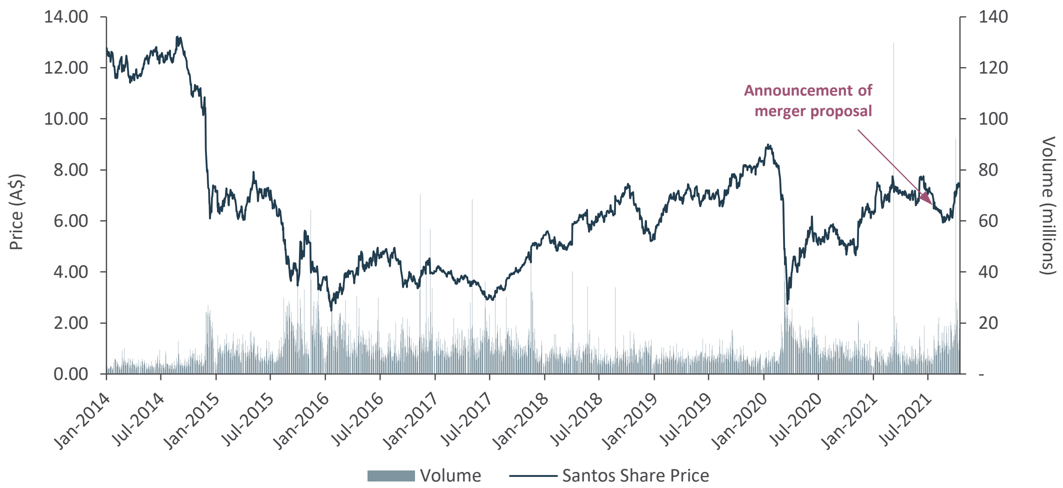
Source: Santos

Santos entered into a strategic partnership with the ENN Group in 2017 to support investments and growth of Santos' upstream gas reserves and LNG production business in Australia and Papua New Guinea. As part of the agreement, the ENN Group was entitled to nominate a director to the Santos Board while it held at least a 15% interest in Santos. The strategic relationship concluded in March 2021 as the ENN Group reduced its interest to below the 15% threshold and the ENN-nominated director resigned from the Santos Board.

4.10 Share Price Performance

A summary of the share trading history of Santos shares since 1 January 2014 is set out in the chart and table below:

SANTOS – SHARE PRICE AND TRADING VOLUME



Source: IRESS

A precipitous fall in oil prices from around $100/bbl in July 2014 to lows of around $26/bbl in mid-January 2016 saw the Santos share price fall from a range of A$11.50-13.00 for the first half of 2014 to a low in January 2016 of A$2.46. Santos shares traded broadly in the range A$3.00-5.00 but generally around A$4.00 through to July 2017 with the price recovery hampered by the GLNG write downs. A series of acquisition proposals from Harbour Energy in 2017 and 2018 against the backdrop of an improving oil market, new management, portfolio rationalisation and the Quadrant acquisition saw the Santos share price recover to above A$8.00 by the end of 2019.

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[25] Under the Acting in Concert agreement dated 27 April 2017, Hony and ENN have a relevant interest in each other's shares. On this basis, their interests are collectively referred to as the interests held by the ENN Group

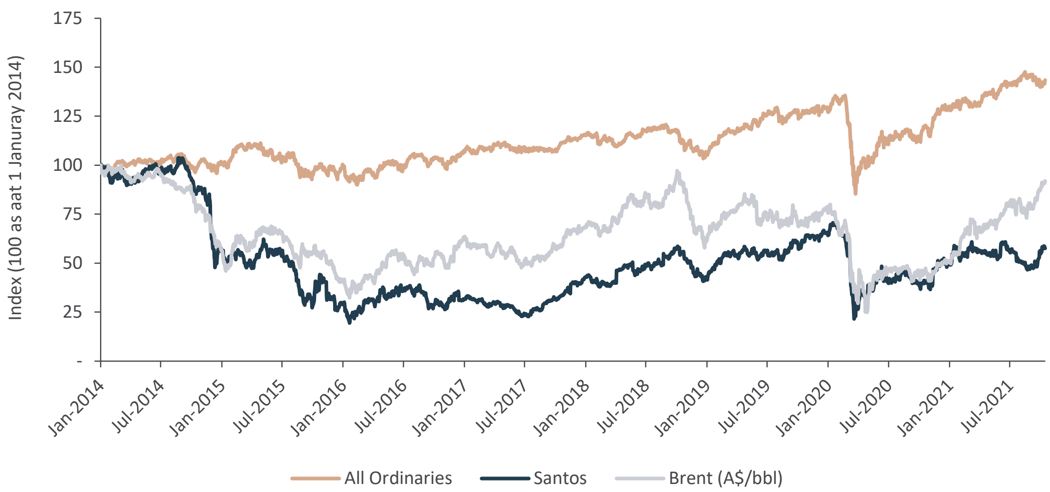
The onset of the COVID-19 pandemic, plunging oil prices and general market weakness resulted in the Santos share price falling by approximately 68% between 31 January 2020 and 19 March 2020, to a low of A$2.73. The subsequent recovery in oil prices, historically low interest rates and overall market strength supported the recovery of the Santos share price to an approximate range of A$6.00-8.00.

Since the beginning of 2021, Santos shares have traded consistently between $6.20 and $7.80, closing at $6.83 on 19 July 2021, immediately prior to the announcement of the proposed Oil Search merger. Since the announcement, Santos shares have traded in a relatively wide range of $5.84-7.59, (at a VWAP of A$6.58) with the price recovering to over $7.00 on the back of a stronger oil price (from $70/bbl to over $80/bbl). The closing price on 15 October 2021 was A$7.34.

Santos has been a liquid stock with high trading volumes. Average trading volumes over the 12 months to 19 July 2021 represent approximately 102% of the share register. Spikes in trading volumes have generally coincided with major movements in global oil prices or changes in substantial shareholdings. The most recent spike, in March 2021, was due to the partial sell-down of the ENN Group's substantial shareholding in the company.

Santos is a member of various ASX indices including the All Ordinaries, S&P/ASX 50 and S&P/ASX 100 Resources. At 6 September 2021, its weighting in these indices was, respectively, 0.51%, 0.78% and 3.27%. The following graph illustrates the performance of Santos shares since 1 January 2014 relative to the All Ordinaries Index and the Brent oil price, measured in Australian dollars:

SANTOS – RELATIVE SHARE PRICE PERFORMANCE



Source: IRESS

Santos' share price performance has broadly reflected movements in the Brent oil price, although operational issues with GLNG and the Cooper Basin decline saw the Santos share price underperform relative to oil for much of the 2016 – 2018 period. Following improved operating performance and the Quadrant Energy acquisition, Santos delivered strong share price performance through to early 2020, before the onset of the COVID-19 pandemic and the consequent collapse in oil prices and equity markets generally. The Santos share price recovered broadly in line with oil prices through to the end of 2020. Since then (and consistent with its ASX-listed peers such as Oil Search and Woodside Energy), it has materially underperformed against Brent oil, potentially reflecting increasing ESG concerns regarding oil and gas companies and a growing disconnect between short term prices and expectations of medium to longer term oil prices. Santos shares have materially underperformed against the All Ordinaries index since 2014, reflecting a combination of oil price performance, underlying operational issues, and, potentially, a structural shift in equity market demand for oil and gas exposures.

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5 Valuation Analysis

5.1 Valuation Methodology

The purpose of the value analysis is to enable an assessment of the relative contributions of value by the shareholders of Oil Search and Santos compared to the share of the Merged Group that they each receive. While the analysis focusses on relative values, the significant debt in each company means that the absolute value of the relevant oil and gas assets is relevant. The values for the oil and gas interests have been estimated on the basis of fair market value as a going concern, defined as the maximum price that could be realised in an open market over a reasonable period of time assuming that potential buyers have full information. Other assets have been valued on the basis of net realisable value.

The valuations represent Grant Samuel's assessment of the underlying value of Oil Search and Santos respectively, although (in the case of both Oil Search and Santos) do not incorporate judgements as to the synergies that might be available to an acquirer and so do not incorporate a full premium for control. Nonetheless, Grant Samuel would in the ordinary course expect that the estimated underlying values would be in excess of the level at which, under current market conditions, shares in Oil Search or Santos could be expected to trade on the sharemarket. Shares in a listed company normally trade at a discount of 15-25% to takeover values for a company as a whole (although such values generally include some allowance for synergies).

The most reliable evidence as to the value of a business is the price at which the business or a comparable business has been bought and sold in an arm's length transaction. In the absence of direct market evidence of value, estimates of value are made using methodologies that infer value from other available evidence. There are four primary valuation methodologies that are commonly used for valuing businesses:

- capitalisation of earnings or cash flows;
- discounting of projected cash flows;
- industry rules of thumb; and
- estimation of the aggregate proceeds from an orderly realisation of assets.

Each of these valuation methodologies has application in different circumstances. The primary criterion for determining which methodology is appropriate is the actual practice adopted by purchasers of the type of business involved.

The primary approach to the valuation of Oil Search's and Santos' oil and gas assets has involved the application of the discounted cash flow ("DCF") methodology. This methodology involves calculating the net present value of projected cash flows. The cash flows are discounted to a present value using discount rates which reflect the risk associated with the cash flow stream. The DCF methodology is particularly appropriate for assets such as oil and gas projects where reserves are depleted over time and significant capital expenditure is required. By contrast, capitalisation of earnings or cash flows is the most commonly used method for valuation of industrial businesses. This methodology is most appropriate for industrial businesses with a substantial operating history and a consistent earnings trend that is sufficiently stable to be indicative of ongoing earnings potential. This methodology is not particularly suitable for start-up businesses, businesses with an erratic earnings pattern or businesses that have unusual capital expenditure requirements.

Cash flow models for each of the oil and gas assets have been developed by Grant Samuel based on scenarios developed by the technical specialist, GaffneyCline, which were in turn based on financial models and field development and production schedules provided by Oil Search and Santos. GaffneyCline reviewed the technical assumptions for each of Oil Search's and Santos's operating and development assets, including assumptions regarding reserve and resource estimates, production profiles, operating costs, capital and abandonment costs and the potential for reserve extensions, and made adjustments to the extent required to develop for each asset two scenarios that were appropriate for valuation purposes. GaffneyCline also valued the exploration interests of both companies. GaffneyCline's report is attached as Appendix 7 to this report. Grant Samuel determined the economic and financial assumptions used in the cash flow models and applied an overall commercial overlay taking into account factors such as sovereign risk and the stage of development. It then made judgements as to where a reasonable value range sat relative to the scenarios.

Alternative valuation methodologies have been considered as secondary evidence of value, where appropriate. In particular, the value estimates for Oil Search's and Santos' assets have been reviewed in terms of multiples of reserves and resources, which are metrics commonly used in the oil and gas sector. These metrics, while relatively crude, are useful in assessing the reasonableness of values as DCF valuations are typically sensitive to the assumptions adopted.

The valuations of the oil and gas assets represent Grant Samuel's overall judgement as to value. They do not rely on any one particular scenario or set of economic assumptions. The valuations have been determined having regard to the sensitivity of the DCF analysis to a range of technical and economic assumptions. They incorporate Grant Samuel's assessment of the impact on value of development status and optionality, to the extent not reflected in the DCF analysis.

The valuations are based on a number of important assumptions (in particular assumptions regarding future oil and gas prices) and reflect the technical judgements of GaffneyCline regarding the prospects for the assets. Oil and gas prices and expectations regarding future operating parameters can change significantly over short periods of time. Such changes can have significant impacts on underlying value. Accordingly, while the values estimated are believed to be appropriate for the purpose of assessing the Merger, they may not be appropriate for other purposes or in the context of changed economic circumstances or different operational prospects for the oil and gas assets.

Grant Samuel's values for the equity in Oil Search and Santos have then been estimated by aggregating the estimated value of each company's operating assets together with the realisable value of exploration interests and any other non-trading assets and then deducting external borrowings and non-trading liabilities. GaffneyCline prepared valuations of Oil Search's and Santos' exploration interests.

5.2 Key Assumptions

There are a number of economic and financial assumptions that apply across the valuation of Oil Search's and Santos' oil and gas assets:

Valuation Date

Oil Search and Santos have been valued as at 30 June 2021 and the DCF analysis has been prepared from 1 July 2021. The primary reference point for the valuations are the balance sheets as at 30 June 2021 for both Oil Search and Santos. While adjustments have been made for relevant subsequent events such as dividends and the impact on hedge positions of movements in commodity prices, no adjustments have been made for movements in other balance sheet items.

Oil Prices

Grant Samuel has assumed that Brent oil prices (in nominal terms) decline from current prices to a range of $60-70/bbl by 2023 and then continue on a flat nominal basis until 2026, after which they are assumed to increase at the assumed rate of inflation (2%). This represents a decline in real terms prices to approximately $54-64/bbl by 2026 and then flat real thereafter. The long-term assumption compared to historical Brent prices (in nominal terms) is shown below:

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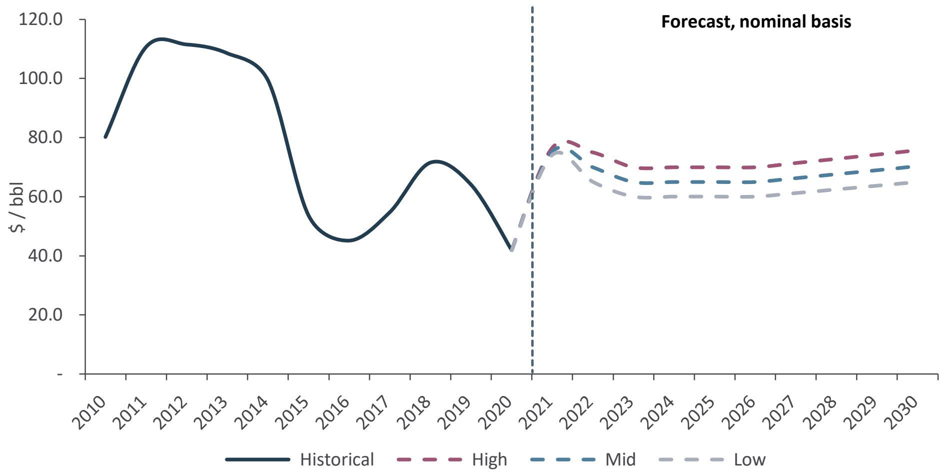
HISTORICAL AND FORECAST BRENT PRICES ($/BBL)



Source: IRESS, Grant Samuel analysis

Grant Samuel's Brent crude oil price assumption is broadly consistent with the range of forecasts used by market analysts. However, assumptions regarding future oil prices are subject to considerable uncertainty:

- recent oil prices have been volatile. Oil traded at very low prices during 2020 as a result of COVID impacts (with oil futures briefly trading on a negative basis) but has recovered strongly and has recently traded over $85/bbl; and
- market participants and commentators have a wide range of views regarding both future supply of and demand for oil, reflecting uncertainty regarding future technological and regulatory developments and the impact of global initiatives to reduce carbon emissions.

LNG Prices

LNG pricing for Oil Search's PNG assets and Santos' GLNG and DLNG interests is generally on the basis of long-term contracts that incorporate JCC oil-linked pricing. The terms of these long-term contracts have been reflected in Grant Samuel's valuation models. Grant Samuel has assumed that when these contracts expire they will be rolled over on a continued oil-linked basis. Grant Samuel has assumed that spot LNG cargoes (including cargoes from Santos' DLNG facility) will be delivered at Japan Korea Marker ("JKM") spot prices that on average reflect long term oil-linked pricing. The following chart shows the historical relationship between JKM spot LNG pricing and oil-linked prices and Grant Samuel's assumptions regarding future JKM spot LNG pricing (in nominal terms):

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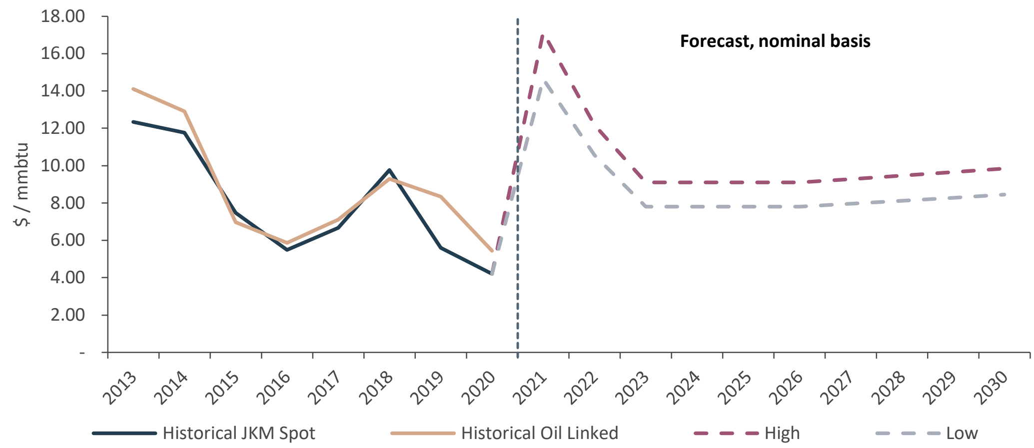
HISTORICAL AND FORECAST SPOT LNG PRICES ($/MBTU)



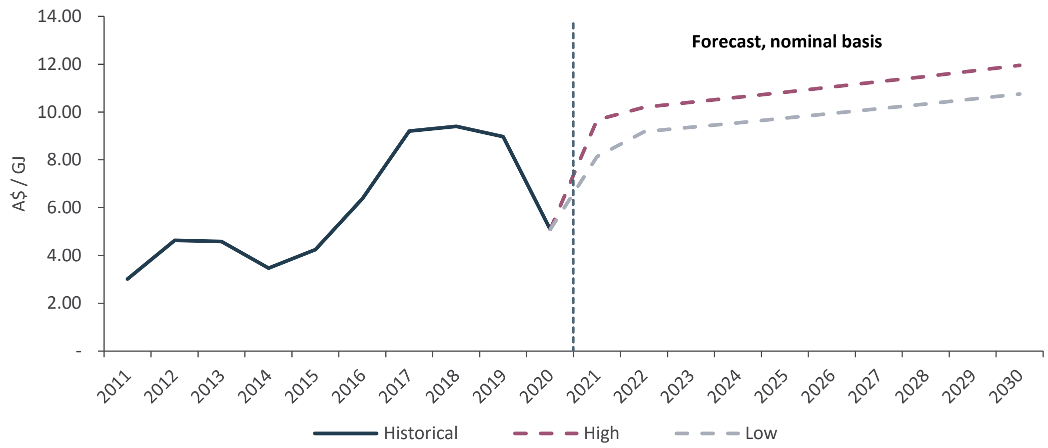
Source: Bloomberg, Grant Samuel analysis

Domestic Gas

The price of domestic gas ("Domgas") in Australian East Coast markets has risen significantly over the last decade. This has reflected factors including continued energy demand, declining gas supply as East Coast gas exploration and development have faced regulatory obstacles, and in recent years the impact of global energy prices as the commencement of LNG operations in Queensland has effectively introduced a global pricing transmission mechanism into the East Coast market. A shortage of gas (in part the result of LNG operations in Queensland) has created pressure for East Coast Domgas pricing to move towards LNG netback pricing, although this pressure has been moderated by regulatory and other factors. Much of Santos' Cooper Basin gas production is sold into East Coast markets via long term fixed or inflation linked contracts. The terms of these long term contracts have been reflected in Grant Samuel's valuation models. It has been assumed that when these contracts roll over or expire, they are replaced by pricing arrangements that deliver Domgas prices in the range A$9-10/GJ (delivered to Sydney, in 2021 terms, inflated at 2% per annum).

The following chart shows historical spot East Coast Domgas prices and Grant Samuel's assumptions regarding future prices:

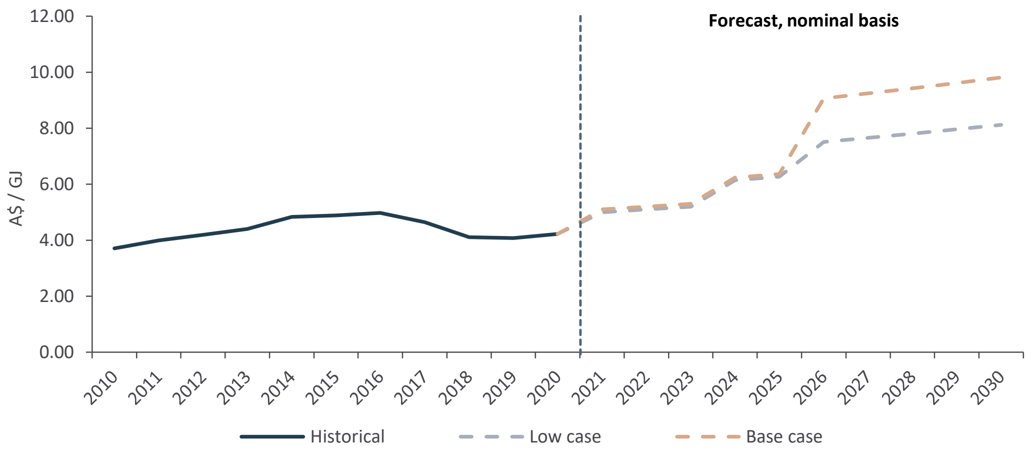
HISTORICAL AND FORECAST DOMESTIC GAS PRICES – EAST COAST (A$/GJ)



Source: Australian Energy Regulator, Grant Samuel analysis

Western Australian Domgas prices have historically been lower than East Coast prices, reflecting in part the domestic gas reservation policies that have delivered significant supply. Grant Samuel's assumptions regarding future Western Australian Domgas prices contemplate growing netback pricing pressure:

HISTORICAL AND FORECAST DOMESTIC GAS PRICES – WESTERN AUSTRALIA (A$/GJ)



Source: AEMO, Grant Samuel analysis

The value of the oil and gas assets of Oil Search and Santos could vary significantly with changes in oil price expectations. The assumptions in relation to future oil prices adopted by Grant Samuel do not represent forecasts by Grant Samuel but are intended to reflect the range of assumptions that could reasonably be adopted by industry participants in their pricing of Oil Search and Santos and their assets.

Inflation

While the majority of the operations of Oil Search and Santos are based in Australia and Papua New Guinea, sales are predominantly denominated in US dollars, which is the functional currency used by both companies. Grant Samuel has assumed inflation rates for both Australia and the United States of 2.0% per annum.

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Exchange Rates

Consistent with the assumption of similar inflation rates in Australia and the United States and a prevailing spot exchange rate of A$1.00 = US$0.74, Grant Samuel has assumed a flat nominal exchange rate for the duration of the valuation models of A$1.00 = US$0.74.

Tax Depreciation

Tax depreciation schedules have been determined on the basis of tax written down values for various asset categories. Accumulated carry forward expenditures deductible for tax purposes have been allowed for in the financial models. In the case of Santos, carried forward tax losses have been valued on the basis that they will be utilised at rates consistent with the projected profitability of assets across the Santos asset portfolio.

Discount Rates

Projected future cash flows have been discounted to present values at nominal discount rates in the range 8.5-9.5%. These rates represent estimates of the systematic riskiness of each of the assets, determined by estimating the rates of return required by marginal investors in integrated oil and gas assets. The rates are estimates of weighted average costs of capital and have been applied to expected future ungeared after-tax cash flows. The basis for the selection of the rates is set out in Appendix 5. In addition, Grant Samuel has:

- made risk adjustments (whether for technical, sovereign or other risks) that imply higher discount rates for certain assets. These higher discount rates are described and discussed in the relevant valuation sections; and
- taken into account incremental values in the case of assets or cash flows with lower risk characteristics, such as infrastructure type assets with third party tolling income or gas sales at fixed or indexed prices. For the relevant assets, Grant Samuel has estimated the additional value attributable to these lower risk attributes through the application of lower discount rates to the relevant cash flow streams.

Other operational and specific assumptions used in the DCF models in this report are set out in the relevant valuation sections.

5.3 Value of Oil Search

5.3.1 Summary

For the purposes of its relative contribution analysis, Grant Samuel has valued the equity in Oil Search in the range $6,766 – 8,341 million. The valuation represents the estimated full underlying value of Oil Search on a standalone basis. It does not include any value for synergies that may be available to acquirers of Oil Search.

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The valuation is summarised below:

OIL SEARCH – VALUE ANALYSIS SUMMARY ($ MILLIONS)

	SECTION REFERENCE	VALUE RANGE	
		LOW	HIGH
PNG LNG	5.3.2	7,350	8,250
P'nyang and Muruk	5.3.3	100	150
Papua LNG	5.3.4	600	800
Operated Oil & Gas Assets	5.3.5	350	400
PNG Exploration Assets	5.3.7	400	600
Alaskan Assets	5.3.6	700	800
Other Assets	5.3.8	25	50
Corporate Overheads	5.3.9	(450)	(400)
Enterprise Value		**9,075**	**10,650**
Adjusted Net Borrowings	5.3.10	(2,309)	(2,309)
Equity Value		**6,766**	**8,341**

Grant Samuel's valuation of Oil Search implies the following valuation parameters:

OIL SEARCH – IMPLIED VALUATION PARAMETERS

	SECTION REFERENCE	UNIT	VALUE RANGE	
			LOW	HIGH
Value Range				
Equity Value	5.3.1	$ millions	6,767	8,342
Enterprise Value	5.3.1	$ millions	9,075	10,650
Reserves and Resources at 31 December 2020				
2P (Proven and Probable)	3.2	$ / boe	20.4	23.9
2P + 2C	3.2	$ / boe	5.1	6.0
Production				
2020 (Actual)	3.3	$ / boe	312.7	367.0
2021 (Forecast)	3.4	$ / boe	330.0	387.3
Financial Performance for Year Ended 31 December 2020 (Actual)				
EBITDAX	3.4	times	12.6	14.8
EBITDA	3.4	times	14.7	17.2
EBIT	3.4	times	41.1	48.3
Core NPAT	3.4	times	n.m.	n.m.
Financial Performance for Year Ending 31 December 2021 (Consensus Forecast)				
EBITDAX	3.4	times	7.7	9.1
EBITDA	3.4	times	7.9	9.3
EBIT	3.4	times	11.8	13.8
Core NPAT	3.4	times	21.7	25.4

The multiples of reserves and resources implied by the valuation are considered reasonable relative to market evidence (see Appendix 7). A significant proportion of Oil Search's value is attributable to the PNG LNG Project, which is a mature, stable, highly cash generative and long-life LNG operation. Oil Search has significant attractive growth options in PNG, both through the development of Papua LNG and through the optionality provided by its large resources base and established PNG infrastructure. The multiples of 2020 earnings appear high, but were affected by the very low oil prices that prevailed in 2020, while the multiples of 2021 earnings reflect a return to more 'normal' levels. Both are broadly consistent with market evidence.

Woodside is arguably the comparable company most relevant given its broadly similar (albeit larger) oil and gas portfolio. The Woodside portfolio comprises significant producing LNG and gas assets (North West Shelf, Pluto LNG and Wheatstone), less material producing oil assets, and significant gas and oil growth potential (Scarborough and Sangomar). As at 29 October 2021, Woodside was trading on multiples of 2P reserves of \$20.53 / boe, 2P reserves plus 2C resources of \$5.17 / boe,[26] and 2021 EBITDAX of 5.4 times. The multiples implied by the valuation of Oil Search generally bracket the multiples for Woodside. The relativities are reasonable given that Oil Search has been valued on a full underlying value basis, whereas the multiples for Woodside are for portfolio interests (i.e. trading of minority parcels of shares), and having regard to factors including Oil Search's PNG sovereign risk exposure.

Arguably the most directly relevant transaction from which to infer valuation parameters for Oil Search is Woodside's proposed (and ultimately rejected) acquisition of Oil Search in September 2015. The offer from Woodside implied multiples of 2P reserves of \$21.26 / boe, 2P reserves plus 2C resources of \$6.22 / boe, and forward EBITDAX of 10.04 times. Comparisons are not straightforward, given different oil price environments (the oil price was around \$45/bbl in September 2015), different interest rates and equity market conditions, different expectations regarding broader energy market dynamics, changes in the composition of Oil Search's asset portfolio (Papua LNG was less developed in 2015 and Oil Search had not yet invested in the Alaskan North Slope), and other factors. Moreover, the Woodside proposed acquisition consideration represented a full takeover value, while Grant Samuel's estimate of the underlying value of Oil Search does not incorporate any value for synergies that could be available to acquirers of Oil Search. Notwithstanding these differences, the valuation parameters and multiples implied by the 2015 Woodside acquisition proposal are broadly supportive of Grant Samuel's valuation of Oil Search.

5.3.2 PNG LNG

Grant Samuel has valued Oil Search's 29.0% interest in the PNG LNG Project in the range \$7,350 – 8,250 million. The valuation takes into account factors including PNG sovereign risk and opportunities to increase value through an integrated development with the P'nyang and Muruk gas fields.

The valuation of the PNG LNG Project, P'nyang and Muruk reflects an expectation that, notwithstanding their different ownership structures, P'nyang and Muruk will ultimately be developed on an integrated basis with the PNG LNG Project. Accordingly, Grant Samuel's valuation of these assets is based on two scenarios for the future integrated operation and development of the PNG LNG Project, P'nyang and Muruk. The production profiles and capital and operating costs for these scenarios have been reviewed and, where appropriate, amended by GaffneyCline.

SCENARIOS AND ASSUMPTIONS

The key assumptions underpinning these two scenarios as they apply to the PNG LNG Project are as follows;

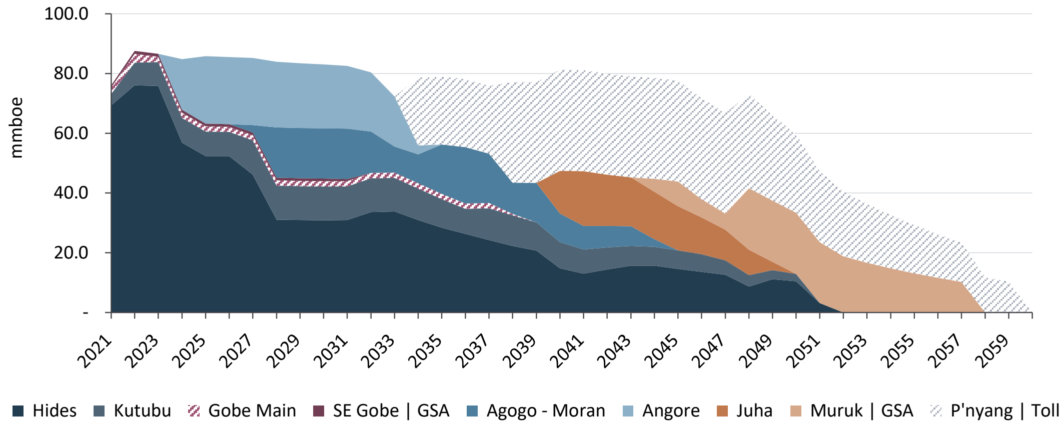
Scenario 1

Scenario 1 assumes the production of 2P reserves and some 2C resources from the fields unitised into the PNG LNG Project in addition to gas purchases from SE Gobe and Muruk. P'nyang volumes are assumed to backfill the two PNG LNG trains from 2034 through a tolling arrangement between the PNG LNG and P'nyang joint ventures. Production from the PNG LNG constituent fields is relatively constant to 2033, after

26 Canada, Greater Sunshine and Myanmar have been removed from the Woodside 2C resource estimates as a result of the low likelihood of development.

which the liquefaction trains also rely on volumes from P'nyang, Juha and Muruk to maintain production at above nameplate capacity. Scenario 1 assumes the production of 10,104 tbtu of LNG, 248 tbtu of domestic gas, 130 mmbbls of condensate and 36 mmbbls of naphtha. The assumed sequence of fields and the associated production volumes are illustrated below:

PNG LNG PROJECT SCENARIO 1 - TOTAL PRODUCTION (100% INTEREST)



Pricing on contracted LNG volumes is based on the current long-term and mid-term pricing arrangements in place. The relevant pricing slopes on contracted LNG volumes revert to the assumed uncontracted slope described in Section 5.2 as the 5-year mid-term and 20-year long-term contracts roll off. The weighted average slope in Scenario 1 is, accordingly, assumed to trend down from over 14.5% to 13.0% from 2035 onwards. Condensate is priced at a small discount to the prevailing Brent price.

Operating costs (excluding abandonment rehabilitation) vary from 2021 to 2050 within the range of $540 – $700 million (2021 $) per annum, as producing fields deplete, others come onstream and the PNG LNG Project shares increasing proportions of the operating costs associated with the Oil Search-operated oil and gas fields. Operating costs subsequently decline to circa $420 million (2021 $) in 2051 and reduce significantly thereafter, with production from Kutubu and Juha ceasing and ongoing costs relating principally to pipeline and downstream infrastructure costs. In addition to these operating costs, Scenario 1 includes shipping costs on 'delivered ex ship' production at $0.65 – $0.83 / mmbtu (nominal) as well as gas purchases from SE Gobe (under the terms of an existing GSA) and from Muruk. PNG LNG pays a volume-based tariff for use of the PL2 pipeline to transport its condensate to the Kumul Marine Terminal. Abandonment expenditures total ~$1.4 billion (2021 $) and are incurred in 2060 following the completion of production from P'nyang. An assumed processing tariff to transport, liquefy and export P'nyang gas through PNG LNG infrastructure has been included, noting that terms have yet to be negotiated between the two joint ventures.

Capital expenditures (excluding abandonment costs) total approximately $7.4 billion (2021 $) over the life of the project, including upstream development costs for Angore and Juha, the addition of Hides booster compression and the modifications required at Agogo and Moran to enable commercial gas production, processing and transport to the PNG LNG Project. Production from Juha is sequenced before Muruk in Scenario 1 and Juha accordingly incurs the cost of a new export pipeline to Hides. The Scenario incorporates assumptions regarding the payment of access fees to PNG LNG by Papua LNG and P'nyang for their use of PNG LNG facilities.

Fiscal assumptions reflect the May 2008 State Gas Agreement and include the arrangements identified in Appendix 2.

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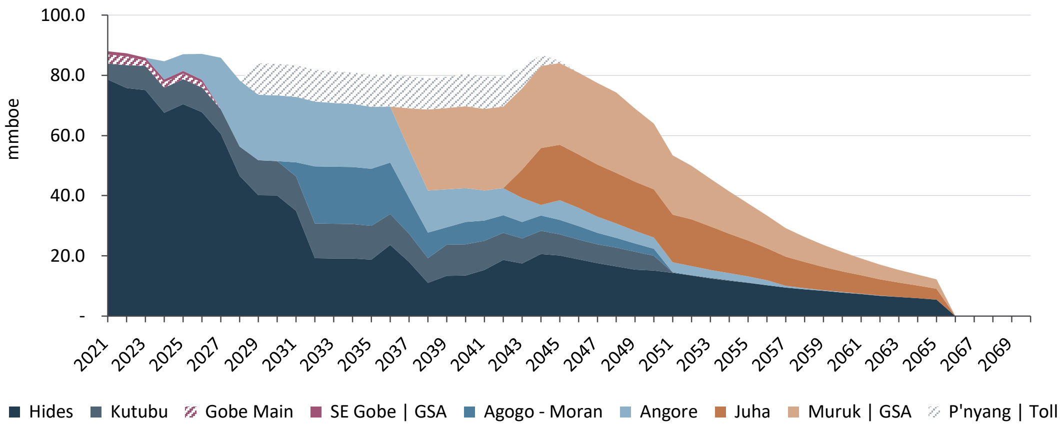
Scenario 2

Scenario 2 assumes the production of 13,949 tbtu of LNG, 314 tbtu of domestic gas, 214 mmbbls of condensate and 45 mmbbls of naphtha. Scenario 2 includes production from the Hides Footwall and Juha North as well as greater recoverable volumes at each of the producing fields assumed in Scenario 1. P'nyang is assumed to support an additional standalone LNG train, owned by the P'nyang Joint Venture and located at the PNG LNG site in Konebada. P'nyang gas volumes in excess of the production capacity of the P'nyang train are tolled through the two existing PNG LNG trains. The development of Muruk is sequenced prior to Juha as Muruk is assumed to be the lower unit cost development, given the significant increase in assumed total recoverable volumes. The sequence of fields and the associated production volumes are illustrated below:

PNG LNG PROJECT SCENARIO 2 - TOTAL PRODUCTION (100% INTEREST)



All price assumptions are consistent with Scenario 1. The PNG LNG Project charges a processing tariff to P'nyang to process its excess volumes from 2029 to 2045. This tariff is higher than for Scenario 1, given that the PNG LNG parties would be deferring a proportion of their own production. Annual operating costs (excluding abandonment rehabilitation) are within the range $390 – 695 million (2021 $) and vary in line with production levels and field closures. The upstream operating cost assumptions (at a field-by-field level) and downstream operating costs are consistent with those for Scenario 1. All other operating cost assumptions, such as shipping, the PL2 tariff and gas purchase prices, are also consistent with those for Scenario 1.

Capital expenditures are around $6.8 billion (2021 $) in Scenario 2, excluding development costs of approximately $2 billion relating to the P'nyang expansion train, which are funded by the P'nyang Joint Venture. Scenario 2 includes reduced pipeline expenditures as Muruk (instead of Juha) incurs the costs to construct the pipeline to Hides. Upstream capital expenditures are also generally below those assumed in Scenario 1, reflecting the lower end of the cost estimate range. It is assumed that the PNG LNG Project receives access fees from Papua LNG and P'nyang, consistent with Scenario 1.

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OUTPUTS AND VALUATION

The following table summarises the projected production, operating and capital costs for the scenarios:

PNG LNG PROJECT – MODEL PARAMETERS (100% INTEREST) [27]

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
LNG	tbtu	384	447	445	437	439	10,104
Domestic Gas	tbtu	2	11	11	11	15	248
Condensate	mmbbl	8	7	7	6	6	130
Naphtha	mmbbl	1	1	1	1	1	36
Total Production	**mmboe**	**76**	**88**	**87**	**85**	**86**	**1,951**
Operating Costs [28]	$ millions	(725)	(731)	(715)	(772)	(843)	(38,298)
Capital Expenditure [29]	$ millions	(206)	(487)	(643)	(673)	(667)	(8,265)
Scenario 2							
LNG	Tbtu	445	447	442	439	444	13,949
Domestic Gas	Tbtu	9	9	9	9	13	314
Condensate	mmbbl	8	7	7	6	7	214
Naphtha	mmbbl	1	1	1	1	1	45
Total Production	**mmboe**	**88**	**87**	**86**	**85**	**87**	**2,718**
Operating Costs [28]	$ millions	(728)	(728)	(712)	(766)	(831)	(65,086)
Capital Expenditure [29]	$ millions	(193)	(510)	(720)	(728)	(842)	(7,300)

The following table summarises the NPV analysis for Oil Search's 29% interest in PNG LNG under each of the scenarios:

PNG LNG PROJECT – NPV ANALYSIS ($ MILLIONS) (OIL SEARCH 29% INTEREST)

	BRENT OIL PRICE SCENARIO		
	HIGH	MID	LOW
Scenario 1			
Discount Rate of 8.5%	9,170	8,543	7,817
Discount Rate of 9.0%	8,857	8,255	7,558
Discount Rate of 9.5%	8,563	7,985	7,314
Scenario 2			
Discount Rate of 8.5%	9,800	8,953	8,212
Discount Rate of 9.0%	9,412	8,606	7,902
Discount Rate of 9.5%	9,053	8,284	7,614

Grant Samuel's valuation of Oil Search's interest in the PNG LNG Project in the range $7,350 – 8,250 million reflects the NPV analysis summarised above and considers the following factors:

- the mid-point NPVs for Scenarios 1 and 2 imply a value for Oil Search's 29.0% interest in the PNG LNG Project in the approximate range of $8.2 – 8.6 billion. This range of NPVs does not make an adjustment for the sovereign and other risks that relate to the PNG LNG Project's location in PNG.

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27 All capital and operating costs presented are in nominal terms and have been escalated at an annual rate of 2.0%.

28 Operating Costs presented include field, well, pipe and plant costs in addition to gas purchase costs, the PL2 tariff and shipping costs.

29 Capital expenditures are presented net of the Papua LNG and P'nyang access fees for Scenarios 1 and 2 and the funding of the expansion train by the P'nyang Joint Venture for Scenario 2.

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Valuation adjustments for sovereign risk are not straightforward and inevitably involve subjective judgements. In this regard:

- it can be argued that the sovereign risks facing the PNG LNG Project are not significant. The project is well past the pre-development point at which arguably it would have been most vulnerable to sovereign risk impacts. It is a major contributor to the PNG economy as a result of its tax contribution, its status as a major employer and the positive spin-off effects for other related businesses in PNG. Any incidence of sovereign risk that materially affected its value could be expected to have a profound impact on global investment and funding appetite for major new projects in PNG and so there are compelling reasons for fiscal and other relevant arrangements to continue to be honoured;
- on the other hand, there can be no guarantee that a future PNG government might not seek to re-visit the fiscal framework within which the PNG LNG Project (and other major resources projects) operates. The recent re-negotiation between the State of PNG and Barrick Gold of fiscal and other arrangements in relation to the Porgera Gold Mine is clear evidence of this, although the circumstances are in some regard very different. The risks of such an outcome could arguably be exacerbated by any prolonged period of high oil prices that might suggest that the joint venturers were earning "super returns"; and
- moreover, the relevant question is not some "objective" measure of sovereign risk, but rather the likely impact of investor or corporate perceptions of sovereign risk on the price that a real-world potential acquirer of the asset may be prepared to pay. The reality in the case of Oil Search's interest in the PNG LNG Project is that there are very few genuine acquirers likely to be interested in acquiring (for cash value) a major stake in the asset.

- application of a risk discount of approximately 10% would suggest a risk-adjusted value for Oil Search's 29.0% interest in the PNG LNG Project in the approximate rounded range of $7.4 – 7.7 billion. Such an adjustment would be consistent with increasing the discount rates applied in the DCF analysis from 8.5% – 9.5% to around 10.0% – 11.0%. Whilst the quantum of the adjustment is subjective and to some extent arbitrary, Grant Samuel believes that some adjustment for sovereign risk is required and that a reduction of circa 10% is reasonable;
- Oil Search is entitled to a carried interest of $176 million from certain non-PNG State project participants, targeted from 2022 to 2024, as compensation for the cancellation of PNG LNG equity interest redeterminations. The carried interest is subject to revision dependent on the success of planned drilling activities, assumptions regarding which differ as between Scenarios 1 and 2. These amounts have been incorporated into the NPV analysis relating to Oil Search's 29.0% interest;
- the individual tax position of Oil Search, including its Allowable Capital Expenditure ("ACE"), cross field allowance, royalty tax credit balances and transferrable exploration expenditure, may differ from the other PNG LNG Joint Venture participants and is incorporated into the DCF analysis. Infrastructure tax credits, offsets and deductions at the corporate level are not captured in the DCF analysis and have an estimated present value of approximately $160 – 180 million; and
- given the likely future abundance of gas in PNG, currently either undeveloped or undiscovered, that could potentially backfill the PNG LNG Project and support expansion optionality and life extension, the deterministic scenarios modelled above are likely to underestimate value. On the other hand, to the extent that any additional volumes (even if material) were ultimately produced at the back end of the life of the project and hence many years into the future, the incremental present value is unlikely to be significant.

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5.3.3 P'nyang and Muruk

Grant Samuel has valued Oil Search's upstream interests in P'nyang and Muruk in the range $100 – 150 million.

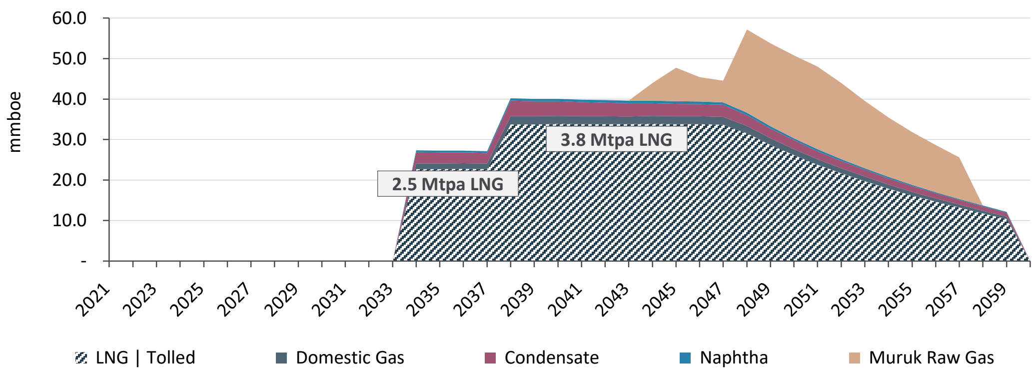
SCENARIOS AND ASSUMPTIONS

The valuation scenarios for the valuation of P'nyang and Muruk were developed as part of two scenarios for the integrated operation and development of the PNG LNG Project, P'nyang and Muruk, as described in Section 5.3.2. The elements of those scenarios which apply particularly to P'nyang and Muruk are as follows:

Scenario 1

Scenario 1 assumes that P'nyang gas is used as backfill for the two existing PNG LNG trains. Total LNG production from P'nyang is approximately 3,852 tbtu from 2034 to 2059, tolled through the two existing PNG LNG trains, accompanied by production of 223 tbtu of domestic gas, 65 mmbbls of condensate and 13 mmbbls of naphtha. Annual production from P'nyang is around 27 mmboe from 2034 to 2037 and increases to around 40 mmboe from 2038 to 2047, after which production progressively declines. Muruk produces 1.1 tcf of raw gas from 2044 to 2057, which is sold to the PNG LNG Joint Venture. The recoverable volumes assumed for Muruk broadly correspond to a P50 outcome. Muruk is assumed to produce swing volumes in the range 25 – 47 bcf from 2044 to 2047, to enable the PNG LNG trains to operate at capacity. Annual production from Muruk increases to around 115 bcf from 2048 to 2051, before progressively declining to around 60 bcf in 2057. The assumed production profile is illustrated below:

P'NYANG AND MURUK SCENARIO 1 – TOTAL PRODUCTION (100% INTEREST)



LNG is priced at an assumed slope of 13.0% to JCC. Assumptions regarding the pricing of domestic gas, condensate and naphtha are consistent with the assumptions used for the valuation of the PNG LNG Project. Muruk is assumed to sell raw gas to the PNG LNG Joint Venture at $4.60 / mcf (2021 $).

Capital expenditures over the total project lives are around $7.7 billion (2021 $) for P'nyang and $2.0 billion (2021 $) for Muruk and predominantly relate to the construction of the gas conditioning plants, pipelines and other infrastructure, as well as upstream development drilling. P'nyang is assumed to pay a processing fee to the PNG LNG Project to transport and liquefy its gas. As Muruk is sequenced after Juha and assumed to tie into the Juha-to-Hides export pipeline, it incurs only $32 million (2021 $) in pipeline expenditures.

Annual upstream operating costs for P'nyang are around $190 million (2021 $) from 2034 to 2037 and around $220 million (2021 $) from 2038 to 2047, before declining due to lower production volumes. P'nyang also pays an assumed capital processing tariff and a volume-based tariff (consistent with that payable by the PNG LNG Project) for use of the PL2 pipeline to transport its condensate to the Kumul Marine Terminal for export. Annual operating costs for Muruk are within the range $14 – 26 million (2021 $) from 2044 to 2047 and increase to around $65 million (2021 $) thereafter, reflecting the assumed

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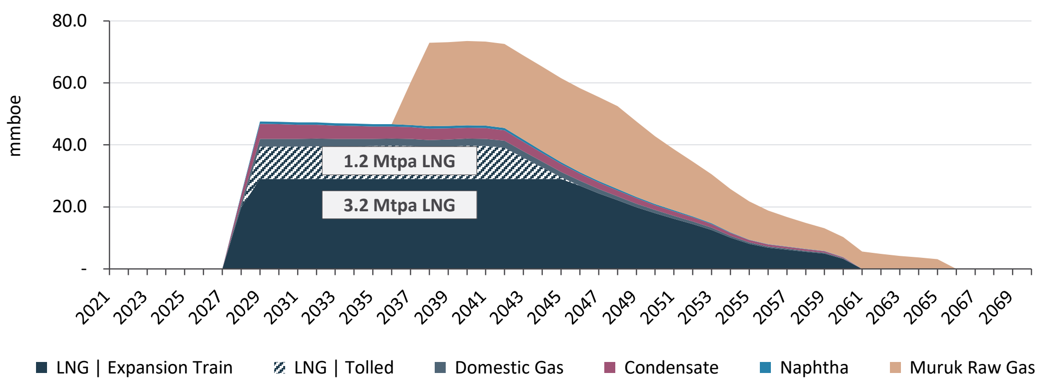
progressive development. Abandonment expenditures total $160 million (2021 $) for P'nyang and $274 million (2021 $) for Muruk and are incurred in the period following the completion of production at each field.

Fiscal assumptions for P'nyang reflect the terms of the Heads of Agreement relating to the P'nyang Gas Agreement that was signed in September 2021. Fiscal assumptions adopted for Muruk include a 2.0% royalty, 2.0% social development levy and 2.0% production levy, charged on the wellhead value of products sold and treated as a tax deduction. APT is assumed at 15% of post-tax cash flows once the internal rate of return exceeds 15%.

Scenario 2

Scenario 2 assumes that P'nyang gas will be processed through a new LNG train to be located at the PNG LNG site at Konebada and constructed broadly in parallel with the construction of Papua LNG, but funded and owned by the P'nyang Joint Venture. Total LNG production from P'nyang is approximately 5,047 tbtu from 2028 to 2060. Of this, 4,129 tbtu is processed through the expansion train, while the remaining 918 tbtu is tolled through the existing two PNG LNG trains when P'nyang upstream production exceeds the 3.2 Mtpa nameplate capacity of the P'nyang train. P'nyang also produces 300 tbtu of domestic gas, 85 mmbbls of condensate and 16 mmbbls of naphtha. Scenario 2 assumes recoverable volumes for Muruk that broadly correspond to a P10 outcome. Successful well penetrations have indicated the potential for a wide range in recoverable volumes at Muruk, and as a result, total gas production in Scenario 2 is materially greater at 2.9 tcf. The development of Muruk is sequenced prior to Juha in Scenario 2 as Muruk is assumed to be the lower unit cost development given its more significant increase in total recoverable volumes. Scenario 2 accordingly assumes that Muruk commences production in 2037. The assumed production profile is illustrated below:

P'NYANG AND MURUK SCENARIO 2 – TOTAL PRODUCTION (100% INTEREST)



Scenario 2 assumes that Santos acquires a 14.32% interest in P'nyang (pre government back-in) for $187 million, payable in contingent instalments. This is consistent with the expired Letter of Intent described in Appendix 3 (Section 2.2) and broadly aligns the ownership structures of the PNG LNG and P'nyang joint ventures post government back-in. All price assumptions for P'nyang and Muruk are consistent with Scenario 1.

Capital expenditures are around $6.2 billion (2021 $) for the upstream development of P'nyang, which represents a reduction of ~19% relative to Scenario 1 and reflects the lower end of the cost estimate range. P'nyang pays $2.4 billion to the PNG LNG Project on the commencement of production, reflecting the assumed acquisition costs for the expansion train and for access to the PNG LNG facilities. As Muruk is sequenced before Juha in Scenario 2, it incurs greater capital expenditures of $3.2 billion (2021 $), including $630 million for the construction of a new export pipeline to Hides. There is also an additional $540 million for the construction of upstream facilities and the drilling of development wells to support the higher

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volumes produced. Scenario 2 assumes that Muruk is fully developed before commencing production, unlike Scenario 1 which assumes a progressive development in line with PNG LNG ullage.

Annual operating costs (excluding abandonment rehabilitation) for P'nyang are $180 million (2021 $) in 2028 and $210 million (2021 $) from 2029 to 2043, after which operating costs fall progressively as production volumes decline. Operating costs for Muruk are ~$59 million (2021 $) per annum, which represents a 9.1% real terms reduction on the operating costs assumed in Scenario 1 from 2048 to 2057. The operating costs assumed in Scenario 2 reflect an assumption around additional cost efficiencies realised over the life of the projects. Scenario 2 also assumes that P'nyang pays a processing tariff to the PNG LNG Project that is approximately 40% higher than assumed for Scenario 1, in recognition of PNG LNG's deferral of its own production to accommodate P'nyang volumes. Abandonment expenditures total $165 million (2021 $) for P'nyang and $306 million (2021 $) for Muruk.

Fiscal assumptions adopted in this scenario for P'nyang generally reflect the terms of the Papua Gas Agreement, rather than the Heads of Agreement for the P'nyang Gas Agreement, given the similarities between the P'nyang Scenario 2 and Papua LNG development concepts.[30] Fiscal assumptions for Muruk are consistent with Scenario 1.

OUTPUTS AND VALUATION

The following table summarises the projected production, operating and capital costs for the scenarios:

P'NYANG AND MURUK – MODEL PARAMETERS (100% INTEREST)[27]

	UNIT	PRE OPS	YEAR END 31 DECEMBER					LIFE OF PROJECT
			2034	2035	2036	2037	2038	
Scenario 1								
LNG	tbtu	-	132	132	132	132	196	3,852
Domestic Gas	tbtu	-	8	8	8	8	12	223
Condensate	mmbbl	-	3	3	3	3	4	65
Naphtha	mmbbl	-	0	0	0	0	1	13
Muruk Raw Gas	bscf	-	-	-	-	-	-	1,093
Total Production	**mmboe**	**-**	**27**	**27**	**27**	**27**	**40**	**971**
Operating Costs [31]	$ millions	-	(462)	(471)	(482)	(493)	(652)	(18,141)
Capital Expenditure [32]	$ millions	(6,578)	(1,064)	(418)	(710)	(678)	(14)	(13,220)

	UNIT	PRE OPS	YEAR END 31 DECEMBER					LIFE OF PROJECT
			2028	2029	2030	2031	2032	
Scenario 2								
LNG	tbtu		115	229	229	229	230	5,047
Domestic Gas	tbtu	-	7	14	14	14	15	300
Condensate	mmbbl	-	3	5	5	5	4	85
Naphtha	mmbbl	-	0	1	1	1	1	16
Muruk Raw Gas	bscf	-	-	-	-	-	-	2,901
Total Production	**mmboe**	**-**	**24**	**48**	**47**	**47**	**47**	**1,525**
Operating Costs [31]	$ millions	-	(210)	(364)	(371)	(379)	(387)	(15,237)
Capital Expenditure [32]	$ millions	(6,295)	(2,822)	(1)	(1)	(1)	(57)	(13,485)

30 Fiscal assumptions broadly reflect the Papua Gas Agreement. See Appendix 3 (Section 2.3) for further information.

31 Operating Costs presented include the PL2 tariff and exclude abandonment expenditures.

32 Capital expenditures are presented net of the P'nyang access fee and are inclusive of the train acquisition costs for Scenario 2.

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The following table summarises the NPV analysis for the scenarios:

P'NYANG AND MURUK – UNRISKED NPV ANALYSIS ($ MILLIONS) (OIL SEARCH INTERESTS) [33]

	BRENT OIL PRICE AND GSA GAS PRICE SCENARIO		
	HIGH	MID	LOW
Scenario 1			
Discount Rate of 8.5%	308	167	34
Discount Rate of 9.0%	225	98	(23)
Discount Rate of 9.5%	154	39	(71)
Scenario 2			
Discount Rate of 8.5%	1,776	1,478	1,179
Discount Rate of 9.0%	1,565	1,288	1,012
Discount Rate of 9.5%	1,373	1,117	861

Grant Samuel's valuation of the Oil Search interests in P'nyang and Muruk reflects the NPV analysis summarised above and other relevant considerations. In particular:

- the unrisked NPVs for Scenario 1 indicate only modest values, reflecting the timetable if P'nyang was to be developed on a backfill basis and Muruk was to be sequenced after Juha, with positive cash flows only starting to flow to the P'nyang Joint Venture around 2034 and to the Muruk Joint Venture around 2044. The values for Scenario 1 also reflect the assumptions regarding the ultimate recoverable gas from P'nyang and Muruk, which broadly correspond to P50 outcomes;
- the unrisked NPVs for Scenario 2 indicate materially higher values, resulting from the assumed acceleration of the commencement of gas production from P'nyang to 2028 and Muruk to 2037, the economic benefits to the P'nyang joint venturers of access to an owned LNG train, as well as an increase in recoverable volumes at both P'nyang and Muruk. However, it should be recognised that this upside scenario is no longer the declared preferred development strategy. The prospects of realising this additional value would be enhanced if there was greater alignment between the various parties in the PNG LNG and P'nyang joint ventures, which would be the case following a merger between Santos and Oil Search;
- P'nyang is still at very early stages of development. P'nyang is pre-FEED and the P'nyang Gas Agreement is not yet complete, with the P'nyang Joint Venture and the PNG Government having concluded a Heads of Agreement in September 2021. There is also considerable uncertainty in relation to the timing of development for Muruk, given that it will depend on the sequence of fields and the expected ullage at the PNG LNG Project over time. Moreover, as with all Oil Search's PNG assets, P'nyang and Muruk are exposed to sovereign risk, which is arguably exacerbated by their pre-development status. Having regard to these factors, Grant Samuel believes that it is appropriate to risk the calculated NPVs by of the order of 70% (i.e. by applying a discount of approximately 30% to unrisked NPVs). Further, while it is not appropriate to completely ignore the upside value that could be available through the development of an additional train, the acceleration of the commencement of gas production and an increase in recoverable volumes, Grant Samuel believes that it is appropriate to focus on Scenario 1, particularly given that it includes the development strategy for P'nyang that is contemplated in the Heads of Agreement and is based on recoverable volume outcomes more likely to be achieved than those assumed in Scenario 2;
- the State of PNG is entitled to back-in to the P'nyang Joint Venture for a 22.5% share at historical cost. Scenario 2 NPVs are on the basis that Santos acquires a 14.32% interest in the P'nyang Joint Venture.

[33] The Muruk GSA gas price in the high and low cases is $5.10 / mcf (2021 $) and $4.10 / mcf (2021 $) respectively.

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Oil Search's interest in P'nyang is accordingly diluted from 38.51% to 29.85% in Scenario 1 and 28.57% in Scenario 2; and

- there is general uncertainty over the assumed fiscal arrangements for Muruk, which would need to be negotiated with the PNG Government in due course.

Having regard to the above factors, Grant Samuel has attributed a value to Oil Search's upstream interests in P'nyang and Muruk in the range $100 – 150 million.

5.3.4 Papua LNG

Grant Samuel has valued Oil Search's 17.7% interest in Papua LNG, post PNG Government back-in, in the range $600 – 800 million.

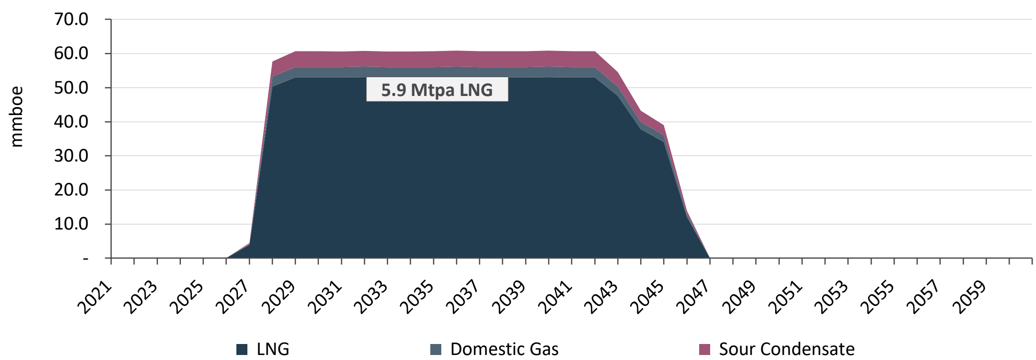
SCENARIOS AND ASSUMPTIONS

Two scenarios were developed for the valuation of Papua LNG.

Scenario 1

Scenario 1 assumes that Papua LNG receives FID in 2023, also commences field development, pipeline construction and construction of two new trains in 2023, and first production occurs in 2027. Based on 2C resources at Elk-Antelope and a field life through to 2046, 5,382 tbtu of LNG, 312 tbtu of domestic gas and 81 mmbbls of sour condensate are produced over the life of the project. The two trains are assumed to outperform nameplate capacity and operate at 5.9 Mtpa, as ExxonMobil has consistently operated the PNG LNG trains at well above nameplate capacity. Production remains relatively constant from 2028 to 2042, after which it declines rapidly. The assumed production profile is illustrated below:

PAPUA LNG SCENARIO 1 – TOTAL PRODUCTION (100% INTEREST)



LNG is priced at an assumed slope of 13.0% with sour condensate (a mixed liquids product) priced at a $3.0 (nominal) discount to the prevailing brent price. Capital expenditures are around $11.1 billion (2021 $), including $6.0 billion for the upstream development of Elk-Antelope and $4.4 billion for the construction of two LNG trains at the PNG LNG site at Konebada. The upstream costs relate predominantly to the construction of the onshore and offshore export pipelines to the PNG LNG site, the Herd gas conditioning plant and supporting facilities and infrastructure, in addition to the drilling of development wells. Other costs relate to exploration, appraisal and FEED. Papua LNG is assumed to pay a material access fee to the PNG LNG Joint Venture at the commencement of production for access to PNG LNG's infrastructure. Operating costs (excluding abandonment rehabilitation) are $275 million (2021 $) per annum. Abandonment expenditures total $299 million (2021 $) and are incurred in 2047 following the completion of production. Fiscal assumptions reflect those included in the Papua Gas Agreement.

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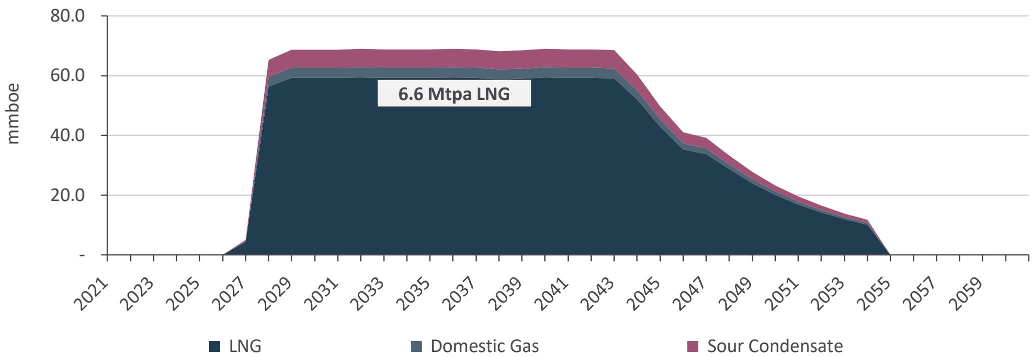
Scenario 2

Scenario 2 is broadly similar to Scenario 1 but assumes the ultimate production of a significantly larger resource, reflecting both a P10 recovery outcome and connectivity to the Mule Deer pinnacle reef. Scenario 2 also assumes that the two trains produce LNG at the higher maximum rate of 6.6 Mtpa. Total production from Elk-Antelope is 7,186 tbtu of LNG, 417 tbtu of domestic gas and 126 mmbbls of sour condensate over the period from 2027 to 2054. The assumed production profile is illustrated below:

PAPUA LNG SCENARIO 2 – TOTAL PRODUCTION (100% INTEREST)



Capital expenditures are $10.2 billion (2021 $), excluding the access fee payable to the PNG LNG Project. Relative to Scenario 1, this represents a reduction of 12.0% on upstream facilities expenditures, a reduction of 10.5% on drilling and pipeline expenditures and a reduction of 4.8% on downstream plant expenditures. The reduction in capital expenditures reflects the lower end of the cost estimate range for Papua LNG. Recovery of the incremental volumes in Scenario 2 does not require additional expenditure relative to Scenario 1, as the increased volumes are due to superior flow rates and geological properties. While the annual operating costs are the same as those assumed for Scenario 1, abandonment expenditures are marginally greater at $308 million (2021 $).

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OUTPUTS AND VALUATION

The following table summarises the projected production, operating and capital costs for the scenarios:

PAPUA LNG – MODEL PARAMETERS (100% INTEREST)[27]

	UNIT	PRE OPS	YEAR END 31 DECEMBER					LIFE OF PROJECT
			2027	2028	2029	2030	2031	
Scenario 1								
LNG	tbtu	-	23	292	307	307	307	5,382
Domestic Gas	tbtu	-	1	17	18	18	18	312
Sour Condensate	mmbbl	-	0	4	5	5	5	81
Total Production	**mmboe**	**-**	**4**	**58**	**61**	**61**	**61**	**1,062**
Operating Costs[34]	$ millions	-	(310)	(316)	(322)	(329)	(335)	(7,523)
Capital Expenditure[35]	$ millions	(8,391)	(2,302)	(577)	-	-	-	(13,297)
Scenario 2								
LNG	tbtu	-	25	327	344	344	344	7,186
Domestic Gas	tbtu	-	1	19	20	20	20	417
Sour Condensate	mmbbl	-	0	6	6	6	6	126
Total Production	**mmboe**	**-**	**5**	**65**	**69**	**69**	**69**	**1,437**
Operating Costs[34]	$ millions	-	(310)	(316)	(322)	(329)	(335)	(11,472)
Capital Expenditure[35]	$ millions	(7,785)	(2,171)	(530)	-	-	-	(12,210)

The DCF analysis takes into account the dilutionary impact of the project buy-in rights of the State of PNG. The State is entitled to acquire a 22.5% interest in Papua LNG upon PDL award. The scenarios assume that the grant of the PDL occurs in 2022, with the acquisition price reflecting the Government's pro-rata share of expenditures incurred over the prior 20-year period. In accordance with the Papua Gas Agreement, the PNG Government will pay the acquisition price (with interest) on a deferred basis.

The following table summarises the NPV analysis (on an unrisked basis) for the scenarios:

PAPUA LNG – UNRISKED NPV ANALYSIS ($ MILLIONS) (100% INTEREST)

	BRENT OIL PRICE SCENARIO		
	HIGH	MID	LOW
Scenario 1			
Discount Rate of 8.5%	1,064	888	712
Discount Rate of 9.0%	944	778	612
Discount Rate of 9.5%	833	677	521
Scenario 2			
Discount Rate of 8.5%	1,705	1,488	1,271
Discount Rate of 9.0%	1,538	1,335	1,132
Discount Rate of 9.5%	1,385	1,196	1,006

Grant Samuel's valuation of Oil Search's interest in Papua LNG reflects the unrisked NPV estimates summarised above and considers the following factors:

- the DCF analysis for Scenarios 1 and 2 spans a wide range of net present values, predominantly due to assumptions regarding ultimate recoverable volumes, annual production rates and capital expenditures. Scenario 1 is considered more probable as the assumed recoverable volumes broadly

34 Operating Costs presented exclude abandonment expenditures.

35 Capital expenditures are presented net of the Papua LNG access fee and include pre-start up operating costs.

correspond to a P50 outcome, as opposed to the P10 outcome assumed in Scenario 2. Scenario 2 also assumes greater train overperformance relative to nameplate capacity. While it should be considered as a possible outcome, Scenario 2 should be viewed as considerably less likely than Scenario 1;

- the area surrounding Elk-Antelope hosts several discoveries and prospects that could potentially supply meaningful quantities of gas to the Papua LNG liquefaction trains and support life extension. GaffneyCline has attributed a value of $179 – 291 million to Oil Search's exploration interests in the Eastern Fold Belt, including Wildebeest, White Tail and Antelope South. See Appendix 3 (Section 4.4) for licence details and Oil Search's ownership interests;
- the valuation scenarios assume that the Papua LNG trains will operate at above nameplate capacity by 0.3 Mtpa in Scenario 1 and 1.0 Mtpa in Scenario 2. ExxonMobil has consistently operated the PNG LNG trains at well above their combined nameplate capacity of 6.9 Mtpa, including at 8.8 Mt in 2020. Similar outperformance for the Papua LNG trains would deliver value additional to that estimated via the DCF analysis. Conversely, failure to outperform at the assumed levels would result in value erosion relative to the NPV estimates;
- Papua LNG is still at an early stage of its development and cost estimates have been compiled on a pre-FEED basis. The Papua LNG Joint Venture intends to commence FEED studies in 2022 with FID targeted for 2023. FEED entry requires agreement between the Papua LNG and PNG LNG joint ventures on infrastructure sharing and synergies, and FID is ultimately dependent on successful FEED and the ability to secure appropriate funding;
- notwithstanding the Fiscal Stability Agreement entered into in February 2021, the Papua LNG Project remains subject to PNG sovereign risk and, arguably, greater risk than a project already in operation such as PNG LNG; and
- having regard to the risks and uncertainties applicable to the project, Grant Samuel believes that it is appropriate to apply a risking factor of approximately 70% to the NPV outcomes for Papua LNG (i.e. apply a 30% discount to unrisked NPVs).

The value range of $600 – $800 million implies the following valuation parameters:

PAPUA LNG – IMPLIED VALUATION PARAMETERS

	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)	
		LOW	HIGH
Value Range ($ millions)		**600**	**800**
Reserves & Resources			
2P Reserves	n.a.	n.a.	n.a.
2C Resources	316	$1.90	$2.53

The multiples of 2C resources implied by the valuation of Papua LNG are reasonable in comparison to the $1.70 / boe multiple implied by ExxonMobil's acquisition of InterOil in February 2017, considering that:

- the acquisition of InterOil also included resource-based deferred and contingent consideration that has not been included in the calculation of the multiple;
- in addition to Elk-Antelope, InterOil held interests in Triceratops, Raptor and Bobcat. Independent reserve auditors had estimated gross, unrisked 2C resources of 790.8 mmboe for Triceratops, Raptor and Bobcat as at 31 December 2015, compared with 607.5 mmboe at Elk-Antelope;
- there have since been three re-certifications of Elk-Antelope – one in July 2016 post Oil Search's acquisition of the relevant PAC LNG Group Companies, another in November 2016 for InterOil, and most recently in September 2017 post ExxonMobil's acquisition of InterOil. The re-certifications

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estimated 2C resource volumes of 6.4 tcf, 7.8 tcf and 7.1 tcf respectively, all of which are lower than the 10.2 tcf estimated at 31 December 2015; and

- the Papua LNG Joint Venture has since progressed the upstream development of Elk-Antelope through entering the Papua Gas Agreement and Fiscal Stability Agreement with the PNG Government, in addition to pre-FEED work and the acquisition of seismic data in 2018 and 2019.

The following acquisitions are also relevant considerations:

- Oil Search acquired its 22.8% interest (pre-PNG Government back-in) in Elk-Antelope in March 2014 through its acquisition of the relevant Pac LNG Group Companies. The consideration comprised $900 million upfront plus a resource-based deferred and contingent payment for Elk-Antelope volumes greater than 7.0 tcf. The relevant certification completed in July 2016 and concluded average 2C resource volumes of 6.4 tcf, meaning that Oil Search has not been required to make an additional payment to the Pac LNG sellers; and
- Total acquired its 40.1% interest (pre-PNG Government back-in) in Elk-Antelope in March 2014 through the acquisition of an InterOil subsidiary. The consideration comprised $401 million upfront, $73 million upon FID and $65 million on the first LNG cargo, as well as several deferred and contingent payments for Elk-Antelope volumes greater than 3.5 tcf, and potential bonus payments for discoveries outside Elk-Antelope but within PRL 15.

5.3.5 Operated Oil & Gas Assets

Grant Samuel has valued the Oil Search interests in the Operated Oil & Gas Assets in the range $350 – 400 million.

SCENARIOS AND ASSUMPTIONS

Two scenarios were developed for the valuation of the Operated Oil & Gas Assets. The production profiles and capital and operating costs for these scenarios have been reviewed and where appropriate amended by GaffneyCline. The scenarios are summarised as follows:

Scenario 1

Scenario 1 assumes the production of 67.5 mmbbls of oil and 2.6 tcf of gas, with gas unitised into the PNG LNG Project apart from 44.4 bcf from SE Gobe, which is sold to the PNG LNG Project under a gas sales agreement. Oil production is predominantly from Kutubu, Agogo and Moran and is expected to increase from 4.9 mmbbls in 2021 to 6.3 mmbbls in 2024, reflecting successful in-field drilling. Thereafter, oil volumes are assumed to average 5.8 mmbbls from 2025 to 2027, and subsequently progressively decline due to natural field depletion. Gas production from SE Gobe is expected to be within the range 3.0 – 4.4 bcf per annum from 2021 to 2031. The assumed production profile is illustrated below:

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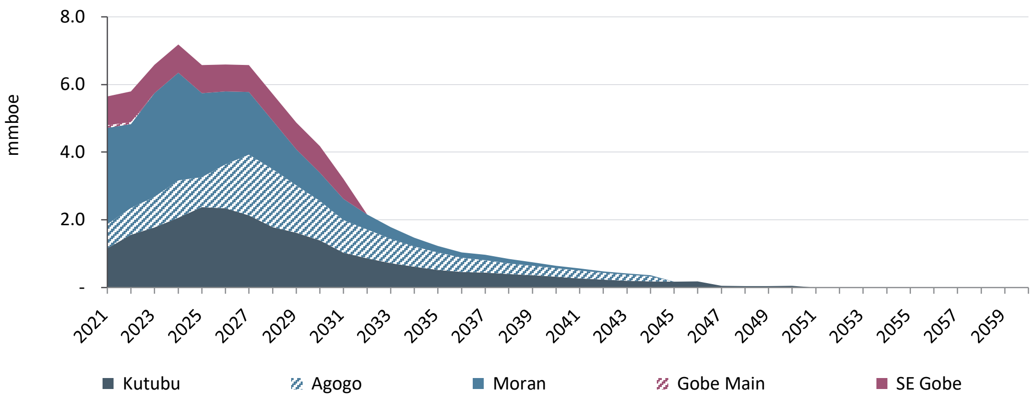
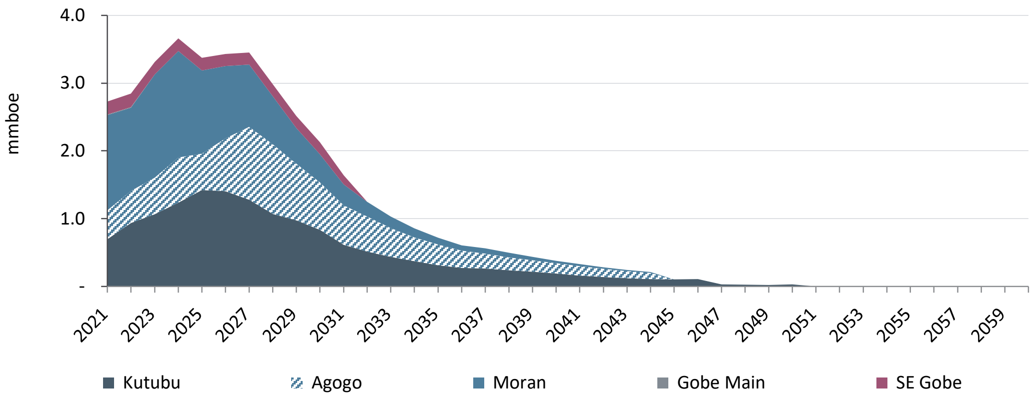
OPERATED OIL & GAS ASSETS SCENARIO 1 - TOTAL PRODUCTION (100%) [36]



The Oil Search share of production from the Operated Oil & Gas Assets is illustrated below:

OPERATED OIL & GAS ASSETS SCENARIO 1 - TOTAL PRODUCTION (OIL SEARCH SHARE) [36]



Oil volumes are blended with condensate from the PNG LNG Project to form the Kutubu Blend, which is then sold at a small discount to the prevailing Brent price. Gas from SE Gobe is sold to the PNG LNG Project based on existing GSA terms. Agogo receives liquids processing and gas handling tariffs from Moran and PL2 receives a tariff for the transport of oil and condensate volumes to the Kumul Marine Terminal, including from Hides GTE and the PNG LNG Project.

Operating costs and capital expenditures for Kutubu, Agogo, Moran, Gobe Main and PL2 are shared with the PNG LNG Project and as between the different joint ventures in accordance with various agreed sharing arrangements, predominantly based on the proportion of gas produced relative to oil, relative pipeline throughput and relative contributions to production.

The share of operating costs (including tariffs) attributable to the operated fields is expected to be around $150 million (2021 $) from 2022 to 2024. Operating costs are assumed to decline progressively thereafter, as the AG fields produce an increasing proportion of gas relative to oil, and the fields continue to naturally deplete.

The share of total capital expenditures attributable to the operated fields is around $1.1 billion (2021 $) and predominantly relates to expenditures at the Central Processing Facility and Kumul Marine Terminal, in

[36] Excludes gas production attributable to the PNG LNG Project.

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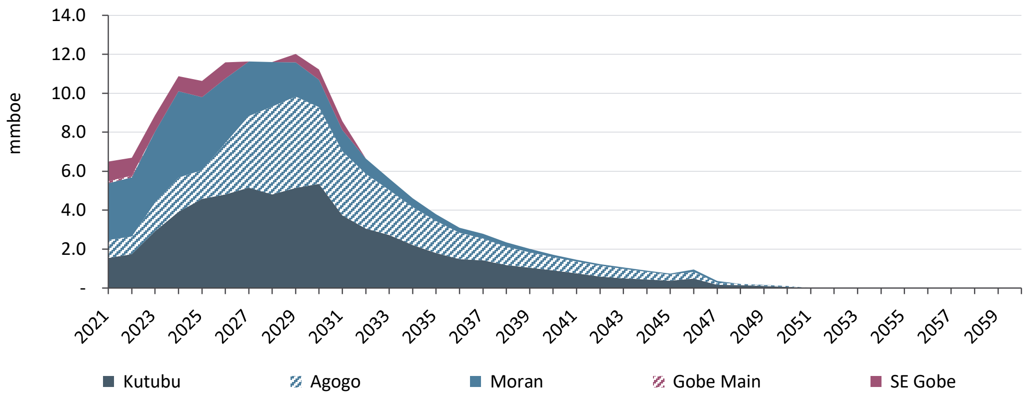
addition to well re-instalments and workovers. The PNG LNG Project is assumed to incur the capital and operating costs related to the Associated Gas Optimisation ("AGO") activities. Fiscal assumptions for oil fields that have yet to convert to gas fields (which are included in the PNG LNG ring-fence), being Moran, Agogo, SE Gobe and Hides GTE, reflect current arrangements, which include:

- a royalty of 2.0% on the wellhead value of products sold, applicable to Moran;
- a development levy of 2.0% on the wellhead value of products sold, applicable to all operated fields;
- APT at 30% of post-tax cash flows once the IRR exceeds 15%, applicable to all operated fields; and
- corporate income tax of 30% on assessable income.

Scenario 2

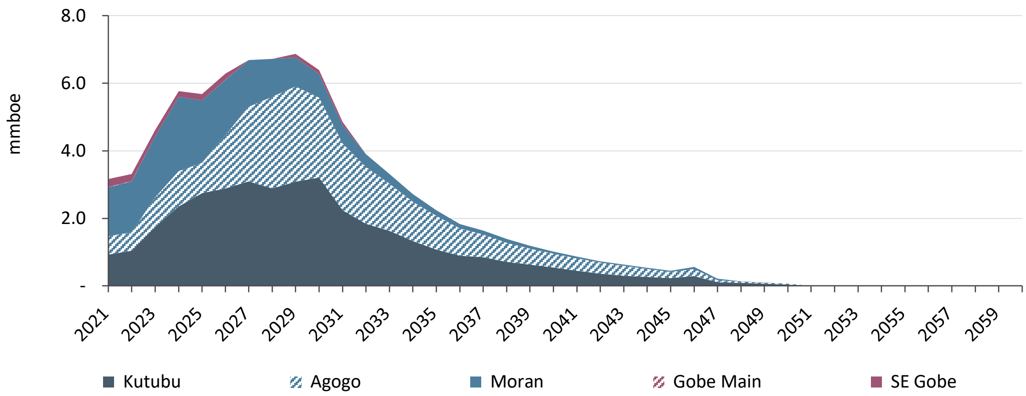
Scenario 2 assumes an additional 78 mmbbls of oil from Kutubu, Agogo, Moran and SE Gobe. Increased oil volumes are based on assumptions regarding ongoing successful exploration and development drilling. The assumed production profile is illustrated below:

OPERATED OIL & GAS ASSETS SCENARIO 2 - TOTAL PRODUCTION (100%)



The Oil Search share of production from the Operated Oil & Gas Assets is illustrated below:

OPERATED OIL & GAS ASSETS SCENARIO 2 - TOTAL PRODUCTION (OIL SEARCH SHARE)



The share of capital expenditures attributable to the operated fields is around $1.9 billion (2021 $), an increase of $750 million (2021 $) relative to Scenario 1, predominantly reflecting incremental in-field drilling at Kutubu, Agogo and Moran, as well as the larger proportion of oil production relative to gas. The

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share of operating costs also increases, predominantly reflecting the cost sharing arrangements as the field-by-field assumptions are mostly consistent with Scenario 1.

OUTPUTS AND VALUATION

The following table summarises the projected production, operating and capital costs for the scenarios:

OPERATED OIL & GAS FIELDS – MODEL PARAMETERS (100% INTEREST) [27]

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
Oil and SE Gas	mmboe	5.7	5.8	6.6	7.2	6.6	76.2
Operating Costs	$ millions	(212)	(157)	(150)	(158)	(130)	(1,484)
Capital Expenditure	$ millions	(103)	(251)	(272)	(135)	(202)	(1,169)
Abandonment Costs	$ millions	-	-	-	-	-	(709)
Scenario 2							
Oil and SE Gas	mmboe	6.5	6.7	8.9	10.9	10.6	150.0
Operating Costs	$ millions	(218)	(162)	(159)	(171)	(152)	(2,209)
Capital Expenditure	$ millions	(108)	(303)	(307)	(212)	(271)	(2,012)
Abandonment Costs	$ millions	-	-	-	-	-	(727)

The following table summarises the NPV analysis for the scenarios:

OPERATED OIL & GAS FIELDS – NPV ANALYSIS ($ MILLIONS) (OIL SEARCH SHARE) [37]

	BRENT OIL PRICE SCENARIO		
	HIGH	MID	LOW
Scenario 1			
Discount Rate of 8.5%	498	421	343
Discount Rate of 9.0%	480	405	329
Discount Rate of 9.5%	463	390	315
Scenario 2			
Discount Rate of 8.5%	1,227	1,086	945
Discount Rate of 9.0%	1,179	1,042	906
Discount Rate of 9.5%	1,133	1,000	868

Grant Samuel's valuation of the Oil Search interests in the Operated Oil & Gas Assets reflects the NPV analysis summarised above and considers the following factors:

- the operated oil and gas fields are mature and will continue to decline, although exploration and capital expenditures may be successful in mitigating natural decline in the short to medium term;
- Scenario 2, in particular, assumes that additional exploration and development is successful in arresting natural production decline, at least for a period of time. Whilst GaffneyCline has accepted this as an "upside" case, the reality is that Oil Search has had limited success in achieving such outcomes in the past and so it is arguably appropriate to focus on the NPVs for Scenario 1. Grant Samuel's valuation range largely discounts the NPVs for Scenario 2 and focuses on the calculated NPVs for Scenario 1; and

[37] The values presented are for the aggregate of Oil Search's different interests in Kutubu, Agogo, Moran, Gobe Main, SE Gobe and PL2.

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- while the oil operations have a relatively limited remaining life (at least by comparison with the PNG LNG Project) they remain exposed to some degree of PNG sovereign risk and it is appropriate to reflect at least some discount to estimated NPVs in the valuation adopted.

5.3.6 Alaskan Assets

Overview

Grant Samuel has valued Oil Search's 51% interest in the Alaskan Assets[38] in the range $700 – 800 million. The valuation incorporates a risked DCF analysis for Pikka Phase 1 and a separate assessment of the remaining Alaskan 2C resource inventory. It reflects an overall judgement on the value currently realisable by Oil Search for its interest in the Alaskan Assets, having regard in particular to corporate and funding appetite for oil assets on the Alaskan North Slope.

The overall 2C resource volumes attributable to the Alaskan Assets are set out below:

ALASKAN ASSETS – 2C RESOURCES (100% INTEREST)

CLASSIFICATION	UNIT	TOTAL	OIL SEARCH[39]
Pikka Phase 1 Development Plan	mmbbls	392	200
Other Development Pending (Post FEED)	mmbls	10	5
Development Pending (Pre FEED)	mmbbls	454	232
Development Unclarified	mmbbls	112	57
Total	**mmbbls**	**968**	**494**

Of the total 2C resource, 392 mmbbls are conceptually included in the Pikka Phase 1 development. Grant Samuel has valued this component of the 2C resource by way of DCF analysis, risked both for technical factors and for broader issues relating to the funding challenges and other risks to value realisation.

The remaining volumes are predominantly contained within the resource sub-maturity classifications of "Development Pending (pre-FEED)" and "Development Unclarified". Having regard to the fundamental uncertainties related to the future development of these resources, the remaining 576 mmbbls have been valued on a $/bbl basis, with GaffneyCline recommending valuation benchmarks based on perceived technical risking, time value of money and capital intensity considerations.

SCENARIOS AND ASSUMPTIONS

Pikka Phase 1

DCF analysis for Pikka Phase 1 is based on three oil production scenarios, which correspond broadly to P90, P50 and P10 ultimate recovery outcomes for the existing Pikka Phase 1 2C resource. The scenarios were reviewed and amended as appropriate by GaffneyCline. In each scenario, production is assumed to commence in 2025. The P90 scenario assumes the production of 252 mmbbls to 2042, the P50 scenario assumes the production of 345 mmbbls to 2048, and the P10 scenario assumes the production of 502 mmbbls to 2057.[40] All other assumptions are consistent as between the scenarios. The assumed production profiles are illustrated below:

[38] Alaskan Assets refer to the Pikka Phase 1 Development Project, other contingent resources not included in the Pikka Phase 1 Development Plan and Oil Search's exploration interests on the North Slope of Alaska.

[39] Based on Oil Search's 51.0% working interest before royalties in the relevant leases.

[40] Production for each scenario assumes the mid case Brent price. Total production will vary at different prices due to the application of an economic cut-off.

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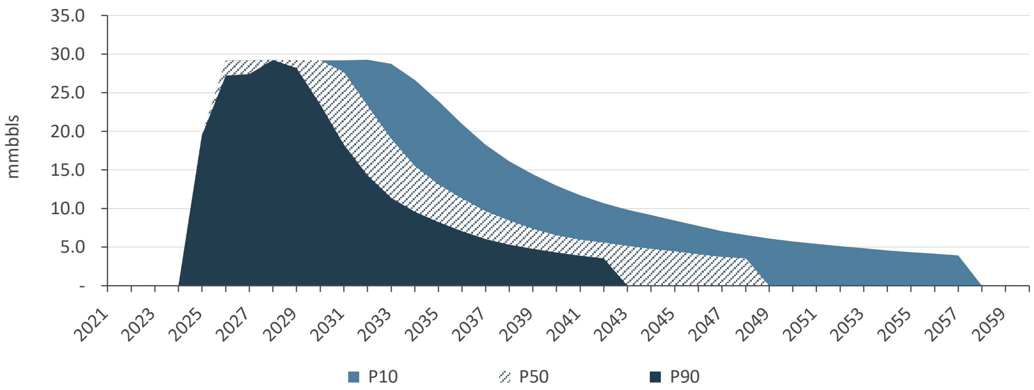
ALASKA NORTH SLOPE – PRODUCTION SCENARIOS (100% INTEREST)



Development capital expenditures total $3.1 billion (2021 $) and comprise $1.1 billion in relation to drilling and completions and $2.0 billion in relation to the construction of facilities. Fixed operating costs are assumed at approximately $95 million (2021 $) per annum, comprising both upstream expenditures and production overheads. Production incurs transportation costs of approximately $8.70 / bbl (2021 $) to deliver the oil to the point of sale, relating to the Trans Alaska Pipe System tariff, marine costs and feeder pipelines. Other cost assumptions include a purchase cost of approximately $3.0 (2021 $) per mscf on third party import gas and various payments to local stakeholder organisations. Abandonment expenditures total ~$460 million (2021 $) and are incurred in the period following the completion of production.

Alaskan oil is priced at close to parity to Brent, consistent with the average over a three-year period.[41]

Fiscal assumptions reflect the arrangements described in Appendix 3 (Section 5) and in addition include the following:

- a royalty of 16.67% payable to the Arctic Slope Regional Corporation and the State Government and applied to Gross Value at Point of Production ("GVPP");[42]
- an overriding royalty interest ("ORRI") of 1.62%, payable to Armstrong and GMT, and applied to GVPP. The assumed ORRI is the weighted average expected ORRI across the relevant leases. In practice, some of these leases will have an ORRI of up to the maximum of 3.33% while others will have an ORRI of nil;
- property tax at 2.0% on the assessed 'true and fair' value of the assets, calculated in proportion with the decline in annual production relative to maximum annual production;
- production tax at the greater of 35% of Production Tax Value ("PTV") and 4% of GVPP less royalties;[43] and
- annual lease rental costs and a statutory conservation surcharge.

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41 Sourced from the Alaska Department of Revenue.

42 GVPP is calculated as revenue less transport costs.

43 PTV is calculated as GVPP – Royalties – Qualified Expenditures – Gross Revenue Exemption.

OUTPUTS AND VALUATION

The following table summarises the projected production, operating and capital costs for the scenarios:

PIKKA PHASE 1 - MODEL PARAMETERS (100% INTEREST) [27]

	UNIT	PRE OPS	YEAR END 31 DECEMBER					LIFE OF PROJECT
			2025	2026	2027	2028	2029	
P90 Scenario								
Oil Production	mmbbls	-	19	27	27	29	28	252
Operating Costs[44]	$ millions	(23)	(88)	(158)	(164)	(170)	(173)	(3,356)
Capital Expenditure[45]	$ millions	(2,552)	(225)	(197)	(201)	(44)	-	(3,219)
P50 Scenario								
Oil Production	mmbbls	-	20	29	29	29	29	345
Operating Costs[44]	$ millions	(23)	(88)	(161)	(166)	(170)	(173)	(4,904)
Capital Expenditure[44]	$ millions	(2,552)	(225)	(197)	(201)	(44)	-	(3,219)
P10 Scenario								
Oil Production	mbbls	-	20	29	29	29	29	502
Operating Costs[44]	$ millions	(23)	(88)	(161)	(166)	(170)	(173)	(7,673)
Capital Expenditure[44]	$ millions	(2,552)	(225)	(197)	(201)	(44)	-	(3,219)

The following table summarises the NPV analysis for the three production scenarios. The calculated NPVs incorporate a 90% risking factor (i.e. a 10% discount to unrisked NPVs), recommended by GaffneyCline to take into account the technical uncertainties that apply to the project.

PIKKA PHASE 1 - RISKED NPV ANALYSIS ($ MILLIONS) (100% INTEREST)

	BRENT OIL PRICE SCENARIO		
	HIGH	MID	LOW
P90 Scenario			
Discount Rate of 8.5%	1,384	1,141	810
Discount Rate of 9.0%	1,294	1,059	739
Discount Rate of 9.5%	1,209	981	671
P50 Scenario			
Discount Rate of 8.5%	2,112	1,851	1,460
Discount Rate of 9.0%	1,983	1,731	1,356
Discount Rate of 9.5%	1,860	1,617	1,256
P10 Scenario			
Discount Rate of 8.5%	3,019	2,697	2,242
Discount Rate of 9.0%	2,822	2,515	2,080
Discount Rate of 9.5%	2,637	2,343	1,927

The calculated NPVs fall within a very wide range, reflecting the early stage of the project and the consequent range of estimated ultimate production between the P90 and P10 outcomes. GaffneyCline has recommended that the range of NPVs be averaged by way of a Swanson's mean, defined as (30% x P90 + 40% x P50 + 30% x P10). This averaging yields the following NPVs, which are marginally higher than the P50 NPVs:

[44] Operating costs presented include production overheads and certain stakeholder payments but exclude royalties and taxes.

[45] Capital expenditures presented exclude abandonment expenditures at end of life.

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PIKKA PHASE 1 - RISKED NPV ANALYSIS USING SWANSON'S MEAN VALUES (100% INTEREST)

	UNIT	BRENT OIL PRICE SCENARIO		
		HIGH	MID	LOW
NPVs				
Discount Rate of 8.5%	$ millions	2,166	1,892	1,500
Discount Rate of 9.0%	$ millions	2,028	1,765	1,388
Discount Rate of 9.5%	$ millions	1,898	1,644	1,282
Implied Resource Multiple				
Discount Rate of 8.5%	$ / bbl	5.31	4.64	3.68
Discount Rate of 9.0%	$ / bbl	4.98	4.33	3.41
Discount Rate of 9.5%	$ / bbl	4.66	4.03	3.15

The NPV analysis suggests a value for the Pikka Phase 1 development (100% interest) of around $1.6 – 1.9 billion. While the calculated NPVs incorporate risking for technical risk, they do not take into account further factors that will bear on the value of Oil Search's Alaskan Assets. These factors include risks relating to Oil Search's achievement of a sell-down of a 15% project interest on acceptable terms, the securing of project finance or other funding, and agreement with Repsol on a path forward for the development of the project. These issues are discussed in further detail below.

Remaining Resource Inventory

Development of the 2C resource volumes in excess of those assumed to be produced in the Pikka Phase 1 development (and valued on a DCF basis) will depend on the ultimate success of Pikka Phase 1. Given the inherent uncertainties related to any follow-on development, GaffneyCline has recommended that the remaining 2C resource volumes attributable to the Alaskan Assets be valued on a $/bbl basis. GaffneyCline has recommended the following benchmarks:

- contingent resource sub-classification "Development Pending" – approximately $1.80 – 2.20 / bbl;
- contingent resource sub-classification "Development Unclarified" – approximately $0.80 – 1.00 / bbl;

The GaffneyCline recommended benchmarks imply a value for the remaining 2C resources in the approximate range $900 – 1,200 million. The $/bbl benchmarks recommended by GaffneyCline incorporate technical risking, reflecting GaffneyCline's judgements regarding probability of follow-on developments subsequent to the Pikka Phase 1 development, and also allow for time value of money based and assessed capital intensity. They are based on discount rates of 8.5% - 9.5%, and so implicitly reflect some level of "standard" risks appropriate for oil and gas assets in general. However, these benchmarks do not reflect the funding, commercial and other value realisation risks addressed in more detail below.

Funding and other value realisation risks

The Pikka Phase 1 development has attractive technical characteristics and prospective financial returns, as reflected in the DCF analysis set out above. However, realisation of this value is not straightforward in the context of markets that have a growing focus on ESG issues. Potential providers of both equity and debt, other financial institutions and oil and gas companies themselves are increasingly concerned with environmental factors and their interaction with investment decisions. The consequence is an uncertain but clearly adverse impact on the value of oil and gas assets in general. The impact on value has been both direct (in the sense that industry participants are likely to be more discriminating about the new investments that they make) and indirect, as constrained access to capital drives up funding costs and reduces funding availability. This trend has particular relevance in locations which might be seen to have greater environmental values, such as Alaska.

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Oil Search's strategy for the development of its Alaskan Assets has reflected a prudent approach having regard to its overall risk appetite and its balance sheet constraints. As early as 23 February 2021,[46] Oil Search signalled publicly that it was planning to sell down its overall interest in the Alaskan Assets from 51% to 36% (in conjunction with a concurrent sell-down by Repsol) and that it was investigating debt funding options. This intention was re-stated in multiple subsequent ASX releases.[47] On 4 May 2021, Oil Search announced that a "Joint Venture Equity Selldown program (is) underway". In an investor presentation on 8 June 2021, Oil Search noted that it was investigating a wide variety of funding options.[48]

As of the date of this report, Oil Search had not announced any meaningful progress on either its sell-down of a 15% interest in the Alaskan Assets or on the various funding options that it had planned to investigate. It is likely that there is a very small number of credible parties that would be interested in acquiring a 15% passive interest in the Alaskan Assets. While there may be a broader range of parties that could consider a larger investment that delivered operatorship, the number of such parties is still likely to be small.

In the absence of a sell-down, it is not clear how Oil Search on a standalone basis would progress with a development of Pikka Phase 1. Project financing of developments for oil and gas assets (and for carbon related assets generally) is becoming increasingly challenging. It is to be expected that such funding challenges would be materially exacerbated given the project's location in Alaska. Any significant delay in development of the Alaskan Assets would clearly reduce the value potential. If Oil Search was forced to realise its interest in the short-term there would be a risk that it would be perceived as a forced seller, which could materially reduce realised value.

Quantification of the impact on value of these issues is not straightforward. The DCF analysis and benchmark $/bbl valuation approach as set out above imply a value for Pikka Phase 1 and other 2C resources (100% interest) of approximately $2.5 – 3.1 billion, or approximately $1.25 – 1.60 billion for Oil Search's 51% share. It is clear that the value of the Alaskan Assets is significantly lower than these theoretical values, although judgements regarding value in this context are inevitably subjective.

Grant Samuel has adopted a valuation range of $700 – 800 million for Oil Search's 51% interest in the Alaskan Assets, including for the Alaskan exploration interests beyond current 2C resources.[49] This range of values represents a deep discount to theoretical DCF based values (in the order of 45-50%). In forming this judgement, Grant Samuel has taken the following into account:

- Oil Search's total costs associated with its acquisition and development of the Alaskan Assets are in the order of $1.3 billion. This is broadly consistent with the range of values that could be inferred from the NPV analysis and $/bbl benchmark analysis set out above (approximately $2.5 – 3.1 billion on a 100% basis). Given that the project appears to be technically and commercially robust, Grant Samuel's valuation range of $700 – 800 million implies that external market factors, and in particular ESG impacts on financier and corporate appetites for Alaskan North Slope oil exposures, have resulted in a dramatic reduction in currently realisable value;

- there is no objective basis for overlaying these funding and other ESG-related risks on the valuation. One approach would be merely to increase the discount rate applied. If a discount rate of (say) 15% was applied to the DCF analysis for the Pikka Phase 1 development and to the $/bbl benchmark-based valuation of the remaining 2C resources, the assessed value of the Alaskan Assets would fall (on a 100% basis) to around $850-1,200 million. However, adoption of a higher discount rate is no less arbitrary than an overall flat rate value adjustment (e.g. a simple assumption that actual values are

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46 Full Year Results Presentation: "Planning underway for equity selldown. Progressing discussions with lenders" (and) "targeting 36% (equity)"

47 For example, Oil Search's First Quarter report of 23 April 2021 noted that "Oil Search is pursuing potential funding options for the Pikka project …Financing and divestment activities are progressing concurrently and to plan. Our intent is to own 36% of this project".

48 Investor presentation of 8 June 2021 referred to a "sale process for 15% equity selldown and (OSH's investigation of) infrastructure optimisation or monetisation opportunities, access to debt capital markets and project debt financing".

49 GaffneyCline valued Oil Search's Alaskan exploration interests in the range $32 - 68 million.

(say) 50-55% of calculated NPVs). On one view, applying a much higher discount rate to all of the project unfairly penalises its value, because it underestimates the optionality inherent in the staged development that is planned for Pikka Phase 1 and the additional contingent resources; and

- Grant Samuel's valuation is for Oil Search's full 51% interest in the Alaskan Assets. It is possible that the value realisable for a 15% interest in the project may be less than that implied by the valuation of the full 51% interest, particularly if the 15% interest did not deliver operatorship. Grant Samuel's valuation assumes that Oil Search is able to realise value for its Alaskan Assets on an orderly basis. It is conceivable that a short-term divestment on what might be perceived as a forced basis would realise lower values. On the other hand, if a divestment was to proceed in the context of the asset being held by a merged Oil Search/Santos, free from funding pressures and with a range of value realisation options, it is plausible that additional value could be realised. Alternatively, the Merged Group could choose to progress with development of the Alaska Assets on a largely self-funded basis or postpone any selldown to a later point in time when development risks had been mitigated, either of which options would have the potential to deliver substantial additional value that was more in line with estimated NPVs.

Overall, while judgements regarding the value of the Alaskan Assets are inherently subjective and to some extent arbitrary, Grant Samuel believes that its valuation range of $700 – 800 million reasonably reflects the ESG, funding and other risks attached to the project. Given the extensive uncertainties, actual value may fall within a relatively wide range. It would be open to others attribute a different range of values, higher or lower, to Oil Search's interest in the Alaskan Assets.

5.3.7 PNG Exploration Assets

Grant Samuel has attributed value to Oil Search's exploration assets in PNG in the range $400 – $600 million, having had regard to the values recommended by GaffneyCline (see Section 4.6 of the GaffneyCline report at Appendix 7). This principally relates to the Wildebeest, White Tail and Antelope South gas prospects in the Eastern Fold Belt, the Karoma gas prospect in the Northwest Fold Belt and the Mosa Deep and Agogo South oil prospects in the Central Fold Belt.

5.3.8 Other Assets

Value in the range $25 – $50 million has been attributed to Oil Search's 50% interest in NiuPower, which owns and operates a 58 MW gas-fired power station in Port Moresby.

5.3.9 Corporate Overheads

For the purposes of this analysis, Oil Search's unallocated corporate overheads in 2021 and 2022 are expected to be approximately $48 million and $45 million accordingly. These costs relate to a range of costs including:

- the salaries and other costs associated with the executive team and head office functions, including treasury, corporate affairs, company secretarial and legal, tax and finance;
- office accommodation costs;
- listed company expenses such as director fees, annual reports and shareholder communications, share registry and listing fees and dividend processing;
- consultants, insurance, subscriptions, travel, and regulation and government charges; and
- other group shared services not fully recharged to the business operations.

Grant Samuel has attributed a capitalised (negative) value of $400 – 450 million to these unallocated corporate overheads, based on discounting the costs (inflated at an annual rate of 2%) at discount rates in the range of 8.5 – 9.5%.

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5.3.10 Adjusted Net Borrowings

Oil Search's net borrowings for valuation purposes are $2,308 million. This amount reflects Oil Search's adjusted net borrowings as at 30 June 2021:

OIL SEARCH – ADJUSTED NET BORROWINGS ($ MILLIONS)

	SECTION REFERENCE	AS AT 30 JUNE 2021
PNG LNG Project Debt	3.5	2,426
Bilateral Revolving Facilities	3.5	200
Finance Leases	3.5	118
Gross Borrowings		**2,743**
Cash	3.5	(504)
Net Borrowings		**2,240**
1HY21 Dividend		69
Adjusted Net Borrowings		**2,308**

Oil Search paid a half year dividend of 3.3 US cents per share on 21 September 2021. The total dividend amount of $69 million has been added back to net borrowings as at 30 June 2021.

Oil Search had finance leases with total principal outstanding as at 30 June 2021 of $374 million. Cash flows for certain of the finance leases were not taken into account in the DCF analysis for the relevant assets. The principal value of these finance leases ($118 million) has been included in net borrowings.

5.4 Value of Santos

5.4.1 Summary

For the purposes of its relative contribution analysis, Grant Samuel has valued the equity in Santos in the range $8,728 - 10,903 million. The valuation represents the estimated full underlying value of Santos on a standalone basis. It does not include any value for synergies that may be available to an acquirer of Santos.

The valuation is summarised below:

SANTOS – VALUE ANALYSIS SUMMARY ($ MILLIONS)

	REPORT SECTION REFERENCE	VALUE RANGE	
		LOW	HIGH
Western Australia	5.4.2	2,700	3,100
Queensland and New South Wales	5.4.3 / 5.4.4	3,180	3,700
Cooper Basin	5.4.5	1,600	1,900
Northern Australia and Timor-Leste	5.4.6	1,200	1,450
Papua New Guinea	5.4.7	3,200	3,600
Exploration interests not included in individual asset valuations	5.4.8	200	400
Other Assets and Liabilities	5.4.9	(5)	55
Capitalised corporate overheads	5.4.10	(440)	(395)
Enterprise value		**11,635**	**13,810**
Adjusted net borrowings	5.4.11	(2,907)	(2,907)
Value of equity		**8,728**	**10,903**

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The valuation is based on estimates of value for each of Santos' operating assets. DCF values for the operating assets were estimated based on valuation scenarios developed in conjunction with, and reflecting the technical judgements of, GaffneyCline. The valuations of each of the operating assets were benchmarked to the extent possible against recent transaction or other relevant evidence. The valuation scenarios developed by GaffneyCline incorporate detailed assumptions relating to annual production, operating costs, capital costs and abandonment expenditures ("Detailed Information"). In the ordinary course, it would be expected that the Detailed Information would be included in Grant Samuel's report. Santos has advised Grant Samuel that some of the Detailed Information is or may be confidential or commercially sensitive to it and others and has declined to provide the releases required for Grant Samuel to include the Detailed Information in its report. Accordingly, Grant Samuel has removed or aggregated the Detailed Information. This has had no impact on the underlying NPV analysis, the calculated NPVs or Grant Samuel's overall valuation conclusions.

GaffneyCline prepared valuations of Santos' exploration interests (i.e. prospective resources and other exploration targets) and certain contingent resources for which it was not appropriate to prepare cash flow based valuations. The total value attributed by GaffneyCline to Santos' exploration interests was in the range $1.1-1.5 billion. Of this, approximately $700-750 million relates to prospective resources and other exploration targets offshore Western Australia, including prospective resources which, if ultimately developed, could provide backfill gas to extend the lives of the Devil Creek and Varanus Island gas facilities[50], and could increase the life and improve the economics of the proposed Dorado development[51]. Approximately $230-350 million relates to conventional and unconventional exploration targets (including certain 2C resources) in the Cooper Basin. GaffneyCline's valuations of Santos' exploration interests in Western Australia and the Cooper Basin have been incorporated in the overall valuations of those assets. The remaining exploration interests (with value in the approximate range $200-400 million) relate principally to unconventional (shale gas) plays and PNG exploration. In addition, GaffneyCline's valuations of certain stranded gas resources offshore north-west Australian have been incorporated in the valuation of the Northern Australian assets.

Other assets include the value of Santos' tax losses, from which have been deducted various contingent payments and other items with negative value.

Grant Samuel's valuation of Santos implies (on a per share basis) values that range from a meaningful discount to Santos' current share price (at the bottom end of the valuation range) to values approximating recent share prices (at the top end of the range). In the ordinary course, Grant Samuel would expect that its estimate of underlying value on a per share basis (at least at the top end) would be significantly higher than the share price. In effect, Grant Samuel's estimate of underlying value represents a more conservative judgement than the market estimates of value reflected in Santos' recent share price. This difference may reflect factors including:

- for Santos' Western Australian and Northern Australian assets, different expectations built into the Santos share price in terms of the likely operating lives of various assets and the timing and quantum of abandonment expenditures;
- for Santos' Western Australian assets, different assumptions regarding the prospects of exploration success in relation to various prospective resources or exploration targets and their impact on prolonging the operating life and increasing the economic value of various assets;
- different assumptions regarding the future upstream gas production volumes and cost structure of GLNG;

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50 The relevant prospective resources are the Dancer and Yoorn fields, which have been valued by GaffneyCline on an EMV basis.

51 The relevant prospective resources are the Baxter, Pavo and Apus fields, also valued by GaffneyCline on an EMV basis.

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- different judgements regarding what GaffneyCline has categorised as "Onshore New Venture" exploration interests, principally shale gas and other unconventional plays; and
- different judgements regarding the possible value of certain Santos business initiatives.

Santos has for some time foreshadowed the possible establishment and realisation for value, at least in part, of a "Midstream Infrastructure" business. Grant Samuel has not ascribed any specific additional value to this opportunity.

Some elements of the Santos business clearly have lower risk, infrastructure style characteristics. In particular, the Western Australian business produces gas from mature gas fields, and processes and sells that gas into what are predominantly fixed price or inflation linked domestic gas contracts. In the Cooper Basin, Santos treats third party gas and other products on a tolling basis such that the third party customers bear all the production and pricing risks. More broadly, a meaningful (but not material proportion) of Cooper Basin gas is also sold into fixed price or inflation-linked domestic gas contracts, although these are generally short term in duration and will be exposed to re-pricing risk at expiry. Grant Samuel has made specific adjustments for these elements of Santos' business by identifying the relevant revenue and cash flow streams and incorporating additional value estimated by the application of lower discount rates.

There is a broader issue of whether there should be a larger valuation uplift to take account of Santos' extensive holdings of infrastructure style assets such as gas processing plants (including LNG trains) and pipelines. In general, assets with infrastructure characteristics and appropriate contractual arrangements in place realise materially higher multiples (>10 times EBITDA) than oil and gas companies overall. Santos has identified a Midstream Infrastructure business unit comprising these assets and has reported that on the basis of hypothetical tariffs or tolling arrangements they could generate approximately $400 million in annual EBITDA.

In Grant Samuel's view it is appropriate to attribute additional value to genuine third party "tolling" earnings but not to other income which effectively represents no more than a carve out of Santos' existing profits, based on notional tariffs paid by the upstream component of the business. Whether such synthetic infrastructure "creates" value is open to question. If the infrastructure were actually sold (whether at the expected higher multiples or otherwise), the sale would change the risk profile of the upstream business by inserting a new fixed (or close to fixed) charge. The result would be to make the residual earnings far more volatile than the previous combined income stream. In effect, to the extent that a component of the business with lower systematic risk was artificially isolated and realised for value reflecting that lower risk, the systematic risk of the remainder of the business would increase. The extent of the offset in the real world can be debated but it is clearly appropriate to be cautious regarding the quantum of any overall value uplift. Essentially, a synthetic infrastructure arrangement is no more than a form of financing. It could be expected to release capital, but not to increase value.

In any event, in the case of Santos' assets, it is not clear that all the identified assets would be appropriate inclusions in a portfolio of infrastructure style assets, either because of uncertainty regarding their remaining operating lives or because high CO_2 characteristics may reduce their investment appeal to certain investors.

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Grant Samuel's valuation of Santos implies the following valuation parameters:

SANTOS – IMPLIED VALUATION PARAMETERS

	SECTION REFERENCE	UNIT	VALUE RANGE	
			LOW	HIGH
Value range				
Equity value	5.4.1	$ millions	8,728	10,903
Enterprise value	5.4.1	$ millions	11,635	13,810
Reserves and Resources at 31 December 2020				
2P (proven and probable)	4.2	$ / boe	12.47	14.80
2P + 2C	4.2	$ / boe	3.62	4.30
Production				
2020 (actual)	4.3	$ / boe	130.7	155.2
2021 (forecast, midpoint)	4.3	$ / boe	130.0	154.3
Financial performance for year ended 31 December 2020 (Actual)				
EBITDAX	4.4	times	6.2	7.4
EBITDA	4.4	times	6.5	7.7
EBIT	4.4	times	14.8	17.5
NPAT (as reported)	4.4	times	30.4	38.0
Financial performance for year ending 31 December 2021 (Forecast)				
EBITDAX	4.4	times	4.1	4.9
EBITDA	4.4	times	4.3	5.0
EBIT	4.4	times	7.5	8.9
NPAT	4.4	times	10.2	12.8

The multiples of reserves, resources, production and earnings are low having regard to market evidence (see Appendix 7) and, particularly, having regard to the Oil Search valuation (see Section 5.3.1.). In Grant Samuels' view, however, these relativities are reasonable, having regard amongst other factors to:

- the short remaining operating lives of a number of Santos assets (particularly Bayu Undan and the Western Australian oil assets);
- the significant near-term abandonment and rehabilitation costs associated with their closures, which are estimated to total of the order of circa $1,970 million (Santos' share) over the period 2021 to 2030 for Bayu Undan and Western Australia alone;
- the mature nature of Santos' Cooper Basin interests, with expectations of production decline past 2030; and
- the significant recurrent capital expenditures (largely drilling costs) to be incurred by both the GLNG upstream operations and the Cooper Basin operations, including the drilling of over 4,000 wells in the GLNG upstream operations and close to 1,000 wells in the Cooper Basin. These recurrent capital expenditures mean that measures of earnings such as EBITDAX, EBITDA and EBIT are at best incomplete measures of economic profitability for Santos.

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5.4.2 Western Australia

Grant Samuel has valued Santos' Western Australian assets in the range $2,700 - 3,100 million. The valuation incorporates the value of Santos' interests in the producing Varanus Island, Devil Creek and Macedon gas facilities and associated gas fields, the producing Van Gogh and Pyrenees oil operations, the Dorado oil and gas project and Santos' development and exploration interests in the Bedout Basin and elsewhere in Western Australia. It does not take into account the Dorado contingent FID payment, which has been incorporated in Other Assets and Liabilities in the valuation of Santos.

SCENARIOS AND ASSUMPTIONS

The valuation is based on scenarios developed by GaffneyCline for each of the individual assets. The valuation scenarios are summarised as follows:

Scenario 1

Gas production from Varanus Island, Devil Creek and Macedon is approximately 245 mmboe over the period to 2035. Annual production is assumed to approach 30 mmboe per annum in 2021 and 2022 before gradually declining as gas fields are depleted. In particular:

- Varanus Island production continues until 2035. Total production is over 194 mmboe, with the majority sourced from the John Brookes field. Approximately 40 mmboe of production is assumed to be sourced from the Spartan, Corvus and Kultarr gas fields, assumed to be brought online in, respectively, 2023, 2026 and 2028. More than 90% of revenues are generated through domestic gas sales, with the balance comprising condensate sales. Approximately half of total abandonment costs are incurred between 2036 and 2038, following cessation of production. The balance is incurred progressively in line with the depletion of individual gas fields;
- Devil Creek production continues until 2023, reflecting the depletion of remaining reserves in the Reindeer gas field. The potential to extend Devil Creek operations through a tie-back of the Dancer field is captured through GaffneyCline's valuation on an EMV basis of the Dancer prospective resource;
- Macedon production continues until 2037;
- oil production from existing oil operations is 31 mmboe. Substantial abandonment expenditures are incurred at Van Gogh once production ceases (after 2025) and Barrow Island (after 2030). Pyrenees production continues to 2038, with nearly 70% of total production completed prior to 2030. Abandonment expenditures are incurred after 2038;
- FID for Dorado is taken in 2022 and project construction commences in the same year. Total up-front capital costs (100%) are $1.7 billion. Dorado's production occurs over two phases:
  - Phase 1 oil production commences in the first half of 2026 and totals 92 mmboe in the period through to 2035. Gas is reinjected during this period; and
  - Phase 2 development commences in 2033. Phase 2 production from 2036 onwards includes material amounts of gas, condensate and LPG to complement the ongoing oil production. Gas is transported to the Varanus Island facility for processing. Production is assumed to continue through to 2048.

  No production is assumed for Dorado's Baxter Oil field or any adjacent prospective fields, including Apus and Pavo. Dorado produces a total of 201 mmboe of oil and gas products. Carbon permit costs of approximately $5-10 million per year are assumed to be incurred due to the expected Scope 1 emissions from Dorado. Abandonment costs of approximately $1.0 billion are incurred at the end of the project life. The value of the Baxter, Apus and Pavo expansion options has been captured in GaffneyCline's EMV-based valuations of those exploration targets.

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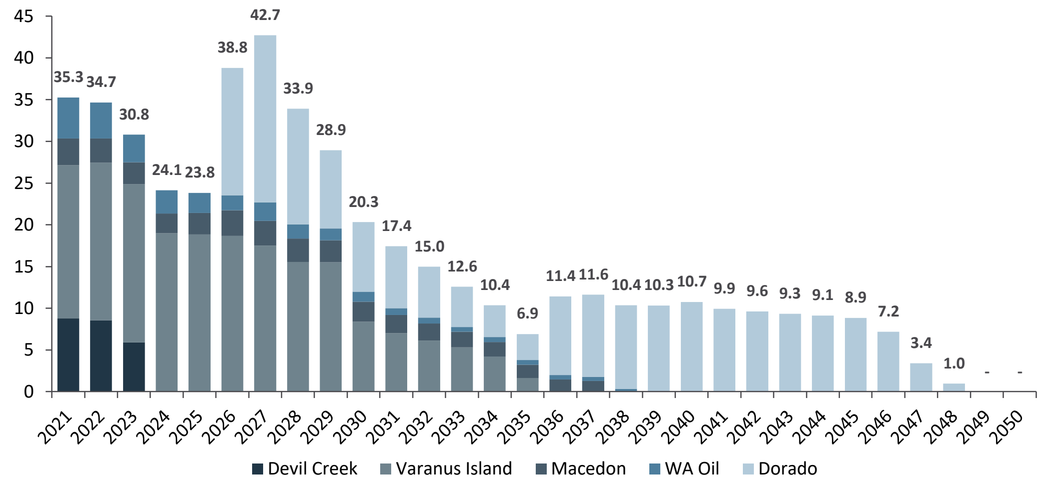
The following chart shows an aggregated production profile for Scenario 1 for Santos' Western Australian assets:

WESTERN AUSTRALIA – PRODUCTION FORECAST (MMBOE) (SANTOS' INTEREST)



Source: GaffneyCline analysis

Scenario 2

Scenario 2 is substantially similar to Scenario 1, save for an assumed increase in production through the Varanus Island facility. Tie-backs of the Ginger and Spar Deep fields deliver an additional 16 mmboe of production, with commensurate increases in capital costs and abandonment expenditures.

OUTPUTS AND VALUATION

The following table summarises projected production and costs for the two scenarios:

WESTERN AUSTRALIA – MODEL PARAMETERS (SANTOS' INTEREST)

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
Liquids production	mmboe	6.5	5.8	4.8	4.2	3.6	169.9
Gas production	PJ	167.6	167.8	151.1	116.1	117.4	989.2
Total cash costs[52]	$ millions	709.9	831.1	895.1	1,001.4	1,112.5	14,037.2
Scenario 2							
Liquids production	mmboe	6.5	5.8	4.8	4.2	3.6	169.9
Gas production	PJ	167.6	167.8	151.1	116.1	117.4	1,075.1
Total cash costs	$ millions	709.9	831.1	895.1	1,001.4	1,112.5	14,491.2

[52] Includes operating costs, capital costs and abandonment expenditures

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The following table summarises the NPV analysis for Western Australia's producing assets and the Dorado development project:

WESTERN AUSTRALIA – NPV ANALYSIS ($ MILLIONS) (SANTOS' INTEREST)

	BRENT OIL PRICE SCENARIO		
	LOW	MID	HIGH
Scenario 1			
Discount rate of 8.5%	1,984	2,168	2,352
Discount rate of 9.0%	1,916	2,095	2,272
Discount rate of 9.5%	1,852	2,024	2,196
Scenario 2			
Discount rate of 8.5%	2,051	2,237	2,422
Discount rate of 9.0%	1,980	2,159	2,339
Discount rate of 9.5%	1,912	2,086	2,259

Grant Samuel's valuation range of $2,700 - 3,100 million takes into account the calculated NPVs set out above and in addition reflects the following:

- the DCF analysis does not include any value for various prospective resources that could potentially provide backfill for the Western Australian operations (such as the Dancer prospective resource for Devil Creek, the Yoorn field for Varanus Island and the Baxter, Apus and Pavo fields for Dorado). GaffneyCline has attributed total value to these resources and to Santos' Western Australian exploration interests, principally in the Bedout Basin, of approximately $725 million;
- while GaffneyCline's valuation of various prospective resources effectively reflects, on a risk weighted basis, the potential for additional oil and gas production from those resources, it does not account for the additional value from the deferral of abandonment expenditure that would result from the inclusion in a production schedule of those prospective resources. In particular, the inclusion of Dancer as a tie-back for Devil Creek and repurposing of the Varanus Island facility to process Dorado gas would increase NPVs (on an unrisked basis) by of the order of $50-60 million through the deferral of abandonment expenditures;
- the majority of gas production for Varanus Island, Devil Creek and Reindeer is under medium-to-long term contracts which are fixed price, inflation-indexed gas sales agreements. Revenues and cash flows from these assets are clearly less risky than for other oil and gas assets, given their limited exposure to oil price risk. On the other hand, the revenues do face re-pricing risk when the current contracts expire and remain exposed to duration risk (through exploration success) so it is not appropriate to treat them as infrastructure-style cash flows. A lower discount rate assumption of 6.5% - 7.5% for these cash flows would support an uplift in NPVs by of the order of approximately $100-150 million;
- the DCF analysis is based on assumptions regarding the future gas prices that will prevail when Santos' existing gas supply contracts expire or are repriced. The NPVs set out above assumes that uncontracted gas will be sold at prices that will reach A$8/GJ by 2026, driven upwards by netback pricing pressures, and then inflate at an assumed 2% per annum. This represents a material uplift to current Western Australia gas pricing. A more conservative assumption that regulatory pressure or greater domestic supply will moderate netback pressures and result in prices of A$7/GJ by 2026 results in a reduction in calculated NPVs by of the order of $150-$200 million; and
- Carnarvon Petroleum Ltd ("Carnarvon") has a 20% interest in Dorado and the Bedout exploration interests in which Santos has an 80% interest. Based on recent share prices in the range $0.25-0.33, Carnarvon has a market capitalisation in the approximate range of A$400-500 million. After adjusting for Carnarvon's cash on hand and broker estimates of the value of its other exploration assets,

Carnarvon's recent share price range suggests a value for its interests in Dorado and related gas fields of broadly $110-200 million, which implies a value for Santos' 80% interest of $450-800 million. Grant Samuel's valuation range implies values for the relevant assets towards the top end of the value range suggested by the cross check.

In aggregate, the value range of $2,700-3,100 million implies the following valuation parameters:

WESTERN AUSTRALIA – IMPLIED VALUATION PARAMETERS

	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)	
		LOW	HIGH
Value range ($ millions)	--	**2,700**	**3,100**
Reserves and Resources (31 December 2020)			
2P reserves	254	10.63	12.20
2P + 2C	656	4.12	4.73

The multiples of reserves and resources for Santos' Western Australian assets are broadly in line with those for other Santos assets (lower in terms of reserves but higher in terms of resources). They reflect:

- the very material abandonment expenditures facing Santos, which mean that, in particular, the oil assets and related reserves have little value; and
- the substantial value attributed to Dorado contingent resources and to prospective resources/exploration success.

Analysis of the price paid by Santos for the Quadrant Energy assets, adjusted for production since the effective acquisition date, broadly supports Grant Samuel's valuation range. Grant Samuel's valuation range implies multiples of 2P reserves ($/boe) that are at a significant premium to the multiples implied by the consideration value for the Quadrant Energy transaction ($9.77/boe), arguably reflecting increasing value for Dorado as it is progressively de-risked and progresses towards FID (the FEED contract was awarded in August 2021).

5.4.3 Queensland

Grant Samuel has valued Santos Queensland interests in the range $3,000 - 3,500 million. The valuation incorporates the value of Santos 30% interest in the GLNG project and its other equity interests in CSG assets in the Bowen Basin.

SCENARIOS AND ASSUMPTIONS

The valuation is based on valuation scenarios developed by GaffneyCline for each of the individual assets. The valuation scenarios are summarised as follows:

Scenario 1

Scenario 1 assumes that GLNG production continues until 2060. Total LNG production over the life of the project is 383.7 mmboe. Annual LNG production is around 17.5 mmboe, meeting minimum contracted offtake requirements, until 2030. Between 2030, when the KOGAS Train 1 sales contract is assumed to be extended, and 2036, annual production declines to approximately 12 mmboe. Thereafter, it is assumed that neither of the remaining PETRONAS and KOGAS offtake agreements is extended, one of the two LNG trains is shut and production progressively declines.

The project is supplied by a combination of GLNG upstream equity gas, Santos equity gas and third-party gas. Upstream equity gas production accounts for approximately 325 mmboe over the life of the project. Approximately 252 mmboe of this production is sourced from existing 2P and 3P reserves, with the balance from 2C contingent resources. Santos equity gas is supplied from its Cooper Basin assets until 2030 and Eastern Queensland CSG assets until 2035. Other third-party supply is from existing gas supply agreements and unsecured spot purchases. Contracted third party gas supply (including Santos equity gas) accounts for approximately 56.5 mmboe. An additional 36.1 mmboe of LNG facility feed is assumed to be sourced from unsecured third-party gas supply.

Santos is able to deliver real terms upstream operating cost reductions up to 2026, whereafter costs are assumed to grow at least at the rate of inflation (2%). Operating expenses (including the cost of acquiring third party supply gas) are around $275 million (2021 $) per annum until 2036 and approximately $132 million (2021 $) thereafter. Total capital expenditure (excluding upstream abandonment and rehabilitation costs) is equal to $2,816 million (2021 $). This includes the drilling of approximately 4,350 wells in the period up to 2035. Upstream abandonment expenditures total $300 million (2021 $), the bulk of which is incurred in the period 2056-2060.

Santos' Eastern Queensland CSG assets in the Bowen Basin continue production until 2060. Total production from these assets is 137.8 mmboe. Gas production is preferentially supplied to GLNG under the Horizon contract until 2030. A further amount is supplied under a gas sales agreement with GLNG until 2035, following which all gas is supplied into the domestic market. The amount supplied to GLNG accounts for approximately 16% of third-party gas supply.

Following completion of the Horizon contract, gas is sold into the domestic market at A$7.29/GJ (2022 $). Total capital costs (Santos' share) are $1,012 million (2021 $), principally consisting of the costs of drilling new wells. Abandonment costs total $106 million (2021 $), the bulk of which are incurred in the period 2051-2060.

Scenario 2

Scenario 2 is similar to Scenario 1, except for the changes noted below. There is a modest increase in total production over the period to 2060 relative to Scenario 1, to 394.3 mmboe. Annual production rates average around 18 mmboe until 2030, before declining to 12 mmboe by 2036 and further thereafter. One of the two trains is closed after 2036. Upstream equity gas production accounts for approximately 338.1 mmboe of supply gas over the life of the project. This equity gas supply assumes the production of 265 mmboe of 2P and 3P reserves and 73 mmboe of 2C contingent resources. Contracted third party gas supply (included Santos equity gas) accounts for approximately 56.5 mmboe and uncontracted supply of 34.4 mmboe makes up the balance.

Operating expenses are lower than for Scenario 1, reflecting an assumption that Santos is able to deliver ongoing efficiency and other cost reduction measures to at least offset cost inflation. Short-term upstream cost reduction measures include A$9 million annually from continued improvements in mean time between well failures, the rationalisation of infrastructure and well-head electrification savings. Midstream operating expense reduction measures include up to A$18.5 million in annual savings related to increases in maintenance, technical and other efficiencies. Annual costs (including the cost of acquiring third party gas) are around $253 million (2021 $) per annum until 2036 and approximately $90 million (2021 $) thereafter. Total capital expenditure (excluding upstream abandonment rehabilitation) is $2,826 million (2021 $), largely in relation to the cost of drilling 4,350 new wells. Upstream abandonment capital expenditures are as for Scenario 1.

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OUTPUTS AND VALUATION

The following table summarises projected production and costs for the two scenarios:

QUEENSLAND – MODEL PARAMETERS[53] (NET SANTOS)

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
GLNG LNG production	mmboe	18	17	17	18	18	384
EQ Gas production	mmboe	3	3	3	3	5	138
Total cash costs	$ millions	348	355	367	482	509	14,006
Scenario 2							
GLNG LNG production	mmboe	19	18	17	18	19	394
EQ Gas production	mmboe	3	3	3	3	5	138
Total cash costs	$ millions	348	352	363	475	499	11,830

The following table summarises the NPV analysis for the Queensland assets:

QUEENSLAND ASSETS – NPV ANALYSIS ($ MILLIONS) (NET SANTOS)

	OIL & GAS PRICE ASSUMPTIONS[54]		
	LOW	MID	HIGH
Scenario 1			
Discount rate of 8.5%	2,666	3,066	3,463
Discount rate of 9.0%	2,554	2,936	3,317
Discount rate of 9.5%	2,449	2,815	3,179
Scenario 2			
Discount rate of 8.5%	3,053	3,464	3,873
Discount rate of 9.0%	2,915	3,308	3,699
Discount rate of 9.5%	2,786	3,163	3,538

Grant Samuel's valuation range of $3,000 - 3,500 million takes into account the calculated NPVs set out above and, in addition, reflects the following:

- both Scenario 1 and Scenario 2 assume the conversion of a very high proportion of GLNG's 2C resources to reserves. GLNG's upstream performance has recently seen significant improvements in terms of both well productivity and cost reductions, reflecting an ongoing cycle of continued learning, the introduction of new well designs and field management process and a focus on costs as the operation has stabilised;
- on the other hand, the reality is that as field development continues the operations will focus on progressively less attractive coal seams (on the assumption that the most productive seams have been targeted first). There is at least a risk that recently seen improvements will not be able to be repeated on a continuous basis into the future, with uncertainty regarding both well productivity and costs;
- in particular, Scenario 2, which assumes real terms cost reductions for the life of the upstream operations, could be viewed as relatively aggressive; and
- neither Scenario attributes any value to the spare LNG treatment capacity that will become available as GLNG equity gas and third party gas availability declines. This spare capacity clearly has some

[53] Operating and capital costs have been presented in nominal terms and have been escalated at an annual rate of 2.0%.

[54] Inclusive of Brent Oil and East Coast domestic gas prices.

value. An indicative case that assumes that one LNG train is shut down after 2036 but that the other continues to be filled via treating third party gas on a tolling basis suggests potential additional value in the order of $100 million.

The valuation range of $3,000 - 3,500 million implies the following valuation parameters:

QUEENSLAND ASSETS – IMPLIED VALUATION PARAMETERS

	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)	
		LOW	HIGH
Value range ($ millions)		**3,000**	**3,500**
Reserves and Resources (31 December 2020)[55]			
2P (proven and probable)	326	9.20	10.74
2P + 2C	476	6.30	7.35

In Grant Samuel's view, the multiples are reasonable having regard to recent transaction evidence. In particular:

- the overall valuation of the Queensland assets in the range $3000-3,500 million incorporates significant value for Santos' Queensland equity gas interests (i.e. gas interests outside the GLNG upstream operations). This value component is of the order of $250 – 300 million;
- the reserves and resources associated with these equity gas interests would attract significantly lower multiples on a $/boe basis, given that they do not have available to them the LNG conversion margin that is effectively available to GLNG's own gas reserves and resources. The recent takeover offer by POSCO International Corporation for Senex Energy implied 2P transaction multiples of $5.62/boe;
- excluding the value indicatively attributable to Santos' Queensland equity gas interests (i.e. gas interests outside the GLNG upstream operations) and the associated reserves and resources, the multiples implied by Grant Samuel's valuation of the Queensland assets increase to approximately $10.37-11.82/boe 2P reserves, and $7.69-8.77/boe 2C resources; and
- these multiples are consistent with valuation evidence from the recent sell down by Origin of a 10% interest in APLNG to EIG Partners. The transaction price of A$2,123 million for 10% implies the following multiples (taking into account the project finance debt held within the APLNG structure):

AP LNG TRANSACTION – IMPLIED VALUATION PARAMETERS

	VALUE	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)
Equity value – 100% (A$ millions)	21,227		
(+) Net project finance debt as at 30 June 2021 (A$ millions)	7,040		
AP LNG enterprise value (A$ millions)	28,267		
AP LNG enterprise value ($ millions)	**21,200**		
Reserves and Resources (31 December 2020)[56]			
2P (proven and probable)		1,950	10.87
2P + 2C		2,569	8.25

The $/boe multiples implied by the APLNG transaction sit within and towards the top end of Grant Samuel's valuation range. In Grant Samuel's view, this is reasonable and supportive of the valuation range, having regard to the following:

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55 As reported in the Santos CY20 annual report.

56 As reported in Santos CY20 annual report

- APLNG is generally regarded as a superior operation. APLNG's reserve base has been de-risked relative to GLNG, with reported 1P reserves accounting for a larger proportion of total reserves. APLNG's upstream operations, focussed on the productive Combabula, Talinga and Spring Gully fields, are reported to have had higher well productivity than the GLNG upstream operations. Recent APLNG LNG production volumes have exceeded contracted amounts whereas, GLNG continues to produce at well below name plate capacity; and
- it is to be expected that APLNG's LNG production would be more profitable per unit of LNG produced. APLNG has sufficient reserves and upstream gas production to fulfil all its own raw gas requirements and keep its LNG facility at capacity, as well as selling to third parties. By contrast, GLNG relies on material volumes of third party gas (including from Santos). In 2022, third party gas will constitute almost 50% of total raw gas supply to the GLNG liquefaction plant. It is to be expected that third party gas will deliver lower overall margins than equity gas. While GLNG equity gas supply is expected to increase in the short term, any shortfall in equity gas relative to expectations will mean that GLNG will be increasingly reliant on uncontracted third party gas supply, which will presumably only be available at prices approaching net back pricing and will accordingly deliver at best modest profits through the LNG treatment plant.

In Grant Samuel's view the overall valuation range for Santos' Queensland operations of $3,000-3,500 million is reasonable, having regard to the DCF analysis and the transaction evidence set out above.

5.4.4 Narrabri

Grant Samuel has attributed a value in the range $180 – 200 million to Santos' 80% interest in the Narrabri gas project.

SCENARIOS AND ASSUMPTIONS

The valuation is based on valuation scenarios developed by GaffneyCline, summarised as follow:

Scenario 1

Production from the Narrabri Gas Project commences in 2025. Total production over the life of the project through to 2060 is 102.8 mmboe. Annual production is maintained at around 6.5mmboe between 2029 and 2035, progressively declining thereafter. Gas is sold into the domestic market at Grant Samuel's assumed gas prices in the range A$9.00-10.00/GJ (2022 $).

Scenario 2

Scenario 2 assumes increased gas volumes, reflecting the production of a larger proportion of 2C resources, including an assumption of additional production from the north-east and south geo-domains within the field. Total production over the life of the project to 2060 is 170.6 mmboe. Total capital expenditure increases as additional wells are drilled. Plateau production rates of around 6.7mmboe are maintained between 2029 and 2044, progressively declining thereafter.

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OUTPUTS AND VALUATION

The parameters for the valuation models are summarised below:

NARRABRI – MODEL PARAMETERS[57] (NET SANTOS)

	YEAR END 31 DECEMBER					LIFE OF PROJECT
	2021	2022	2023	2024	2025	
Scenario 1						
Gas production (mmboe)	-	-	-	-	3	103
Total cash costs ($ million)[58]	71	38	299	230	234	3,172
Scenario 2						
Gas production (mmboe)	-	-	-	-	3	171
Total cash costs ($ million)	71	38	299	230	234	5,273

The following table summarises the NPV analysis for the Narrabri project:

NARRABRI – NPV ANALYSIS ($ MILLIONS) (NET SANTOS)

	GAS PRICE ASSUMPTIONS[59]		
	LOW	MID	HIGH
Scenario 1			
Discount rate of 8.5%	46	105	164
Discount rate of 9.0%	18	74	129
Discount rate of 9.5%	(8)	45	97
Scenario 2			
Discount rate of 8.5%	134	214	294
Discount rate of 9.0%	92	167	242
Discount rate of 9.5%	55	125	195

Grant Samuel's valuation range of $180 – 200 million reflects the higher end of the range of NPV outcomes summarised above. While Santos has not yet secured all final development consents, the third party gas pipeline required to export the gas (the Western Slopes Pipeline) is still to receive environmental[60] and other approvals and the project has not reached FID, the prospects of Narrabri development appear to be improving following the recent environmental appeal finding in Santos' favour.

The value range of $180 – 200 million implies the following valuation parameters:

NARRABRI – IMPLIED VALUATION PARAMETERS

	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)	
		LOW	HIGH
Value range ($ millions)		**180**	**200**
Reserves and Resources (31 December 2020)			
2P + 2C	285	0.63	0.70

In Grant Samuel's view, the multiples are reasonable having regard to the limited recent comparable transaction evidence available. In February 2019, Origin announced the $166 million[61] sale to AP LNG of its

57 Total cash costs (operating and capital costs) have been presented in nominal terms and have been escalated at an annual rate of 2.0%.

58 Inclusive of transportation costs.

59 East Coast domestic gas prices.

60 APA Group website.

61 A$230 million announced transaction value converted at an AUD:USD spot exchange rate on 19 February 2019 (0.7168)

Ironbark CSG project in the Surat Basin. At the time, Ironbark had 129 PJ of 2P reserves and 497 PJ of 2C resources. Origin had announced in August 2018 that it had entered Stage 1 FEED. The transaction consideration represented a multiple of $7.47/boe of 2P and $1.54/boe of (2P plus 2C). Comparisons with Narrabri are not straightforward, given that Ironbark was clearly at a more advanced stage of development and would have provided an opportunity for a tie-in to AP LNG's existing operations.

5.4.5 Cooper Basin

Grant Samuel has valued Santos' Cooper Basin assets in the range $1,600-1,900 million. The valuation incorporates the value of Santos' interests in the producing fields of the South Australian Cooper Basin Joint Venture and the Southwest Queensland Joint Venture, its interests in the Moomba Gas Processing Facility and the Port Bonython facility, as well as the value of its Carbon Capture and Storage (CCS) project planned for development during 2022 to 2024.

The valuation is based on valuation scenarios developed by GaffneyCline for Santos' upstream and midstream Cooper Basin assets as well as the proposed CCS project. GaffneyCline's valuation scenarios for the upstream and midstream Cooper Basin assets are based on Santos' life of field plans, modified as deemed appropriate by GaffneyCline. These field plans incorporate various assumptions regarding future exploration success (i.e. they assume future production of oil and gas from prospective resources or other exploration targets, in addition to production of existing reserves and 2C resources). To allow the valuation of the Cooper Basin exploration potential on an appropriately risked basis, GaffneyCline has removed the exploration volumes (and the associated drilling and other capital expenditure, operating and abandonment costs) from the valuation scenarios. The exploration potential of the Cooper Basin has been valued separately by GaffneyCline. Accordingly, the valuation scenarios should not be viewed as forecasts of likely life of field outcomes, but rather as a construct to allow the valuation of the Cooper Basin reserves and contingent resources.

SCENARIOS AND ASSUMPTIONS

The valuation scenarios are summarised as follows:

Scenario 1

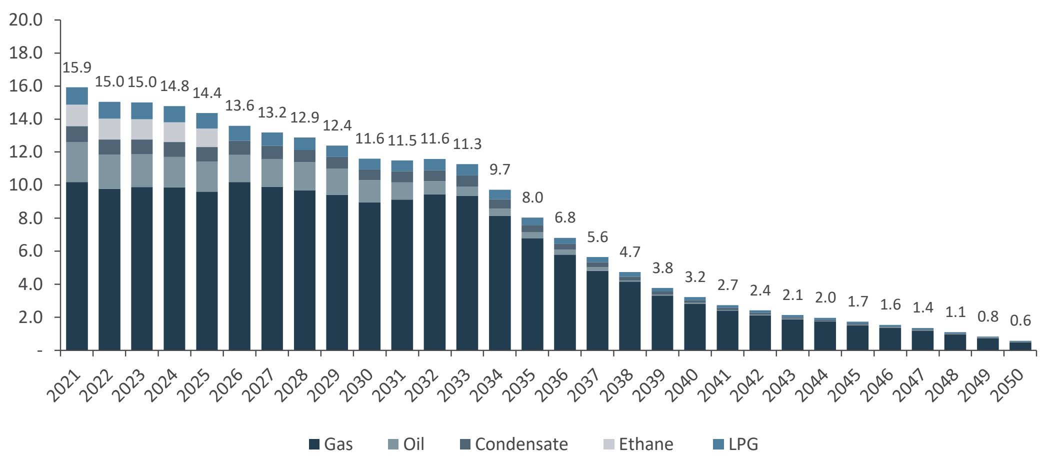
In relation to upstream and midstream operations, GaffneyCline's Scenario 1 assumes the following:

- total production (Santos' interest) is 231 mmboe over the period 2021 to 2050, representing the production of all Santos' 145 mmboe 2P reserves and 86 mmboe of contingent resources, representing the majority of Santos' conventional 2C resources. Production comprises the following:
  - gas represents the majority of production, with 1,022 PJ produced over the life of the forecast. Gas production is relatively stable, with approximately 50 PJ produced per annum up to 2035, at which point the rate of production falls with natural reservoir decline. Gas production is delivered into existing domestic gas contracts in place covering 51 PJ of production over the five years to 2025 and to GLNG under the Horizon contract (217 PJ of gas production over the period to 2030, priced on an Brent oil-linked basis);
  - 22 mmboe of oil is produced over the life of the forecast with 18 mmboe produced over the first 10 years to 2030. Oil production volumes decline year on year reflecting natural reservoir decline across the mature oil field assets;
  - 35 PJ of ethane is produced over the five year period from 2021 to 2025, all of which is contracted to Quenos Pty Ltd; and
  - condensate and LPG make up the remainder of production with approximately 27 mmboe produced over the life of the forecast;

- Santos generates approximately $570 million of third-party tolling/treatment revenue in the period to 2050 from processing third party production at the Moomba Processing Facility and the Port Bonython facility;
- upstream operating costs over the life of the field total approximately US$2.1 billion, comprising:
  - $0.9 billion of downhole operating costs, i.e. well maintenance costs. These costs have been forecast on a per producing well basis; and
  - $1.2 billion of surface operating costs, which are assumed to be directly proportional to the level of production;
- midstream operating costs total approximately $1.0 billion over the life of the field. Midstream operating costs are assumed to fall significantly in the short term as various cost saving and efficiency measures are implemented and to reduce further (in real terms) over time as production volumes fall. GaffneyCline has assumed a 2% inflation overlay on the real terms cost assumptions;
- upstream capital expenditure totals $3.7 billion. This is predominantly downhole development capital expenditure of $2.2 billion, required to deliver 945 wells drilled over the forecast scenario. The vast majority of downhole development capital is undertaken over the period 2021 to 2033. Other upstream capital expenditure includes approximately $320 million of surface expenditure and $770 million of supporting upstream infrastructure;
- midstream capital expenditure totals approximately $500 million over the life of the field. Annual midstream capital expenditure is maintained at a relatively stable level up to 2039, following which the expenditure profile declines as production continues to fall and part of the Moomba processing plant is decommissioned; and
- abandonment expenditure totals $1.4 billion[62] over the life of the field. This includes relatively consistent abandonment expenditure of approximately $5-10 million (real 2020) per year as Santos progressively decommissions ageing wells and fields across the region. Material abandonment expenditures are incurred at end of field life.

The following chart shows the volumes assumed to be produced from Santos' Cooper Basin reserves and resources:

COOPER BASIN – RESERVE AND RESOURCE PRODUCTION ASSUMPTIONS (MMBOE) (SANTOS' INTEREST)



Source: GaffneyCline Analysis

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62 Estimated by GaffneyCline

Scenario 2

Scenario 2 is based on Scenario 1, but assumes 21 mmboe of additional production, largely gas, delivered via the production of a total of 107 mmboe contingent resources. This represents the production of effectively 100% of Santos' available conventional 2C resources in the Cooper Basin[63]. The scenario includes an additional $40 million of surface operating expenditure commensurate with the increase in production, but also assumes (compared to Scenario 1) that Santos is successful in delivering continued cost reductions and efficiency measures, consistent with its recent track record. The net effect is that on a unit basis real terms costs continue to decline until the end of field life.

OUTPUTS AND VALUATION

The following table summarises projected production and costs for the two scenarios:

COOPER BASIN – MODEL PARAMETERS

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
Gas production	PJ	59	57	58	57	56	1,022
Oil/liquids production	mmboe	5	5	5	5	5	56
Total cash costs	$ millions	458	449	388	449	364	8,708
Scenario 2							
Gas production	PJ	60	59	60	60	59	1,124
Oil/liquids production	mmboe	5	5	5	5	5	57
Total cash costs	$ millions	469	455	418	454	383	7,536

The following table summarises the NPV analysis for the Cooper Basin reserves and resources:

COOPER BASIN – NPV ANALYSIS ($ MILLIONS)

	BRENT OIL AND DOMGAS PRICE SCENARIO		
	LOW	MID	HIGH
Scenario 1			
Discount rate of 8.5%	745	879	1,012
Discount rate of 9.0%	721	849	977
Discount rate of 9.5%	697	820	944
Scenario 2			
Discount rate of 8.5%	1,217	1,364	1,510
Discount rate of 9.0%	1,166	1,307	1,448
Discount rate of 9.5%	1,118	1,253	1,389

Grant Samuel's valuation range of $1,600-1,900 million takes into account the calculated NPVs set out above and, in addition, reflects the following:

- the overall valuation assessment ultimately represents a judgement regarding Santos' ability to continue to replace reserves and resources, maintain production at or around current levels and continue to drive down operating costs. In the period 2017 to 2020, Santos grew production volumes from 14.4 mmboe to 16.8 mmboe. Santos' life of field plans for the Cooper Basin contemplate the maintenance of production at 2020 levels (or even some growth) for the period through to 2030, before the commencement of progressive decline. On the other hand, Cooper Basin production for

63 Of Santos' total Cooper Basin 2C resources of 286 mmboe, a total of 105 mmboe relate to the Deep Coals and Granite Wash plays, and a further 74 mmboe are classified as 2C-Unviable or 2C-Unclarified. The remaining 107 mmboe are incorporated in full in Scenario 2.

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the first three quarters of 2021 was only around 11.7 mmboe, with production flat in the first quarter and declining in each of the second and third quarters, suggesting run rate annual production of around 15.5 mmboe. Moreover, limited exploration drilling during 2020 and in particular in 2021 suggest that these lower levels of production will continue. The extent to which recent performance has been affected by one-off issues including COVID impacts is not clear. While GaffneyCline's analysis is based on a very strong conversion of contingent resources to reserves, its assumptions regarding exploration success are more conservative than those of Santos. In particular, in the period following 2025, GaffneyCline's assumptions are more consistent with Santos' historical record of production from exploration/prospective resources;

- given the significant fixed cost structure in the Cooper Basin (both in terms of capital costs and operating costs), assumptions regarding exploration success and annual production volumes have a significant impact on projected free cash flows and estimated NPV;
- GaffneyCline has valued Santos' conventional Cooper Basin exploration interests in the range $150-270 million. This valuation incorporates a risked assessment of Santos' Cooper Basin exploration interests, but represents a material discount to the implied exploration values and overall field values that are suggested by Santos' life of field plans;
- Cooper Basin revenues are not fully exposed to oil price risk and so there are arguments that lower discount rates should be applied to take account of its lower systematic riskiness. Over the five year period from 2021 to 2025, 21% of modelled Cooper Basin revenue is related to fixed price domgas and ethane contracts, 13% is related to currently uncontracted gas that will be sold into the domestic gas market, 8% is related to processing of third party production at Santos' midstream infrastructure assets and 60% is related to production subject to oil-linked pricing. It appears appropriate for valuation purposes to focus on NPVs estimated using discount rates at the bottom end of (and potentially even below) the range of 8.-9.5%. Each 0.5% reduction in discount rates adds approximately $30-35 million to the estimated NPVs;
- in particular, Santos generates infrastructure style revenues through the tariffs that it charges to process third-party production at the Moomba Processing Facility and Port Bonython. Given that Santos does not bear the upstream and commodity price risks associated with these revenues, there are compelling arguments to suggests that significantly lower discount rates, appropriate for infrastructure style assets, should be used in valuing this component of the Cooper Basin free cash flows. If discount rates in the range 6.0% - 7.0% are applied to the relevant revenue streams (after allowing for some modest marginal midstream operating costs), the incremental NPV is of the order of $30-50 million;
- the NPVs set out above do not incorporate the value of Santos' planned Carbon Capture and Storage project. Santos has recently received confirmation that the project will qualify for ACCU eligibility, is progressing with outstanding regulatory approvals and announced FID for the project on 1 November 2021. GaffneyCline has advised that the project is technically robust. Grant Samuel has undertaken indicative NPV analysis for the project. The analysis is based on total development costs of approximately $110 million, and the commencement of carbon storage in 2024 at average annual operating costs of approximately $12 million (2020 $). The analysis assumes the sequestration of a total of 29.6 Mt over the life of the project to 2049, at ACCU prices rising in real terms from A$32/tonne of CO_2 in 2024 to A$55/tonne of CO_2 by 2030. The NPV analysis suggests indicative values in the range $150-179 million; and
- GaffneyCline has valued Santos' other exploration interests in the Cooper Basin at a point estimate of around $80 million, principally comprising value attributed to the Deep Coal and Granite Wash plays.

The valuation range of $1,600-1,900 million has been cross-checked against valuation evidence based on the market value of Beach Energy, which has significant Cooper Basin interests, as well as the transaction multiples implied by the price at which Beach acquired Senex' Cooper Basin interests in 2020.

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COOPER BASIN – IMPLIED VALUATION PARAMETERS

	VARIABLE	IMPLIED MULTIPLE	
		LOW	HIGH
Value range ($ millions)	--	1,600	1,900
Reserves and Resources (31 December 2020)			
2P (proven and probable)	145	11.03	13.10
2P + 2C	286	5.59	6.64

Beach is trading on multiples of $7.37/boe 2P reserves and $4.71/boe 2P+2C resources. Broker analysis suggests multiples in the range of $6.42-14.51/boe 2P reserves and $3.87-8.75/boe for 2P+ 2C resources in relation to its Cooper Basin interests. The Beach acquisition of Senex' Cooper Basin interests represented multiples of $8.59/boe for 2P reserves and $3.62/boe for 2P+2C resources.

While the multiple ($/boe) analysis should be viewed as no more than indicative, it is consistent with and generally supportive of Grant Samuel's valuation range of $1,600 – 1,900 million.

5.4.6 Northern Australia and Timor-Leste

Grant Samuel has valued Santos' Northern Australian assets in the range $1,200-1,450 million. The valuation incorporates the value of Santos' interests in the following:

- 43.4% interest in the producing but near end-of-life Bayu-Undan gas and condensate project;
- 43.4% interest in the DLNG processing facility and associated Darwin gas transport pipeline;
- 62.5% interest in the Barossa gas and condensate development project[64] and the related Caldita field;
- 40.3% interest in the Petrel and 100% interest in the Tern gas fields (together Petrel Tern); and
- Santos' various interests in the Greater Poseidon, Crown, Lasseter, and other stranded offshore gas fields.

SCENARIOS AND ASSUMPTIONS

The valuation is based on valuation scenarios developed by GaffneyCline for each of the individual assets. The valuation scenarios are summarised as follows:

Scenario 1

Bayu-Undan continues production until 2023, at which point the field ceases production and decommissioning and rehabilitation commences. Total production over the field's remaining life is 24 mmboe (net to Santos), predominantly comprising LNG, which is sold into the spot market. Abandonment and rehabilitation expenditures are incurred over the period 2023 to 2029, at a total cost of $658 million (Santos' share).

Upstream development capital costs of approximately $2.3 billion (Santos' 62.5% share) are incurred over the period 2021 to 2024. Life extension capital of approximately $250 million (Santos' share) is incurred at the DLNG processing facility to enable the plant to process Barossa gas, with production commencing in late 2024. Total production from the field is 402 mmboe (Santos' share) over the life of the project, comprising 375 mmboe LNG and 27 mmboe of condensate. Decommissioning and rehabilitation takes place from 2048 to 2051 at a total cost of $918 million (Santos' share).

64 Santos is currently in the process of divesting a 12.5% interest in Barossa to JERA.

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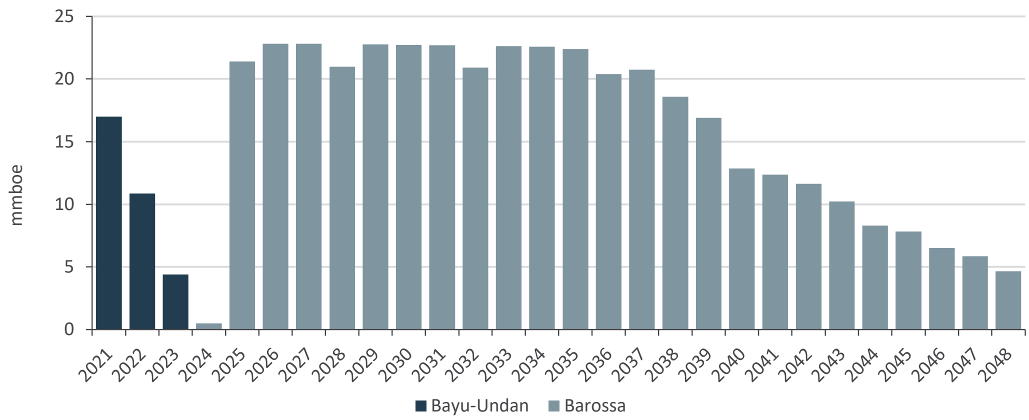
The following chart shows an aggregated production profile for Scenario 1 for Santos' Northern Australia and Timor-Leste assets:

NORTHERN AUSTRALIA AND TIMOR-LESTE – PRODUCTION (MMBOE) (SANTOS INTEREST)



Source: GaffneyCline analysis

Scenario 2

Scenario 2 incorporates the development of the Caldita gas and condensate field as a life extension project to Barossa. The project involves incremental upstream development capital of $740 million incurred over the period 2036 to 2039, at which point Caldita commences production. A total of 35 mmboe (net Santos) of gas and condensate is produced over the life of the field. Barossa and Caldita are decommissioned over the period 2048 to 2053 at a total cost of $1.0 billion (Santos' share).

OUTPUTS AND VALUATION

The following table summarises projected production and costs for the two scenarios:

NORTHERN AUSTRALIAN ASSETS – MODEL PARAMETERS (SANTOS INTEREST)

	UNIT	YEAR END 31 DECEMBER					LIFE OF PROJECT
		2021	2022	2023	2024	2025	
Scenario 1							
LNG production	PJ	85	48	18	3	115	2,332
Other production	mmboe	2	3	1	0	2	33
Total cash costs	$ millions	650	840	937	641	671	18,968
Scenario 2							
LNG production	PJ	85	48	18	3	115	2,518
Other production	mmboe	2	3	1	0	2	35
Total cash costs	$ millions	650	840	937	641	671	20,488

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The following table summarises the results of the NPV analysis for Santos' Northern Australia and Timor-Leste assets:

NORTHERN AUSTRALIAN ASSETS – NPV ANALYSIS ($ MILLIONS)

	PRICE SCENARIO		
	LOW	MID	HIGH
Scenario 1			
Discount rate of 8.5%	894	1,190	1,484
Discount rate of 9.0%	799	1,085	1,368
Discount rate of 9.5%	710	986	1,259
Scenario 2			
Discount rate of 8.5%	889	1,197	1,504
Discount rate of 9.0%	793	1,090	1,386
Discount rate of 9.5%	703	989	1,274

Grant Samuel's valuation range of $1,200-1,450 million takes into account the following factors:

- the NPVs set out above represent the sum of NPVs for Santos' existing 62.5% interest in Barossa and its interests in Bayu-Undan and DLNG;
- essentially all of the estimated NPV is contributed by the Barossa project. Bayu-Undan has benefited from the surge in JKM LNG spot prices over the period from July to October 2021, and Grant Samuel's price assumptions incorporate continued elevated spot LNG prices in the short term. However, Bayu-Undan's substantial abandonment obligations effectively offset the value derived from the project's remaining production;
- on 30 April 2021 Santos completed the sale of a 25% interest in Bayu-Undan and DLNG to SK E&S for net proceeds of $186 million, which represented the nominal sale price of $390 million less the net cashflows attributable to the 25% interest from the effective date of 1 October 2019 to completion. Having regard to factors including the continued reduction in value resulting from ongoing production to 30 June 2021, the reduction in the value of Bayu Undan between October 2019 and 30 June 2021 as future abandonment costs grew nearer, and the low oil prices that prevailed during much of 2020, the terms of the sale of the 25% interest to SK and the net amount finally received by Santos reinforce the conclusion that Santos' interests in Bayu Undan and DLNG had no more than modest value at 30 June 2021;
- while Barossa has favourable economics, its very high CO_2 content (approximately 16-20%) is a negative for value. The NPV modelling incorporates a carbon charge for emissions over baseline, commencing at $26/tonne of CO_2 in 2024 and climbing to $50/tonne of CO_2 by 2030. Judgements regarding future carbon costs could fall within a very wide range. If carbon costs were ultimately to be much higher than assumed in the DCF analysis, the impact on value could be material. In certain contexts, the growing focus on ESG issues on the part of both corporates and investors could significantly affect the value realisable for the project, given its CO_2 content;
- Santos' investigation of a potential CCS project that would re-purpose the Bayu-Undan reservoirs for the storage of CO_2 from Barossa and, potentially, third parties is a potential risk mitigant. Given the very early stage of this potential project and the issues (including jurisdictional issues) still to be addressed, Grant Samuel has not attributed any explicit value to this project. In addition to mitigating some or all of the direct CO_2 costs and broader CO_2 risks, a CCS project would result in the deferral of material Bayu-Undan abandonment expenditures, resulting in a reduction in the present value of abandonment expenditures, indicatively in the range $350-400 million;

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- GaffneyCline has attributed a value of $109-226 million to Santos' interests in the Greater Poseidon, Crown, Lasseter and other Browse Basin resources. This value is not incorporated in the NPVs set out above; and
- Grant Samuel has carried out DCF analysis to assess the value of Santos' interests in the Petrel Tern fields, based on technical advice provided by GaffneyCline as to potential production, costs and capital expenditures for a possible development of the fields. Having regard to the modest indicative NPVs suggested by the DCF analysis, and the benchmark rules of thumb applied by GaffneyCline in the valuation of the Greater Poseidon, Crown, Lasseter and other Browse Basin resources, Grant Samuel has attributed a value of $25-50 million to Santos' interests in the Petrel Tern fields.

The valuation range of $1,200-1,450 million has been cross-checked against the transaction multiples implied by Santos' acquisition of ConocoPhillips' Northern Australian assets in 2020.

NORTHERN AUSTRALIA AND TIMOR LESTE – IMPLIED VALUATION PARAMETERS

	VARIABLE (MMBOE)	IMPLIED MULTIPLE ($/BOE)	
		LOW	HIGH
Value range ($ million)	--	1,200	1,450
Reserves and Resources (31 December 2020)			
2P (proven and probable)	32	37.50	45.31
2P + 2C	1,138	1.05	1.27

These multiples are broadly consistent with the $29.30/boe 2P reserves and $2.71/boe 2P+2C resources multiples implied by Santos' acquisition of ConocoPhillips' Northern Australian assets for total consideration of $1,465 million. Overall, the multiples implied by Grant Samuel's valuation range are higher in terms of multiples of 2P reserves and lower in terms of multiples of 2P + 2C resources.

In Grant Samuel's view this is appropriate having regard to the details of the ConocoPhillips transaction. The total consideration was an upfront "face value" payment of $1.265 billion plus a payment contingent on Barossa FID of $200 million. The actual net settlement amount was only $655 million, after adjusting for net cash generated from the effective date and other settlement adjustments. It appears that a substantial component of the value of the ConocoPhillips assets (possibly of the order of $600 million) had been delivered through Bayu-Undan production between the effective date of 1 January 2019 and transaction completion 17 months later on 28 May 2020, and that by completion the residual value of the acquired assets was of the order of $650 million, largely attributable to Barossa resources.

5.4.7 Papua New Guinea

Grant Samuel has valued Santos' 13.53% interest in the PNG LNG Project in the range $3,200 – 3,600 million.

Section 5.3.2 contains a description of the approach used to value Oil Search's 29.0% interest in the PNG LNG Project, which Grant Samuel valued in the range $7,350 – 8,250 million. Grant Samuel's valuation of the Santos 13.5% interest is lower (on a pro rata basis) than its valuation of Oil Search's interest due to certain specific adjustments.

The value attributed to Oil Search's interest accounts for circumstances that are specific to Oil Search, including its individual tax position and its free carried interest (i.e. effectively, net receivable) in relation to future capital expenditures. This free carried interest relates to the cancellation of the PNG LNG equity interest redeterminations. Grant Samuel has accordingly made several adjustments in its valuation of Santos' interest in the PNG LNG Project, including for:

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- the individual tax position of Santos, which generally contains lower balances of accrued tax credits, offsets and deductions relative to Oil Search on an equivalent interest basis. Given that Santos does not have an interest in P'nyang, this also specifically excludes the transfer of assessable income deductions from P'nyang to the PNG LNG Project; and
- Santos' estimated net liability (as opposed to Oil Search's net receivable) in relation to the $200 million in gross free carried interests in favour of Oil Search and JX Nippon arising out of the cancellation of the PNG LNG equity interest redeterminations. The precise quantum of the liability will only be known following the outcome of planned drilling activities at Angore and in the Hides Footwall.

Santos has a 7.45% interest in SE Gobe. Oil Search's 22.34% interest in SE Gobe was included as one of the assets that form part of the Operated Oil and Gas Assets in Section 5.3.5. Having regard to the limited remaining life and expected abandonment costs for SE Gobe, Grant Samuel has attributed no significant value to Santos' interest in SE Gobe. Santos also holds a 10.5% economic interest in Muruk. Oil Search's 25.05% interest in Muruk was valued as part of the combined valuation of P'nyang and Muruk in Section 5.3.3. No significant value has been ascribed to Santos' interest in Muruk, given the uncertainties associated with and likely timing of a future Muruk development.

5.4.8 Exploration Assets

Santos' exploration assets have been valued by GaffneyCline in the range $1,100 – 1,500 million (see Section 5.8 of the GaffneyCline report at Appendix 7). Grant Samuel has adopted GaffneyCline's valuation range and allocated the exploration assets to the business units as summarised below:

SANTOS - VALUATION OF EXPLORATION ASSETS ($ MILLIONS)

	REPORT SECTION REFERENCE	VALUE RANGE	
		LOW	HIGH
Western Australia Offshore	5.4.2	722	722
Cooper Basin conventional	5.4.5	151	271
Papua New Guinea	5.4.7	51	145
Onshore New Ventures		189	378
Value of exploration interests		**1,113**	**1,516**

The Western Australia offshore exploration interests, which principally comprise EMV-based estimates of the value of prospective resources in fields such as Dancer, Yoorn, Baxter, Pavo and Apus, which represent backfill opportunities for existing operations or the Dorado development. Grant Samuel has included the value of these interests in its valuation of Santos' Western Australian operations.

The Cooper Basin conventional exploration valuation represents GaffneyCline's EMV-based estimate of the value attributable to future Cooper Basin operations over and above current reserves and resources. Grant Samuel has reflected this valuation in its valuation of Santos' Cooper Basin operations. Included in the valuation of Onshore New Ventures are amounts totalling approximately $80 million for the Deep Coal and Granite Wash plays in the Cooper Basin. Grant Samuel has similarly reflected these values in its valuation of Santos' Cooper Basin operations.

The remaining exploration interests (with GaffneyCline valuations totalling of the order of $150 - $450 million) relate to PNG and to Santos' interests in the South Nicholson and McArthur shale gas plays. For the purposes of its overall valuation, Grant Samuel has attributed a value in the narrower range of $200 - 400 million to these other exploration interests.

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In addition to the exploration valuations set out above, GaffneyCline has valued various stranded resources offshore north-west Australia (principally Greater Poseidon, Crown and Lasseter) in the range $109 - 226 million. This valuation has been reflected in the valuation of Santos' Northern Australia business.

5.4.9 Other Assets and Liabilities

Santos's other assets and liabilities have been valued in the range $(5)-55 million. These other assets and liabilities comprise:

- the present value of the utilisation of corporate tax losses as at 30 June 2021 (circa $2,000 million gross). This value has been estimated having regard to the projected generation of taxable income by each of Santos' operating assets. It reflects an expectation that the losses will be fully utilised by 31 December 2022;
- an adjustment for the tax-effected mark-to-market value of Santos' derivatives portfolio (e.g. oil price hedges and interest swaps) as of 30 September 2021, estimated to be approximately $160 million (pre-tax);
- a liability to ConocoPhillips, the amount of which is the subject of a dispute, in respect of the contingent payment due once Barossa reached FID. Some or all of any amount ultimately payable is expected to be tax deductible, either immediately or over time;
- contingent payments payable on Dorado reaching FID. The precise amount is uncertain due to the variable resource-linked component of the payment; and
- an onerous take or pay contract in relation to the Horizon contract.

Due to issues of commercial confidentiality, Grant Samuel has not disclosed the estimated amounts of certain of the individual liabilities described above. Where appropriate, Grant Samuel has tax effected the payments or liabilities and included the net after tax amount in the overall range of values of $(5) – 55 million attributed to other assets and liabilities.

5.4.10 Corporate Overheads

Santos' 2021 unallocated corporate overheads are expected to be approximately $50 million. These costs represent costs associated with running Santos's head office and include:

- the Santos executive office (such as costs associated with the Chief Executive Officer, Chief Financial Officer, company secretarial and legal, corporate affairs, treasury, tax, etc.);
- listed company expenses (such as directors' fees, annual reports and shareholder communications, share registry and listing fees and dividend processing); and
- certain group shared services not fully recharged to the business operations during the year.

Grant Samuel has estimated a value of ($440)-(395) million for unallocated corporate costs. The range of negative values attributed to unallocated corporate overhead costs has been estimated using DCF analysis (at discount rates of 8.5 - 9.5%). This range represents multiples of approximately 8-9 times estimated 2021 unallocated corporate costs.

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5.4.11 Net Borrowings

Santos' net borrowings for valuation purposes are $2,907 million. This amount reflects Santos' net borrowings as at 30 June 2021 adjusted as follows:

SANTOS – ADJUSTED NET BORROWINGS ($ MILLIONS)

	REPORT SECTION REFERENCE	AS AT 30 JUNE 2021
Net debt	4.5	3,398
Dividends	--	104
Finance leases	4.5	(417)
Mark-to-market value of oil price hedging as of 30 June 2020	5.4.9	(178)
Adjusted net borrowings		**2,907**

Adjustments have been made to reported net debt at 30 June 2021 to reflect:

- 1HY21 dividends. Santos declared a 5.5 US cents per share dividend in conjunction with its 1HY21 results. The dividend was fully paid on 25 August 2021; and
- exclusion of finance leases and fair value of derivatives. Cash flows associated with finance leases have been included in the DCF analysis for individual assets. The mark-to-market value of Santos' derivatives portfolio has been classified under Other Assets and Liabilities.

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6 Evaluation of the Merger

6.1 Summary

Evaluation of the Merger requires an assessment of both value related considerations and broader issues relating to strategy, commercial imperatives and funding and other synergies.

The Merger comprehensively addresses the significant capital constraints facing Oil Search. In particular, the Merged Group would have the funding capacity to progress the development of Oil Search's Pikka project or otherwise realise value for Pikka on an optimal basis. In addition to the explicit synergies expected to be achieved (cost savings estimated at $90-115 million), the Merger is likely to deliver other synergistic benefits. The potential for improved alignment of interests between the participants in the PNG LNG and Papua LNG projects could facilitate an optimised development of the extensive PNG gas resource base. The Merged Group's Australian domicile, its access to global capital markets and its size, share liquidity and enhanced index ranking all suggest that it would enjoy a lower cost of capital than a standalone Oil Search, with shares likely to trade closer to underlying value. The Merger would also resolve the question of future management and leadership that would otherwise need to be addressed by a standalone Oil Search. While these benefits cannot be quantified with any precision, there is no doubt that they are collectively material.

At the same time, PNG LNG is a world class project and Papua LNG is an attractive expansion option. There is a credible standalone path forward that might involve sub-optimal outcomes for Pikka but would ultimately see value created as Oil Search's funding issues were resolved and Papua LNG progressed through development.

Grant Samuel's analysis suggests that the financial terms of the Merger are not reflective of the relative contributions of underlying value by Oil Search and Santos. Oil Search shareholders are contributing around 43-44% of the aggregate estimated underlying value of the Merged Group compared to the 38.5% of the Merged Group that they will receive. Even after taking into account the value of the cost savings expected to be realised, the analysis indicates that the Merger will result in a reduction in the underlying value attributable to Oil Search shareholders.

These relativities do not correspond with those based on share market values. On one view, underlying value is in any event of limited relevance, since shareholders could only access underlying value through a fully priced cash takeover offer for Oil Search. Parties who might be interested in bidding for Oil Search will have had ample opportunity to do so prior to the Scheme meeting to approve the Merger. In the absence of such an offer, shareholders could justifiably attribute more significance to share market values. The Merger terms provided a premium to Oil Search shareholders of around 16% at the time of announcement of the Merger.

A relative weighting of the valuation issues against the broader benefits of the Merger is not straightforward. The dilution of underlying value implied by the Merger terms is material. There is clearly a risk that the funding and other strategic benefits do not fully compensate shareholders for this dilution. On the other hand:

- the options to maximise the value realised for Pikka and, over time, to optimise the development of its PNG interests are significant benefits of the Merger that are not available to Oil Search on a standalone basis;
- any estimates of underlying value are inherently uncertain, particularly in the current environment; and
- Oil Search faces real challenges in funding its growth opportunities on a standalone basis.

In the circumstances, an overall judgement on the merits of the Merger is finely balanced. At a minimum, Grant Samuel believes that it is appropriate for the Merger to be put before shareholders for their consideration. Grant Samuel's view is that Oil Search shareholders are likely to be better off if the Merger proceeds than if it does not. Accordingly, the Merger is in the best interests of shareholders, in the absence of a superior proposal.

However, the judgement is highly subjective and shareholders could reasonably weigh these factors differently, attributing less weight to the strategic, funding and other benefits and voting against the Merger. In doing so, they should be aware that if the Merger did not proceed it is likely that the Oil Search share price would fall (assuming continuation of current oil prices and broader market conditions). More importantly, shareholders would need to recognise the risks inherent in such a decision, including the real possibility that a standalone Oil Search would require equity support from its shareholders to maximise the value of its future development projects. A decision by shareholders as to whether to vote in favour of the Merger would depend on factors including their views on value, their willingness to support the funding required by a standalone Oil Search, their views on future oil prices, appetite for PNG risk, the strategic benefits available from the Merger and other matters.

6.2 Value Analysis

6.2.1 Approach

The Merger involves Santos acquiring 100% of the shares in Oil Search. In a typical control transaction, fairness involves comparing the full underlying value of the target with the value of the offer (with any scrip component to be valued at "market" value (i.e. minority value)). There are factors that would suggest that there is a "change of control":

- upon implementation of the Merger, Oil Search shareholders will, in aggregate, own only 38.5% of the Merged Group;
- the agreed terms implied a premium for Oil Search shareholders of around 16% based on closing share prices on 19 July 2021, the day prior to market awareness of the merger proposal;
- only three Oil Search directors will be appointed to the Santos board (which has eight existing members); and
- the current Chairman and the CEO of Santos will remain in those roles for the Merged Group.

On the other hand:

- the Merger is a full scrip offer (with no cash alternative), so shareholders are in a situation different from a cash offer, where they would clearly be selling "control" and would not retain any exposure going forward;
- a change of control at a board and management level should not be confused with a change of control from the perspective of a shareholder. The board serves at the behest of shareholders and former Oil Search shareholders will, collectively, have a significant vote. In turn, management is appointed by the board; and
- from a shareholder perspective the critical issue for control is shareholdings. Post implementation, there will be no shareholders with more than a 6% interest in the Merged Group. Oil Search shareholders will therefore retain the opportunity to receive a control premium at some time in the future.

While the Merger does not precisely fit a "merger of equals", in Grant Samuel's opinion, the better view, on balance, is that merger analysis is the appropriate basis on which to undertake an evaluation.

Accordingly, Grant Samuel has compared the share of the value of the Merged Group received by Oil Search shareholders with the relative contribution by Oil Search shareholders measured by reference to:

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- Grant Samuel's estimate of fundamental (underlying) value of both businesses, calculated on the same basis;
- sharemarket value; and
- key parameters such as earnings and reserves/resources.

Nevertheless, as the relative shares (38.5%/61.5%) are at the outer bounds of what might be considered a "merger", Grant Samuel has also considered the terms of the Merger from the perspective of a takeover/change of control transaction for the sake of completeness.

6.2.2 Merger Analysis

Underlying Value

The table below compares the value contributed by Oil Search and Santos shareholders to the share of underlying value received by the shareholders of each company. The values:

- are based on Grant Samuel's estimate of the value of the operating businesses of Oil Search and Santos (see Sections 5.3 and 5.4 respectively). In particular, it should be noted that:
  - values were estimated in US$;
  - separate values have been ascribed to various groups of individual assets as set out below:
    - Oil Search – PNG LNG, P'nyang & Muruk, Papua LNG, the operated oil & gas assets, Alaska and Exploration; and
    - Santos – Western Australia, Queensland & New South Wales (including GLNG), Cooper Basin, Northern Australia & Timor-Leste, Papua New Guinea and Exploration;
  - the value of each asset group has been assessed primarily by reference to the DCF methodology and reflects the characteristics and outlook for each asset as discussed in Section 5;
  - individual asset values and overall values for Oil Search and Santos have been cross checked to alternative methodologies such as valuation benchmarks ($ / boe of reserves and $ / boe of 2P reserves plus 2C resources and earnings multiples; and
  - the values for each asset represent a "full underlying value" (i.e. value of 100% of the business) but do not purport to represent the change of control value that might be realised in a change of control transaction for each of the companies, as the analysis does not take into account the synergies that might be available to potential purchasers. The full change of control value for each company would include value for factors such as listed company and head office cost savings as well as operational savings. Synergies have been excluded to assist in ensuring the value of the various businesses is estimated consistently across the two companies; and
- reflect the balance sheets as at 30 June 2021 but allow for the subsequent payment of interim dividends (in respect of the six months to 30 June 2021) paid by both Oil Search and Santos.

Estimates of the underlying value of Oil Search and Santos are imprecise, given that they depend on assumptions regarding uncertain matters such as future oil prices and discount rates. However, the consequences of this imprecision are moderated because the analysis is a relative valuation and both companies are affected in a similar fashion (even if not in exactly the same way or to the same extent). The underlying assumptions and absolute levels of estimated value would be far more important if a cash offer were being made.

The analysis suggests that Oil Search shareholders are receiving a smaller share of the Merged Group (38.5%) than their relative contribution of underlying value to the Merged Group (43-44%):

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RELATIVE CONTRIBUTION – UNDERLYING VALUE ($ MILLIONS)

		UNDERLYING VALUE RANGES	
		LOW	HIGH
Oil Search (Equity Value)	A	6,766	8,341
Santos (Equity Value)	B	8,278	10,903
Combined group (aggregate)	C = A+B	**15,494**	**19,244**
Relative value contributed			
Oil Search shareholders	**A/C**	***43.7%***	***43.3%***
Santos shareholders	B/C	*56.3%*	*56.7%*

Source: Grant Samuel analysis

An alternative approach is to compare the aggregate underlying value contributed by Oil Search shareholders with the aggregate value that they will hold in the Merged Group (i.e. in absolute rather than proportionate terms). The potential synergies of $90-115 million per annum are a significant factor in the Merger. Consideration of the value of these synergies allows a comparison of the "value in" with the "value out":

VALUE IN/OUT ANALYSIS ($ MILLIONS)

	UNDERLYING VALUE RANGES	
	LOW	HIGH
Oil Search Equity Value In	**6,766**	**8,341**
Oil Search Equity Value Out		
Oil Search	6,766	8,341
Santos	8,728	10,903
Synergies (excluding associated implementation costs)	950	1,050
Total	**16,444**	**20,294**
Oil Search Share (38.5%)	**6,331**	**7,813**
Change	*-6%*	*-6%*

This analysis indicates that Oil Search shareholders will suffer a reduction in the underlying value of their shares of approximately 6% even including synergies. However:

- that reduction may not be reflected in market values, depending on the relative discounts to underlying value at which shares in the Merged Group could trade. Grant Samuel would expect shares in the Merged Group to trade at a lower discount to underlying value than shares in a standalone Oil Search, reflecting factors including a lower cost of capital; and
- the underlying value could strengthen over time relative to a standalone Oil Search if the Merger benefits (e.g. funding for growth projects) were realised.

Limitations of Underlying Value Analysis

Merger analysis based on estimated underlying value is, at best, an incomplete approach in the circumstances of the Merger:

- estimates of value for oil and gas businesses are inherently uncertain. This uncertainty is exacerbated in the current market. Estimates of future oil and gas prices fall within a wide range, given the wide range of views about the likely trajectory of global energy markets. In general, Oil Search is more leveraged to higher oil prices, while Santos' significant domestic gas business provides price protection in softer markets. In the face of rapidly mounting ESG pressures, the cost of capital for oil and gas assets (and therefore the discount rates to apply in estimating underlying values) are not

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clear. To the extent that costs of capital have risen (or are likely to rise in the future), these higher costs are likely to be more significant for Oil Search, given the long dated nature of its cash flows relative to those of Santos. The reality is that, while estimates of underlying value appear precise, such precision is spurious. Judgements regarding underlying value are subjective;

- the underlying value of Santos estimated above is at or below its market value. The market price may reflect:
  - different views on the value of Santos' asset portfolio (e.g. through different assumptions as to life extensions, exploration success or the timing and quantum of capital and abandonment expenditures); and/or
  - other factors that would contribute to value, including plans for future initiatives (of which Santos has several);
- underlying value is essentially a theoretical construct. It is based on an estimate of the market value of individual assets that does not take into account the particular capital structure of the company in question. Given the funding constraints facing Oil Search and their possible impact on shareholder value, analysis based on underlying value should be treated with some caution; and
- individual shareholders cannot "access" the underlying value of a company's assets except in the context of a cash takeover offer. Rather, the interests of minority investors in Oil Search are intermediated through the corporate and capital structure of company. In this regard, there is no doubt that the "true" equity value contributed by Oil Search shareholders is less than indicated by the underlying value analysis. Oil Search is a PNG incorporated entity that generates over 90% of its cash flows from a single (non-operated) asset, the PNG LNG joint venture. It incurs a higher cost of debt than Santos because of this structural risk. Additionally, Oil Search is capital constrained and has limited capacity to fund its growth program (on an efficient basis) over the next few years (at least until 2026). Intuitively, its cost of equity is also almost certainly higher than for a company like Santos, because of its concentration risk and the sovereign risk associated with its assets (although this is difficult to measure reliably). In contrast, Santos has a diversified asset portfolio (mostly in Australia) and a stronger balance sheet. Accordingly, Oil Search shares are likely to trade at a larger discount to underlying value than Santos shares and any proper test of relative contribution should reflect this differential, because that will be reflected in market values that shareholders can realise in the ordinary course.

Having regard to these factors, it is appropriate to incorporate in the analysis estimates of the relative contributions of market value made by Oil Search and Santos shareholders, as well as estimates of value contribution based on other approaches. Market values are volatile, but they are at least objective (and the analysis is consistent over several months).

Sharemarket Value

Oil Search's contribution to the aggregate sharemarket value of the two companies (based on daily closing prices) compared to the share of the Merged Group received by Oil Search shareholders over the period from 1 July 2020 to 19 July 2021, the last trading date prior to public confirmation of the potential merger is shown in the following chart:

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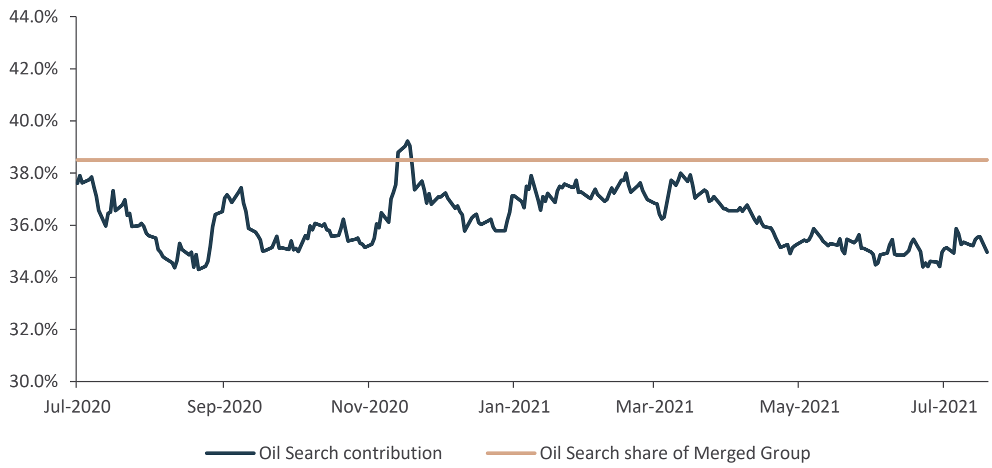
OIL SEARCH – SHARE OF COMBINED MARKET VALUE

1 JULY 2020 TO 19 JULY 2021



Source: IRESS and Grant Samuel analysis

The following table shows the relative contributions based on VWAPs compared to the relative values received under the Merger terms by the shareholders of each company across different periods prior to 19 July 2021:

RELATIVE CONTRIBUTION – SHAREMARKET VALUE

		19 JULY 2021		PERIOD TO 19 JULY 2021 (VWAP)				
		LAST PRICE	VWAP FOR THE DAY	ONE WEEK	ONE MONTH	THREE MONTH	SIX MONTH	TWELVE MONTH
Oil Search								
Price (A$)		3.67	3.72	3.82	3.86	3.87	4.00	3.64
Market capitalisation (A$ millions)	A	7,626	7,719	7,946	8,025	8,039	8,316	7,553
Santos								
Price (A$)		6.83	6.85	7.03	7.17	7.15	7.17	6.40
Market capitalisation (A$ millions)	B	14,227	14,269	14,634	14,925	14,902	14,944	13,338
Combined sharemarket value (A$ millions)	**C=A+B**	**21,853**	**21,988**	**22,579**	**22,950**	**22,941**	**23,259**	**20,891**
Oil Search % contribution	***A/C***	***34.9%***	***35.1%***	***35.2%***	***35.0%***	***35.0%***	***35.8%***	***36.2%***
Santos % contribution	*B/C*	*65.1%*	*64.9%*	*64.8%*	*65.0%*	*65.0%*	*64.2%*	*63.8%*

Source: IRESS and Grant Samuel analysis

The analysis demonstrates that, based on sharemarket prices up to 12 months prior to the announcement, Oil Search shareholders are contributing a consistently lower share (of around 35%) of the combined sharemarket value than they are receiving (38.5%).

In theory, the most recent share prices reflect the "best" market estimate of values, because they incorporate the most recent information on broader economic and business conditions and company specific matters such as operating performance.

Immediately prior to announcement of the Merger, Oil Search and Santos were trading at different earnings multiples:

SHAREMARKET RATINGS (PRE ANNOUNCEMENT)

	2021 (BROKER MEDIAN FORECAST)	
	OIL SEARCH	SANTOS
Last price (19 July 2021) (A$)	3.67	6.83
EBITDAX multiple	6.9x	4.9x
EBIT multiple	10.5x	8.9x
Price earnings (NPAT) multiple	13.4x	12.3x

Source: S&P Global Market Intelligence and Grant Samuel analysis

The differential likely reflects various factors including:

- the different mix of assets and stages of development of the two businesses including factors such as:
  - sensitivity to oil price movements;
  - operating margins;
  - future production profiles and likely remaining production lives;
  - future capital expenditure and abandonment expenditure requirements; and
  - status of major projects;
- the relative strengths and weaknesses of the respective businesses including:
  - asset performance;
  - emissions intensity; and
  - financial leverage.

However, there is no reason to believe that these differences reflect anything other than rational assessments of a well informed market:

- both companies enjoy relatively liquid trading. Annualised turnover is summarised below:

ANNUALISED TURNOVER (% OF ISSUED CAPITAL)

	OIL SEARCH	SANTOS
Three months to 19 July 2021	163.2%	83.4%
Six months to 19 July 2021	136.4%	99.8%
Twelve months to 19 July 2021	140.3%	102.2%

Source: IRESS

- both companies are well followed by brokers (Oil Search – 13, Santos – 12).

Accordingly, it is reasonable to conclude that the share prices for both companies provide a clear indication of the market's views on the value of Oil Search and Santos on a standalone basis (at that time).

Nevertheless, analysis of relative contributions of value based on sharemarket prices needs to be treated with some caution. Sharemarket views on value can shift significantly in short periods of time. Notably, Oil Search's shares fell 20 cents on 19 July 2021 with the announcement of the resignation of the CEO. Accordingly, less emphasis should be placed on prices on this date and more on prices over a longer period (albeit they all give similar results).

On balance, Grant Samuel believes that the sharemarket analysis is sufficiently robust to be a valuable benchmark in assessing the relative contribution of value by Oil Search shareholders.

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Other Parameters

Grant Samuel has also considered the relative contribution of Oil Search and Santos to the Merged Group based on a range of parameters:

- various measures of resources and production; and
- various measures of earnings.

The results are set out below:

RELATIVE CONTRIBUTIONS – OTHER PARAMETERS

	PARAMETER		*CONTRIBUTION (%)*	
	OIL SEARCH	SANTOS	*OIL SEARCH*	*SANTOS*
Reserves and Resources at 31 December 2020 (mmboe)[65]				
2P	445	933	***32.3***	*67.7*
2P + 2C	1,768	3,215	***35.5***	*64.5*
Production (mmboe)				
2020 (actual)	29	89	***24.6***	*75.4*
2021 (forecast)	28	91	***23.2***	*76.8*
Earnings ($ millions)				
2020 (actual)				
EBITDAX[66]	726	1,898	***27.7***	*72.3*
EBIT (normalised[67])	221	787	***21.9***	*78.1*
NPAT (normalised[67])	22	287	***7.1***	*92.9*
1HY21 (actual)				
EBITDAX[66]	491	1,231	***28.5***	*71.5*
EBIT (normalised[68])	279	588	***32.2***	*67.8*
NPAT (normalised[68])	139	317	***30.5***	*69.5*
2021 (broker median forecast)				
EBITDAX	1,175	2,805	***29.5***	*70.5*
EBIT	770	1,558	***33.1***	*66.9*
NPAT	419	852	***33.0***	*67.0*

[illegible] Oil Search, Santos, S&P Global Market Intelligence and Grant Samuel analysis

The analysis needs to be treated with considerable caution. It is a relatively crude and incomplete analysis. In particular:

- none of the measures, apart from NPAT, takes into account differences in gearing between the two companies. Oil Search has higher gearing than Santos so Oil Search's true contribution is actually less than shown in the table above;
- reserves, resources and production parameters do not allow for:

65 As reported by each company in their respective Annual Reports. Note that Oil Search and Santos apply different conversion factors for gas (bcf into mmboe).

66 EBITDAX is before impairment charges but after significant items. Oil Search's EBITDAX has been adjusted to include share of net profit from investments in joint ventures so that it is shown on a consistent basis with Santos' EBITDAX.

67 Normalised EBIT and NPAT are as reported by Oil Search and Santos. EBIT and NPAT include share of net profit from investments in joint ventures and are before impairment and other significant items.

68 Only Santos' EBIT and NPAT have been normalised for other significant items in 1HY21 as Oil Search did not report any other significant items.

  - different levels of profitability across:
    - products (oil, condensate, natural gas, unconventional gas);
    - field locations (costs to find, extract and transport and carbon intensity); and
    - jurisdictions and tax regimes (specifically as between Australia and PNG);
  - different stages of development including:
    - the quantum of capital expenditure yet to be incurred; and
    - future production profiles;
    - probabilities of success in exploration; and
    - other risks associated with growth projects
  - asset location (sovereign risk); and
  - different capital expenditure and abandonment expenditure profiles (including timing);
- earnings parameters are impacted by:
  - COVID-19, at least in respect of 2020 when oil prices in particular fell sharply in the immediate aftermath with a significant adverse (but temporary) impact on profitability across the entire industry; and
  - the inherent volatility of product prices and the sometimes limited (or at least delayed) correlation between different products;

  They also do not take into account:
  - differences in future capital, exploration and abandonment expenditure profiles; and
  - potential changes in future earnings as existing projects wind down and new projects come on stream.

Nevertheless, the analysis is consistent with the market value analysis, which indicates that Oil Search shareholders are receiving a greater share of the Merged Group (38.5%) than they are contributing.

6.2.3 Takeover Analysis

While Grant Samuel does not consider it to be necessarily the appropriate basis for evaluation, the Merger can also be looked at as a takeover/change of control transaction. Under this construct, it is necessary to assess a value for the consideration being offered. In this case, Oil Search shareholders will receive 0.6275 shares in Santos for each share in Oil Search. The value of the consideration is the market value of a share in Santos (rather than the underlying value). This is essentially a "minority" or "portfolio" value. The relevant benchmark is the likely post offer share price rather than pre offer as that is the consideration being received by Oil Search shareholders.

Conventionally, for a scrip offer, the starting point is the recent traded price of the offeror's shares on the stock market. It is then necessary to address two questions, whether:

- there is any reason why the market price is not a true reflection of the fair market value of the offeror's shares; and
- the Merger, if implemented, will have a material impact on the price.

As discussed above, Santos shares are well traded with reasonable liquidity and Santos is closely followed by a number of analysts.

The Santos share price which had been around A$7.00 throughout 2021 (with occasional spikes to over A$7.50) fell following announcement of the initial approach by Santos on 20 July 2021. It continued to

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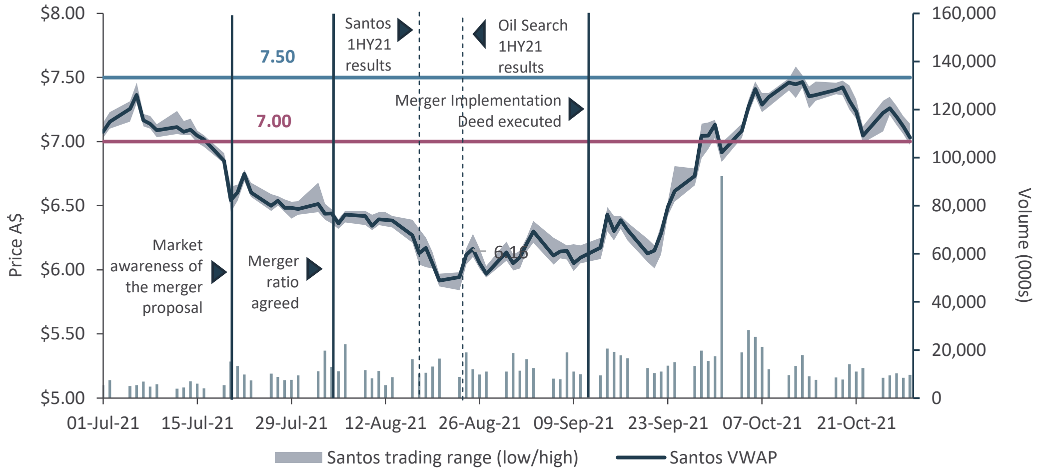
trade down over the next month to just below A$6.00 per share but has since recovered to generally over A$7.00 (the closing price on 29 October 2021 was A$6.98). This recovery broadly coincides with strengthening in the global oil price and spikes in other energy prices.

SANTOS – SHARE PRICE AND TRADING VOLUME

1 JULY 2021 – 29 OCTOBER 2021



Source: IRESS

The Merger will have a material impact on Santos, increasing its issued capital by over 60% and EBITDA by more than 40%, materially changing the mix of assets (with reserves and resources located in PNG increasing from 7% to 30%) and realising (if achieved) cost synergies of at least $90 million per annum. However, the impacts are all readily able to be estimated by the market (analysts can easily prepare models combining the businesses from publicly available data) and the terms of the Merger and estimated cost synergies have been in the public domain since 2 August 2021. In this respect, the significant impacts should be already incorporated into the Santos share price.

The post announcement market trading would suggest that a reasonable market value estimate for Santos shares is A$7.00 - 7.50, arguably weighted towards the bottom end of that range given that the volume weighted average price for Santos shares for October was A$7.16.

The table below summarises the value parameters of the Merger at various alternative Santos share prices:

SCHEME VALUE PARAMETERS (TAKEOVER ANALYSIS)

	SANTOS SHARE PRICE			
	A$6.50	**A$7.00**	**A$7.50**	**A$8.00**
Value for Oil Search shareholders				
Value of consideration per Oil Search share	A$4.08	A$4.39	A$4.71	A$5.02
Premium to share price				
- last price on 19 July 2021 ($3.67)	11.1%	19.7%	28.2%	36.8%
- VWAP for one month ending 19 July 2021	5.6%	13.7%	21.9%	30.0%
- VWAP for three months ending 19 July 2021	5.4%	13.5%	21.6%	29.7%

Source: IRESS and Grant Samuel analysis

Caution is warranted in interpreting the premiums over the share price. The rise in the Santos price since mid-August 2021 appears to be largely due to the strength of the oil price and other related energy prices (particularly the spot LNG price). To the extent this is the case, it is reasonable to assume that Oil Search's shares would also have strengthened over this period, even in the absence of the Merger. In other words, the "true" premium is less than shown in the table. A more accurate measure of the premium is approximately 16%, based on same day prices in the period prior to 19 July 2021.

Nevertheless, the analysis indicates that:

- Santos is not paying a full premium for control (around 16%[69] compared to the typical 20-35%); and
- the offer terms do not correspond to the full underlying value of Oil Search in a change of control situation. Oil Search shareholders are receiving consideration that has a market value of A$4.39 - 4.71 per Oil Search share (and based on the closing price on 29 October 2021, at the bottom end of that range). This value can then be compared to the underlying value of Oil Search shares. Grant Samuel has estimated the value of 100% of Oil Search on a standalone basis to be in the range A$4.40 - 5.42 per share. However, this value does not include any value for synergies which normally are included in an assessment of change of control value (at least to some extent).

In any event, as discussed in Section 6.4, the value of the consideration cannot be compared directly with a takeover offer price (where shareholders give up control to a third party bidder). The nature of the Merger means that:

- shareholders have an ongoing exposure to the future performance of the businesses and will share in any synergy benefits that are realised;
- shareholders still have the potential to receive an offer for the Merged Group incorporating a premium for control; and
- any comparison needs to take into consideration a range of factors in addition to value (e.g. residual exposure, tax and certainty of completion).

6.3 Other Considerations

6.3.1 Background

The Merger is being proposed against the backdrop of profound changes in global energy markets. A focus on reductions in carbon emissions has resulted in a growing emphasis on renewable energy and increasing uncertainty about the future role of traditional carbon-based energy sources. Oil and gas producers have reduced investment in exploration and new production, while challenges associated with integrating intermittent renewable energy sources into traditional energy systems have not been resolved. Capital and bank markets have responded to ESG concerns by reducing the flow of funding to the oil and gas sectors. Global energy demand is expected to continue to grow, largely reflecting ongoing energy intensive economic growth in China, India and other Asian nations. In this context, supply side pressures have exacerbated price volatility. The increasing integration of energy markets has meant that regional demand and supply mismatches are no longer contained but instead have global impacts.

The result has been a fundamental change in the challenges facing oil and gas sector participants. The most obvious and pressing impact relates to access to capital. Given the growing funding constraints faced by oil and gas sector participants, financial strength (in terms of capital structure, liquidity, access to capital markets and underlying cash flow generation underpinned by high quality assets) is increasingly a key competitive advantage. It allows participants to fund asset developments on a value-maximising basis, while minimising their vulnerability to price volatility and other risks.

[69] Based on the one month and three month VWAPs.

6.3.2 Advantages and Benefits

Diversification

The Merged Group will have a highly diversified portfolio of oil and gas assets across:

- product types including oil, condensates, LNG and domestic (Australia) gas with a wide range of end markets and pricing regimes;
- onshore and offshore sources;
- jurisdictions including Australia, PNG, Timor-Leste and Alaska;
- locations across Australia including Western Australia, Northern Territory, South Australia, Queensland and New South Wales; and
- operating assets (e.g. PNG LNG, Western Australia, Cooper Basin and GLNG) and development projects (e.g. Papua LNG, P'nyang, Pikka, Barossa and Dorado) as well as new ventures such as CCS.

There will be a degree of concentration in PNG but for Oil Search shareholders this would actually represent a significant reduction in concentration. In any event, the Merged Group would have the flexibility to reduce the holding in PNG LNG if it is proving problematic.

Such diversification should be valuable for shareholders going forward in an environment where:

- oil prices are inherently volatile and resilience though the cycle is paramount for survival;
- individual oil and gas products may be vulnerable to changing demand profiles whether through political or regulatory action, competition or alternative energy sources; and
- risk mitigation is critical in a highly complex, technical industry. Ideally, no one asset or project should be so large as to endanger the overall enterprise if it fails or experiences a major problem. In this context, Oil Search is heavily exposed to the sovereign risks attached to investment in PNG and is dependent on the consistent operating performance of the PNG LNG operations. The 2018 earthquake highlights the potential risks associated with this PNG concentration. The Merger substantially reduces this risk.

Financial Scale and Strength

Oil Search faces a number of real challenges on a standalone basis. In particular, it faces significant funding constraints which bear on its ability to develop its growth assets in a manner that maximises value for shareholders:

- free cash flow is severely constrained until after 2026 when PNG LNG will have fully repaid its project debt facility and will have access to its full operating cash flows;
- bank debt markets are becoming more fickle and harder to access, particularly as ESG pressures on lenders continue to mount. Oil Search's experience has been that project financing for Pikka is particularly challenging;
- Oil Search is unlikely to be able to secure an investment grade credit rating given its asset concentration (and incorporation) in PNG and therefore cannot access debt capital markets on attractive terms, if at all; and
- Oil Search believes there is limited shareholder appetite for any meaningful equity funding of a Pikka development, certainly at the current level of commitment (i.e. 51%).

Oil Search faces major potential funding commitments in the short term, both in relation to the Papua LNG project and to the Pikka Phase 1 development on the Alaskan North Slope. The challenge is most acute in relation to Pikka, which is approaching FID. In February 2021, Oil Search announced that it intended to sell down a 15% interest in the project (i.e. reducing its stake to 36%). Such a sale would provide funding capacity, reduce Oil Search's funding obligation and provide commercial and technical validation of the project. However, to date no quantifiable offers have been received.

Any deferral of development would risk a substantial reduction in the value of the project, while less conventional forms of finance (if available) would be expensive. An early sale of Oil Search's interest in Pikka would be suboptimal as full value recognition is unlikely until the project is close to, or has commenced, production.

By contrast, the Merged Group will have both scale and a strong funding platform as a result of:

- the expected maintenance of Santos' "investment grade" credit ratings[70]. These ratings enable Santos to access debt capital markets on attractive terms. In April 2021, Santos raised $1 billion in ten year unsecured bonds in the United States 144 market at a total cost of approximately 3.6% per annum;
- the combined liquidity. At 30 June 2021, pro forma cash was $2.9 billion and undrawn facilities were $2.8 billion (compared to Oil Search standalone cash of $0.5 million and $0.7 million of undrawn facilities);
- the relatively modest gearing levels (proforma 2021 net debt/EBITDAX of 1.5 times compared to Oil Search standalone of 2.2 times);
- the combined cashflows from the two businesses (proforma 2021 EBITDAX of over $4 billion);
- the flexibility to sell down a significant part of the combined 42.5% interest in PNG LNG to, say, around 30% while still maintaining a clear position as the second largest investor behind ExxonMobil (the operator), potentially releasing over $3 billion;
- the diversified asset base (across geographies, products and lifecycles) but anchored by a world class, long life, low cost asset (PNG LNG); and
- the reduced average carbon intensity (compared to Santos standalone).

The Merged Group should therefore be able to optimise its development portfolio. In particular, it will have strategic flexibility to "carry" developments on its own balance sheet to the point where selldown makes most economic sense. It will not be forced to sell down prematurely (at least to the same extent) to secure development funding. In other words, it will be able to pursue development funding from a position of strength. Specifically, it could readily commit to developments such as Pikka or Papua LNG.

Potential Alignment of Interests in PNG

At present, Santos is an investor in PNG LNG but has no interest in either P'nyang or the planned Papua LNG project, while Total (the main proponent of the project Papua LNG) has no interest in PNG LNG or P'nyang. The Merged Group will have flexibility to sell down part of its 42.5% interest in PNG LNG, therefore potentially facilitating a realignment of interests across PNG LNG, P'nyang and Papua LNG. Such a realignment would improve co-ordination across these projects and, more importantly, help accelerate the development of Papua LNG and P'nyang, and in the long term help to back fill PNG LNG on an optimal basis. This improved alignment has the potential to deliver significant value accretion for the benefit of all participants. In this scenario, the Merged Group would obviously have funds available to meet any funding obligations.

Synergies

The nature of oil and gas businesses means that mergers offer more limited scope for synergies than many other sectors (e.g. industrials or financial). With a commodity product sold into global markets, mergers cannot provide pricing power. Companies are generally collections of individual projects across different

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70 S&P has expressed some concern about the substantial increase in exposure to PNG as a result of the Merger but notes Santos' track record with acquisitions and the scope to rebalance the combined portfolio following implementation. No decisions have yet been made by either S&P or Fitch regarding changes, if any, to the credit ratings.

locations and there is limited ability to extract direct operational synergies (i.e. at field or plant level). The major area of potential savings is the scope to reduce duplicated costs across head office, marketing functions and support services (including technical services to individual operating assets and development projects).

Santos has estimated that it will be able to achieve annual cost savings of $90 - 115 million. The expected cost savings encompass:

- corporate overheads including board, listing fees and audit;
- employees, predominantly in Australia, across:
  - senior executives;
  - support functions (finance and administration); and
  - procurement, contracting and development.

  The savings comprise employee costs as well as travel and office space;
- information systems; and
- borrowing costs.

One-off costs associated with achieving the cost synergies have not been quantified.

There is no guarantee that the synergies will be realised. See Section 6.3.3 for a discussion of the risks and uncertainties associated with these synergies.

As Oil Search shareholders will collectively own 38.5% of the shares in the Merged Group, to the extent that they continue to hold shares in the Merged Group, they will share in the synergies that are realised. The estimated synergies (before one off costs) have a notional value of approximately 30 US cents per Merged Group share if they are realised in full.

Impact on Earnings and Dividends

The impact on attributable earnings per share and dividends per share for Oil Search shareholders is difficult to determine largely because of the inherent volatility of earnings (driven by oil prices) as well as the different bases for the respective dividend policies.

2020 earnings fell sharply for both entities but particularly for Oil Search, which reported a minimal NPAT even before significant items. Oil Search did not pay an interim dividend in 1HY20. There has been a recovery in 1HY21 and the maintenance of current oil prices would see Oil Search report very strong earnings for 2HY21. An illustration of the potential impact is set out in the table below using median broker forecasts for the full 2021 year and for 2022.

PRO FORMA EPS IMPACT PER EQUIVALENT OIL SEARCH SHARE

	OIL SEARCH STANDALONE	MERGED GROUP	EQUIVALENT OIL SEARCH SHARE	CHANGE	
				ABSOLUTE	%
2021 Earnings per share (before significant items)					
- before synergies	20.2c	37.5c	23.5c	3.4c	16.8%
- after synergies	20.2c	39.6c	24.9c	4.7c	23.4%
2022 Earnings per share (before significant items)					
- before synergies	30.8c	53.4c	33.5c	2.7c	8.7%
- after synergies	30.8c	55.5c	34.8c	4.0c	13.0%

Source: S&P Global Market Intelligence and Grant Samuel analysis

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On this basis it is reasonable to conclude that Oil Search shareholders will benefit from a significant uplift in earnings per share, at least in the short to medium term.

The impact on dividends for Oil Search shareholders is less clear. The two companies have different dividend policies:

- Oil Search targets a payout of 35-50% of NPAT; while
- Santos targets a payment of 10-30% of free cash flow which is defined as operating cash flow less investing cash flow (including capital expenditure, exploration expenditure and interest) but with discretion to exclude material growth projects.

2020 dividends are not a useful guide but 1HY21 may provide a better indication. Oil Search paid 3.3 cents while Santos paid 5.5 cents, equivalent to 3.5 cents per Oil Search share. On the other hand, consensus broker forecasts of dividends for 2021 and 2022 suggest there could be an effective diminution in equivalent dividends per share from the Merger. This comparison does not allow for additional dividends that may arise from the contribution of realised synergies to net earnings.

However, shareholders should note:

- that the primary driver of earnings (and therefore dividends) will be external factors such as oil prices;
- future dividend decisions will be determined by the board of the Merged Group having regard to financial and other circumstances at the time and the Santos policy provides a wide range of outcomes; and
- the dividend policy could be changed at any time.

Additionally, for Australian resident shareholders there should be a further benefit in terms of dividend franking. As a PNG incorporated entity with operations in PNG, Oil Search's dividends have historically not been franked and (assuming the asset composition does not change) will not be so in future. In contrast, Santos dividends have been 100% franked because of its significant proportion of Australian based assets. Future dividends of the Merged Group should be able to be at least partially franked.

Increased Market Presence

The Merged Group will have a pro forma market capitalisation of approximately A$25 billion (based on a Santos share price of A$7.34). On this basis, it will be a top 20 ASX company. It will also be among the top 20 oil and gas companies globally.

This increased scale should increase market relevance and investor awareness although:

- the ASX 200 is the key index for institutional investment. Both Oil Search and Santos are already well within the S&P/ASX 200, ranking around 59 and 34 respectively;
- both Oil Search and Santos already have reasonable liquidity and the Merger itself will not directly have any impact on liquidity except for the benefit of combining into a single pool; and
- there is no net effect on index weighting that would automatically lead to increased demand for shares in the Merged Group.

Access to Expertise

Santos has a well developed group strategy for reducing or offsetting its emission impacts with an overall goal of being carbon neutral by 2040. More importantly, it has continued to advance various CCS projects and announced FID for the Cooper Basin CCS project on 1 November 2021. Accordingly, Oil Search assets will benefit from access to this expertise if the Merger proceeds.

While the PNG LNG asset and the Papua LNG project have relatively low emission intensity and are arguably less exposed to carbon emission regulation than projects in Australia, global pressures (possibly from buyers) will almost inevitably start to require some action in relation to carbon abatement throughout the gas industry.

6.3.3 Disadvantages, Costs and Risks

Change in Mix of Assets

Oil Search shareholders will have a much lower exposure to Oil Search's assets (e.g. from collective ownership of a 29% interest in PNG LNG to a little over 16%). While these assets do carry some degree of sovereign risk, the PNG LNG joint venture has been in operation since 2014, largely without incident, and the assets are considered world class with long life resources, low operating costs and quality (rich) gas with low CO_2 content.

Correspondingly, they will have a significant exposure (over 60% of the value of their investment) to Santos' assets. In broad terms, these assets can be regarded as lower quality than PNG LNG, with an overall faster anticipated decline in production over time, lower margins and higher emissions intensity.

Some shareholders may not welcome this diversification and reduced exposure to the PNG assets. If they are already shareholders in Oil Search they are presumably comfortable with the highly concentrated exposure to LNG projects in Papua New Guinea. Shareholders seeking exposure to Santos assets could easily buy Santos shares. Diversification is more efficiently achieved by shareholders themselves rather than through being locked into a specific mix of assets within a corporate entity.

At the same time, it should be recognised that:

- asset "quality" differences should be reflected in the relative valuations. In addition, the merger terms indicate Oil Search shareholders are receiving a premium, in the order of 16% (based on the share prices at the time of announcement of the Merger);
- other aspects of the diversification may be of value to shareholders, in particular the increased exposure to domestic gas markets which tend to have more stable pricing than LNG and oil; and
- some of Santos' assets offer a lower risk profile than Oil Search (e.g. some domestic gas sales and midstream assets that could be considered to have some infrastructure type characteristics at least to the extent they derive "tolling" revenues from third parties).

Santos Share Price Risk

The underlying value analysis would suggest that there is a risk that the Santos share price could fall in future (even if oil prices remained stable). At the same time, Santos is a liquid share that provides detailed disclosures and is followed by over ten analysts. Market prices may reflect factors other than underlying value that may prove sustainable over time.

Reduced Likelihood of Takeover Premium

The Merger, if implemented, is evidence that an acquisition (at least in a technical sense) of Oil Search is achievable. The concerns of the PNG government are likely to be that:

- the owners of the assets are committed to fully exploiting the resource to provide the maximum economic benefit to the PNG population; and
- that PNG citizens have a readily available opportunity to invest (even if indirectly) in these assets.

In contrast, a takeover of the Merged Group may be more problematic. The Merged Group will have a relatively open share register. Upon implementation no shareholder is expected to have more than a 6% shareholding. Accordingly, there is at least a theoretical possibility of a third party making a takeover offer, including a full control premium, at some future date. However, it is arguable that the prospect of a takeover is lower for the Merged Group than it is for Oil Search:

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- as the Merged Group would have a proforma enterprise value of almost $25 billion, the field of potential suitors with the financial capacity to make an offer is more limited;
- the highly diversified asset base may be less attractive than one narrowly focussed on a single world class asset; and
- the acquirer, if foreign, may face issues in obtaining approval under Australia's Foreign Acquisitions and Takeovers Act. The Merged Group would be one of only two major Australian oil and gas producers (the other being Woodside, whether merged with BHP Petroleum or not). Given the importance of energy security there is a risk of failure to obtain the necessary approvals. In this context, the Commonwealth Treasurer refused approval for the proposed acquisition of Woodside by Royal Dutch Shell plc in 2001 and the proposed acquisition of APA by CKI in 2018.

At the same time:

- it is evident that there is no shortage of capital for acquisitions globally. The oil and gas industry includes a significant number of large, well-capitalised participants. Very large institutionally backed transactions have also become more common; and
- foreign ownership and investment has been a major feature in the development of the Australian oil and gas sector for decades (from Bass Strait to the North West Shelf). Government policy priorities appear to be to ensure developments are progressed so that growing energy needs are met.

On the other hand, there is probably only a handful of possible acquirers of a standalone Oil Search. All will already have good insights into Oil Search and its assets. By the time of the shareholders' meeting to approve the Merger, any potential counter-bidders will have had over four months to formulate an alternative proposal. In the absence of any alternative offer, Oil Search shareholders could conclude that their prospects of realising a full takeover premium are remote.

Accordingly, while the Merger may theoretically reduce the likelihood of Oil Search shareholders realising a takeover premium, any real world disadvantage is unlikely to be material.

Transaction and Integration Costs

Oil Search and Santos will each incur transaction costs in relation to the Merger. Transaction costs are estimated to total approximately A$124 million (A$79 million for Oil Search and A$45 million for Santos). Some of these costs will be incurred regardless of whether the Merger is implemented. The Merged Group will also incur integration costs associated with achieving the cost savings which have not been quantified. However, these integration costs are one off and unlikely to be material in the context of the Merged Group.

Oil Search shareholders will, in aggregate, bear 38.5% of these costs (as well as 38.5% of the integration costs). The transaction costs represent less than 0.5% of the pro forma market capitalisation of the Merged Group.

In certain circumstances, Oil Search will also be liable to pay Santos an $80 million break fee (although not if shareholder approval of the Merger is not forthcoming). On the other hand, in certain circumstances, Santos will be liable to pay Oil Search an $80 million break fee.

Integration Risks

The benefits of the Merger relate largely to the broader strategic benefits, enhanced financial capacity and cost synergies expected to be realised through the combination and integration of the Oil Search and Santos businesses. The extent of the strategic benefits and the quantum of the cost synergies essentially reflect the complementary nature of the Oil Search and Santos businesses. However, it should be recognised that realisation of the expected benefits will not be an automatic consequence of the Merger but will require the successful integration and ongoing management of the Merged Group. Business

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integrations are inherently risky. There may be unanticipated issues or costs that arise on integration of the Merged Group. Anticipated savings may not be able to be achieved to the extent expected. On the other hand, Santos has a strong track record from acquisitions and integrations implemented over the last three years, in particular the 2018 acquisition of Quadrant and the 2020 acquisition of the Northern Australian assets from ConocoPhillips. Santos states that it has achieved synergies in relation to these acquisitions of $35 - 80 million more than initially forecast (and announced).

Given the risks involved, it is to be expected that the share market value of the Merged Group will only fully reflect the benefits of the Merger over time, as the integration process is successfully completed, expected cost synergies are realised and management demonstrates its ability to leverage real value from the stronger strategic positioning of the Merged Group.

Other

There are a number of other costs, disadvantages and risks for Oil Search shareholders:

- some shareholders may not want to hold Santos shares. However, they will be able to sell their shares into an enlarged market for Santos shares, although there is no certainty that they will be able to realise the scrip received for an amount equivalent to the value attributed by the merger terms (e.g. due to transaction costs and the risks associated with any sharemarket investment); and
- Section 7 of the Scheme Booklet details a number of other risks relating to investment in Oil Search, Santos and the Merged Group, and the Merger. Shareholders should consider these risks in making a decision on whether to vote in favour of the Merger.

6.4 Alternatives

Standalone

A standalone Oil Search does have a viable future.

While a standalone Oil Search may face challenges in funding Pikka, the Company is under no direct and broader funding pressure. PNG LNG is a world class project and should generate strong positive cash flows at current oil prices. An outcome that saw Pikka divested or otherwise dealt with would see Oil Search able to focus on the funding of Papua LNG. A successful Papua LNG development would offer the potential for real value uplift over time for Oil Search.

On the other hand:

- a sale of Pikka in the short term may result in a significant loss of value. Similarly, any significant development deferral would result in value diminution;
- a decision to reject the Merger and proceed on a standalone basis would not be without risk. It is likely that the Oil Search share price would fall, at least in the short term. The way forward for Pikka is unclear and could involve more value loss than implied in Grant Samuel's estimate of current value. Shareholders should expect that they would be required to support the Company's future funding via some significant equity raising; and
- Oil Search has an Acting CEO and CFO, with the previous CEO having left Oil Search shortly before news of Merger discussions was announced. If the Merger were not to proceed, Oil Search would need to make permanent appointments for these roles. In addition, it is likely that the Board renewal process already underway would need to be accelerated.

Shareholders who would prefer not to be exposed to these uncertainties or to address Oil Search's funding challenges via direct equity support would be justified in preferring to pursue the Merger.

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Other Acquirors

Oil Search and Santos have agreed to mutual no-shop and no-talk restrictions and Santos has a right to match a competing transaction for Oil Search. Oil Search and Santos have agreed to pay each other $80 million break fees if the Merger does not go ahead (in certain prescribed circumstances). The $80 million break fees are not material having regard to the standalone values of the two companies.

In deciding to enter into the Merger Implementation Agreement, the Oil Search board considered the potential alternatives available to Oil Search, including acquisition by a third party and maintenance of the status quo. The board decided to recommend the Merger to Oil Search shareholders in the absence of a superior proposal. However, Oil Search shareholders could choose to reject the Merger, in the expectation that Oil Search would be better off on a standalone basis, or that a superior proposal might be made by some third party.

The decision as to the relative merits of alternative proposals is not just a question of the headline price. If a counter proposal is, for example, a 100% cash offer (or even a predominantly cash offer), then shareholders are very clearly selling control of Oil Search to a third party under which they will have no ongoing exposure to the business and its growth potential or benefit from any synergies (i.e. it is a one time sale opportunity).

In contrast, under the Merger they are not giving up control per se but will continue to have an exposure (albeit diluted) to the Oil Search businesses and will have a 38.5% (aggregate) share of future growth and any cost synergies realised from the Merger (which are notionally worth around 30 US cents per Merged Group share, before one off costs, if achieved in full).

Moreover, the Merger does not prevent some change of control proposal for the Merged Group emerging in the future. The Merged Group will have a largely open share register and in some respects would be a more attractive target than Oil Search on a standalone basis. Shareholders (including former Oil Search shareholders) will also retain the opportunity to sell "control" of the Merged Group at some future time, albeit that this may be less likely because of the size of Merged Group and national interest considerations that may come into play.

In addition, there may be other differences between alternative proposals including:

- taxation consequences. For example, a cash offer may result in material CGT liabilities for some shareholders while scrip offers may provide CGT rollover relief; and
- certainty and timing of completion particularly where regulatory approvals are required.

Accordingly, any comparison of proposals must be a more nuanced comparison across a number of dimensions (e.g. value, control, residual exposure, tax and certainty).

It is not possible to know whether there may be an alternative that is superior to the Merger. In any event, there is no meaningful obstacle to a third party making an alternative proposal to Oil Search prior to the meeting at which shareholders will vote on the Merger (although the matching right might be a disincentive to any competing proposal). By the time of the meeting, there will have been more than enough time for an alternative acquirer to do so. Moreover, potentially interested parties are likely to have a reasonable understanding of Oil Search and its assets and able to make at least an indicative offer based on public information. If no such proposal is received it may be an indication that there is no prospect of a higher offer at the present time. In that case, it would be imprudent for shareholders to vote against the Merger in the hope of a subsequent higher offer from a third party.

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6.5 Other Matters

Taxation Consequences

Details on taxation consequences of the Merger for PNG and Australian resident and non-resident shareholders that hold their investment on capital account are set out in Section 8 of the Scheme Booklet.

There is no capital gains tax ("CGT") in PNG and accordingly, there will be no tax consequences for these categories of shareholders.

The Merger will give rise to a CGT event for Australian Oil Search shareholders. Australian resident shareholders should be eligible to receive CGT rollover relief (even though Oil Search shares are in a PNG incorporated entity). If shareholders receive rollover relief, the capital gain that would otherwise be generated will be deferred until they dispose of their Merged Group shares.

The cost base of the Merged Group shares received should be equal to the cost base of an Oil Search shareholder's original Oil Search shares. Furthermore, the Merged Group shares will be taken to be acquired at the time the Oil Search shares were originally acquired.

For a shareholder who chooses not to receive rollover relief, the CGT provisions will apply. The acquisition date of the Merged Group shares will be the implementation date and the cost base of the Merged Group shares received should be the market value of the Merged Group shares on implementation.

In any event, the taxation consequences for shareholders will depend upon their individual circumstances. If in any doubt, shareholders should consult their own professional adviser.

Ineligible Foreign Shareholders

Ineligible foreign shareholders are not entitled to receive shares in the Merged Group. However:

- the Merged Group shares that they would otherwise have received will be sold on market and they will receive the cash proceeds on sale (after payment of applicable brokerage, stamp duty and other costs, taxes and charges); and
- they can acquire Santos shares through the ASX if they wish to retain an exposure to the Merged Group.

6.6 Shareholder Decision

Grant Samuel has been engaged to prepare an independent expert's report setting out whether in its opinion the Merger is in the best interests of Oil Search's shareholders and to state reasons for that opinion. Grant Samuel has not been engaged to provide a recommendation to shareholders in relation to the Merger, the responsibility for which lies with the directors of Oil Search.

In any event, the decision whether to vote for or against the Merger is a matter for individual shareholders based on each shareholder's views as to value and business strategy, their expectations about future economic and market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. In particular, taxation consequences may vary from shareholder to shareholder. If in any doubt as to the action they should take in relation to the Merger, shareholders should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell shares in Oil Search, Santos or the Merged Group. These are investment decisions upon which Grant Samuel does not offer an opinion and are independent of a decision on whether to vote for or against the Merger. Shareholders should consult their own professional adviser in this regard.

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7 Qualifications, Declarations and Consents

7.1 Qualifications

The Grant Samuel group of companies provide corporate advisory services in relation to mergers and acquisitions, capital raisings, debt raisings, corporate restructurings and financial matters generally. The primary activity of Grant Samuel & Associates Pty Limited is the preparation of corporate and business valuations and the provision of independent expert's reports in connection with mergers and acquisitions, takeovers and capital reconstructions. Since inception in 1988, Grant Samuel and its related companies have prepared more than 575 public independent expert and appraisal reports.

The persons responsible for preparing this report on behalf of Grant Samuel are Stephen Cooper BCom (Hons) CA and Stephen Wilson MCom (Hons) CA SF Fin. Each has a significant number of years of experience in relevant corporate advisory matters. Jaye Gardner BCom LLB (Hons) CA SF Fin GAICD, David Szeleczky BCom (Hons) LLB (Hons), Nicholas Papas BCom LLB (Hons), Shaun Yu BBA CFA, Daniel Moore BCom BEng CFA and Daniel Robinson BCom assisted in the preparation of the report. Each of the above persons is a representative of Grant Samuel pursuant to its Australian Financial Services Licence under Part 7.6 of the Corporations Act.

7.2 Disclaimers

It is not intended that this report should be used or relied upon for any purpose other than as an evaluation as to whether the Merger is in the best interests of shareholders. Grant Samuel expressly disclaims any liability to any Oil Search shareholder who relies or purports to rely on the report for any other purpose and to any other party who relies or purports to rely on the report for any purpose whatsoever.

Grant Samuel has had no involvement in the preparation of the Scheme Booklet issued by Oil Search and has not verified or approved any of the contents of the Scheme Booklet. Grant Samuel does not accept any responsibility for the contents of the Scheme Booklet (except for this report).

7.3 Independence

Grant Samuel considers itself to be independent of Oil Search and Santos.

Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any business or professional relationship with Oil Search or Santos or any financial or other interest that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Merger.

Grant Samuel had no part in the formulation of the Merger. Its only role has been the preparation of this report.

Grant Samuel will receive a fixed fee for the preparation of this report. This fee is not contingent on the conclusions reached or the outcome of the Merger. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.

7.4 Declarations

Oil Search has agreed that it will indemnify Grant Samuel and its employees and officers in respect of any liability suffered or incurred as a result of or in connection with the preparation of the report. This indemnity will not apply in respect of the proportion of any liability found by a court to be primarily caused by any conduct involving negligence or wilful misconduct by Grant Samuel. Oil Search has also agreed to indemnify Grant Samuel and its employees and officers for time spent and reasonable legal costs and expenses incurred in relation to any inquiry or proceeding initiated by any person. Any claims by Oil Search

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are limited to an amount equal to the fees paid to Grant Samuel. Where Grant Samuel or its employees and officers are found to have been negligent or engaged in wilful misconduct Grant Samuel shall bear the proportion of such costs caused by its action.

Advance drafts of this report were provided to Oil Search and its advisers and to Santos and its advisers. Certain changes were made to the drafting of the report as a result of the circulation of the draft report. In particular, Santos advised Grant Samuel that some of the detailed assumptions relating to annual production, operating costs, capital costs and abandonment expenditures set out in the valuation scenarios developed by GaffneyCline ("Detailed Information") are or may be confidential or commercially sensitive to it and others. In the ordinary course, it would be expected that the Detailed Information would be included in Grant Samuel's report. Santos has declined to provide the releases required for Grant Samuel to include the Detailed Information in its report. Accordingly, Grant Samuel has removed or aggregated the Detailed Information. This has had no impact on the underlying NPV analysis, the calculated NPVs, Grant Samuel's overall valuation conclusions or Grant Samuel's opinion as to whether the Merger is in the best interests of Oil Search shareholders.

There was no alteration to the methodology, evaluation or conclusions as a result of issuing the drafts.

7.5 Consents

Grant Samuel consents to the issuing of this report in the form and context in which it is to be included in the Scheme booklet to be sent to shareholders of Oil Search. Neither the whole nor any part of this report nor any reference thereto may be included in any other document without the prior written consent of Grant Samuel as to the form and context in which it appears.

7.6 Other

The accompanying letter dated 9 November 2021 and the Appendices form part of this report.

GRANT SAMUEL & ASSOCIATES PTY LIMITED

9 November 2021

Grant Samuel & Associates

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APPENDIX 1

OVERVIEW OF THE OIL AND GAS SECTOR

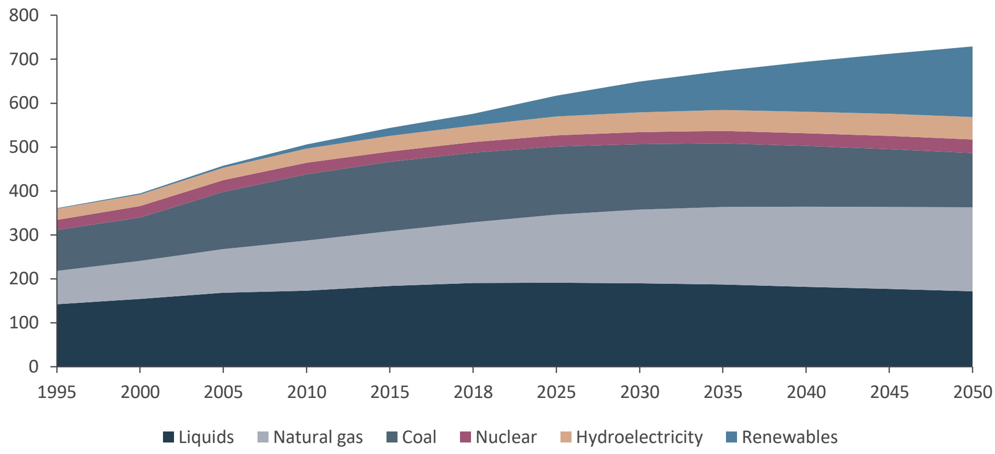
1 Overview of the Oil and Gas Sector

1.1 Global Energy Market

World energy consumption increased by an average of 2.0% per annum from 1995 to 2018[1]. Most of the world's energy requirements are met from oil, coal and natural gas, although alternative sources, in particular renewables, are growing in importance. Recent years have seen continued growth in overall global energy demand, changing geopolitical circumstances, the impact of policy responses to concerns related to climate change, unsettled economic conditions and, most recently, the impact of the COVID-19 pandemic on energy demand and supply. The consequences have included increased demand worldwide for natural gas, the growth of renewable energy sources and, recently, extreme price volatility.

Since 1995, compound annual growth in consumption of natural gas (2.6%) and coal (2.3%) has outpaced demand growth for oil (1.3%). Although there is a wide range of forecasts regarding future energy markets, oil and coal consumption are generally expected to decline, while natural gas is seen as a "transition fuel" that is expected to continue to play an important role in global energy markets. For example, BP expects consumption of natural gas to grow at 1.0% per annum until 2050. As a result, natural gas is forecast to marginally grow its share of global energy consumption from 25% in 2020 to 26% in 2050. On the other hand, BP expects that oil's share of global energy consumption, which has declined from around 39% in 1995 to 31% in 2020, will fall further to around 24% in 2050. Coal's share of energy consumption is expected to fall from around 27% in 2020 to around 17% by 2050. Renewables (renewable power such as wind and solar and biofuels) are expected to gain share relative to oil and coal, with BP forecasting growth in renewables energy of 5.7% per annum from 2018 to 2050, resulting in renewables' share of global energy consumption increasing from 5% to 22% over the period.

ENERGY DEMAND BY FUEL TYPE (EXAJOULES)



Source: BP Energy Outlook 2050, BP plc

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[1] The major sources of statistical and forecast data on the energy sector in this report is from "BP Statistical Review of World Energy 2021", "BP Energy Outlook 2050 (Business-as-usual scenario)", "2021 World LNG Report", "2021 GIIGNL Annual Report"

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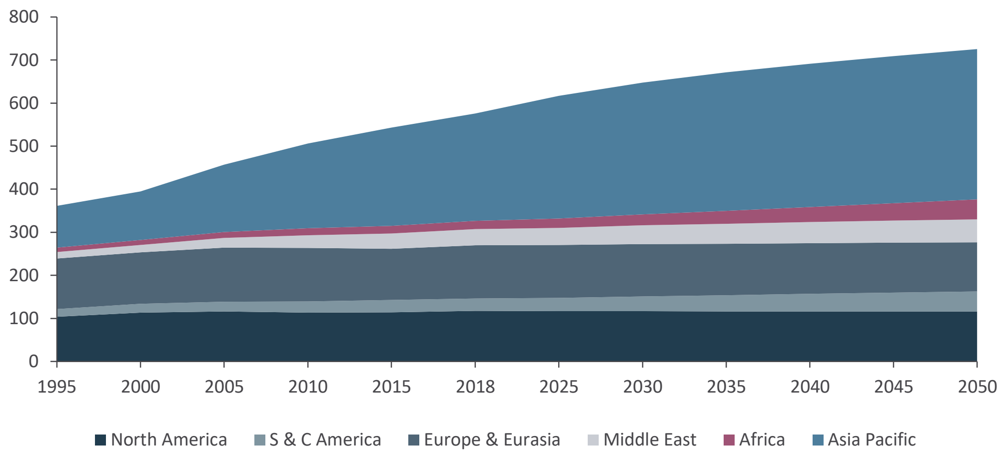
Asia Pacific accounted for 45% of global energy demand in 2020, more than half of which relates to China, while North America and Europe & Eurasia each contributed less than one quarter. The Asia Pacific region is forecast to account for two thirds of the growth in demand to 2050, with the Middle East, South & Central America and Africa expected to contribute most of the remaining growth. As a result, Asia Pacific is expected to account for 48% of global energy consumption by 2050:

ENERGY DEMAND BY REGION (EXAJOULES)



Source: BP Energy Outlook 2050, BP plc

China and India are expected to be the two countries that contribute most to growth in energy demand. While China will have the largest impact on energy demand over the first ten years of the forecast, its growth is projected to slow over the second half of the forecast as it transitions to a more sustainable pattern of economic growth. India is forecast to be the largest driver of energy demand growth from 2030 onwards, reflecting expectations of continued high rates of growth and industrialisation. Over the period 2040 to 2050, India's demand growth represents more than a third of the projected global increase in energy demand.

Energy demand growth has been largely driven by the industrialisation and electrification of growing economies. While these factors are expected to continue to drive growth, analysts are forecasting a gradual diminution in their impact as developing economies approach economic maturity and lower energy intensities are required per unit of GDP.

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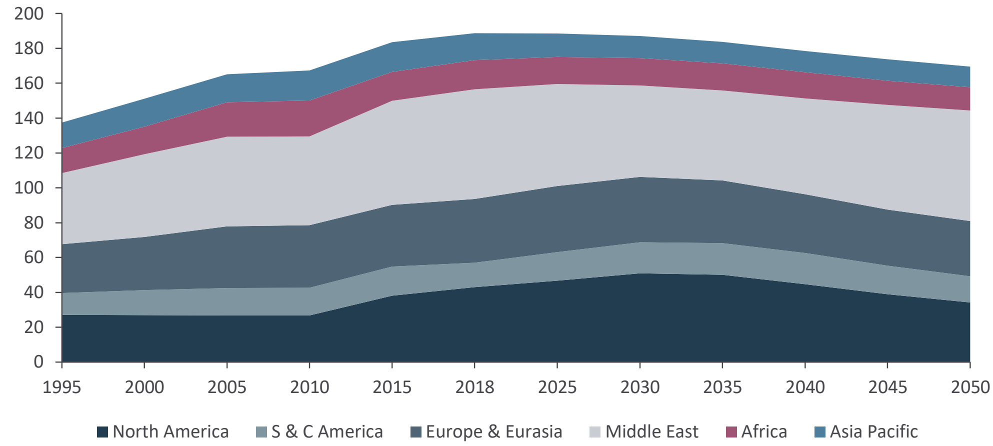
1.2 Oil Industry

Supply

Global oil production since 1995 and projected oil production to 2050 are illustrated on the following chart:

OIL PRODUCTION BY REGION (EXAJOULES)



Source: BP Energy Outlook 2050, BP plc

The production of oil is heavily influenced by the Organisation of Petroleum Exporting Countries ("OPEC"), an intergovernmental organisation of 13 oil-exporting developing nations that coordinates and unifies the petroleum policies of its member countries[2]. Between 1995 and 2018, oil production increased by 1.4% per annum, with most of the increase in production from North America and the Middle East. The sharp increase in North American supply reflected technological advances that improved the economic viability of unconventional oil sources such as shale oil and tight oil. After peaking sometime in the 2020s, global oil production is forecast to slowly decline to 2050, with only the Middle East and South and Central America maintaining production levels.

Demand

Oil's primary use is as transport fuel, mostly for motor vehicles. Although the North American market has historically been the largest consumer of oil, it was overtaken by the Asia Pacific region around 2004. Between 2018 and 2050, oil consumption is expected to decline by 0.3% per annum reflecting the general trend to a lower carbon fuel mix offset in part by the ongoing demand for oil in road transport in emerging markets such as Africa and South & Central America.

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[2] Members are Algeria, Angola, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela and the Republic of Congo (as at September 2021).

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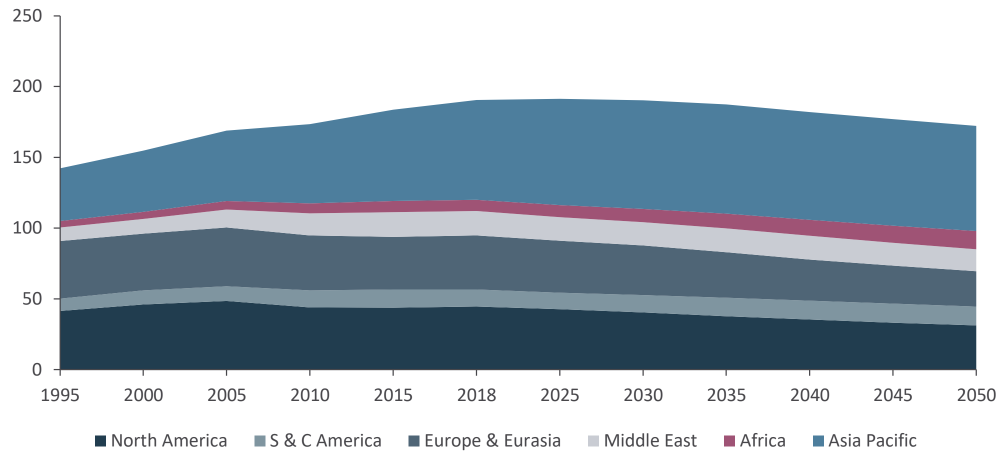
OIL DEMAND BY REGION (EXAJOULES)



Source: BP Energy Outlook 2050, BP plc

Pricing

Oil is one of the most heavily traded commodities in the world. Prices are typically set against one of the following two international benchmarks and are adjusted to reflect the specific characteristics of the products and the location of the ports of origin and destination:

- West Texas Intermediate ("WTI"), a light, sweet crude oil, is the primary benchmark for oil produced in the United States. Cushing, Oklahoma, is a major hub and delivery location for WTI and represents the settlement point for WTI. Futures contracts on WTI are traded on NYMEX[3]; and
- Dated Brent ("Brent"), which is also a light crude oil, although not as light as WTI, is a composite blend of oils from 15 different oilfields in the North Sea. It has historically been used as a crude oil benchmark primarily within Europe.

However, the impact on WTI pricing of United States market specific factors has reduced the relevance of WTI as an international benchmark. Instead, Brent is increasingly being used as a pricing benchmark in Asia and other markets.

The Brent and WTI oil prices and the Brent/WTI spread since the beginning of the 21st century are illustrated below:

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[3] A designated contract market operated by CME Group that offers derivative products subject to NYMEX rules and regulations.

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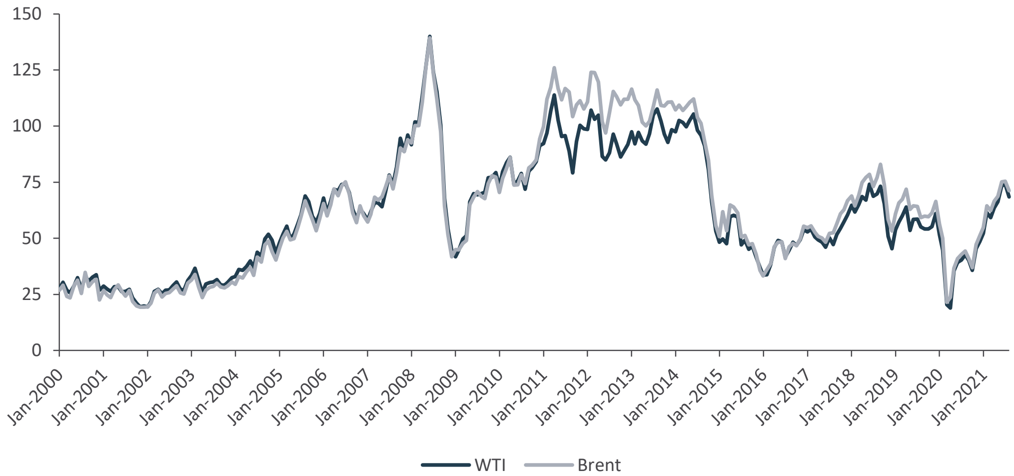
BENCHMARK OIL PRICES – BRENT AND WTI ($ PER BBL)



[illegible] Bloomberg

Following an all-time high of $145/bbl in early July 2008, the impact of the global financial crisis ("GFC") on global economic activity saw a precipitous fall in the Brent oil price to $31/bbl in late December 2008. The oil price then slowly recovered and Brent oil broadly traded in the $100-125/bbl range in 2011, 2012, 2013 and the first half of 2014. Key to this recovery was OPEC's decision to limit production, as well as increasing demand from developing countries in Asia. Furthermore, while political instability across North Africa, the Middle East and Russia/Ukraine caused some price volatility, it also provided general support for higher oil prices.

From July 2014 the oil price fell from around $100/bbl to lows of around $26/bbl in mid-January 2016. This was primarily due to relatively high levels of OPEC production, led by Saudi Arabia, continued growth in production, particularly from non-OPEC sources, including from shale sources in the United States, softening demand growth in China and a market re-evaluation of China's economic growth prospects.

In order to address global oil oversupply, OPEC, Russia and other oil producers signed a Declaration of Cooperation ("DOC") in December 2016, centred around a production reduction of approximately 1.7 million bbl per day. Combined with increased demand driven by global economic growth, this resulted in the oil price increasing by approximately 29% over the course of 2017. The oil price continued to rebound during the first three quarters of 2018, reaching $83/bbl by the end of September 2018.

Despite two OPEC production cutbacks and the attack on the Abqaiq processing facility, oil prices were unable to generate any gains through 2019 and closed at $61/bbl at the end of 2019. A major factor was the boom in shale oil production in the United States, providing an alternative source of supply and making the United States the world's top oil producer, pumping out a record 12.3 million bopd in 2019.

In the first quarter of 2020, OPEC failed to agree production curtailments with its key partners. Russia, the largest of OPEC's external allies, refused to agree deep output cuts and, in retaliation, Saudi Arabia slashed the price at which it sells oil and boosted supply. The oil price collapsed, declining by approximately 60% to around $20/bbl. Against this backdrop, the COVID-19 pandemic created a demand shock for commodities including oil, given lower GDP and growth forecasts as well as restrictions on movement. In April 2020, as surplus oil continued to flood the market, an exhaustion of storage capacity drove WTI to a negative price for the first time in history. Over the past 12 months, deep production cuts by United States oil producers and an agreement to cut output by OPEC, coupled with partial recoveries in demand as the world tentatively emerged from COVID-19 restrictions, helped to lift prices closer to $80/bbl. More recently prices have surged above $80/bbl amid constrained supply issues across global energy markets.

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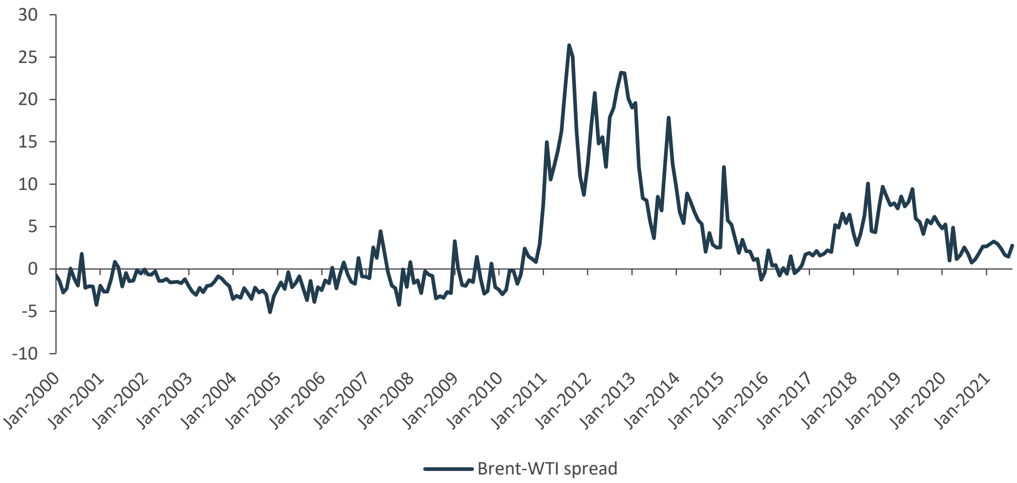
The WTI and Brent benchmarks have historically traded in line with each other, but an increase in United States production combined with a shortage of pipeline capacity to transport the oil to refiners has led to a build-up of WTI inventories, with the result that WTI has traded at a discount to Brent since August 2010. The gap widened over the last couple of years but has since closed following the recent oil price collapse.

BENCHMARK OIL PRICES – BRENT – WTI SPREAD ($ PER BBL)



Source: Bloomberg and Grant Samuel analysis

1.3 LNG Industry

Background

Natural gas primarily comprises methane but may also contain other hydrocarbons (such as propane, butane and ethane), nitrogen and carbon dioxide. Natural gas has a range of uses in the industrial, power generation, commercial and domestic sectors.

Natural gas is often categorised as "conventional" or "unconventional" depending on its source. Conventional gas is typically found in underground reservoirs (both onshore and offshore), sometimes in association with oil. A hydrocarbon reservoir consists of hydrocarbon-rich porous rocks or sands, capped by overlying rock formations of lower permeability that effectively trap the hydrocarbons within the reservoir. Unconventional gas includes coal seam gas, (contained within coal seams), shale gas (contained within low permeability organic rich rocks), tight gas (contained in low permeability reservoir rocks) and gas from renewable sources such as biogas (landfill and sewage gas) and biomass (wood, wood waste and other plant-based material). Dramatic technological improvements have seen a massive expansion in unconventional gas resources. These now represent a significant proportion of the world's estimated remaining technically recoverable gas resources and have been a major factor in the expansion of global gas resources from around 50-60 years of supply to current estimates of more than 200 years of supply. The majority of identified unconventional gas is shale gas, located principally in North America.

While large scale liquefaction of natural gas has been undertaken since the early 20th century for industrial purposes, the growth in the use of Liquefied Natural Gas ("LNG") has been driven by the power needs of countries such as Japan and South Korea, which have limited natural gas resources and little or no access to international gas pipelines. LNG is produced by refrigerating natural gas using large turbines and cryogenic heat exchangers to temperatures below its condensing temperature of negative 160 degrees Celsius, thereby converting the gas into a liquid. LNG has a reduced volume relative to natural gas (by a factor of approximately 600 times), which makes it economic to transport over long distances. LNG is typically

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shipped in specially designed tankers for delivery to purpose built inbound terminals, where it is converted back into gas before being distributed as pipeline natural gas.

Supply

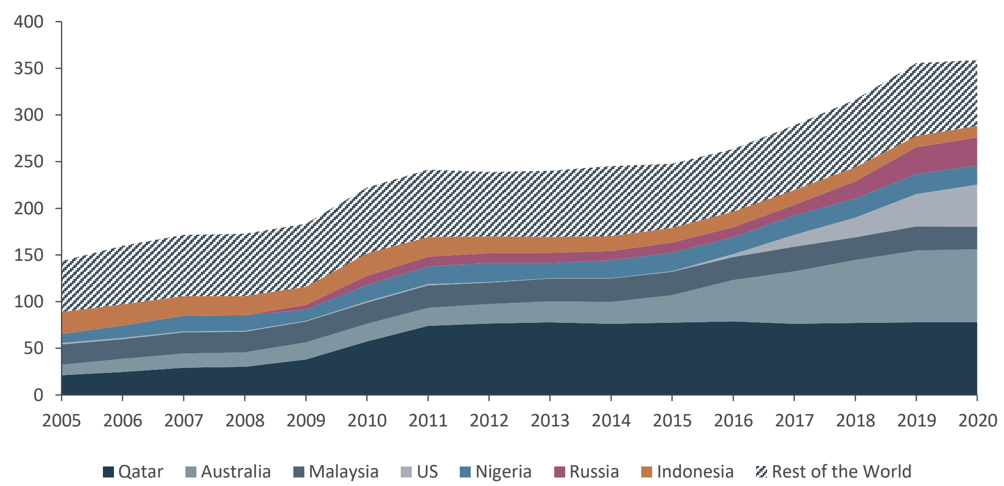
Commercial scale LNG liquefaction commenced in 1964 at Arzew in Algeria. Early industry growth was supported by the development of substantial LNG capacity in Malaysia and Indonesia. Australia's first LNG production (from the North West Shelf project) commenced in 1989. Since 2000, global liquefaction capacity has more than doubled, with significant new capacity from major new LNG projects in Qatar and, to a lesser extent, the expansion of Australian LNG production. While consumption of natural gas has grown overall by around 2.6% per annum from 1995 to 2018 and is forecast to grow at around 1.0% per annum in the period through to 2050, the volume and diversity of LNG trade flows are increasing, with the International Gas Union reporting a 5% increase in liquefaction capacity from 2019 to 2020.

At the end of 2020, global installed LNG production capacity totalled approximately 454 Mtpa and production capacity under construction was 108 Mtpa[4]. According to the International Gas Union, at the beginning of 2021 there was 892.4 Mtpa of 'aspirational' liquefaction capacity in the pre-FID stage, primarily in the United States and Canada. In reality, a significant portion of the pre-FID projects are unlikely to progress.

While installed capacity has steadily increased, global liquefaction capacity utilisation has generally been in decline since 2010. Utilisation fell to 74.6% in 2020, down from 81.4% in 2019. Numerous factors affect the utilisation of LNG facilities globally. In 2020, utilisation was impacted by cancellations to cargoes because of COVID related falls in demand with industrial gas use negatively impacted by lockdowns, a warmer winter in Europe, a sustained period of lower LNG prices and increased competition among gas supply sources that eroded margins and put pressure on gas and LNG producers. Utilisation has fallen further in 2021 due to the ongoing impacts of COVID restrictions and delays to maintenance and unplanned outages.

LNG exports are fairly concentrated. In 2020, Australia was the largest exporter of LNG and accounted for circa 22% of global LNG exports with 77.8 Mt, narrowly outstripping Qatar with 75.4 Mt of global LNG exports. The United States was the third largest exporter in 2020, exporting 44.8 Mt. Four other countries (Malaysia, Nigeria, Russia and Indonesia) together contributed another 25% of global LNG exports:

LNG EXPORTS (MT OF LNG PER ANNUM)



Source: BP Statistical Review of World Energy 2021, BP plc.

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[4] Source: International Group of Liquefied Natural Gas Importers, 2021 Annual Report

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The LNG sector in Australia has undergone a substantial expansion in recent years with a wave of LNG investment in seven new projects between 2014 and 2019. Australia overtook Qatar as the market with the highest liquefaction capacity during 2019 and it remains the largest today. By the end of 2020, Australia's liquefaction capacity, with 21 LNG trains operational, was 87.6 Mtpa nameplate capacity. Woodside Petroleum Limited ("Woodside") is targeting FID on Pluto LNG T2 in 2021. However, as offshore gas fields mature and coal seam gas production declines faster than expected, investment in Australia is focused on upstream backfill projects rather than liquefaction projects. Woodside has proposed to develop the Browse area fields for North West Shelf LNG, the Julimar field for Wheatstone LNG T1-T2, the Pyxis field for Pluto LNG T1 and the Scarborough field for Pluto LNG T2.

As a result of the January 2018 merger between the state-owned Qatargas Operating Company Limited ("Qatargas") and RasGas Company Limited, Qatargas is now the only operator of LNG facilities in Qatar. Qatargas has 14 LNG trains in operation, with a total LNG liquefaction capacity of 77 mtpa.

In August 2021, Qatar awarded Spain's Tecnicas Reunidas a contract for the expansion of its LNG production facilities with the addition of two more trains (in addition to the previously announced four train expansion) and now expects to produce 126 Mtpa from these six new trains by 2027.

The entry of United States based sources of LNG supply has materially affected the global LNG market. Technical advances and regulatory changes have allowed the viable production of shale gas, the consequent identification of substantial resources of shale and other unconventional gas, and rapid growth in unconventional gas production. The availability of significant volumes of low cost gas led to a large number of proposals for the development of LNG export facilities.

The United States had six export facilities (Sabine Pass, Freeport LNG and Corpus Christi LNG in Texas, Cove Point LNG in Maryland, Cameron LNG in Louisiana and Elba Island in Georgia) with 24 trains in service and accounted for all new global liquefaction capacity added in 2020.

It is expected that US LNG will continue to have a significant impact on the global LNG market. Customers from China in particular are likely to be motivated to geographically diversify their sources of supply and access LNG priced off US gas benchmark pricing rather than the oil-based pricing that applies to most LNG contracts in the Asian markets.

While Canada has vast gas reserves, since 2015 most of the proposed Canadian LNG export projects have either been cancelled, integrated into other projects, such as LNG Canada (e.g. the Petronas-led Pacific Northwest LNG and BG's Prince Rupert LNG), or remain active and awaiting FID. There are many reasons that explain why so many US LNG projects have proceeded while Canadian projects have remained stalled. These include feed gas transport costs (given the location of the Canadian gas basins at a considerable distance from the West Coast), indigenous land rights, greenfield versus brownfield construction and environmental issues.

While the impact of COVID-19 has delayed a number of projects, there are other potential new sources of gas supply to come online in the coming years including across Africa and the Asia Pacific. In West Africa, 10.1 Mtpa of liquefaction capacity is currently under construction with the majority coming from onshore greenfield and brownfield LNG projects in Nigeria. There are numerous large gas fields located offshore Mozambique and Tanzania and, in total, 36 Mtpa of liquefaction capacity is proposed in East Africa. In 2021, Total Energies SE ("Total") and the Papua New Guinea government signed a fiscal stability agreement and renewed the retention lease over the large Elk-Antelope gas fields for the dual-train Papua LNG project (5.6 Mtpa). Around 9.5 Mtpa of liquefaction capacity is also proposed at the Adabi LNG onshore development in Indonesia.

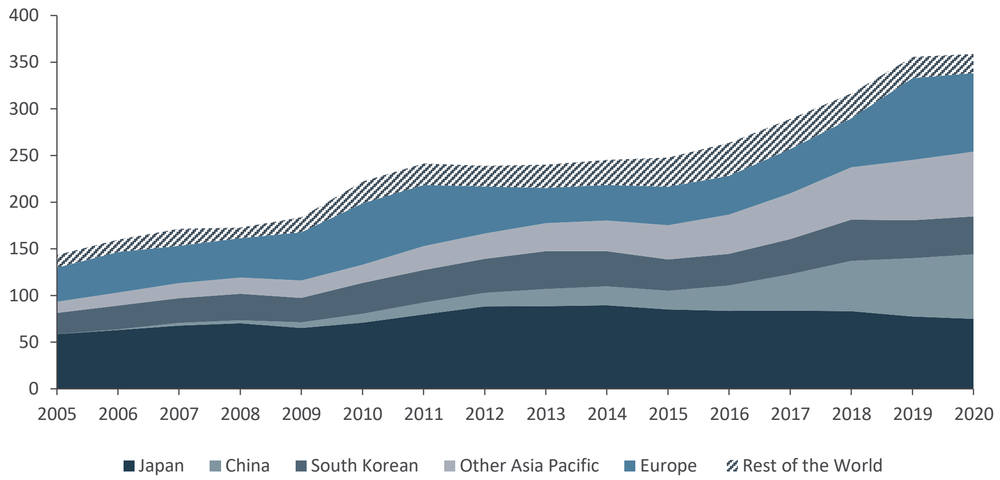
Demand

Japan and South Korea remain major importers of LNG, primarily for power generation. Japan is heavily reliant on LNG and was the world's largest importer of LNG in 2020 (74.4 Mt), ahead of China (68.9 Mt) and

South Korea (40.8 Mt). These three countries together accounted for around 50% of global demand. As industrialised countries with limited domestic energy alternatives, Japan and South Korea are viewed as premium markets for LNG supply.

The following chart shows the dominant share of global LNG consumption that is attributable to the Asian region:

LNG IMPORTS (MT OF LNG PER ANNUM)



Source: BP Statistical Review of World Energy 2021, BP plc.

While Japan and South Korea will continue to be major consumers of LNG, growth in their demand for LNG is likely to be modest and China is expected to become the largest importer from 2021. Other growth in LNG demand is expected to come from India and other Asian countries and, to a lesser extent, Europe. China has implemented a plan to gasify its economy by increasing the share of gas in the energy mix. LNG imports into China in 2020 increased by 11%, largely due to industrial coal to gas conversions and a strong rebound following its first wave of COVID-19. China has stated that it will start phasing down coal use from 2026 to reduce greenhouse emissions in an effort to become carbon neutral by 2060. The resulting increased demand for gas is expected to be met principally by gas imports, both in the form of LNG and by way of gas transported via pipelines from Russia, Central Asia and Myanmar. While China and India are expected to be responsible for much of the LNG demand growth, their access to alternative energy sources may make them more price sensitive and less willing to pay the "security premia" available in traditional Asian markets. On the whole, LNG is expected to continue to have a significant long term role to play in the future energy mix due to its competitiveness compared with other fossil fuels and its ability to facilitate the integration of renewables.

Pricing

LNG projects are characterised by large capital investments and long development lead times. Accordingly, LNG producers and consumers have historically generally entered into long term gas supply contracts of 15 to 20 years or more in duration, both to underpin the funding of the project developments and to provide certainty of supply to LNG consumers. More recently, however, the share of LNG sold on the spot market or under short term (less than two years) and medium term (two to five years) contracts has increased. This development has taken place in the context of rising liquefaction capacity and oil price volatility and is, in part, a result of growing demand, supply and price uncertainty.

LNG prices in most long term contracts are linked to an energy index, with different indices and methodologies used in different regions:

LNG PRICING

REGION	INDEX	COMMODITY
Northern Asia	Japan Crude Cocktail	Crude oil
Continental Europe, United Kingdom	Dutch Title Transfer Facility, National Balancing Point	There has been a shift away from oil-linked pricing in North-west Europe to gas-on-gas pricing
United States	Henry Hub	Domestic gas

Australian LNG suppliers participate principally in the North Asian market, where the major customers are Japan, China, South Korea and Taiwan. Contracts for supply in the North Asian market are generally priced relative to the Japan Customs-cleared Crude benchmark, also known as the Japanese Crude Cocktail ("JCC"). The JCC is the average price of customs-cleared crude oil imports into Japan and is calculated on a monthly basis. The JCC typically moves in line with oil benchmark prices, albeit with a time lag reflecting the timing of deliveries:

BENCHMARK OIL PRICES – BRENT AND JCC ($ PER BBL)

Source: Bloomberg

LNG pricing in the North Asian market is commonly based on the energy relativities between natural gas and oil. One million btu of gas has approximately 17.2% of the energy content of a barrel of Brent oil. LNG pricing is generally based on a discount to oil parity (for example 13-15% rather than 17.2%) reflecting general market demand and supply dynamics and allows for a small discount to account for shipping costs. Some contract arrangements, known as "S-curves", are more complex with flatter slopes at low prices (to protect the seller) and at high prices (to protect the buyer). The diagram below compares a typical S-curve arrangement with the oil parity line. The middle portion of the S-curve has a lower gradient than the oil parity line (13-15% vs 17.2%) and is lower (discount for shipping costs):

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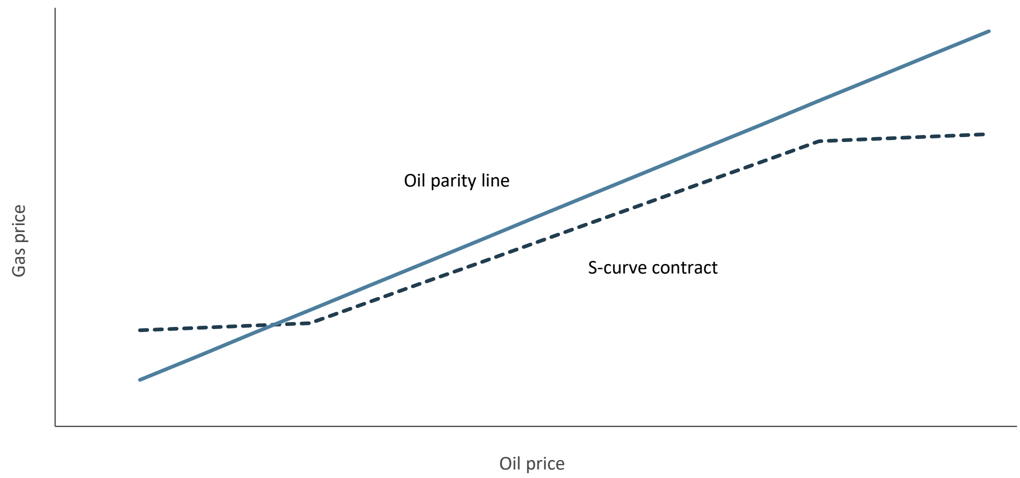
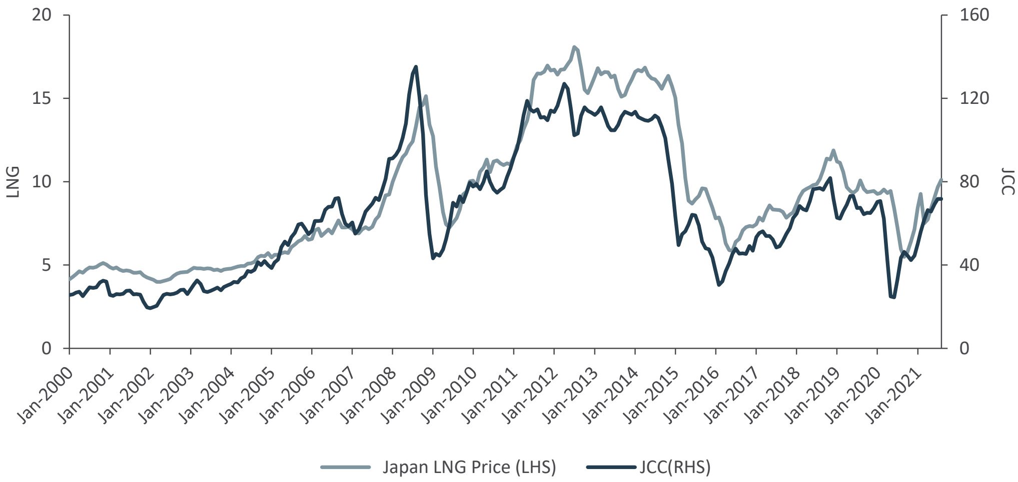
LNG PRICING STRUCTURE



The linkage between oil and LNG prices is further illustrated by the charts below, which compare the historical LNG price for all imports into Japan, reflecting contract and spot sales, with the JCC price:

LNG PRICE ALL IMPORTS INTO JAPAN ($ PER MMBTU) VS JCC PRICE ($ PER BBL)



Source: Bloomberg

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LNG PRICE ALL IMPORTS INTO JAPAN AS A PERCENTAGE OF JCC PRICE[5]

Bloomberg

Between the GFC and December 2014, the price of LNG imported into Japan generally traded within a range of 13-15% relative to the JCC price, albeit with a three-month lag reflecting the timing of deliveries. This is consistent with typical contract terms and the fact that most sales were made under contract with prices linked to the JCC or another oil price benchmark.

While the vast majority of LNG cargoes into north-east Asia continue to be supplied under long-term oil-linked contracts, and new project developments are generally supported by such contractual arrangements, an increasingly liquid spot market for LNG has developed. Spot cargoes are generally priced by reference to the Platts Japan-Korea Marker ("JKM") index, first launched in 2009. The JKM index reflects the spot market value of cargoes delivered into Japan, South Korea, China and Taiwan. In recent years, JKM pricing has been highly correlated with European gas pricing, demonstrating the globalised nature of gas markets. JKM pricing has also been broadly (at least directionally) consistent with oil-based LNG pricing, although through 2021 (and particularly September and October 2021) spot LNG prices spiked dramatically in response to energy shortfalls in both Asian and Europe. Outside of project finance requirements, the structure of longer term LNG contracts may ultimately migrate towards incorporating some direct pricing references to spot LNG, depending in part on the future role of oil in Asian energy systems.

During 2019, a surplus of LNG in Asian markets saw spot LNG prices fall well below LNG prices under long term oil-linked contracts. Conversely, in mid-2020 the JCC price fell below $25/bbl in the face of plummeting demand for oil as a result of the COVID-19 pandemic. The price of LNG imported into Japan was in excess of 20% of the JCC. In January 2021, the spot LNG price into Japan reached record levels on the back of an extremely cold winter in Asia and supply constraints. More recently, there has been a further surge in gas prices in both Europe and Asia, with JKM pricing reaching a daily high of $56 MMBtu in October 2021, although the factors driving the current price rises are likely to be transitory.

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5 Incorporates a three-month LNG price lag reflecting the timing of deliveries.

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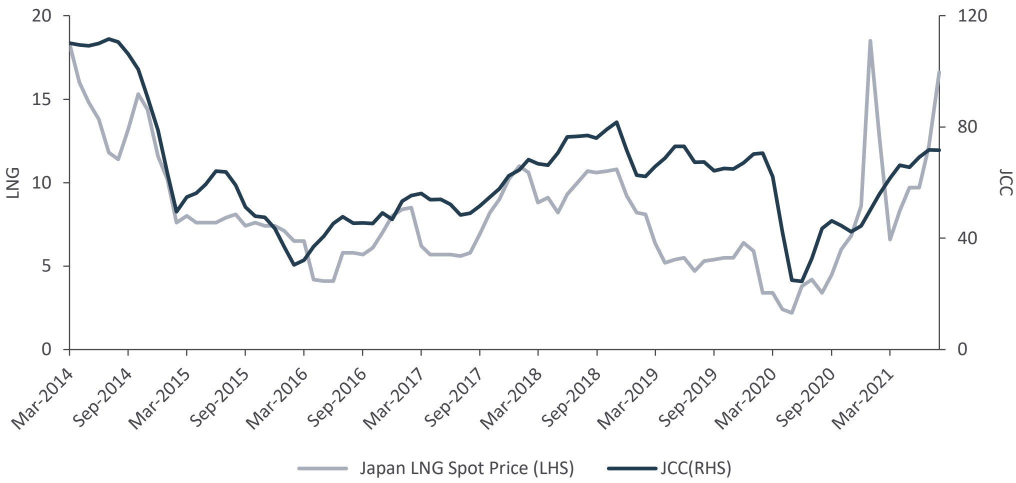
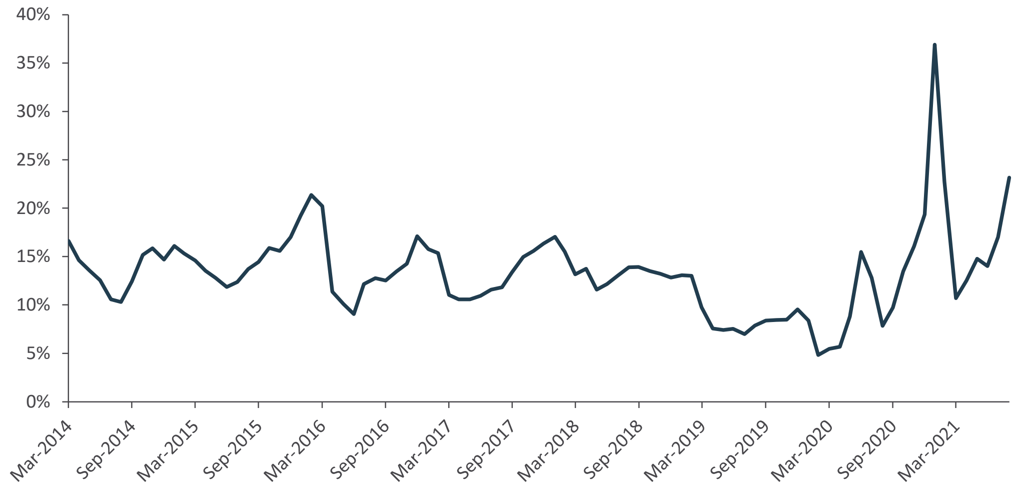
LNG PRICE SPOT IMPORTS INTO JAPAN ($ PER MMBTU) VS JCC PRICE ($ PER BBL)



Source: Bloomberg

LNG PRICE SPOT IMPORTS INTO JAPAN AS A PERCENTAGE OF JCC PRICE



Source: Bloomberg

Outlook

From 2015 to 2020, there was generally ample supply in the global market for LNG. A confluence of factors has resulted in a dramatic turnaround in this position. In particular, the sharp COVID-related fall in energy prices during 2020 (and arguably diminishing investor and financier appetite for the funding of carbon based energy sources) saw a drop in investment in new production in oil, coal and gas.

A prolonged European winter, lower than expected renewables energy production in Europe in much of 2021, a limited energy response from Russia and energy shortfalls in China have seen an overall demand/supply imbalance in global energy markets and a significant increase in demand for LNG to fill short term deficits in energy supplies from other sources. There has been an acute shortage of LNG cargoes across Asia through 2021 and a number of extreme price spikes in spot LNG markets.

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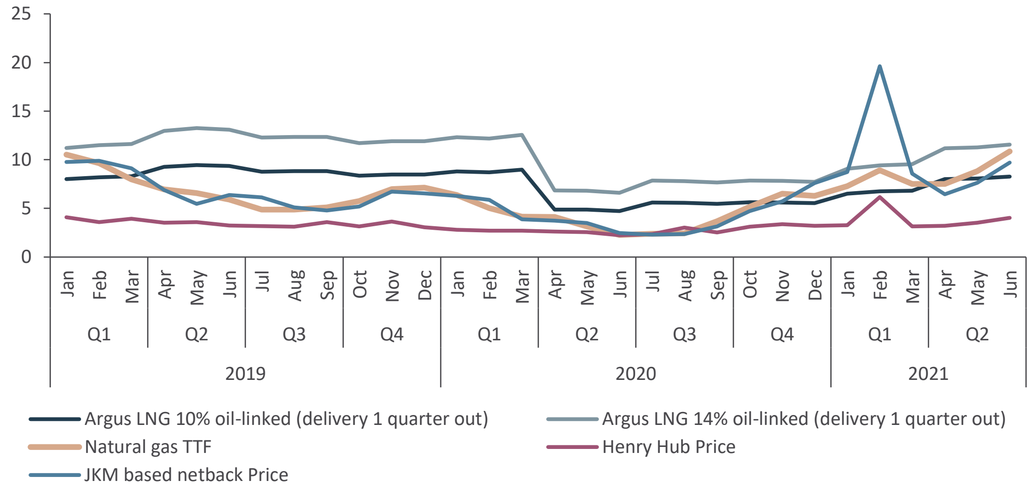
INTERNATIONAL GAS PRICES ($ PER GJ)



Source: Australian Energy Regulator

Extremely high spot LNG prices are unlikely to continue. However, given the 4-5 year lead time post FID for LNG projects to become operational, the LNG market is likely to remain in a supply deficit until the mid 2020s, when approximately 100 Mtpa of new supply projects are expected to ramp up. While a supply deficit provides a positive backdrop for producers with uncontracted LNG or contracts due for renewal, there are a number of factors that complicate forecasts of future LNG pricing in the North Asian market:

- at a global level, the contrast between the growing scarcity of (relatively high cost) oil and the increasingly abundant supplies of inexpensive natural gas suggests that there will be growing pressure to modify and perhaps break the traditional nexus between LNG and oil prices;
- this pressure will be particularly acute when LNG is competing with other gas (potentially delivered by pipeline) or other energy sources. Those countries that are likely to represent the bulk of future LNG demand growth (China and India) are paradoxically likely to be the most price sensitive, given their potential access to other sources of energy. In the case of China, this may include both Russian and Central Asian pipeline gas and domestic sources of unconventional gas;
- an increasingly liquid spot market for LNG may mean that some LNG buyers will be less willing to pay the premium for certainty of supply that is implicit in long term oil-linked contracts;
- global market access to US shale gas has the potential to materially affect the supply/demand balance, and Russia's access to the Northern Sea route in the Arctic region allowing access to the North Asian market;
- estimates of future global LNG demand are highly leveraged to assumptions relating to ongoing economic growth on the part of, in particular, China and India. However, as China transitions from a period of rapid industrialisation to a more sustainable pattern of growth, slower energy demand growth is expected to follow. While growth in industrial energy consumption will likely be, in part, displaced to lower-income economies such as India, China's coal-to-gas switching policy is expected to significantly contribute to its LNG demand growth;
- the restart of Japanese nuclear power stations (to the extent that this occurs) along with increases in end use energy efficiency may mitigate its LNG demand. Conversely, environmental pressures to reduce reliance on coal-fired power, a preference to use gas fired generation to supplement any shortfall in global renewables generation, limited potential for renewables in key north Asian markets

such as Japan and Korea, and the phasing out of nuclear power in South Korea and Chinese Taipei should all provide support for LNG.

On the other hand:

- the LNG business will remain a high capital cost business and will require prices sufficient to incentivise new supply;
- customers that are critically reliant on LNG and have limited alternatives (e.g. the "premium customers" of Japan, Taiwan and South Korea) will presumably continue to attribute considerable value to low risk sources of supply that can provide a high degree of certainty; and
- ongoing underestimation of gas requirements by buying countries and/or reluctance by LNG producers to build new projects due to low price signals may result in demand/supply imbalances and erratic price movements over time.

Many market commentators have focussed on the impact of a growing US LNG export business on the global LNG market, both in terms of contract pricing structure and absolute pricing levels.

The contractual arrangements for customers of US LNG export facilities are very different from the North Asian long-term contract arrangements with integrated projects under which Australian LNG producers supply LNG. US LNG export facilities generally operate on a flexible tolling basis, whereby customers will:

- acquire their own gas in the US market, linked to Henry Hub benchmark prices;
- arrange and pay for the transport of that gas to the liquefaction facility;
- bear the cost of the gas used in the liquefaction process ("fuel gas");
- pay a capacity charge on a "take or pay" basis for liquefaction of the gas; and
- arrange and pay for the shipping of the LNG to its ultimate destination.

The consequence will be that almost all of the supply side risks will be passed on to the customer, including Henry Hub pricing risk and continuity of supply risk. In a worst case, customers would continue to be liable to pay capacity charges notwithstanding supply interruptions. Even in contractual arrangements in which the risks were more evenly shared (e.g. where LNG was sold on a free on board ("FOB") basis), end users (including customers) are likely to be exposed to full Henry Hub pricing risk.

By contrast, North Asian long-term contracts are structured to essentially relieve the customers of as much risk as possible, with cargoes generally delivered on a Delivered Ex Ship ("DES") basis, with the supplier responsible for all costs and bearing all risks until the cargo arrives at the destination port.

Until recently, the supply of large volumes of US-sourced gas based on Henry Hub pricing appeared to have significantly disrupted the global LNG market and to have exerted sustained downward pressure on LNG prices, including into the Asian market. The abundance of associated gas from shale oil being produced and exported from the US has made Henry Hub a global gas price reference. However:

- after accounting for capacity (i.e. liquefaction) charges and costs for shipping to Asian markets, and adjusting for the incremental risks borne by end users or customers in import countries under the US LNG supply arrangements, US-sourced LNG may not be materially cheaper than LNG priced on a traditional oil-linked basis;
- substantial sales of US gas for LNG export may, in any event, drive up US gas prices, eroding some of the apparent price advantage of Henry Hub-priced gas; and
- most operational US LNG projects are based on the conversion of mothballed LNG import facilities into export facilities, and the take-or-pay capacity charges negotiated to date reflect the relatively modest capital costs of these brownfield conversions. However, current proposed LNG developments

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are mostly greenfield sites, potentially involving much higher capital costs. The higher capacity charges required to recover these higher capital costs may also undermine the price advantage of US-sourced LNG.

There appears to be little doubt that, over time, continued growth of US LNG exports and other new sources of LNG supply (including East Africa and Canada) will affect the global LNG market, although the magnitude and timing of this impact is uncertain. It is possible that Asian LNG customers will choose to diversify their sources of supply, both in terms of geographic location and pricing structures. Supply agreements, outside of project financing constraints, may reflect "hybrid" pricing arrangements, referencing oil prices, Henry Hub gas prices and/or spot pricing. Some potential new suppliers of LNG (particularly participants in the East African gas fields that are not currently significant LNG suppliers) may be motivated to attempt to break down existing market structures and pricing mechanisms. However, LNG pricing will continue to reflect the high costs of liquefaction capacity and certain customers will presumably continue to be prepared to pay a premium for security of supply and quality of product. It is conceivable that a future market imbalance, perhaps resulting from a material demand shock and/or growth in supply from new participants, could have a more pronounced effect on the LNG market in terms of structure and pricing. However, there is unlikely to be any major change to the North Asian market in the short to medium term as macroeconomic forces continue to drive growth in demand and the majority of existing contracts are long-term, oil price-linked contracts.

1.4 Domestic Gas Market

Background

Over the past four decades, natural gas has grown to become an important source of energy in Australia as the country has progressively moved away from its historical reliance on coal-fired power. In 2020, gas accounted for nearly 27% of the country's energy mix[6].

As the management of energy resources, production and supply of energy and stability of energy markets are critical to the economy, the sector remains subject to regulation (now generally harmonised nationally). The Energy Council of the Council of Australian Governments is responsible for harmonisation of regulatory arrangements and energy market reform. The Energy Council (and its predecessors) has created three agencies to separate the major functions for the energy market as follows:

- **Australian Energy Market Commission ("AEMC")**, which is responsible for rule making and market development;
- **Australian Energy Regulator ("AER")**, which is responsible for monitoring and regulating electricity and gas transmission and distribution networks and retail markets. Western Australia has opted not to transfer regulatory responsibility for its energy markets to the AER (but has adopted a modified version of the National Gas Law for which the Economic Regulatory Authority of Western Australia ("ERAWA") has regulatory responsibility) and in the Northern Territory the AER has not been empowered to perform functions relating to energy retailing; and
- **Australian Energy Market Operator ("AEMO")**, which operates the National Electricity Market ("NEM") and the retail and wholesale gas markets of eastern and southern Australia.

As a result of these legislative changes, over the last three decades Australia's energy sector has transformed from an amalgamation of state based enterprises into a privatised and integrated energy network across jurisdictions. The domestic gas industry is segmented into three distinct regional markets, each supported by their own gas reserves and integrated processing and supply transmission infrastructure. Gas consumption varies across the different states and territories due to a range of factors such as the relative availability and price of other energy sources. The East coast market is the largest of

6 Source: Department of Industry, Science, Energy and Resources, Australian Energy Statistics, September 2021

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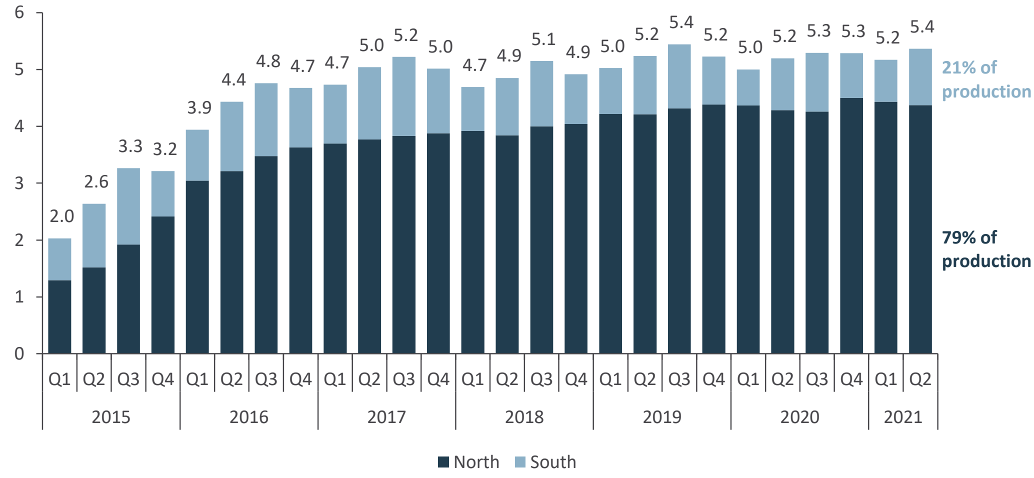
these markets and comprises an integrated network across Queensland, New South Wales, South Australia and Tasmania. This market accounts for more than 50% of domestic gas consumption and about 30% of gas reserves. The West coast market covers Western Australia and accounts for approximately 40% of domestic gas consumption and over half of the country's gas reserves. The Northern Territory market is the smallest domestic market.

EAST COAST MARKET

Supply

The East coast market is estimated to hold more than 34,000 PJ of 2P gas reserves and more than 56,000 PJ of 2C gas resources. More than 80% of available 2P reserves are located in coal seam gas fields in the Bowen and Surat Basins in Queensland[7], as mature conventional gas fields in the southern state gas basins (e.g. Cooper Basin, Gippsland Basin and Otway Basin) have gradually been depleted in recent years. The Cooper and Eromanga Basins still retain significant areas of prospective resources but are subject to further drilling and assessments before they can be upgraded to 2C resources. This geographical spread of reserves is broadly aligned with relative gas production across the states. Gas flows have generally become southbound as the Queensland gas fields are net exporters of gas into the southern states[8].

EAST COAST MARKET – HISTORICAL SOURCE OF SUPPLY BY REGION (PJ PER DAY)[9]



Source: Australian Energy Regulator, Wholesale Markets Quarterly Q2 2021

The development of three LNG export facilities in Gladstone, Queensland, which in turn were based on the development of extensive coal seam gas ("CSG") fields in regional Queensland, has profoundly affected the demand/supply dynamics of the East coast market. These LNG plants introduced an export alternative to selling gas into the domestic market, thereby at least in part integrating the eastern Australian gas market with international gas markets. Domestic gas customers now compete with international markets, where LNG prices, which have been directly or indirectly oil price linked, have historically been higher that East coast gas prices on a net-back basis. Gas producers are incentivised to sell excess uncontracted gas into the domestic market only when local gas prices are competitively aligned with LNG export prices[10]. This has led to significant rises in domestic gas prices.

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7 Source: AEMO, *Gas State of Opportunities*, March 2021
8 Source: Australian Energy Regulator, Wholesale Markets Quarterly, Q2 2021
9 North includes Roma, Moomba and Ballera. South includes all other production in the East coast market
10 Source: ACCC, LNG netback review – Final Decision Paper, September 2021

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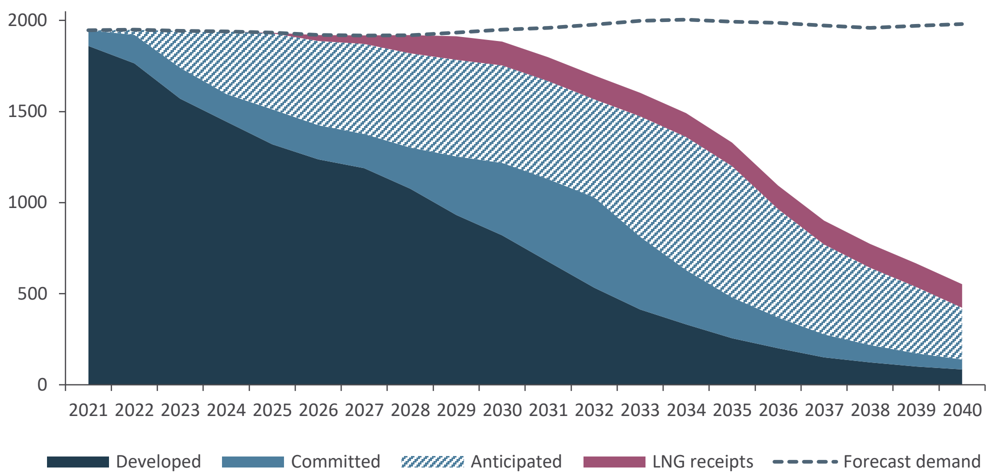
The Australian Domestic Gas Security Mechanism ("ADGSM") was introduced in July 2017 to enable the Federal Government to directly intervene and impose LNG restrictions until 2023 during years that have been declared supply "shortfall years". While the ADGSM has not been enacted since its introduction, the Federal Government has periodically entered into Heads of Agreements with LNG producers to ensure that they would first offer sufficient gas to the domestic market on reasonable terms to meet any expected supply shortfalls.

The outlook for gas supply is summarised graphically below:

EAST COAST MARKET – FORECAST GAS SUPPLY, CENTRAL SCENARIO (PJ)



Source: AEMO, Gas State of Opportunities, March 2021

The near-term supply and demand outlook for domestic gas remains in a delicate balance and dependent on the ability of producers to develop 2P reserves and to develop contingent resources in the time frames required to meet demand. Moreover, any fluctuation in LNG export allocation or gas powered generation demand could easily tip the tight balance into a supply shortfall. The January 2021 Heads of Agreement is expected to help alleviate the expected supply shortfalls in the coming year.

However, upstream supply is expected to remain constrained due to current government regulations on exploration and development of onshore gas resources (particularly in New South Wales and Victoria) as well as the decline in production from offshore Victoria. The NSW Government's 2021 *Future of Gas Statement* reiterated this policy stance as the area available for gas exploration was reduced by more than 75%[11]. Consequently, domestic wholesale gas consumers have been considering alternatives to secure gas supply such as the importation of LNG (e.g. the proposed facilities at Crib Point, Victoria and Port Kembla, New South Wales), development of new gas basins (e.g. Santos' Narrabri Gas Project) and capacity expansion of existing midstream assets and pipelines.

As existing gas reserves decline, investment in exploration and development will be required to deliver contingent and prospective gas resources. This will involve substantial investment in gas infrastructure including transmission pipelines and midstream gas processing plants.

Demand

Gas represents approximately 18% of overall energy needs across the East coast market. While gas is more highly utilised in South Australia (circa 35% of energy mix), gas usage in New South Wales, Victoria, Queensland and Tasmania is significantly lower[6].

[11] Source: NSW Government, Future of Gas Statement, 2021

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Historically, gas demand on the East coast was nearly evenly split across industrial, residential and commercial, and electricity generation use. Since 2015, the commissioning of the three LNG export projects at Gladstone has led to a sharp increase in gas demand, which nearly tripled in three years. The majority of this growth related to gas earmarked for LNG exports. Due to a range of factors, including higher gas prices (due to the linkage to the LNG export market) and the progressive shift to renewable energy, domestic gas consumption in the East coast market has declined steadily since 2014 at an average rate of 3% per year.

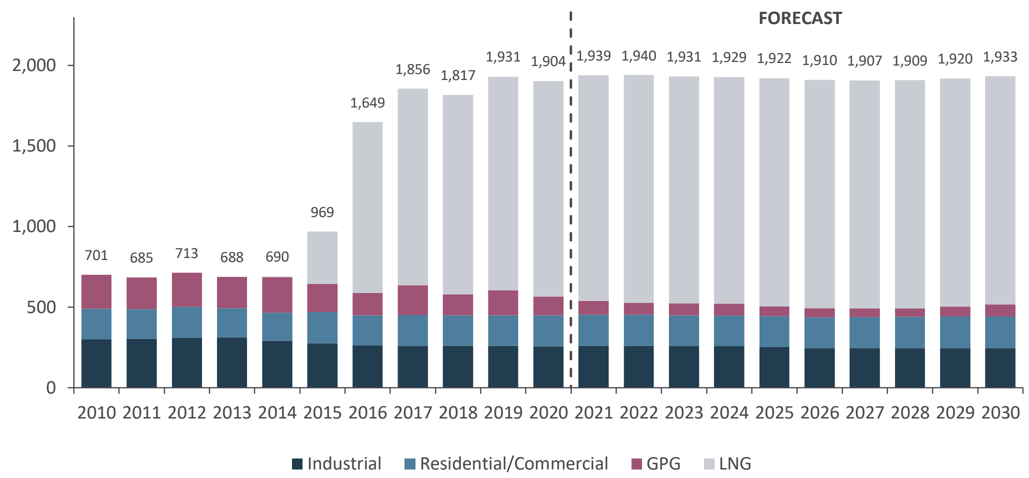
The outlook for domestic gas consumption remains uncertain. According to AEMO, gas consumption is more likely to decline or, at best, remain flat due to:

- increasing availability of renewable energy generation in the NEM;
- potential closures of industrial users due to extended weak economic conditions and high gas prices; and
- long-term potential to be displaced by hydrogen fuel substitution.

These risks are offset by the expected reduction in generation capacity of coal-fired power as well as the requirement for gas-fired power to provide seasonal peaking energy during hot summer months (i.e. high energy needs for cooling) and winter months (i.e. lower efficiency of renewable assets).

AEMO's projections for consumption to 2030 are presented in the following graph:

EAST COAST MARKET – HISTORICAL AND FORECAST GAS CONSUMPTION, CENTRAL SCENARIO (PJ)



Source: AEMO, Gas State of Opportunities, March 2021

Pricing

Gas has historically been sold in Australia under confidential bilateral long term contracts between producers and downstream buyers, but in recent years there has been a move towards shorter term contracts, the inclusion of review provisions in contracts and the emergence of facilitated spot markets in eastern Australia[12]. Wholesale gas prices reflect a range of factors including cost of production, contract volume, available reserves, length of contract, price escalations, flexibility and typically include some

[12] Victoria operates a spot market in which approximately 5-15% of Victorian wholesale gas volume is traded. Short term trading markets commenced in Sydney and Adelaide in September 2010 and in Brisbane in December 2011. These markets provide a spot mechanism to manage contractual imbalances and not prices that would be agreed under longer term arrangements. AEMO has also established gas trading exchanges at Queensland's Wallumbilla gas pipeline hub (in March 2014) and at South Australia's Moomba gas pipeline hub (in June 2016), the aim of which is to promote transparent and efficient trading. However, trading at the hubs is relatively thin and pricing can be volatile. As a result, these market mechanisms sit alongside bilateral contracts rather than replacing them.

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adjustment for inflation or periodic price reset. Contracted gas prices have generally been set at a premium over wholesale spot prices because of the need for supply certainty over the contract duration. Wholesale spot prices are subject to higher volatility since they reflect excess demand or supply at any given point in time and are typically for a smaller volume[13].

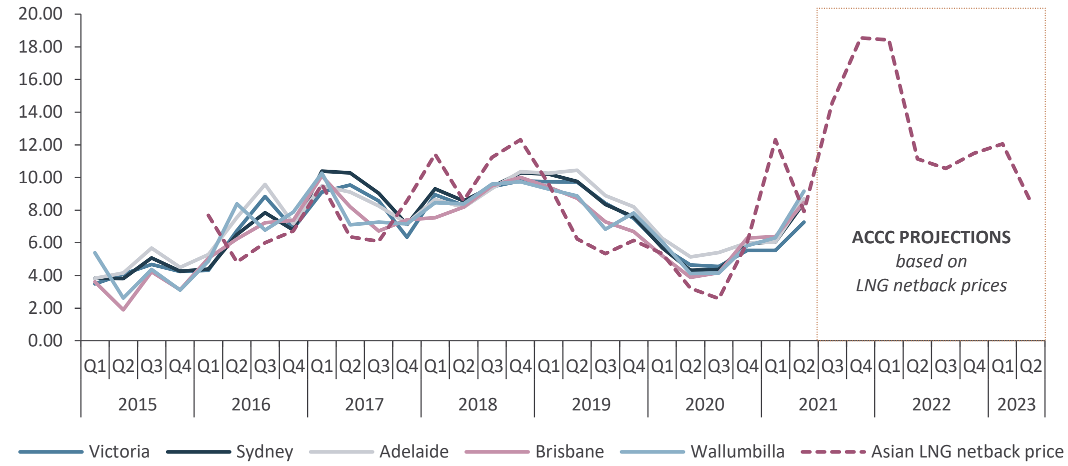
Australian gas prices have historically been low relative to international prices due to the abundant coal and natural gas reserves and geographic isolation. However, over the last decade, wholesale gas prices have risen materially reflecting:

- the run off of existing long term gas supply contracts;
- the commissioning of the three LNG export facilities in Gladstone in 2015/2016. As noted above, this has at least partially integrated the eastern Australian gas market with international gas markets. Domestic gas customers now effectively compete in international markets and gas prices are increasingly being shaped by LNG netback prices[14], which in turn are closely related to the oil price;
- rising domestic gas production costs; and
- a demand/supply imbalance in eastern Australia resulting from:
  - a slower than expected CSG well development program for GLNG, which required GLNG to purchase gas for LNG export that would otherwise have been available to the domestic market;
  - the depletion of traditional sources of gas for the domestic market (e.g. the Otway and Bass Basins in Victoria);
  - lower international oil prices, which have reduced the economic incentive for gas exploration and new project development; and
  - constraints on the exploration for, and development of, onshore gas resources as a result of government environmental restrictions in New South Wales, Victoria, Tasmania and (until recently) the Northern Territory (in some cases amounting to blanket prohibitions and in some cases more limited (e.g. in relation to hydraulic fracturing processes ("fracking") used in production from some unconventional gas fields).

Notwithstanding these overarching trends, slower economic and industrial activity in 2020 and the fall in Asian LNG spot prices resulted in a reduction in domestic gas prices in 2020. Gas prices resumed their decade-long increase in 2021 as the tightening Asian LNG market have pushed prices higher. In addition, unplanned outages of coal-fired power generators (i.e. Callide), weaker wind energy generation and midstream storage supply constraints have further buoyed prices in the past nine months.

[13] Source: Reserve Bank of Australia, Understanding the East Coast Gas Market, 2021
[14] LNG netback price is the LNG export price less shipping and liquefaction costs.

EAST COAST MARKET – HISTORICAL AND FORECAST DOMESTIC GAS PRICES (A$/GJ)



Source: Australian Energy Regulator, Wholesale Markets Quarterly Q2 2021

LNG netback prices in eastern Australia are expected to continue rising in the near term, reflecting strong global gas demand on the back of increased industrial activity in Asia and a spike in LNG demand because of energy shortages across Europe. Wholesale gas prices will follow this trend but will be constrained by affordability issues (certainly at above A$10/GJ). In the longer term, future gas prices in eastern Australia will depend on the interaction of a range of complex factors including:

- continuation of the growth in demand for energy in Asia;
- the global demand/supply balance for LNG (with LNG prices also closely related to the oil price);
- the growth in demand for energy in Australia (which is expected to moderate as the energy intensity of the economy decreases);
- the demand in Australia for gas to generate electricity, which will be affected by government energy and climate change policies (e.g. further coal fired generation asset retirements, renewable energy targets, the level of renewable asset development) and the balance between base load and intermittent sources of electricity; and
- the quantum and timing of new domestic gas supply, which will be affected by:
  - changes to state government environmental restrictions, which have impeded onshore exploration and development;
  - whether higher gas prices stimulate gas development projects (which are otherwise economically marginal); and
  - the time required to bring new supply to market; and
  - the development of LNG import terminals on the east coast which would increase the volume of gas in the domestic market and offer gas buyers an alternative source of supply.

WEST COAST MARKET

Supply

The development of Western Australia's gas industry was underpinned by the State Government's investments in key upstream assets and in transmission infrastructure. This included underwriting the development of the North West Shelf gas project in the 1980s via a long-term supply contract and the

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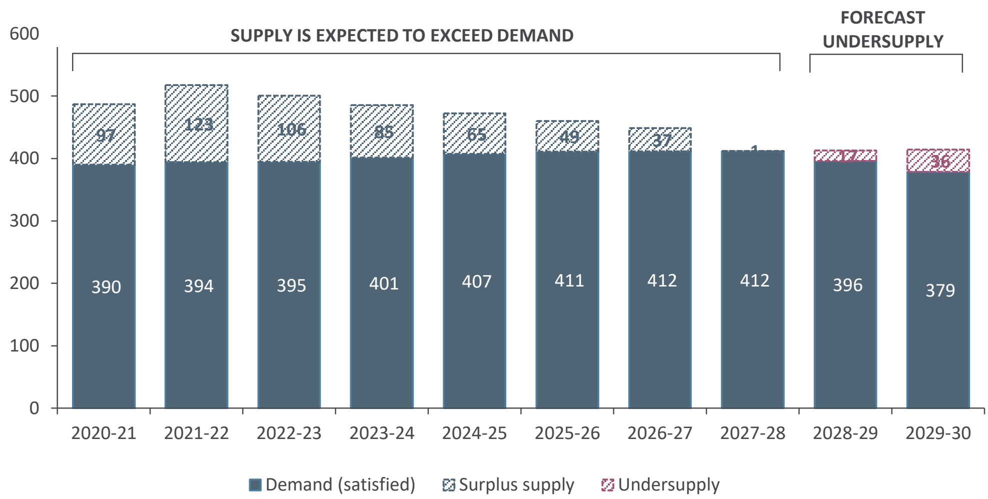
financing of the Dampier to Bunbury Natural Gas Pipeline that connected the gas reserves in the Carnarvon Basin to key population centres at the southwestern end of the state. Today, Western Australia's domestic gas is supported by an integrated supply chain of offshore gas fields, gas processing facilities, multi-user gas storage facilities and gas transmission pipelines.

Western Australia is estimated to hold 143 tcf of conventional and unconventional (e.g. shale) gas resources. Upstream supply is predominantly sourced from offshore gas fields such as those in the Carnarvon Basin and is supplemented by other gas fields in the Browse Basin, Bonaparte Basin and, to a lesser extent, the Perth Basin. While the majority of gas reserves are ultimately used by LNG producers, the Western Australian government introduced the Domestic Gas Policy in 2006 to ensure that domestic consumption needs are still met. This requires LNG project proponents to reserve and actively market gas equivalent to 15% of LNG exports for domestic consumption within the state[15]. In effect, this policy generally requires domestic gas plants to be constructed as part of the LNG project.

There are nine gas production facilities that supply the West coast gas market with an aggregate nameplate capacity of 1,838 TJ per day. These includes Varanus Island, Devil Creek and Macedon, which collectively constitute approximately 40% of total capacity. Production at each of the facilities is heavily influenced by individual gas supply contracts with large industrial and mining users as well as seasonal variations in demand. Recent investments in new processing capacity have provided ample capacity to support domestic consumption needs. For example, the Chevron-operated Wheatstone Gas Project delivered its first domestic gas in 2017. Woodside is also evaluating the brownfield expansion of its Pluto LNG project to construct a second gas processing train. In 2020, average utilisation across the facilities was well below nameplate capacity, or at approximately 60%.

AEMO projects the West coast gas market to be adequately supplied over most of the next decade, with supply expected to exceed demand through 2026 by more than 20% over that period. New domestic gas sources such as Waitsia stage 2 and West Erregula are expected to launch over the next decade to bring additional supply into the domestic market.

WEST COAST MARKET – FORECAST GAS SUPPLY-DEMAND BALANCE (PJ)



Source: AEMO, 2020 Western Australia Gas Statement of Opportunities, December 2020

[15] Source: State Government of Western Australia, WA Domestic Gas Policy

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Over the long term, AEMO expects that satisfaction of demand will require producers to identify new sources of supply through:

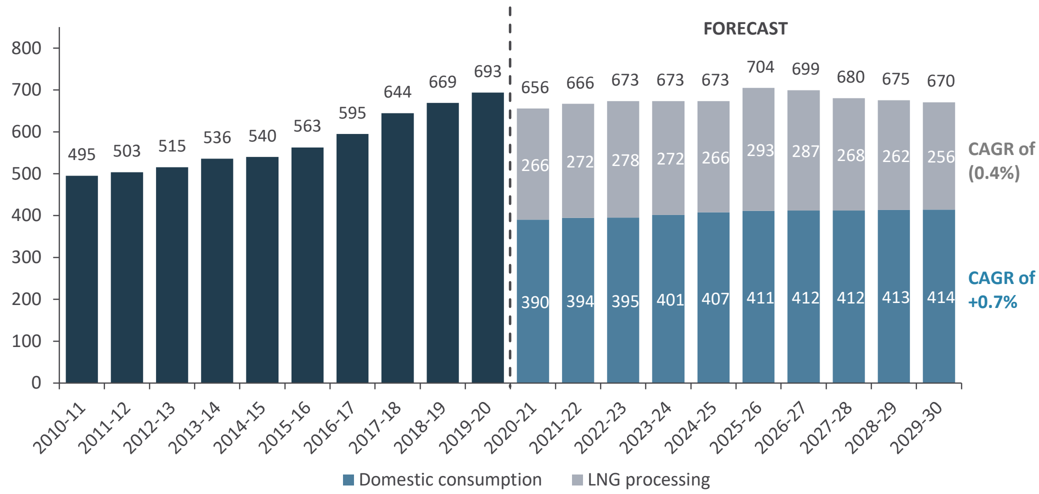
- continued drilling and exploration at existing gas fields to identify additional reserves;
- development of identified gas fields that may be connected to existing gas production facilities; and
- investments in exploration and drilling activities to uncover new gas fields.

Demand

Over the past decade, gas has been the primary source of energy in Western Australia and has accounted for over 50% of the state's energy needs[6]. The majority of demand (approximately 58%) is from large industrial and resources companies that enter into bilateral long-term gas sales contracts with suppliers. These include mine sites (e.g. iron ore and gold), mineral processing facilities (e.g. alumina refineries) and large industrial users (e.g. brickworks and cement manufacturers). The balance is sold to domestic gas-power generators and residential and commercial customers.

AEMO expects demand to continue to grow at an average rate of 0.7% per year due to the growing demand in the resources sector. As of December 2020, there were at least five committed resources projects[16] that were expected to add another 40 TJ per day of gas demand by 2023 (additional demand of approximately 3.5%).

WEST COAST MARKET – HISTORICAL AND FORECAST DOMESTIC GAS CONSUMPTION, BASE SCENARIO (PJ)



Source: AEMO, 2020 Western Australia Gas Statement of Opportunities, December 2020

Pricing

Gas sales in the West coast market are typically sold under confidential bilateral long term contracts between producers and downstream buyers.

Wholesale gas prices in Western Australia have trended lower since 2016 and below average gas prices in the East coast market. The stability of prices can be largely attributable to the domestic gas reservation policy and strong wave of investments in LNG infrastructure and consequently domestic gas processing capacity.

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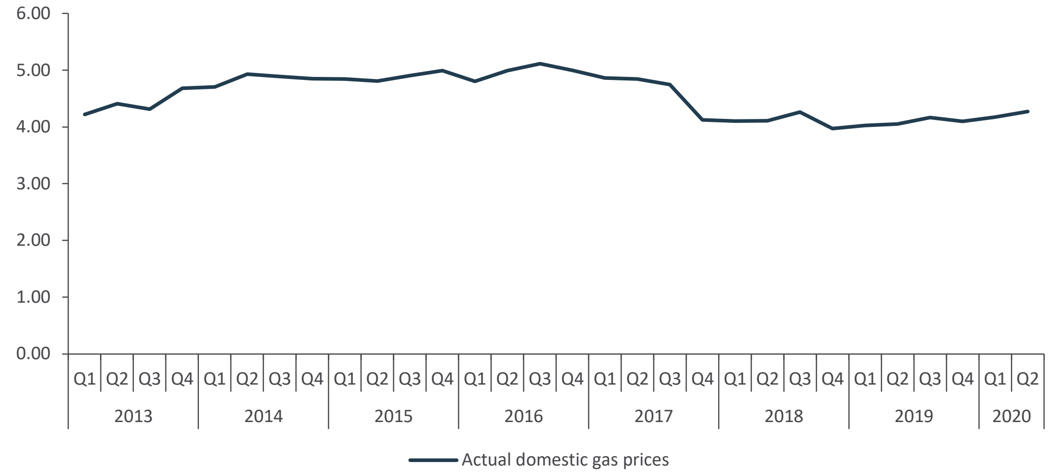
[16] These include Albemarle Corporation's Kemerton lithium processing plant, Rio Tinto's Gudai-Darri iron ore project, FMG Magnetite and Formosa Steel IB's Iron Bridge magnetite processing project, Capricorn Metal's Karlawinda Mine and Kalium Lake's potash project

WEST COAST MARKET – HISTORICAL DOMESTIC GAS PRICES (A$/GJ)



Source: AEMO, 2020 Western Australia Gas Statement of Opportunities, December 2020

Domestic wholesale prices in the West coast market are expected to remain at a discount to the East coast market due to the greater availability of supply resulting from the gas reservation policy. However, studies by Core Energy & Resources suggest that prices could increase by approximately A$1 per GJ between 2021 and 2033 due to the partial influence of LNG netback prices on domestic prices in the West coast market[17].

[17] Source: Core Energy & Resources, *Delivered Wholesale Gas Price Outlook 2020-2050*, December 2019. Core Energy & Resources has been engaged by AEMO to provide annual projections of wholesale delivered prices. The scope of the study pertains only to residential & commercial and gas powered generator consumption

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APPENDIX 2

OIL AND GAS INVESTMENT IN PAPUA NEW GUINEA

1 PNG Overview

Papua New Guinea comprises the eastern half of the island of New Guinea and 600 adjacent islands covering a combined area of 463,000 km^2, situated between the Coral Sea and the South Pacific Ocean. PNG has a population of approximately 9 million,[1] comprising over 1,000 distinct ethnic groups speaking over 800 languages. Less than 15% of the population lives in urban centres and approximately 5% of the population lives in PNG's capital Port Moresby, located in the southeast region of the mainland. As the majority of the population lives in traditional tribal societies that practice subsistence-based agriculture, employment statistics are not particularly relevant. PNG's terrain is extremely rugged, which has contributed to the continuation of a strong tribal social structure and hampered the development of infrastructure and of the country's rich mineral and oil and gas resources.

PNG became a sovereign state and member of the Commonwealth of Nations in 1975. It is a parliamentary democracy under a constitutional monarchy. The legal system is based on a mix of English common law and customary PNG law. Since taking power in May 2019, Prime Minister Marape has commissioned inquiries into several resources projects in PNG and made legislative changes to gain more favourable benefits for the state and landowners. This has ultimately resulted in protracted negotiations in relation to tenure or fiscal arrangements for a number of major mining and oil and gas projects, including in relation to the development of P'nyang and has resulted in the shut-in of the Porgera mine and consequently the Hides GTE operations.

PNG's economy is largely reliant on export-based agriculture, fishing and the extraction of its oil and gas and mineral resources. The country has enjoyed annual GDP growth of 5.2% over the last decade,[2] supported by the construction and operation of the PNG LNG Project. Notwithstanding strong historic GDP growth, agriculture remains a source of subsistence livelihood for the majority of PNG's inhabitants. Inflation has been in the range 3.6% – 6.7% over the past 10 years.[3]

2 Oil and Gas Licensing

The PNG oil and gas licensing regime provides for three types of petroleum licences, corresponding to the various stages of project development (exploration, commercial feasibility assessment, and development and production):

- Petroleum Prospecting Licence ("PPL") – initial six-year exploration period with a possible five-year extension period. 50% of the original area is relinquished at the end of the initial term;
- Petroleum Retention Licence ("PRL") – initial five-year period with two possible five-year extensions for discoveries for which commercial viability has not yet been demonstrated; and
- Petroleum Development Licence ("PDL") – 25-year term with possible 20-year extensions.

PRLs only apply to gas discoveries as oil discoveries transition directly from a PPL to a PDL when development commences. Rental fees are payable but charges are minimal.

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1 World Bank
2 Grant Samuel analysis based on World Bank data
3 World Bank

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3 Oil and Gas Fiscal Regime

The fiscal regime for petroleum assets is based on a combination of royalties, taxes and levies. Petroleum licences are governed by concession terms in scenarios where the participants have entered into a Gas Agreement and a Fiscal Stability Agreement with the State. The fiscal and regulatory terms under which the PNG LNG Project operates are set out in the May 2008 State Gas Agreement. The agreement covers a total gas volume of 10.5 tcf. The producing PNG LNG oil fields are covered by the fiscal regime contained in the State Gas Agreement upon their conversion to gas fields, and until that time are subject to the fiscal regime set out in current tax legislation and Oil and Gas Act. A separate gas agreement covering the Papua LNG (Elk-Antelope) expansion has been agreed between the PRL 15 joint venture parties and the State of Papua New Guinea. The Papua LNG agreement covers a total gas volume of 10.3 tcf with an option to renegotiate once those volumes are processed.

The following taxes apply to Oil Search's oil and gas assets in PNG:

- a 2% royalty based on the wellhead value of the products sold, treated as a tax credit for the PNG LNG Project but to be treated as a tax deduction for Papua LNG and other projects;
- a 2% social development levy based on the wellhead value of the products sold, treated as a tax deduction;
- a 2% production levy for Papua LNG, based on the wellhead value of the products sold, treated as a tax deduction;
- a Corporate Income Tax ("CIT"), which is applied at a rate of 30% of taxable income on all resources projects; and
- the additional profits tax ("APT"), which applies to all resources projects at a rate of 30% of post-tax cash flows after adjustment for an annual 15% accumulation rate uplift for any annual carry forward APT loss amount, unless there are conflicting fiscal stability clauses. It applies as follows to the PNG LNG Project and Papua LNG:
  - PNG LNG Project – a two tier calculation, with Tier 1 subject to a rate of 7.5% of post-tax cash flows after adjustment for an annual 17.5% accumulation rate uplift for any annual carry forward Tier 1 APT loss amount, and Tier 2 subject to a rate of 10% after adjustment for an annual 20% accumulation rate uplift for any annual carry forward Tier 2 APT loss amount; and
  - Papua LNG – 15% of post-tax cash flows after adjustment for an annual 15% accumulation rate uplift for any annual carry forward APT loss amount.

Oil and gas assets are subject to indirect taxes and withholding taxes unless otherwise exempted by an agreement with the State. In particular, the PNG LNG Project and the Papua LNG Project are exempt from withholding taxes on interest payable on borrowings (non-resident only for Papua LNG Project) and on dividends paid.

The Government has the option to acquire up to 22.5% in a project upon the granting of a PDL, of which 2% is allocated to the local landowners. The acquisition price is equal to a pro-rata share of the sunk costs.

The Marape-led government has flagged its intention to change the current concession-based licensing regime to a production-sharing contract or hybrid regime, to improve the state's share of benefits. This could result in a fundamental change in resource development in PNG for resources projects that are not fiscally stabilised. In addition, PNG Treasury is currently working on a rewrite of the PNG Income Tax Act to modernise and simplify the income tax laws of PNG. If enacted, the laws are proposed to apply with effect from 1 January 2023.

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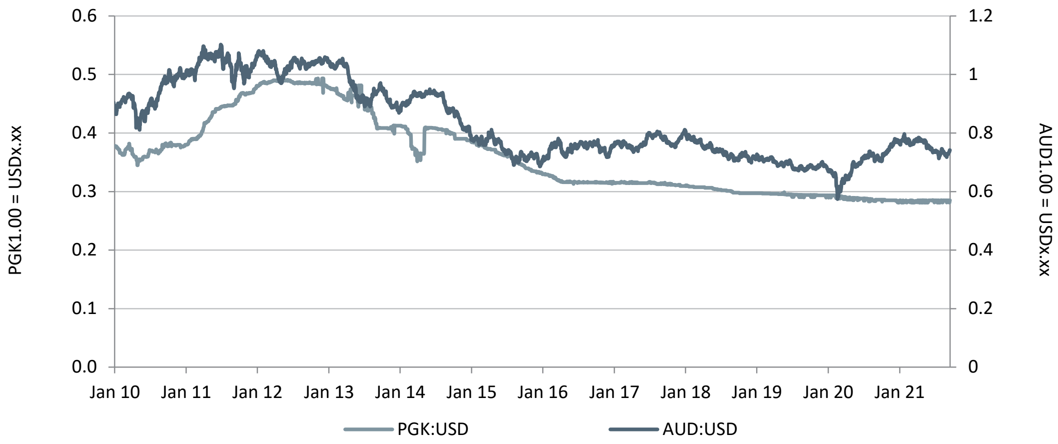
4 Currency

The PNG currency is the Kina. The performance of the Kina and the Australian Dollar against the US dollar over the past 10 years is illustrated on the following chart:

KINA AND AUSTRALIAN DOLLAR VS US DOLLAR



Source: IRESS

The Kina and the Australian dollar traded at historical highs against the US dollar in the years following the GFC, reflecting factors including strong commodity prices, record low interest rates in the United States and demand for Kina during the PNG LNG construction period. In recent years, however, both currencies have trended towards longer term averages and shown more stability.

The Kina and Australian dollar were at historical highs during the peak construction period for the PNG LNG Project, which resulted in a $1.4 billion increase in construction costs between December 2009 (FID) and November 2012. The Kina (and the Australian dollar) subsequently fell from March 2013 to December 2015, which resulted in an easing of cost pressures. The Bank of PNG controls the PGK:USD rate and, in June 2014, it introduced a new foreign exchange policy that included a revaluation of the Kina against the US Dollar by 22% higher than the commercial rate. Since then it has gradually trended down to around 0.28. Although there is a lack of demand for Kina (shortage of foreign currency), this foreign exchange policy has maintained a degree of stability for the Kina. In contrast, the Australian dollar has been relatively stable apart from a dip to a 17-year low of 0.57 on 19 March 2020 related to the COVID pandemic. The Australian dollar has since recovered, in large part due to commodity prices and interest rates, and is currently around 0.73.

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APPENDIX 3

PROFILE OF OIL SEARCH ASSETS

1 PNG LNG

1.1 Overview

The PNG LNG Project is an integrated LNG project operated by ExxonMobil PNG Limited, a subsidiary of Exxon Mobil Corporation ("ExxonMobil"). The project extracts gas (and condensate) from gas and oil fields located in the Highlands of PNG and liquefies the gas for export at two LNG trains, with a combined nameplate capacity of 6.9 Mtpa, located near Port Moresby. The PNG LNG Project is expected to produce more than 11 tcf of LNG over its 30+ year life, although opportunities exist for expansions and life extensions. It is the largest development ever undertaken in PNG.

The project is held in a joint venture ("PNG LNG JV") between ExxonMobil (33.2%), Oil Search (29.0%), Santos (13.5%), JX Nippon Oil & Energy Corporation ("JX Nippon") (4.7%), the PNG Government (16.8% held through Kumul Petroleum Holdings Limited ("Kumul")) and landowners (2.8% held through Mineral Resources Development Company Limited ("MRDC")). Dividends paid to the PNG Government and landowners are governed by the Benefits Sharing Agreement and multiple Licence Based Benefits Sharing Agreements. To 30 June 2021, the PNG LNG Project had generated approximately 10.2 billion Kina for the State and Provincial governments and landowners.

The initial development concept was for the export of gas to Gladstone in Queensland, Australia, via a 4,000 km pipeline. The Gladstone project was suspended in January 2007 due to lack of customer support and a new project concept, involving the production of LNG in PNG, was developed. On 22 May 2008, the Government of PNG and the project consortium signed an agreement outlining the project's fiscal and legal framework. Final investment decision was made in December 2009, construction commenced in March 2010 and first production of LNG occurred in April 2014. Operational completion occurred in January 2015 and financial completion, defined as the point at which the project is free to distribute profits to its shareholders, occurred in February 2015. The PNG LNG Project has been consistently producing at rates above its nameplate capacity. It produced 8.8 Mt of LNG in 2020 and at an annualised production rate of 8.2 Mtpa in H1 2021.

Feed gas is currently sourced from the Hides gas field and from the Kutubu and Gobe oil fields, all of which are located in the Highlands of PNG. The gas is transported by pipeline to an onshore LNG facility located at Caution Bay, 20 km northwest of Port Moresby on the eastern coast of the Gulf of Papua, where it is liquified.

GRANT SAMUEL

A map showing the key components of the PNG LNG Project is set out below:

Source: Oil Search

1.2 Project Components

The PNG LNG Project incorporates the ExxonMobil-operated Hides, Angore and Juha gas fields together with the Oil Search-operated Kutubu, Gobe Main, Moran and Agogo associated gas fields ("AG Fields") and the South East Hedinia ("SE Hedinia") gas field. Gas (and associated liquids) is currently sourced from Hides, Kutubu and Gobe Main. The PNG LNG Project also purchases third party gas from the Oil Search-operated South East Gobe ("SE Gobe") field.

Hides was developed as part of the PNG LNG Project and has accounted for over 80% of the feedstock to date. Kutubu, Gobe Main, SE Gobe, Agogo and Moran have been producing oil since the 1990s. The associated gas produced from Kutubu, Gobe Main and SE Gobe was historically re-injected into their reservoirs for pressure maintenance. As oil production from these fields has continued to naturally decline, Oil Search now predominantly uses these fields as a source of gas feedstock for the PNG LNG Project. Gas produced at Agogo and Moran is still re-injected.

The Angore field is currently undergoing development, the Juha and SE Hedinia gas fields are undeveloped and, in conjunction with Agogo and Moran, are expected to backfill the two existing LNG trains.

The liquids-rich feed gas from Hides is stripped of its condensate and water at the Hides Gas Conditioning Plant. The resulting dry gas is transported 292 km to the coast via a dedicated onshore gas pipeline and then a further 407 km to the Caution Bay LNG facility via a subsea pipeline. The gas produced at Kutubu, Gobe Main and SE Gobe is dehydrated and compressed at the Central Processing Facility and Gobe Production Facility, and then transported to the LNG facility at Caution Bay via export pipelines that tie into the onshore PNG LNG gas pipeline. The gas is subsequently purified, cooled and liquefied, and then shipped to international markets.

Condensate stripped at the Hides Gas Conditioning Plant is transported via a condensate pipeline to Kutubu and mixed in with the Kutubu Blend. From there, the Kutubu Blend is transported via the oil pipeline to the offshore Kumul Marine Terminal, located in the Gulf of Papua, and loaded onto tankers for export.

2

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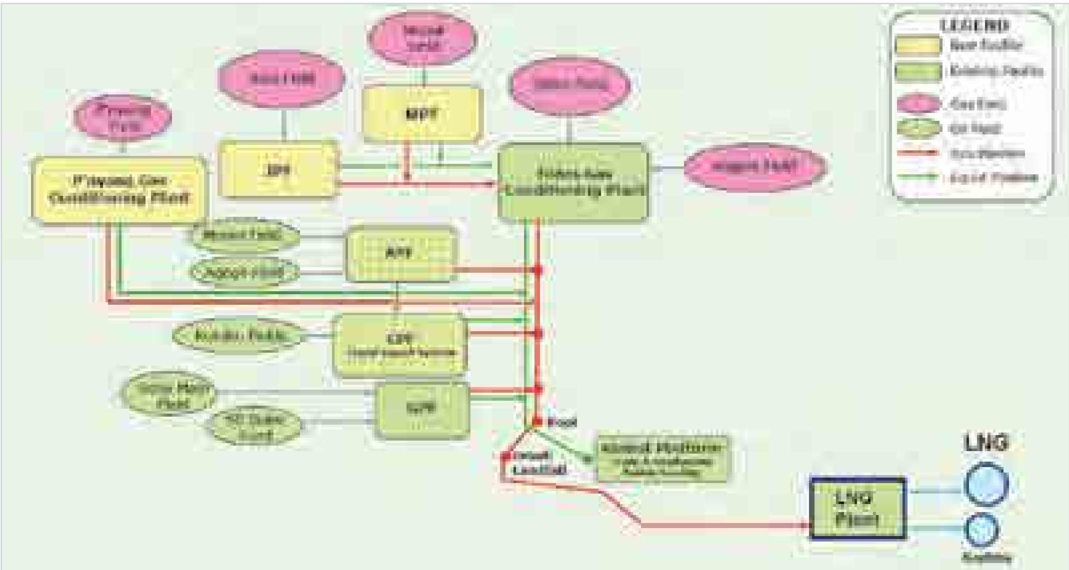
The LNG plant comprises two 3.45 Mtpa processing trains utilising conventional APCI technology,[1] two 160,000 m^3 storage tanks, a 2.4 km jetty (suitable for tankers with capacity up to 215,000 m^3) and other associated infrastructure. It is located on a relatively flat 700 ha site with a protected harbour offering direct access to deep water. The site is large enough to support at least three additional trains.

The gas fields and treatment facilities[2], the condensate pipeline from Hides to Kutubu, the onshore and offshore gas pipelines and the LNG processing facilities are owned by the PNG LNG JV and operated by ExxonMobil. Oil Search is the operator of the AG fields and supplies gas sourced from those fields to the PNG LNG Project. The liquids export pipeline from Kutubu to Kumul and the Kumul Marine Terminal are owned by the PL2 joint venture and operated by Oil Search. The PNG LNG Project pays a tolling fee for their use.

PNG LNG EXISTING AND EXPANSION SYSTEM



Source: Oil Search

1.3 Reserves

Oil Search's share of the reserves estimated for the PNG LNG Project at 31 December 2020 is summarised as follows:

PNG LNG PROJECT – RESERVES AS AT 31 DECEMBER 2020 (NET TO OIL SEARCH)

	PROVEN (1P)			PROVEN & PROBABLE (2P)	
	LIQUIDS (MMBBL)	GAS (BCF)		LIQUIDS (MMBBL)	GAS (BCF)
Total Reserves	**34.7**	**1,735.9**		**38.8**	**1,955.0**

Source: Oil Search 2020 Annual Report

The reserves shown above are for the Kutubu, Moran, Gobe Main, SE Hedinia, Hides, Angore and Juha fields. The reserves in relation to the Kutubu, Moran and Gobe Main oil fields relate to the gas and associated liquids that have been unitised into the PNG LNG Project. Oil reserves for these fields are accounted for under the PNG Oil Fields.

1 APCI stands for Atmospheric Pressure Chemical Ionization. 3.45 Mtpa refers to nameplate capacity.
2 Excluding the Hides GTE gas reserves and the GTE plant.

1.4 Marketing

ExxonMobil markets all the PNG LNG gas on behalf of the joint venture participants. In total, 7.9 Mtpa is contracted under long- and medium-term agreements, with 6.6 Mtpa contracted under 20-year take or pay contracts with four buyers and 1.3 Mtpa contracted under mid-term sale and purchase agreements with two buyers.

PNG LNG FOUNDATION PROJECT – SALES CONTRACTS

	COMMENCING	CONTRACT	COUNTRY	AMOUNT CONTRACTED (MTPA)
JERA	H2 2014	20 Year ToP	Japan	1.8
Osaka Gas	H2 2014	20 Year ToP	Japan	1.5
CPC	H2 2014	20 Year ToP	Taiwan	1.2
Sinopec	H2 2014	20 Year ToP	China	2.0
Sub Total LT Take or Pay				**6.6**
BP[3]	August 2018	5 Year SPA	Singapore	0.9
Unipec	April 2019	4 Year SPA	Singapore	0.45
Sub Total Mid-Term SPA				**1.3**
Total				**7.9**

Source: Oil Search
Note: Numbers may not add due to rounding.

Annual production in excess of contracted volumes is currently sold on the spot market. ExxonMobil markets its share of the liquids. Oil Search markets both its own share of the liquids and that of the other joint venture participants other than ExxonMobil.

1.5 Initial Development

It was originally contemplated that the project would be developed in five phases. The first phase, which involved the development of the majority of the facilities and infrastructure, consisted of the following:

- development of the Hides field, including five well pads with nine new production wells;
- construction of the Hides Gas Conditioning Plant, which collects and separates the gas from the associated liquids from the Hides field and conditions it to feed the LNG plant;
- construction of the two-train LNG plant at Caution Bay and other onshore and marine facilities;
- laying of 292 km of onshore gas lines, 100 km of onshore condensate lines and a 407 km subsea gas pipeline linking the oil and gas fields located in the Highlands to various processing facilities and the LNG plant;
- modifications to the Central Processing Facility at Kutubu and the Gobe Production Facility at Gobe to allow the production of pipeline specification gas and the handling of condensate;
- construction of the Kutubu and Gobe gas pipelines that connect to the PNG LNG gas pipeline;
- upgrades to the 270 km crude oil pipeline from Kutubu to Kumul and the offshore Kumul Marine Terminal to extend asset life and increase reliability;
- construction of an airstrip at Komo in the PNG Highlands, which was a critical element of the logistics chain; and
- the leasing of four LNG ships.

[3] Amount contracted to BP increased to 0.9 Mtpa (from 0.45 Mtpa) for the last two years of the agreement. The incremental 0.45 Mtpa replaced the same amount previously contracted to PetroChina under a three-year agreement which expired in July 2021.

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Phase 1 of the project was completed in April 2014, within the revised budget of $19 billion. Phase 2 is currently undergoing development. Future development will predominantly include the development of new gas fields and the construction of pipelines and other infrastructure to existing fields.

Development of the upstream portion of the project is complicated by remoteness, steep topography, jungle environment, tropical weather conditions and lack of existing infrastructure. Managing the relationships with and the appropriate sharing of benefits between the region's numerous groups of landowners affected by the project is also key to minimising disruptions to the operations.

1.6 Joint Venture Agreement

The PNG LNG Project is an integrated project comprising upstream and pipeline infrastructure as well as LNG processing plant facilities. The Coordinated Development and Operating Agreement ("CDOA") covers all activities required to operate the PNG LNG Project.

The CDOA defines each participant's project interest in the PNG LNG Project. As is common with joint venture arrangements for unitised projects, the CDOA provided for several redetermination procedures by which participants' project interests could be potentially adjusted at various stages in the lifecycle of the PNG LNG Project.

In September 2021, the participants agreed to cancel the first redetermination, which had commenced in December 2020, and all future redeterminations provided for under the CDOA with no adjustment being made to the participants' project interests. As part of the agreement, Oil Search is entitled to a carried interest of $176 million from certain non-PNG State joint venture partners, targeted over the years ending 31 December 2022 to 31 December 2024 in respect of certain agreed PNG LNG capital expenditures. A further carry (either positive or negative) could be payable late in the decade once the result of future drilling activities are assessed.

1.7 Production

The project is expected to process over 11 tcf of gas and 200 mmbbl of liquids over an operational life in excess of 30 years. [4] Production of LNG is expected to be relatively constant for the majority of the project's life, before tapering off due to the combination of natural field depletion and the lack of remaining tie-in opportunities. Condensate has historically contributed 13% of total production, significantly enhancing the project's financial returns.

First production at PNG LNG occurred in April 2014. The project has since been performing well above expectations. It produced 7.9 Mt of LNG in 2016, 8.2 Mt in 2017, 7.4 Mt in 2018, 8.5 Mt in 2019 and 8.8 Mt in 2020, compared to nameplate capacity of 6.9 Mtpa. The decline in production in 2018 was due to the two-month shut-in of operations caused by the Highlands earthquake.

Oil Search expects the PNG LNG Project to produce 8.1 – 8.4 Mt of LNG in the 2021 calendar year, lower than 2020 LNG production due to scheduled maintenance at both the Hides Gas Conditioning Plant and the liquefaction plant at Caution Bay.

Oil Search's share of LNG production is expected to be in the range of 21.0 – 21.4 mmboe in 2021. The company's share of liquids production has been in the range of 3.0 – 3.5 mmbbl since 2015 and is expected to be in the range of 2 – 3 mmbbl in 2021. Production of gas for power generation is expected to be in range of 0.2 – 0.25 mmbbl in 2021. [5]

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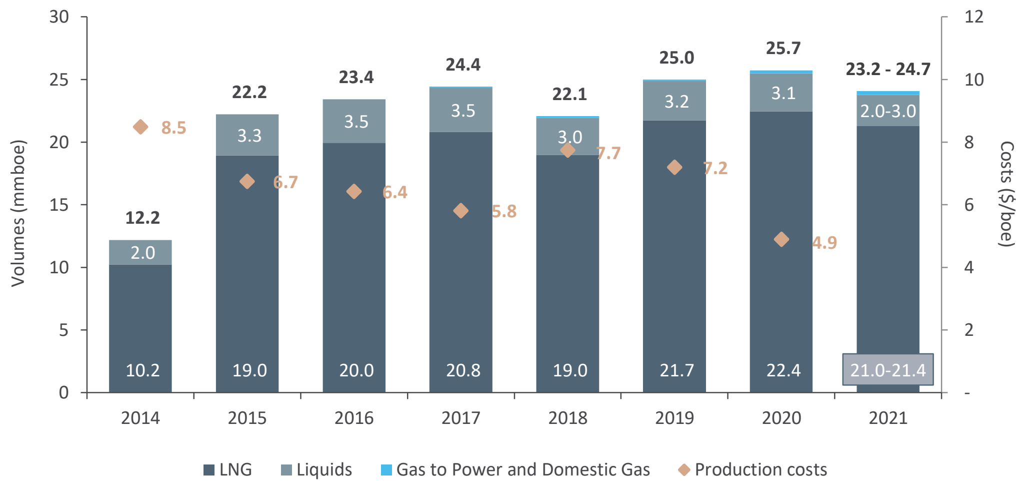
[4] Excludes non-Project fields not currently tied into the PNG LNG Project, such as P'nyang and Muruk, which may ultimately backfill the PNG LNG Project on commercial terms to be agreed and significantly increase its life-of-project production and operational life.

[5] Prior to 2017, production of gas for power generation was accounted for as losses within the PNG LNG plant, but has since been presented separately.

PNG LNG – PRODUCTION VOLUMES (MMBOE, NET TO OIL SEARCH) AND COSTS ($ PER BOE)



Source: Oil Search

Several optimisation workstreams have continually generated benefits that have contributed to ongoing increases in production capacity. These have included work on compressors, modifications to the Hides Gas Conditioning Plant to optimise upstream production rates and other optimisation and debottlenecking initiatives.

Unit operating costs have fallen significantly since the commencement of production, with the exception of 2018 and 2019, which were impacted by the reduction in production and the remediation costs associated with the Highlands earthquake. The general downward trend in unit operating costs reflects the lower-cost economic environment following completion of project construction, operational optimisation, cost reduction initiatives including continued nationalisation of the labour force and the deferral of non-critical work in 2020. There are further opportunities to optimise the operations.

1.8 Future Development and Backfill Opportunities

Future phases of the PNG LNG Project include two ExxonMobil-operated undeveloped gas fields, Angore and Juha, as well as the Oil Search-operated Agogo and Moran AG fields and the SE Hedinia gas field. Oil Search and its partners intend to develop these fields to gradually backfill the two existing LNG trains as production from existing fields decline.

Angore is currently undergoing development and is planned to be connected to the Hides Gas Conditioning Plant. Supply of additional Associated Gas from the Agogo and Moran fields are anticipated to follow. Thereafter, booster compression at Hides Gas Conditioning Plant (HGCP) is expected to be installed and with subsequent Juha development to backfill the PNG LNG Project toward the latter end of its life. While not currently part of the PNG LNG Project, other undeveloped gas fields (P'nyang and Muruk) may also backfill the existing LNG trains. These fields are all located in the Southern Highlands and Western provinces of PNG. P'nyang and Muruk are further described in section 2.2 of this Appendix.

Angore

The Angore gas field is predominantly in PDL 8 and is located in the Central Highlands of PNG, approximately 8 km northeast of Hides and 50 km northwest of Kutubu. The field was initially discovered by the drilling of the Angore-1A well in 1990, which encountered gas and condensate within the Toro and Upper Imburu sandstones.

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Two well pads (Angore A and Angore B) were established as part of the initial PNG LNG development, and three development wells were drilled in 2014 and 2015, two from Angore A and one from Angore B. The Angore B1 well, which was drilled in 2014, failed to reach the targeted reservoir. The Angore A1 and A2 wells, which were drilled in 2015, were initially considered a success and were cased for future production. The PNG LNG JV commenced construction with the intention to complete the tie-in in 2019. However, further studies conducted in 2018 concluded that the Angore A1 and A2 wells were drilled in suboptimal locations. The parties subsequently agreed on the need to re-design and re-drill the wells to overcome shallow geological complexities and well integrity issues.

The development plan now includes two new wells from one new well pad (Angore C) located approximately 2 km from Angore A, surface facilities and a wet gas pipeline connecting Angore to the Hides Gas Conditioning Plant. Angore is planned to come onstream in 2024 and is targeting an export rate of 330 mmscf per day.

Associated Gas Optimisation

The AGO is a project operated by Oil Search that is designed to accelerate gas production from Kutubu as well as enable gas production from Agogo and Moran. The PNG LNG JV considers the AGO a comparatively low-cost method of maintaining upstream gas production, particularly as it will leverage existing infrastructure. It is currently planned to provide backfill to the two existing LNG trains.

Accelerated gas export from Kutubu is planned to commence in the near term to provide an increased plateau export rate into the PNG LNG system. Oil Search and its partners plan to drill a new production well, convert existing injection wells to producers and potentially implement upgrades to the Central Processing Facility to increase its gas export capacity. To maintain production levels, Oil Search also plans to develop the SE Hedinia gas field and connect it to the Central Processing Facility via a 25 km flowline.

The PNG LNG joint venture is currently undertaking studies to optimise the timing and gas export rate from Agogo and Moran. As part of this work, an annual average export rate of up to 280 mmscf per day is being contemplated, offering a material backfill opportunity to the LNG plant. For a 280 mmscf per day development, Oil Search plans to drill additional gas production wells at Agogo and Moran, and make a substantial expansion and upgrade to the Agogo Production Facility to increase and improve gas compression and handling capabilities for gas export to PNG LNG. The development will also include new flowlines to deliver gas to the Agogo Production Facility and a new export line to connect the facility to the PNG LNG Project pipeline. While gas production will occur within existing PDLs, the planned modifications to the facilities will require licence variations.

Juha

The Juha gas field is in PDL 9 and located in the Central Highlands of PNG, approximately 35 km north-east of Hides. Juha forms part of the PNG LNG Project and has the potential to backfill the two existing LNG trains as production from other fields decline.

Juha was initially discovered in 1983 with the drilling of the Juha-1X well, which encountered gas in the Toro sandstone. Juha has since been appraised by an additional 3 wells, specifically Juha-2X in 1984, Juha-3X in 1985 and Juha-5X in 2007, in addition to the acquisition and later reprocessing of seismic data. Juha-4X was drilled in 2006 but was side-tracked due to mechanical issues and ultimately penetrated a separate fault block in Juha North.

The conceptual development plan includes the drilling of four wells from one well pad as well as the construction of the Juha Gas Conditioning Plant (JGCP) and export pipelines to the Hides Gas Conditioning Plant. It is anticipated JGCP will export gas at a rate of 200 mmscf per day. While not part of the PNG LNG project, a proximate discovered field, Muruk, may offer a material reduction in development costs of Juha through synergies.

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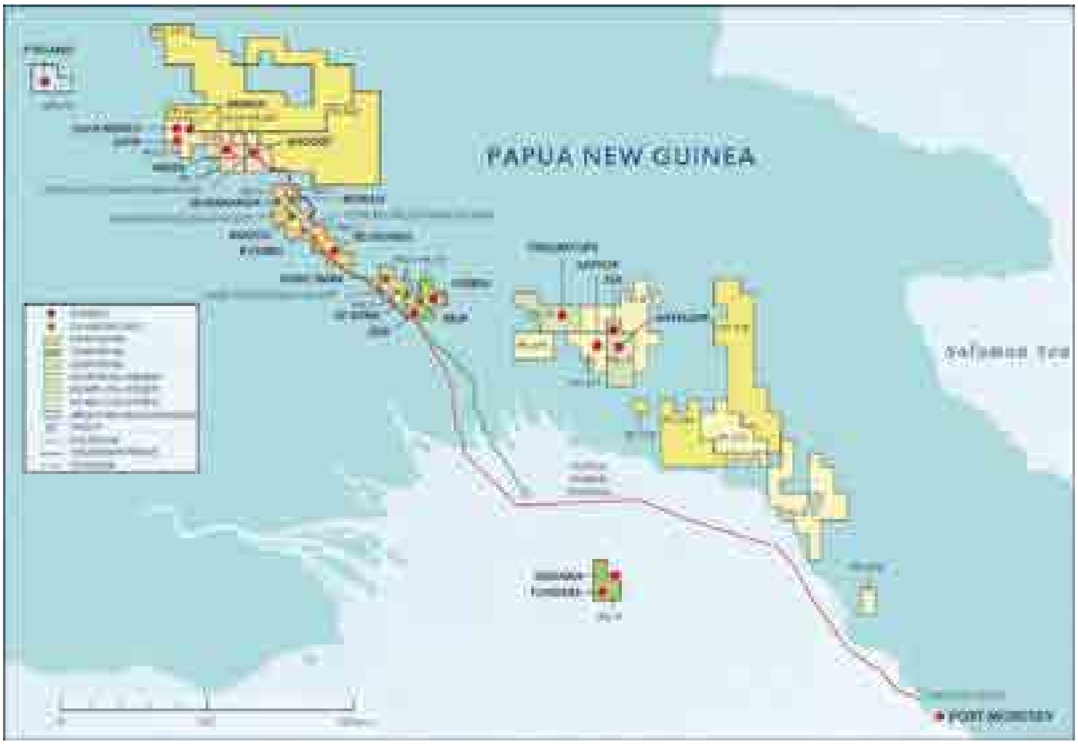
2 LNG Expansion

2.1 Overview

Oil Search and its partners own interests in a large number of licences, onshore and offshore, that are at various maturity levels and are not yet part of the PNG LNG Project. The following map shows Oil Search's acreage in PNG in addition to its areas of focus and the most advanced expansion opportunities:

OIL SEARCH PNG ACREAGE



Source: Oil Search

The licences are situated within four general areas:

- **Northwest Highlands**: the area hosts the P'nyang field (PRL 3, Oil Search: 38.51%), the Muruk field (PPL 402, Oil Search: 37.50%; PDL 9, Oil Search: 24.42%) and prospects along the Hides-P'nyang trend. While these fields are relatively close to the existing PNG LNG processing facilities, pipelines and other infrastructure, the rugged nature of the terrain complicates development. P'nyang and Muruk and are planned to backfill the PNG LNG Project once developed;
- **Eastern Fold Belt**: Oil Search has interests in licences covering a large area, but the focus of activities has been on pre-FEED work at the Elk-Antelope fields (PRL 15, Oil Search: 22.8%) and appraisal work on the Raptor (PPL 475, Oil Search: 25%), Triceratops (PRL 39, Oil Search: 25%) and Bobcat (PPL 476, Oil Search: 25%) fields. While the development of fields in the region is unlikely to involve a tie-in to existing upstream infrastructure, the fields are generally closer to the PNG LNG site at Caution Bay and are in relatively low-lying areas. The undeveloped Elk-Antelope fields are planned to underpin the Papua LNG Project, which will produce LNG through two additional trains at Caution Bay;
- **Central Fold Belt**: this area hosts the Iehi, Cobra and Bilip (PRL 14, Oil Search: 62.6%) gas discoveries. These resources are of insufficient scale for standalone developments and are unlikely to be developed in the near-medium term; and

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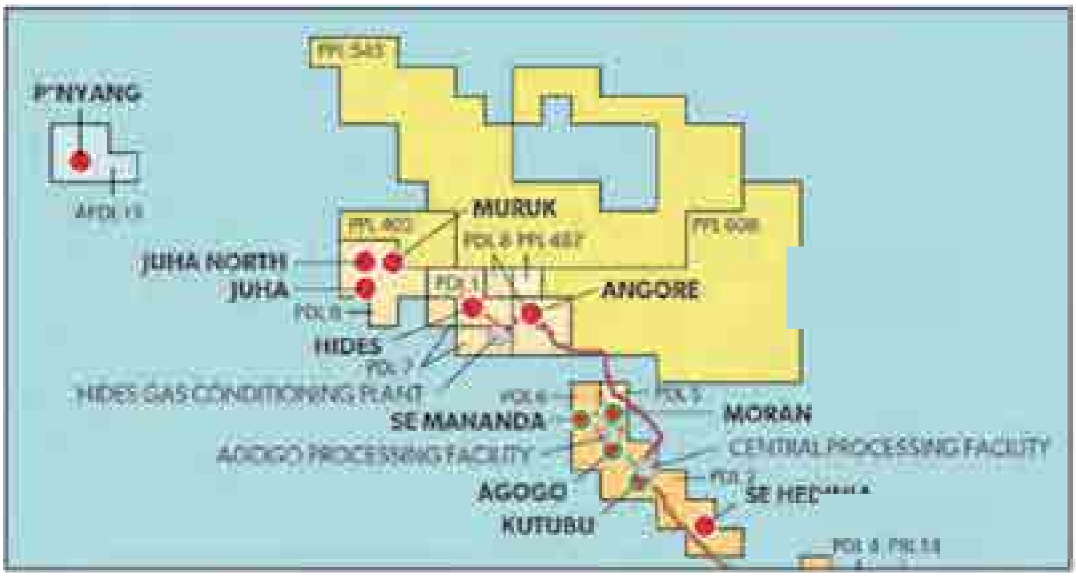
- **Offshore Gulf**: Oil Search has interests in multiple licences in the shallow and deep waters of the Gulf of Papua but plans to exit this acreage, with the exception of PRL 41 (Oil Search: 100%). PRL 41 contains the Flinders and Hagana gas discoveries.

The P'nyang, Muruk and Elk-Antelope fields in the Northwest Highlands and the Eastern Fold Belt are planned for development, and are further discussed in sections 2.2 and 2.3 below.

2.2 Northwest Highlands

The location of Oil Search's key gas interests in the Northwest Highlands, comprising both producing fields and existing infrastructure, is shown on the map below:

NORTHWEST HIGHLANDS - OIL SEARCH INTERESTS



Source: Oil Search

P'nyang

The P'nyang gas field is in PRL 3 in the Western Highlands of PNG, approximately 100 km northwest of Juha and 150 km northwest of Hides. The partners in the PRL 3 joint venture are Oil Search (38.51%), ExxonMobil (48.99% and operator) and JX Nippon (12.50%). The field consists of two compartments, P'nyang North and P'nyang South, which contain the Toro, Imburu, Digimu and Emuk reservoirs.

The P'nyang gas field was discovered by the drilling of the P'nyang-1X well, which flowed gas and condensate from the Emuk formation in 1990. Three appraisal wells and sidetracks were subsequently drilled in 1991, 2012 and 2017-2018 to further define the field. The most recent appraisal programme included the drilling of the P'nyang South 2 ST1 well, which completed in January 2018. The well encountered gas in the Toro, Digimu and Emuk sands and confirmed the extension of the field to the south-east. A recertification of P'nyang resources occurred in April 2018, incorporating the results of the P'nyang South 2 ST1 well in addition to reprocessed seismic and core data. A gross 1C contingent resource of 3.5 tcf and 2C contingent resource of 4.5 tcf (net 2C contingent resource of 1.7 tcf) are currently defined at the field.

Prior to November 2020, the PNG LNG, PRL 3 and PRL 15 joint ventures were progressing plans for an integrated development of a three-train expansion at the PNG LNG site at Caution Bay. Plans were for P'nyang to supply gas under a tolling arrangement for processing through a PNG LNG expansion train, and for the Elk-Antelope fields to own and supply the remaining two expansion trains. The PRL15 participants have since agreed to target a two-train expansion, primarily due to delays experienced in negotiations on the P'nyang Gas Agreement with the PNG Government. As a result, P'nyang is now planned to backfill the existing PNG LNG trains as production from PNG LNG Project fields starts to decline. P'nyang may enter into tolling arrangements with the PNG LNG Project, or it could alternatively provide the PNG LNG Project with third party sales gas. It is anticipated that P'nyang development will be planned to suit the ullage of the two existing PNG LNG trains. Development may consist of field hydrocarbon transportation to a new gas conditioning plant located within the P'nyang licence area and an export pipeline to the PNG LNG pipeline at Kutubu for delivery to the liquefaction facility at Caution Bay.

ExxonMobil, as PRL3 Operator, is currently negotiating the terms of the P'nyang Gas Agreement with the PNG Government, to define the fiscal framework for the project. Although negotiations reached an impasse in January 2020 due to disagreements over the apportionment of the project's value and benefits, dialogue resumed in 2021 and recently culminated in the signing of a Heads of Agreement on 27 September 2021 which captures key fiscal, regulatory and licensing terms. Discussions are currently underway between ExxonMobil and the PNG Government to finalise the fully termed P'nyang Gas Agreement.

The PRL 3 joint venturers have also applied for but have not yet been granted a Petroleum Development Licence (APDL 13) over PRL 3. Oil Search anticipates that the State of PNG will exercise its right to back-in for a 22.5% project interest upon PDL award.

Muruk

The Muruk gas field straddles PPL 402 (Oil Search: 37.50% and operator) and PDL 9 (Oil Search: 24.42%), between the Hides and Juha fields in the PNG Highlands. The field was identified by seismic data in 2015 and the discovery well, Muruk 1, was drilled in PPL 402 at the end of 2016. A second well, Muruk 2, completed drilling in 2019 and was in PDL 9, approximately 11.7 km to the northwest of Muruk 1. The field constitutes a material gas discovery with two hydrocarbon pools.

Muruk 2 encountered hydrocarbons in the Toro sandstone and pressure data and test results were consistent with reservoir continuity from Muruk 1. Muruk 2 flowed at a rate of 16.5 mmscf per day. However, the potential flow rate was affected by drilling induced formation damage. Based on a combination of flow results, pressure build up data and reservoir modelling, Oil Search estimates gross 1C contingent resources of 453 bcf and 2C contingent resources of 843 bcf (114 bcf and 211 bcf net to Oil Search). In March 2020, Oil Search decided to curtail the 2D seismic survey that it was conducting in the Highlands, as a result of the low oil price environment. Oil Search still completed one of three planned 2D seismic lines, which will assist with constraining the Muruk discovery.

Muruk represents a low-cost potential development given its proximity to the Hides infrastructure (which is only 21 km away), thereby providing additional field sequencing optionality. The field's development would potentially include 5-10 wells drilled from two well pads and a new gas conditioning plant with capacity of approximately 300-400 mmscf per day. The development would likely tie into the Juha-to-Hides export pipeline, although a new export pipeline to Hides may also be possible depending on the sequence of field developments.

Commercial terms for the processing of gas through PNG LNG facilities will need to be agreed prior to development.

Other Highlands

The Hides-P'nyang trend is prospective for gas, having been further validated by the Muruk discovery. Other, less advanced prospects are discussed in further detail in section 4 of this Appendix.

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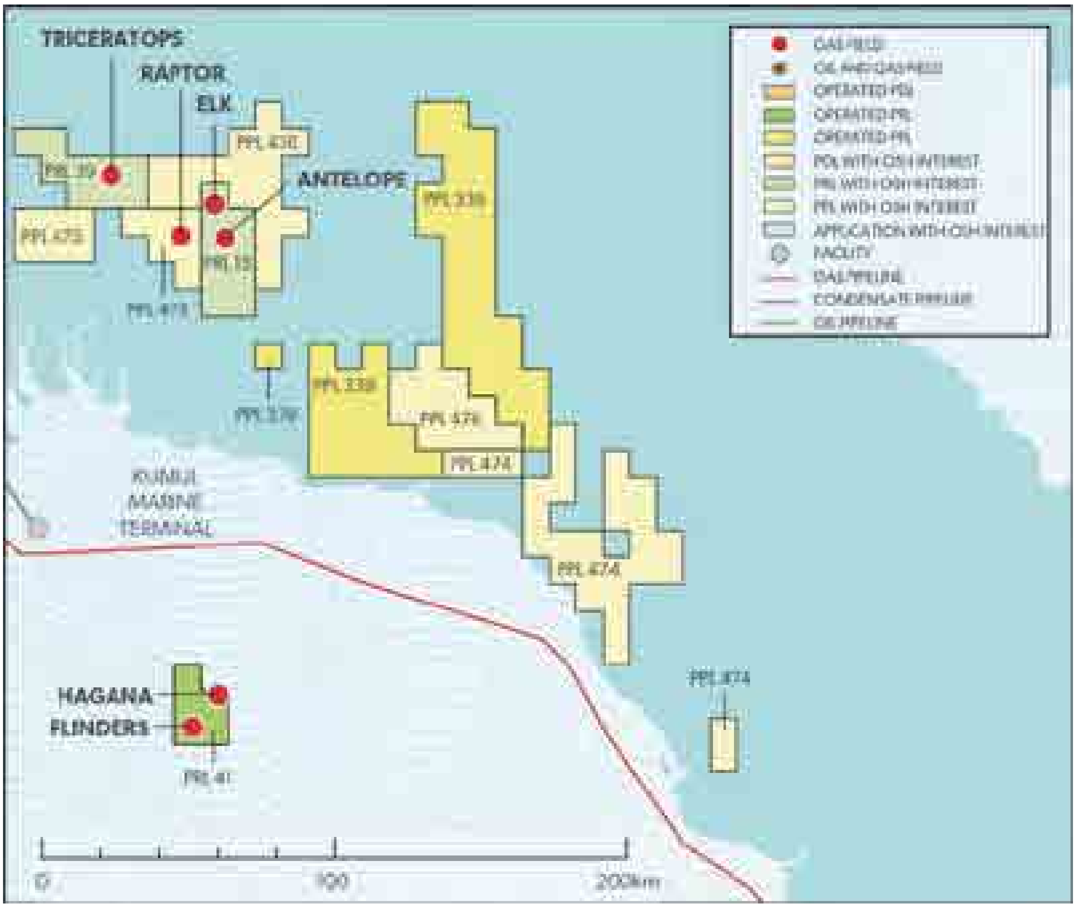
2.3 Eastern Fold Belt

The location of Oil Search's key gas interests in the Eastern Fold Belt are shown on the map below:

EASTERN FOLD BELT - OIL SEARCH INTERESTS



Source: Oil Search

Papua LNG Project (incl. Elk-Antelope fields)

The Elk-Antelope fields are located within PRL 15, in the eastern region of the Papua Basin, and are operated by Total. The PRL 15 ownership interests pre and post PNG Government equity back-in are illustrated below:

ELK-ANTELOPE (PRL 15) EQUITY PARTICIPATION

	PRE GOVERNMENT BACK-IN	POST GOVERNMENT BACK-IN
Oil Search	22.8%	17.7%
Total	40.1%	31.1%
ExxonMobil	37.1%	28.7%
PNG [6]	-	22.5%

Source: Oil Search

6 Denotes PNG government and landowners

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InterOil discovered the Elk field in June 2006 and the Antelope field in May 2008. Elk-Antelope has been delineated and appraised by 2D seismic data, well log data from 10 wells, whole core and sidewall core data as well as drill stem, production and interference tests. The fields currently carry a gross 1C contingent resource of 5.7 tcf and a 2C contingent resource of 6.8 tcf of gas (1.5 tcf net to Oil Search). The resource was certified in 2017, following the entry of ExxonMobil into the joint venture.

The Elk-Antelope gas fields are located too far east to utilise PNG LNG's existing upstream facilities and pipelines. As a consequence, gas and condensate extracted from Elk-Antelope will be processed at separate facilities and piped to the PNG LNG site at Caution Bay via a new pipeline. The upstream development of Elk and Antelope is planned to include:

- one well-pad at Antelope comprising up to seven production wells;
- one well-pad at Elk comprising one production well;
- one produced water re-injection well;
- the construction of multi-phase gathering flowlines;
- the construction of a gas processing facility at Herd, located ~30 km south of the field;
- the laying of 320 km of gas and condensate pipelines to the PNG LNG site, comprising 60 km of onshore pipelines and 260 km of offshore pipelines; and
- the construction of supporting facilities and infrastructure.

A separate LNG project (Papua LNG) is planned to process gas from the Elk and Antelope fields. The expansion plans comprise two additional LNG trains, each with the same train design and nameplate capacity of 2.8 Mtpa, to be located on the existing PNG LNG site at Caution Bay. While the construction of additional LNG trains and infrastructure will be required, Papua LNG will be able to use many of the existing infrastructure at the PNG LNG site, such as the jetty, storage tanks and utilities, resulting in substantial cost savings and greater schedule certainty relative to a greenfield LNG project. ExxonMobil, operator of the existing PNG LNG trains, will also operate the Papua LNG expansion trains.

Total, Kumul and MRDC have agreed to jointly market their shares of the LNG and condensate produced by Papua LNG. Oil Search and ExxonMobil will each market their own respective shares of LNG and condensate production.

Because of the overlapping ownership interests in the PNG LNG Project and the Papua LNG, there is some degree of alignment between the parties:

PNG LNG AND PAPUA LNG – OWNERSHIP

	PNG LNG	PAPUA LNG (POST GOV'T BACK IN)
Gas volumes (Tcf, gross)	7.4 (2P)	6.8 (2C)
Licence	Various	PRL 15
Oil Search	29.0%	17.7%
ExxonMobil	33.2%	28.7%
Santos	13.5%	-
JX Nippon	4.7%	-
Total SA	-	31.1%
PNG [7]	19.6%	22.5%

Source: Oil Search

[7] Denotes PNG government and landowners

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The Papua LNG joint venturers entered the Papua Gas Agreement with the O'Neill-led PNG Government in April 2019, defining the fiscal framework for the development of Elk-Antelope. The Marape-led PNG Government sought to re-negotiate the agreement after taking office in May 2019, although ultimately validated the agreement in September 2019. The PNG parliament passed six amendments to legislation in November 2020 and one in August 2021 to allow Papua LNG to proceed. The Papua LNG joint venturers and the PNG Government also entered a Fiscal Stability Agreement in February 2021, guaranteeing the terms of the Papua Gas Agreement signed in 2019. A five year extension to the Petroleum Retention Licence (PRL15) was also granted to the joint venture in February 2021.

The key terms of the Papua Gas Agreement include a 2% production levy, an obligation to provide up to 5% of produced gas to the domestic market at a fixed price, and a deferred payment mechanism allowing the PNG Government to pay its share of past costs (in relation to its equity back-in) from production. Oil Search and its partners have also committed to prepare a national content plan (to be finalised prior to FID), and to negotiate to enable third party access to the gas export pipeline if requested.

The Papua LNG joint venturers are currently updating pre-FEED work to reflect changes from a three-train to a two-train expansion. Negotiations on commercial terms for the integration of Papua LNG and PNG LNG are also underway. Papua LNG is expected to commence FEED studies in 2022, leading to a final investment decision in 2023 and the commencement of production in 2027.

Other

The area around Elk-Antelope hosts several discoveries including Raptor (PPL 475, Oil Search: 25%), Triceratops (PRL 39, Oil Search: 25%) and Bobcat (PPL 476, Oil Search: 25%). It is believed that the region could host multiple Antelope look-alikes. Oil Search conducted a major two-phase 2D seismic program throughout 2018 and 2019, with the first phase covering approximately 330 km over PPL 475, PPL 476, PRL 39 and PRL 15 and the second phase spanning 220 km over PPL 475 and PPL 476. Oil Search and its partners plan to conduct further seismic acquisition covering 190 km in late 2021 and 2022 to further assess these discoveries and help to define a drilling campaign. While it is premature to schedule the development of these discoveries, it is conceivable that meaningful quantities of gas could be sourced from these fields to backfill Papua LNG.

3 PNG Operated Production

3.1 Overview

Oil Search has interests in and operates all PNG's producing oil fields and the Hides GTE project, which provides gas for power generation and transmission to the Porgera gold mine. Oil Search also has interests in several oil exploration prospects in PNG. Oil production in PNG commenced in the early 1990s and Oil Search assumed operatorship of the fields in 2003, when it acquired Chevron Niugini Limited to further increase its interests in the assets.

The PNG producing assets comprise:

- the Kutubu Oil Project, which produces oil from the Iagifu-Hedinia, Usano and Agogo fields. The Kutubu Oil Project owns the Agogo Production Facility and Central Processing Facility, the 270 km crude oil export pipeline to the coast ("Kutubu Export Pipeline") and the Kumul Marine Terminal liquids loading facility in the Gulf of Papua;
- the Greater Moran Oil Project, which produces oil from the Central Moran Oil Field and North West Moran. These fields have been unitised into the Greater Moran Unit at a unitisation split of 55:44:1 to PDL 5, PDL 2 and PDL 6 respectively;
- the Gobe Oil Project, which consists of the SE Gobe and Gobe Main oil fields, as well as the Gobe Processing Facility; and

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- the Hides gas field, which provides feedstock to the PNG LNG Project and to the Hides GTE project.

Oil Search's producing fields and processing facilities are located in the Southern Highlands and Gulf provinces of PNG across the Gulf of Papua from Port Moresby:

PNG – FIELD LOCATION

Source: Oil Search

3.2 Production

The chart below shows PNG oil production (on a 100% basis) from the fields since first production at Kutubu in 1992:

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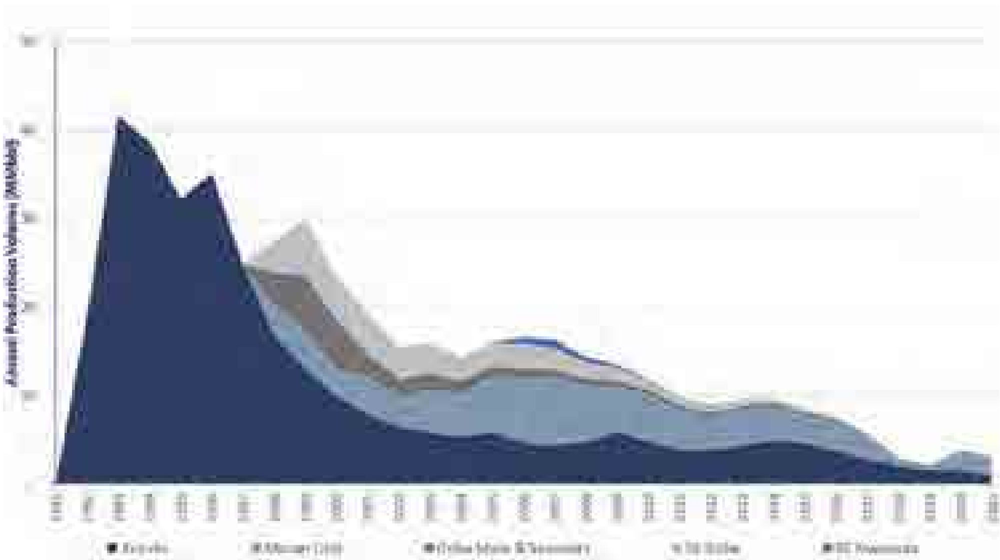
PNG OIL – ANNUAL PRODUCTION (MMBBL, 100%)



Source: Oil Search

The oil fields are mature and in decline. Oil Search has been successful in mitigating the natural decline rates through an active drilling programme, involving a combination of development wells, workovers and gas injection, and through wellbore flow performance and reservoir management. Development drilling has been focussed on areas within or close to existing infrastructure, which has facilitated the quick and relatively inexpensive tie-in of new oil pools. As a result, Oil Search has partially offset the decline in reserves and slowed the decline in production.

Production has declined materially since February 2018, in large part due to the damage caused by the Highlands earthquake. Following the earthquake, wells were incrementally brought back online as Oil Search undertook remedial works to repair the damage to well pads, flow lines, pipelines, control systems, processing facilities and other infrastructure. Production also declined in 2019 due to unscheduled repairs to the Kumul Marine Terminal. However, production from additional wells, workovers and improved plant performance resulted in a partial recovery in 2020. Production guidance for 2021 is consistent with 2020 production.

3.3 Reserves and Contingent Resources

The reserves and contingent resources of the Oil Search operated projects are summarised below. The gas reserves and contingent resources of Kutubu, Moran and Gobe Main have been unitised into the PNG LNG Project and are therefore not reflected in the estimates set out below:

15

PNG OPERATED PRODUCTION – RESERVES AS AT 31 DECEMBER 2020 (NET TO OIL SEARCH)

	PROVED (1P)		PROVED & PROBABLE (2P)	
	LIQUIDS (MMBBL)	GAS (BCF)	LIQUIDS (MMBBL)	GAS (BCF)
RESERVES				
Kutubu (PDL 2)	8.3	-	13.7	-
Moran Unit (PDL 2/5/6)	4.9	-	8.5	-
Gobe (PDL 4)	0.0	-	0.0	-
SE Gobe (PDL 3/4)	-	-	0.0	5.4
Hides GTE (PDL 1)	-	-	-	-
Total oil fields and Hides GTE	**13.2**	**-**	**22.2**	**5.4**

Source: Oil Search
Note: Numbers may not add up due to rounding

PNG OPERATED PRODUCTION – CONTINGENT RESOURCES AS AT 31 DECEMBER 2020 (NET TO OIL SEARCH)

	1C		2C	
	LIQUIDS (MMBBL)	GAS (BCF)	LIQUIDS (MMBBL)	GAS (BCF)
CONTINGENT RESOURCES				
Kutubu & Agogo (PDL 2)	-	-	0.5	76.1
Moran Unit (PDL 2/5/6)	-	-	0.1	17.9
Gobe (PDL 4)	-	-	0.0	2.5
SE Gobe (PDL 3/4)	-	-	-	2.3
Hides GTE (PDL 1)	-	-	-	-
Total oil fields and Hides GTE	**-**	**-**	**0.7**	**98.8**

Source: Oil Search
Note: Numbers may not add up due to rounding

3.4 Kutubu

The Kutubu Oil Project consists of a network of oil producing wells in the Iagifu-Hedinia, Usano and Agogo fields, a gathering system, the onsite Agogo Production Facility and Central Processing Facility, a 270 km crude oil pipeline to the coast and the Kumul Export Terminal located in the Gulf of Papua, 40 km from the coast. The oilfields are operated under PDL 2 while the pipeline operates under PL 2. Both licences were issued in December 1990 for terms of 25 years and were extended in December 2009 for an additional 25 years until December 2035. Oil Search has a 60.05% interest in the project and is the operator. The other joint venture participants are ExxonMobil (14.52%), Merlin Petroleum Company (18.69%) and Petroleum Resources (Kutubu) Ltd (6.75%). Petroleum Resources (Kutubu) Ltd represents the PNG Government and landowners.

Oil was first discovered in the Iagifu-Hedinia structure in 1986 and production commenced in June 1992, making Kutubu the first commercial oilfield development in PNG. Kutubu has produced a total of 371 mmbbl to December 2020. Production peaked in 1993 at approximately 125,000 bopd and has since declined significantly due to natural field depletion. From 2006 to 2016, production was relatively stable in the range 5.0 – 6.5 mmbbl per annum, in part due to the drilling of additional development wells at Kutubu, Agogo and Usano that were successful in arresting the natural field decline. Production further declined to 4.4 mmbbl in 2017, 2.7 mmbbl in 2018 and 2.3 mmbbl in 2019, before a marginal increase to 2.6 mmbbl in 2020. Recent production levels reflect the impact of the Highlands earthquake, outages at the Central Processing Facility and repairs to the Kumul Marine Terminal. Oil Search drilled an additional development well in 2019, although suspended its plans to drill a second well in 2020 due to the low oil price environment.

Since 2014, gas from Kutubu has been delivered to the PNG LNG Project, with the balance of produced gas reinjected into the reservoirs to maintain pressure and enhance oil recovery. Kutubu delivered gas to the PNG LNG Project at a rate of 77 mmscf per day in 2020.

As at 31 December 2020, the Kutubu and Agogo fields had remaining recoverable 2P reserves of 13.7 mmbbl of oil and 2C contingent resources of 0.5 mmbbl net to Oil Search. The main reserves are contained within high permeability oil rims in the Toro and Digimu sandstones with smaller volumes in the Iagifu and Hedinia reservoirs. There are 21 active wells in the Iagifu-Hedinia fields, including three gas injection wells and two water injection wells, 13 active wells in the Agogo field, including two gas injection wells, and 11 active wells in the Usano field, also including two gas injection wells. The light, sweet ~55-degree API oil produced ("Kutubu Blend") is transported to the Kumul terminal via the PL 2 pipeline and exported to Australia, China and other markets in Asia. Other oil producers in the region use the PL 2 pipeline and Kumul terminal and pay a volume-based tariff.

3.5 Moran

The Greater Moran Oil Project ("Moran") includes the Central Moran and North West Moran ("NW Moran") fields and is operated under three licences, PDL 2, PDL 5 and PDL 6, with a unitisation split of 44:55:1. Moran is located in the Southern Highlands Province, 480 km north-west of Port Moresby. Oil Search has a 49.51% interest in Moran and is the operator. The other joint venture participants are ExxonMobil (26.82%), Eda Oil Ltd (11.28%), Merlin Petroleum Company (8.31%) and landowner interests (4.09%).[8]

Oil was first discovered at Moran in PDL 2 in 1996. Production commenced within licence area PDL 2 in 1998, PDL 5 in 2000 and PDL 6 in 2005. Between 1998 and 31 December 2020, Moran yielded a total of 95 mmbbl of oil. Moran produced 3 – 5 mmbbl per annum from 1998 to 2004, after which production increased in each year to 2007 as a result of the tie-in of NW Moran, infrastructure debottlenecking and the drilling of several additional infill wells. [9] Production has been in general decline since 2007, and while it was relatively stable at around 3 – 4 mmbbl per annum from 2012 to 2016, it then materially declined. Production fell to 2.6 mmbbl per annum in 2017, 0.6 mmbbl per annum in 2018 and 0.3 mmbbl per annum in 2019. The Highlands earthquake in 2018, in addition to unscheduled maintenance at the Kumul Marine Terminal in 2019, significantly affected Moran and its associated facilities. [10] Tribal conflicts following the earthquake also restricted Oil Search access to the NW Moran site, and thereby delayed earthquake-related repairs. Production recovered to 2.1 mmbbl in 2020, reflecting contributions from a well sidetrack and two well workovers conducted in 2019, improved plant reliability and the resumption of production from NW Moran.

As at 31 December 2020, 2P reserves at Moran were 8.5 mmbbl and 2C contingent resources were 0.1 mmbbl (Oil Search share). The reserves are generally contained within high permeability oil rims in the Toro and Digimu sandstones. There are 10 production wells and four gas injection wells. Moran production is first processed at the Agogo Production Facility to separate the oil from the gas. The liquids are then transported to the Central Production Facility for further processing, storage and export through the crude oil export pipeline. The Moran participants pay a tariff to the Kutubu (PDL 2 and PL 2) participants for the use of these facilities. Separated gas is reinjected back into the reservoirs for pressure maintenance. The Moran crude is similar to the Kutubu crude and blended with the Kutubu Blend for export.

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[8] Eda Oil Ltd is a subsidiary of Kumul Petroleum and represents the PNG Government. Merlin Petroleum Company is a subsidiary of JX Nippon.

[9] NW Moran was tied-in in 2005 via a 23 km pipeline to the Agogo Production Facility.

[10] During 2019, Moran was shut-in for 202 days, primarily to preserve reservoir pressure given extended compression outages at the Agogo Production Facility. The compression system issues were ultimately a result of the damage caused by the Highlands earthquake in 2018.

3.6 Gobe

The Gobe Oil Project ("Gobe") comprises two producing oil fields, SE Gobe and Gobe Main, and the undeveloped Saunders field. The fields are located approximately 85 km to the southeast of Kutubu. SE Gobe was discovered in 1991 and Gobe Main in 1993, approximately 5 km to the northwest of SE Gobe. The discovery of SE Gobe was particularly significant because, in contrast to other fields in the region, commercial quantities of oil were discovered in the Iagifu sandstones rather than in the Toro sandstones. Gobe Main's oil is also located in the Iagifu sandstones. In 2001, the Saunders well was drilled in PDL 4 at the southeast margin of SE Gobe but did not produce hydrocarbons

Gobe Main is located wholly within PDL 4, while SE Gobe straddles PDL 4 and the adjoining PDL 3. PDL 3 and PDL 4 were initially unitised in 2000. There have since been two redeterminations, one in June 2001 and another effective from February 2016. [11] The current economic ownership structure is outlined below:

GOBE OIL PROJECT – OWNERSHIP

FIELD	PERMITS	JV PARTNERS
SE Gobe	PDL 3 / PDL 4	Oil Search (22.34%) Merlin Petroleum Company (39.09%) Santos (7.45%) ExxonMobil (7.72%) Kumul Petroleum (21.4%) Petroleum Resources (2%)
Gobe Main	PDL 4	Oil Search (10%) Merlin Petroleum Company (73.48%) ExxonMobil (14.52%) Petroleum Resources (2%)

Source: Oil Search

Oil Search operates Gobe Main and SE Gobe and is the operator of PDL 4. Santos operates PDL 3.

Production commenced at both SE Gobe and Gobe Main in 1998, and has totalled approximately 76 mmbbl to 31 December 2020. Production from SE Gobe peaked at 18,500 bopd in December 1998 and from Gobe Main at 20,000 bopd in September 1999. Production has since declined in each year since due to natural depletion, with the exception of slight increases in production from SE Gobe in 2005 and 2006, in part due to the drilling of an additional well. For the year ended 31 December 2020, Gobe Main produced 0.11 mmbbl and SE Gobe 0.10 mmbbl on a 100% basis. Relative to Kutubu and Moran, Gobe was the least affected by the Highlands earthquake in 2018, and both SE Gobe and Gobe Main have benefited from stable operations at the Gobe Processing Facility (GPF).

Since March 2015, the Gobe Oil Project has been exporting gas to the PNG LNG Project. In 2020, Gobe Main exported 11.7 bcf (gross) and SE Gobe exported 6.6 bcf (gross). Gobe Main is an AG field and forms part of the PNG LNG Project, while SE Gobe supplies PNG LNG through third party gas sales.

As at 31 December 2020, Gobe Main had 2P reserves of 0.01 mmbbl of oil and 2C contingent resources of 0.03 mmbbl of oil net to Oil Search. SE Gobe had 2P reserves of 0.02 mmbbl of oil and 5.4 bcf of gas net to Oil Search. SE Gobe also had contingent resources of 2.3 bcf of gas net to Oil Search. Both fields are approaching the end of their lives. The Gobe operations comprise four production and two injection wells at SE Gobe and three production wells and one injection well at Gobe Main. Oil is processed at the GPF located in PDL 4 and exported via an 8 km pipeline to the Kutubu Export Pipeline and the Kumul Marine Terminal. As part of the PNG LNG Project, the PL 3 export line was modified which allowed the PL 2 participants to utilise the crude storage tanks at the GPF. Gobe pays a tariff to the PL 2 participants for the

[11] The redetermination in 2016 resulted in a reduction in Oil Search's interest in SE Gobe from 25.55% to 22.34%, in line with a previously agreed amendment to the relevant field unitisation and operating agreement. The redetermination was triggered by the cumulative gas exported from SE Gobe exceeding 8.0 bcf. Oil Search's interests in PDL 3 and PDL 4 were not impacted.

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use of the Kutubu Export Pipeline and associated infrastructure. The Gobe crude is blended in with the Kutubu Blend for sale.

3.7 Hides GTE

The Hides GTE project consists of the large Hides gas field located 80 km northwest of Kutubu in PDL 1, a small gas conditioning plant at the Hides Production Facility, a pipeline and other infrastructure. Oil Search owns 16.66% of PDL 1 and 100% of the Hides GTE project.

Hides was discovered in 1987 and is approximately 30 km long and 5 km wide. The majority of gas production from Hides is dedicated to the PNG LNG Project, with the balance purchased and treated by the Hides GTE project and on-sold to the Porgera Gold Mine for power generation. Hides GTE has supplied the Porgera Gold Mine since 1991 and production to 31 December 2020 has totalled 137 bcf of gas and 3.0 mmbbl of condensate.

Gas is produced from two wells within the Hides gas field (Hides 1 and Hides 2) and transported via pipeline (PL 1) to the gas conditioning plant at the Hides Production Facility. The gas produced is sold under a long-term gas supply contract to the Porgera Joint Venture ("Porgera") and delivered to a Porgera-owned 42 MW power station, located adjacent to the Hides Production Facility, for electricity generation. The electricity is subsequently transmitted to the Porgera Gold Mine via overhead wire. The condensate produced along with the gas is distilled into naphtha and diesel which is used within the Hides Production Facility and sold into the local market, with the balance transported to the Central Processing Facility at Kutubu for export.

Hides GTE is currently in care and maintenance, being shut-in in April 2020 due to the suspension of mining operations at the Porgera Gold Mine. The current supply contracts, due to expire in December 2021, are accordingly in Force Majeure. The PNG government denied an extension to the mining lease to force the renegotiation of the Porgera Joint Venture Agreement. Porgera and the PNG government agreed to a revised arrangement in April 2021 and the mine is expected to resume operations in early 2022. Oil Search expects to negotiate a multi-year extension with Porgera allowing for total production to reach the initial allocation of 150 bcf.

Nil reserves were booked at 31 December 2020 due to the uncertainty around resumption of operations.

A simplified schematic of Oil Search's PNG oil operations is set out below:

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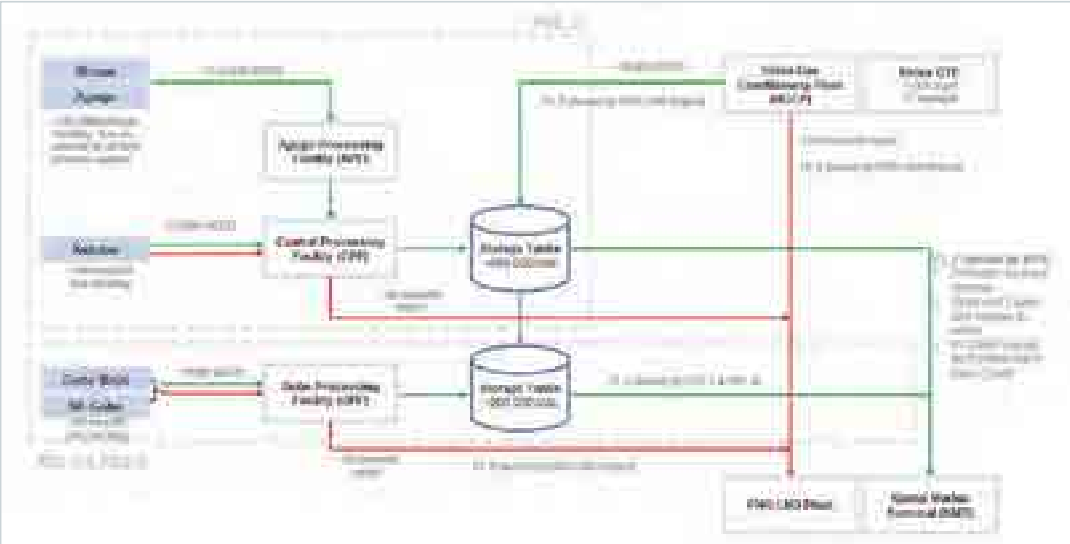
PNG OIL OPERATIONS – SIMPLIFIED SCHEMATIC



Source: Oil Search

4 PNG Exploration

4.1 Overview

Papua New Guinea remains highly prospective for oil and gas. The 2016 Oil Search Total Petroleum Systems Analysis report estimated that PNG could host 40 tcf of gas and in excess of 550 mmbbl of oil yet to be discovered. In the past few years, Oil Search has undertaken a comprehensive review of the Papuan Basin leading to a refresh of its licence portfolio and the exit of acreage it considered non-prospective. During 2020 and 2021, Oil Search approximately halved its number of exploration and appraisal licences. The licences that it retained are mostly close to existing infrastructure and represent greater value for limited near-term expenditure. Oil Search is focused on commercialising its discovered resources and does not intend to conduct any greenfield exploration in the foreseeable future.

4.2 Northwest Fold Belt

In addition to the undeveloped gas fields discussed above, which are intended to backfill the two existing PNG LNG trains, the Northwest Foldbelt also hosts the Karoma prospect in PPL 402 (Oil Search: 37.5% and operator) and the Hides Footwall in PDL 1 (Oil Search: 16.66%). Oil Search completed the acquisition of 2D seismic in 2020, which will assist with constraining Karoma and determining appropriate drill locations. If developed, Karoma would likely backfill the PNG LNG Project. The Hides Footwall prospect, located in the footwall structure beneath the northeast area of the Hides gas field, would likely provide volumes to the PNG LNG Project. Oil Search has planned for appraisal drilling at both the Karoma and Hides Footwall prospects in 2024. Oil Search also intends to acquire seismic across two other prospecting licences in the Northwest Fold Belt, PPL 545 and PPL 487, in 2023.

4.3 Central Fold Belt

The Central Foldbelt contains several prospects that are adjacent to the Oil Search-operated oil fields and have either standalone development or tie-back potential. The Central Foldbelt includes the Agogo South, South Usano East, Moran Deep and Mosa Deep prospects in PDL 2 (Oil Search: 60.05% and operator) . Agogo South and South Usano East are proximate to producing fields and would tie-in through new or

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existing flowlines to the Agogo Production Facility and Central Processing Facility respectively. Moran Deep and Mosa Deep are believed to contain oil in the footwall structures beneath the existing Moran, Agogo and Hedinia oil fields. Oil Search has begun planning to drill Agogo South in 2023 and it continues to look for opportunities to drill out other exploration prospects in future. Oil Search drilled an exploration well at Gobe Footwall in 2020, but this was ultimately unsuccessful and abandoned.

4.4 Eastern Fold Belt

The Eastern Foldbelt hosts several targets that offer good potential for commercial oil and gas discoveries. As discussed in section 2, there is the potential for discovered gas fields to be tied into to Papua LNG. The Eastern Foldbelt also contains several prospects such as Whale and Mako in PPL 474 (Oil Search 25.0%), White Tail and Puri Deep in PPL 475 (Oil Search 25.0%), Wildebeest, Wolverine and Bear South in PPL 476 (Oil Search 25.0%) and Antelope South in PRL 15 (Oil Search 22.8%). During 2018 and 2019, Oil Search completed 2D seismic acquisition covering approximately 550 km over PPL 475, PPL 476 and PRL 39 and plans to conduct further seismic acquisition covering 190 km in 2022 to mature a selection of these prospects to drillable status. Wildebeest, in particular, is a large volume prospect with the potential to host sufficient gas to support an additional two LNG trains in the future. White Tail, Puri Deep, Bear South and Antelope South are located near Elk-Antelope and would likely tie into the Papua LNG infrastructure. The Operators have planned exploration drilling at White Tail in 2023/24, Wildebeest in 2024, Whale in 2025 and Antelope South in 2026.

4.5 Offshore

Oil Search currently has interests in multiple licences in the shallow and deep waters of the Gulf of Papua. Oil Search plans to exit the majority of this acreage, with the exception of PRL 41 (Oil Search: 100%) which contains the Flinders and Hagana gas discoveries. Oil Search discovered Flinders and Hagana in 2013. They are located approximately 80 km from the Kumul export terminal and is estimated to contain around 200 bcf of gas. The shallow water Gulf of Papua should allow for relatively low appraisal and development costs.

5 Alaska

5.1 Background

On 1 November 2017, Oil Search announced the acquisition from Armstrong Energy LLC ("Armstrong") and GMT Exploration Company LLC ("GMT") of a 25.5% interest in the Pikka Unit and adjacent exploration acreage, a 37.5% interest in the Horseshoe acreage and a 37.5% interest in the Hue Shale acreage for a cash consideration of $400 million. The assets are located in the Alaska North Slope area, on Alaska's north coast. The acquisition completed on 14 February 2018 and Oil Search assumed operatorship of the assets in March 2018.

Oil Search materially increased its interest in June 2019, by exercising an option to acquire the remaining Armstrong and GMT interests in the Pikka Unit and the Horseshoe Block, 25.5% and 37.5% respectively, as well as an additional 25.5% interest in the adjacent exploration acreage and 37.5% in the Hue Shale, for $450 million. Oil Search also entered arrangements with Repsol to align its ownership interests such that it would own a 51% interest in all co-owned leases and a 51 % share of a 76% interest in exploration in the Quokka area in which Armstrong and GMT retained a combined 24% interest. Pursuant to the arrangements, Oil Search transferred a 24% interest in the Horseshoe area and a 12.24% interest in the exploration acreage to Repsol, in exchange for a 51% interest in the Kooka leases in which Repsol had a 100% interest, located immediately east of the Horseshoe area, for a net payment to Oil Search of $64.4 million.

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Since 2018 it has also acquired a number of smaller interests in leases and lease tracts for a total consideration of approximately $24 million.

Oil Search is currently considering the divestment of a 15% interest in the Pikka Unit and adjacent exploration acreage. Oil Search plans to retain operatorship of the assets following any divestment.

The current ownership structure of the assets noted above (together the "Alaskan Assets") is outlined below:

ALASKAN ASSETS – OWNERSHIP STRUCTURE

LEASE AREA	OIL SEARCH	ARMSTRONG	GMT	REPSOL	BOREALIS ALASKA
Pikka Unit [12]	51%	-	-	49%	-
Thetis	51%	-	-	49%	-
Horseshoe	51%	-	-	49%	-
Quokka | Atlas A, Kachemach	38.76%	18%	6%	37.24%	-
Kooka | Grizzly	51%	-	-	49%	-
Lagniappe A | Hue Shale	75%	25%	-	-	-
Lagniappe B | East Hue Area	50%	50%	-	-	-
Lagniappe C | East Hue Area	50%	50%	-	-	-
Nanushuk West A	36%	36%	-	-	28%
Nanushuk West B	50%	50%	-	-	-

Source: Oil Search

Oil Search has established a team in Anchorage dedicated to the Alaskan Assets, comprising 134 employees and 25 contractors.

5.2 Asset Overview

The Alaskan Assets comprise 592 leases across 7,652 km^2 of acreage and are situated in an established and highly prolific oil producing region. The leases are surrounded by established infrastructure with easy access to supply and export markets as shown on the map below. The town of Deadhorse is a major supply base for the Alaska North Slope. The Dalton Highway, which links Deadhorse to the port of Valdez on the Alaskan south coast, approximately 1,300 km from the fields, allows year-round road support. The Trans Alaska Pipeline System ("TAPS") runs parallel to the Dalton Highway and then south through Alaska and transports crude oil to the Valdez Marine Terminal ("VMT") for export.

12 Includes Pikka East and Pikka North.

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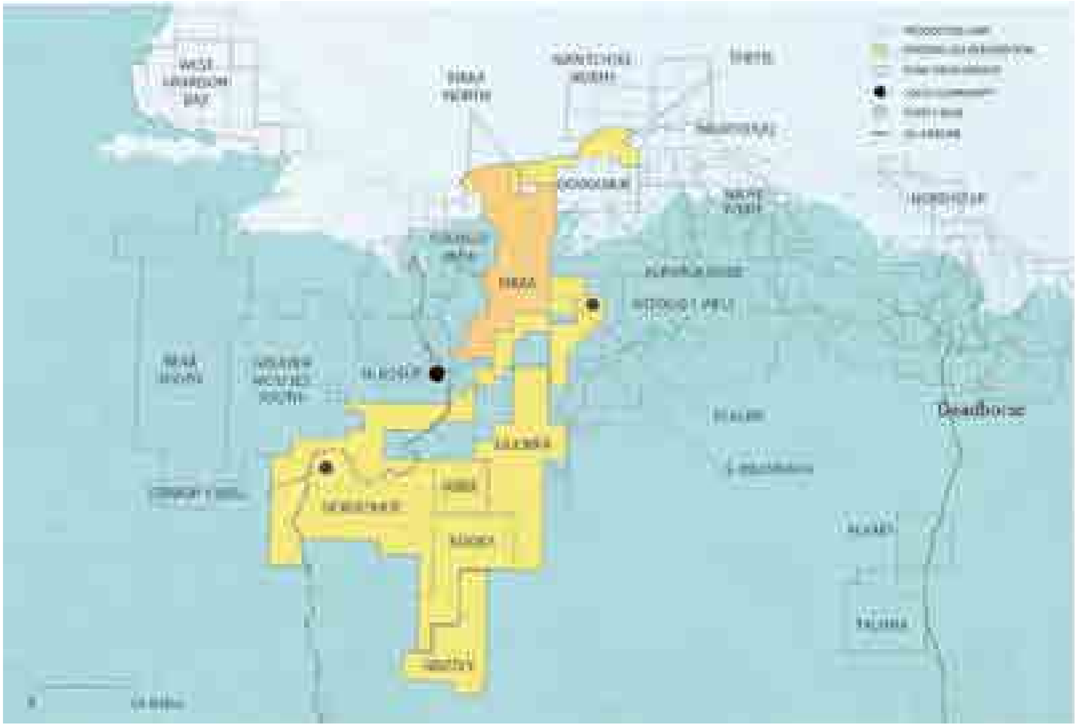
KEY ALASKAN ASSETS – LOCATION



Source: Oil Search

The leases contain the discovered Nanushuk conventional oil field and numerous satellite field resources. Nanushuk is a long and narrow reservoir (50km long and 4-6km wide) that extends along a broadly north-south trend through the Pikka Unit down to the Horseshoe area. The field was intersected by drilling in the Pikka Unit in 1995, but not recognised due to a lack of seismic data. Nanushuk was discovered in the Pikka Unit in 2013 and was intersected in the Horseshoe area by the Horseshoe 1 well in 2017. Nanushuk was more recently appraised by the Pikka B, Pikka C, Mitquq 1 and Stirrup 1 wells, drilled by Oil Search in the Pikka Unit and Horseshoe Block, as well as the Putu 2, CD-595 and Stony Hill 1 wells, drilled by ConocoPhillips between the Pikka Unit and the Horseshoe Block. The field has been defined by a total of more than 20 wells, 10 production tests and 3D seismic data. Nanushuk contains sweet crude oil with an API of around 30 degrees.

At the time of acquisition, Oil Search had assumed a gross 2C discovered resource of 400 mmbbl in the Pikka Unit Nanushuk reservoir and 100 mmbbl in the adjacent satellite fields. Oil Search accordingly booked net 2C resources of 127.5 mmbbl at 31 December 2018, reflecting its 25.5% interest in the Pikka Unit at the time. As a result of successful appraisal programmes throughout 2018, 2019 and 2020, as well as the acquisition of additional equity interests in the Alaskan Assets, Oil Search now carries net 2C resources of 391.5 mmbbl in the Pikka Unit and 102.1 mmbbl in the Quokka and Horseshoe trends (31 December 2020).

Oil Search plans initially to develop the Pikka Unit, which is located approximately 84 km west of Deadhorse and 11 km northeast of the community of Nuiqsut. The Pikka Unit consists of 89 separate subsurface leases and is situated between existing facilities and the currently producing ConocoPhillips-operated Colville River Unit and Kuparuk River Unit. It is proximate to the ConocoPhillips-operated Alpine and Kuparuk River producing oil fields, in addition to several others. The majority of the Nanushuk exploration and appraisal wells were drilled within the Pikka Unit or immediately adjacent to and on trend with the Pikka Unit.

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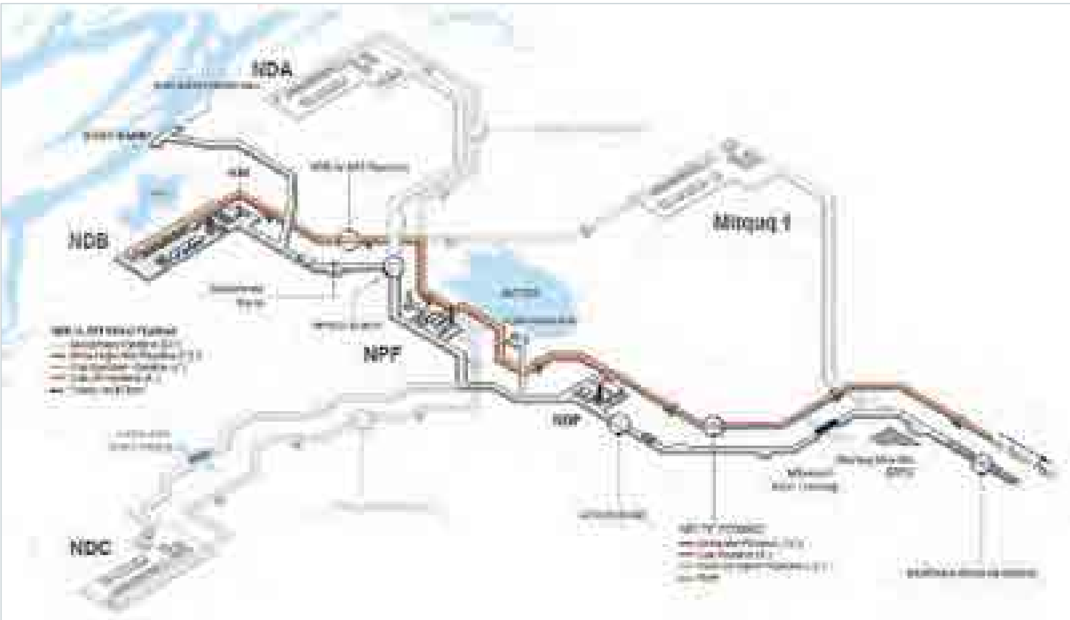
Most of the remaining acreage acquired is unexplored and represents exploration and appraisal upside, with unrisked resource potential estimated at ~1,400 mmbbl outside the Pikka Unit.

5.3 Pikka Unit Development

Oil Search and Repsol had initially planned a "full field development" including three drill sites (ND-A, ND-B and ND-C), 106 production and injection wells, a processing facility with nameplate capacity of 120,000 bopd, pipelines and other supporting infrastructure. Total development costs had been estimated in the range $4.8 billion to $6.1 billion. In March 2020, Oil Search announced that it would delay FID due to the prevailing low oil price environment and in November 2020, announced that it would pivot to a lower cost, phased development for the Pikka Unit.

The initial project ("Pikka Phase 1") will target oil accumulations in the Nanushuk and Alpine C reservoirs and produce around 80,000 bopd with first oil in 2025. Pikka Phase 1 is planned to include one well pad ("ND-B"), a central processing facility ("NPF"), an operations pad ("NOP"), infield, import and export pipelines, and a tie-in pad to the northeast of the ConocoPhillips-operated Kuparuk Central Processing Facility 2 ("Kuparuk CPF2"). Pikka Phase 1 will also include a bridge, a boat ramp, a seawater treatment plant ("STP"), a grind-and-inject facility and infield and access roads. Most of the facilities will consist of modules that are fabricated offsite in Canada, Alaska or Asia , including the NPF and STP. The following diagram provides a stylised representation of the key facilities, including the contemplated Phase 2 development:

PIKKA UNIT DEVELOPMENT



Source: Oil Search

The Nanushuk and Alpine C reservoirs will be developed using waterflood as the primary depletion strategy, supplemented by miscible water-alternating-gas ("MWAG") injection to enhance oil recovery. The Pikka Phase 1 development plan includes 43 producer and injector wells that will employ multi-stage hydraulically stimulated completions. 41 of these will target the Nanushuk reservoir with the remaining 2 to target the Alpine C reservoir. Wells will be spaced at approximately 1,800 feet. The wells are categorised into four tiers, based on step-out requirements. Tier 1, 2 and 3 wells will be drilled using an available "standard" drill rig. An extended reach drilling rig will be required for the Tier 4 wells, although these wells are not expected to be drilled before 2030. The planned development also includes two disposal wells that are designed to handle all drilling and operational waste, comprising a grind-and-inject well, located at ND-B, and a produced water well, located near the NPF.

Oil Search and Repsol plan to construct the NPF on a gravel pad, which will house processing and utilities modules, including a power generation facility. Field wide power will be generated at the NPF and provided to ND-B, the NPF and the NOP. The NPF will be fabricated in truckable modules and use standardised equipment, allowing for the simple addition of capacity as subsequent phases of the Pikka Project are undertaken.

The operations centre, to be developed on the gravel NOP, will include a camp for operations and maintenance personnel, maintenance shops, warehouses, water and wastewater treatment, a fuel station, telecommunications infrastructure, and stand-by diesel power generators.

Hydrocarbon fluids from ND-B will be transported for processing at the NPF via multi-phase infield pipelines. Crude oil processed at the NPF will be transported via an export pipeline to the tie-in pad (located adjacent to Kuparuk CPF2) for tie-in to the Kuparuk Pipeline Extension, which will deliver it to the TAPS. The TAPS will subsequently transport the oil to the VMT for export. The TAPS is operated on an open access regime and has sufficient ullage due to the declining production profile of existing North Slope fields.

The produced water separated at the NPF, and water imported from the STP, will be transported back to ND-B for re-injection into the reservoirs for pressure maintenance and enhanced oil recovery. Separated gas will be compressed and dehydrated at the NPF and used for fuel, with surplus gas piped back to ND-B for gas lift and reinjection. Third party import gas will be used for operational efficiency and when produced gas is insufficient to meet fuel needs.

Total gross development costs for Phase 1 have been estimated in the range $2.7 billion to $3.1 billion, comprising facilities capital expenditures of $1.7 billion to $1.9 billion and drilling expenditures of $1.0 billion to $1.2 billion. Pikka Phase 1 is expected to require a Brent price of less than $40/bbl to break even on a PV10 basis.

The roads and pads for Pikka Phase 1 were installed and completed in 2020, including construction of the ND-B, NPF and NOP gravel pads, a 59m bridge and an 18.5km road. Pikka Phase 1 entered FEED in February 2021 and is targeting FID in the next six months. FID timing is ultimately dependent on completing FEED, receipt of approvals from Repsol, securing appropriate funding and achieving the desired ownership structure, including Oil Search's proposed sell down to ensure the appropriate risk allocation is in place.

The modular concept enables Oil Search to better manage the Pikka Unit development through oil price cycles because the expansion modules are at smaller increments and require reduced engineering, manufacturing lead time and cost. Phase 2 would include the development of two additional (already permitted) drill sites at ND-C and ND-A. It would also include the construction of infield pipelines to connect ND-C and ND-A to the NPF as well as an increase in the capacity of the NPF, the STP and other infrastructure. Phase 2 is planned for 40,000 bopd and could either backfill the Pikka Unit or be an expansion, increasing Pikka Unit production to 120,000 bopd. An expansion would be consistent with the development plan originally contemplated.

There are numerous additional reservoirs drillable from ND-B, ND-C and ND-A that could backfill the Pikka Unit facilities at a relatively low incremental cost of development, subject to further appraisal. There are also satellite reservoirs, both inside and outside the Pikka Unit, that could be tied into the NPF but would require the development of additional drill sites. Mitquq, Pikka North or Horseshoe North could be commercialised as step-out extensions and modular expansions of the Pikka Unit or alternatively backfill the Pikka Unit, subject to further appraisal.

Oil Search has received all key regulatory approvals in relation to Pikka Phase 1 and Phase 2. Armstrong and Repsol had initially submitted a permit application for the development to the US Army Corps of Engineers

("USACE") in June 2015.[13] The USACE conducted an environmental impact study ("EIS") and published its draft EIS on 1 September 2017 and its final EIS on 2 November 2018. Following an amendment to the development plan, the USACE issued the permit and positive record of decision in May 2019.[14] Oil Search has since received a modified USACE permit to allow for the construction of the STP, entered into a land use agreement with Kuukpik Corporation, the representative native corporation and landowner for Nuiqsut, and has received approval from the North Slope Borough Assembly.

5.4 Exploration

In April 2020, Oil Search completed an exploration programme, comprising the Mitquq 1 and Stirrup 1 wells, to evaluate the upside resource potential of the Nanushuk field. Both wells were drilled, logged, cored and flow tested before being plugged and abandoned.

The Mitquq 1 exploration well was located in the Pikka East area, approximately 9 km east of the proposed ND-A pad site. The well targeted a structure of less than 100 mmbbl for potential tie-in to the planned Pikka Unit NPF. Mitquq 1 included both a vertical well and a sidetrack. Mitquq 1 encountered 52.5 metres of net hydrocarbon pay with a gas cap of 9 metres. The well flowed at a stabilised rate of 1,730 bopd from a single stimulated zone.

The Stirrup 1 exploration well was located within the Horseshoe area, approximately 12 km west of the Horseshoe discovery and 35 km south-west of the Pikka Unit development area. Stirrup 1 targeted a significantly larger Nanushuk structure relative to Mitquq 1, encountered an oil column with net hydrocarbon pay of 23 metres and flowed at a stabilised rate of 3,520 bopd from a single stimulated zone.

The technical studies on these explorations wells, in addition to reprocessed 3D seismic data, resulted in a 122.5 mmbbl net 2C resource addition as at 31 December 2020. The results have indicated that Mitquq is suitable to tie into the Pikka Unit while Stirrup and the existing Horseshoe discovery may support a standalone processing facility further south. While further appraisal is ultimately required, no additional activities are planned for the remainder of 2021. Most exploration in the Alaska North Slope requires extensive planning given the short window of time when ice roads can be constructed to allow access across the frozen tundra to areas inaccessible via existing roads.

5.5 Investment Regime

Alaska is a stable investment destination, favourable to the development of oil and gas resources. Alaskan state tax amounts to 9.4% with allowances for royalties, production tax, property tax and conservation surcharges. The US federal income tax is 21% with deductions available for state tax, production tax and other charges. Oil Search estimates that the effective overall state and federal government takes in relation to the Pikka Project at prevailing oil prices will be approximately 35 - 40%.

6 Other Assets and Liabilities

6.1 NiuPower

NiuPower, an entity held 50:50 by Oil Search and Kumul, owns and operates the 58 MW gas-fired Port Moresby Power Station ("PMPS"). The PMPS is located adjacent to the PNG LNG plant site in Port Moresby and is connected to the Port Moresby Grid ("Grid"), providing power to the capital city and its surroundings, including the Central Province. NiuPower completed construction of the PMPS in February 2019 and the plant commenced commercial operation in October 2019. Total pre-production development costs approximated $100 million.

[13] The USACE is the lead federal agency for the Pikka Unit Development and sits under the United States Department of Defence.
[14] Pursuant to Section 404 of the U.S. Clean Water Act.

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NiuPower purchases gas from NiuEnergy (an entity also held 50:50 by Oil Search and Kumul) which in turn purchases the gas from the PNG LNG Project and presently pays a toll charge for delivery of the gas via a PNG LNG-owned pipeline which is on-charged to PPL.

Electricity is produced from six reciprocating internal combustion engines that can flexibly deliver power to the Grid from 6 MW to 58 MW in line with demand. NiuPower supplies power to PNG Power Limited under a long-term Power Purchase Agreement ("PPA").

At full capacity, the PMPS supplies approximately 70% of the average load of the Grid and supplants higher cost liquid fuel (heavy fuel oil and diesel) power generation. The PMPS reduces the GHG intensity of PNG's power generation by reducing the use of heavy fuel oil-based generation. It also significantly enhances the reliability of Port Moresby's electricity generation, which would otherwise rely on hydroelectric power generation.

PORT MORESBY POWER STATION

Source: Oil Search

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APPENDIX 4

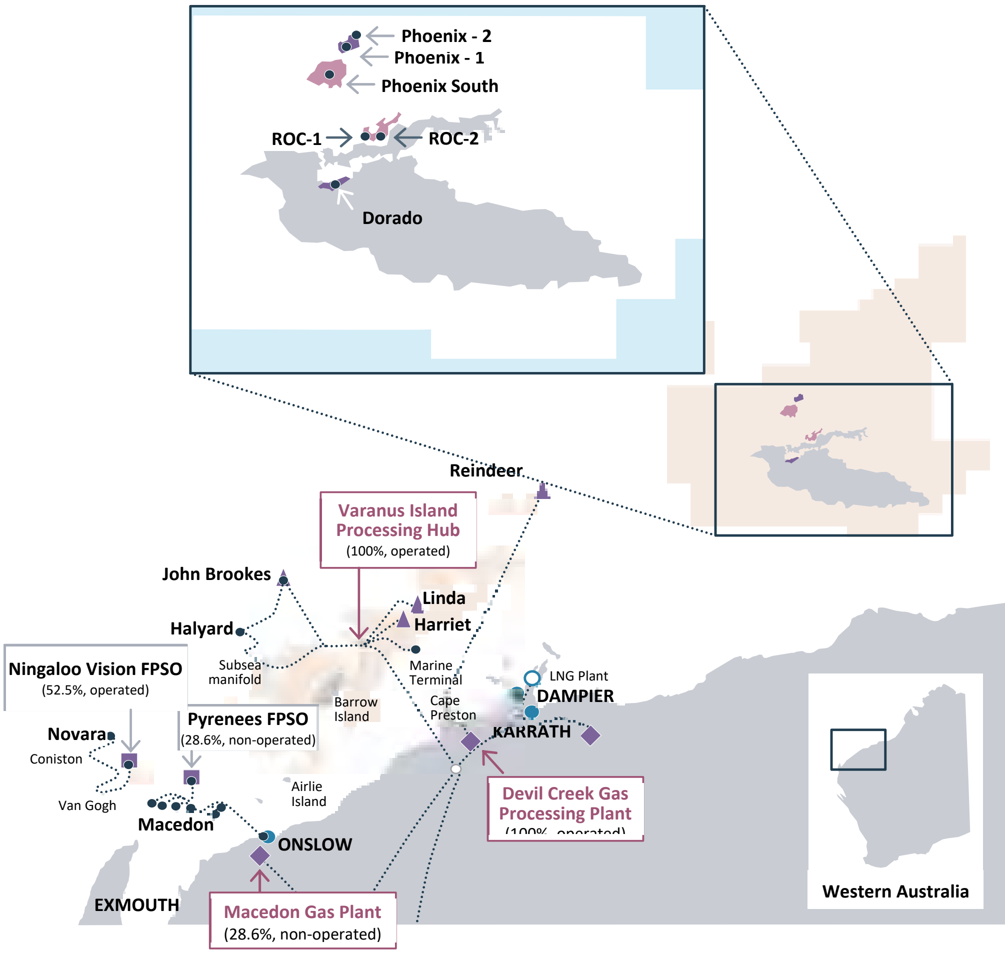
PROFILE OF SANTOS ASSETS

1 Western Australia

1.1 Overview

Santos has been operating in Western Australia since discovering oil in the Carnarvon Basin in the 1980s and is the largest supplier of domestic gas in the state. The acquisition of Quadrant Energy in 2018 resulted in Santos increasing its interests in the Varanus Island and Devil Creek gas processing hubs from 45% to 100%, acquiring a 28.6% interest in the Macedon gas processing facility and acquiring interests in producing oil assets (Ningaloo Vision FPSO (52.5% interest) and Pyrenees FPSO (28.6% interest)) and associated oil fields. Santos also acquired Quadrant Energy's portfolio of exploration permits covering approximately 22,000 km^2 in the Bedout Basin, including the Dorado oil and gas project currently in the final phase of FEED evaluation.

SANTOS WESTERN AUSTRALIA – ILLUSTRATIVE MAP OF OPERATIONS



Source: Santos

In aggregate, Santos' gas processing facilities in Western Australia have a total processing capacity of over 670 TJ per day (equity adjusted). All of Santos' gas production is sold into the domestic Western Australia

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market, in which Santos had a market share in 2020 of close to 45%. The majority of its gas sales are under long-term inflation-indexed gas supply agreements to industrial users and energy retailers.

The majority of Santos' WA oil production is sold into the spot market for export. The Varanus Island processing plant also produces oil and condensate by-products.

1.2 Producing assets

Varanus Island Gas Project

Santos has a 100% interest in, and is the operator of, the Varanus Island facility and related offshore gas fields. The second largest supplier of domestic gas in Western Australia, the Varanus Island hub was approved for development in 1985 shortly after significant oil and gas reserves were discovered in the Harriet fields. Production from Harriet has now ceased and the facility sources gas from the following fields:

- **John Brookes**, Santos' largest gas reserve in Western Australia. This gas field was first discovered in 1998 and approved for development in 2004. The John Brookes field has been developed with an unmanned wellhead platform and four production wells. The gas field is connected to the Varanus Island onshore facilities via a 55 km subsea pipeline; and
- **Greater East Spar,** which is comprised of the Halyard and Spar fields. Halyard was first discovered in 2008, before being approved for development in 2010. The 44 km long East Spar subsea pipeline transports gas outputs to the Varanus Island processing facility.

Santos is developing the Spartan project to replace existing reserves and extend the life of the Varanus Island gas hub, following FID in February 2021. The Spartan development is a single well subsea development in shallow waters that will be tied-back approximately 18km to the John Brookes well head platform, at an upfront capital cost of approximately $120m. Production is expected to commence in 1Q 2023.

Varanus Island is located approximately 60 km offshore from the north-west coast of Western Australian coast, near Karratha. The Varanus Island gas facility comprises a three-train gas processing facility with a nameplate capacity of 390 TJ per day, two 39,750 kL crude oil storage tanks, and a camp and mess facilities that can support up to 150 on-site employees.

To offset declining reservoir pressure in the John Brookes fields, increase production flow rates and extend the life of the John Brooks gas field, Santos is installing inlet gas compression equipment at the Varanus Island facility. The compression project is nearing completion and expected to commence operations by the end of 2021.

Processed sales gas from the Varanus Island facility is transported via a high-pressure undersea pipeline to the mainland. Once onshore, the pipeline connects to the Dampier to Bunbury Natural Gas pipeline and the Goldfields Gas Transmission pipeline, through which gas is distributed for domestic consumption.

The facility also produces oil and condensate by-products. Its crude oil products are generally viewed as very light sweet crude, with relatively high middle distillate yields and low residual yields. Varanus Island crude oil is sold to Australian and regional refineries on a short term or spot basis. Oil and condensate are exported from Varanus Island via tanker.

Devil Creek Gas Project

Launched in 2011, the wholly-owned Devil Creek gas project is Western Australia's third domestic-focused gas hub. The processing facility is the centrepiece of the Devil Creek gas hub which comprises an offshore gas field, subsea pipeline and the processing plant.

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Gas and condensate are sourced from Santos's wholly-owned Reindeer gas field in the Carnarvon Basin, 45 km northwest of Dampier. The gas field was first discovered in 1997 and, prior to the commencement of production, was expected to support more than 20 years of production based on approximately 485 PJ of 2P sales gas reserves and 1.6 million barrels of condensate. Neighbouring prospective resources (e.g., Dancer) have the potential to extend the life of the operations. FID for Reindeer and the Devil Creek processing facilities was announced in 2008 and the development was completed in 2011.

Gas production at Reindeer is via an unmanned wellhead platform and three production wells installed at a water depth of 65 metres. Raw gas is transported via a 105 km long offshore and onshore pipeline to the Devil Creek gas processing facility.

The Devil Creek facility was constructed on a greenfield site approximately 50 km from Karratha, Western Australia. The facility features a two-train gas processing facility with a combined nameplate capacity of 220 TJ per day as well as two 190kL condensate storage tanks. The gas processing facility compresses sales gas, which is sold into the domestic market via the Dampier to Bunbury pipeline. The Devil Creek gas project also produces stabilised condensate which is transported via haul road to the Kwinana Refinery.

Macedon Gas Project

The Macedon gas project is one of the newest domestic gas hubs in Western Australia and supplies close to 20% of Western Australia's gas supply[1]. The project is jointly owned by BHP Billiton (71.4% interest and operator) and Santos (28.6% interest) and comprises the Macedon gas field a subsea pipeline which connects to the onshore gas treatment and processing facilities and gas transport.

The Macedon gas project sources gas from the Macedon gas field in the Exmouth sub-basin, approximately 100 km offshore the Western Australian coast. This field was discovered in 1997 and the project was approved for development in 2010. Recoverable reserves were estimated to be between 400 and 750 bcf of gas[2]. The $1.5 billion project was completed in 2013 and produced first gas in August of that year.

The Macedon gas field was developed via four subsea production wells. Production output is transported onshore via a 75 km long subsea pipeline and umbilical. Once onshore, gas is transported via a 15 km long underground wet gas pipeline to the Macedon gas plant at Ashburton North. The Macedon gas plant consists of a single-train gas treatment and compression facility with a nameplate capacity of 220 TJ per day. Once processed, sales gas is transported via a 67 km long pipeline that connects the Macedon gas plant to the Dampier to Bunbury Natural Gas Pipeline.

Van Gogh Oil Project

Santos is the operator of the Van Gogh oil project, in which it owns a majority 52.5% interest. The remaining interest in the joint venture is held by Inpex Alpha Ltd (47.5% interest). The project comprises a network of offshore oil fields, subsea infrastructure, the Ningaloo FPSO vessel ("Ningaloo Vision") and smaller logistical support vessels.

The Van Gogh oil project is located approximately 45km offshore in the Exmouth sub-basin portion of the Carnarvon Basin. Production is sourced from three neighbouring oil fields, namely Van Gogh, Coniston and Novara, via subsea production wells. The Van Gogh oil field was discovered in 2003 at a water depth of approximately 400 metres and is the foundational oil field for the project. The Coniston and Novara fields were developed as tie-backs to the Van Gogh Oil project and commenced production in 2015 and 2016 respectively. Production requires reinjection of water and excess gas and the operations have reinjection capacity of up to 140,000 barrels of water and 80,000 Mcf of gas per day.

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[1] Source: Western Australia Gas Bulletin Board

[2] Source: ASX release, BHP Billiton, 24 September 2010

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The joint venture is undertaking the second phase of infill drilling in the Van Gogh field, to accelerate production and extend the life of the oil fields. This will involve the tie-in of three horizontal dual-lateral production wells, targeting approximately 10 mmbbl of gross reserves. Total capex is estimated to be $225 million (or $118 million for Santos' share) and excludes the incremental investment required for Phase 3 infill development.

Oil is transported to the Ningaloo Vision for processing and storage, with water and gas by-products transported back into the subsea development for re-injection. The Ningaloo Vision FPSO is a double-sided tanker with an internal turret mooring system that enables it to be anchored to the ocean floor near the Van Gogh oil field. The FPSO has a processing capacity of 63,000 bbl per day and storage capacity of 540,000 bbl. On-site FPSO operations are outsourced to Teekay.

Processed crude oil is offloaded to offtake tankers. Crude oil from the Van Gogh oil project is a heavy and moderately acidic semi-sweet crude with a high yield of distillates that is sought after by refiners with hydro processing and hydrocracking facilities. It is also in demand in the fuel oil market as a blending ingredient for low sulphur fuel oil. These products are predominantly exported to Asian fuel oil blenders and refiners at a premium over the spot Brent Oil benchmark price.

Pyrenees Oil Project

The Pyrenees oil project is a joint venture between the operator BHP (71.4% interest) and Santos (28.6% interest) and comprises a subsea development and an FPSO vessel that is used to process, store and offload oil to export tankers.

The Pyrenees FPSO vessel is located approximately 20 km from the Western Australia shoreline in the Exmouth sub-basin portion of the Carnarvon Basin. Development of the Pyrenees project was approved in June 2007 with first oil production in February 2010.

Oil is produced from 24 wells across the Stickle, Crosby, Ravensworth, Moondyne, Wild Bull and Tanglehead oilfields. The oil reserves from the Pyrenees oilfields are expected to support an estimated economic life of 25 years. In addition, the joint venture parties are pursuing the Pyrenees infill development Phase 4, a brownfield development comprising one dual lateral well and water shut-off intervention, which is expected to deliver up to 2.9 mmbbl of net reserves. The development is still at an early stage with production expected to commence in late 2022. Total capex is estimated to be $110 million (or c.$31 million for Santos' share) and excludes the incremental investment required for Phase 5 infill development.

Production from the Pyrenees oil fields is transported to the Pyrenees FPSO vessel for processing and storage. The FPSO is capable of producing 96,000 bbl per day with additional storage capacity of up to 850,000 bbl. Operations and maintenance activities are outsourced to MODEC under a 15-year contract.

Once stabilised, the processed crude oil is shipped by offtake tankers for export. The Pyrenees project produces heavy sweet crude oil that has similar qualities to the Van Gogh oil. Pyrenees crude oil is predominantly exported to Asian fuel oil blenders and refiners at a premium over the spot Brent oil benchmark price. The Pyrenees fields also produce gas by-products, which are reinjected into the nearby Macedon gas field for future recovery.

1.3 Future development and backfill opportunities

Santos owns interests in a number of offshore exploration permits in the Carnarvon Basin and Bedout Basin. Santos is focused on development of the Dorado oil and gas project.

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Dorado Project

The Dorado project is a shallow water (circa 90 meters in depth) integrated oil and gas development in the Bedout Basin. It is one of the largest oil discoveries on the North West Shelf and the largest oil discovery in the region in the past three decades.

The oil field was initially discovered in 2018 by the joint venture between Quadrant Energy and Carnarvon Petroleum. In August 2018, Carnarvon announced 2C resources for Dorado of 186 mmboe of liquids (oil and condensate) and 97 mmboe of gas (on a 100% basis). Santos acquired Quadrant Energy and its 80% interest in the joint venture, including the Dorado field, shortly thereafter. Appraisal activity commenced the following year and confirmed neighbouring oil and gas reservoirs. Based on initial studies, Santos expects Dorado to produce high quality crude oil with low CO_2 that will price at a premium to the Brent oil benchmark price.

The Dorado project is planned to be developed over two phases:

- **Phase 1**, which would involve the production of oil and condensate through a well head platform ("WHP") and an FPSO facility. Gas will be reinjected to enhance the oil and condensate recovery rates. First production is planned for 2026 with initial gross oil production estimated to be in the range of 75,000 to 100,000 bbl per day; and
- **Phase 2**, which would focus on gas production as backfill for Santos' domestic gas infrastructure in WA.

In August 2021, Santos announced the award of the FEED contracts for the FPSO facility and Wellhead Platform. The FPSO contract will confirm the technical requirements of the FPSO facility and seek to retain sufficient flexibility to support future growth and exploration.

During the FEED phase, Santos also intends to progress the drilling of exploration wells for the Apus and Pavo prospects, within 40 km of the Dorado field. These two prospects are potential subsea tiebacks to the Dorado project.

Santos submitted production licence applications in September 2021, with FID planned for mid-2022. Total capital expenditure for Phase 1 is estimated to be approximately $2 billion (or $1.6 billion for Santos's share). Santos has publicly stated its intention to consider options to sell down a portion of its majority interest in the Dorado project.

Other Exploration and Development

The remainder of Santos' exploration and development activities in Western Australia are tied to the backfill of its infrastructure assets. In addition to the advanced development projects described above (the Spartan development and Pyrenees infill development Phase 4), Santos has a number of other development opportunities including Corvus, Ginger, Kultarr, Spar Deep, Dancer and Yoorn.

Santos is also exploring carbon capture and storage technologies to repurpose depleted fields.

1.4 Resources and reserves

The resources and reserves for Santos' WA operations as at 31 December 2020 are summarised as follows:

SANTOS WESTERN AUSTRALIA – RESOURCES & RESERVES (NET TO SANTOS)

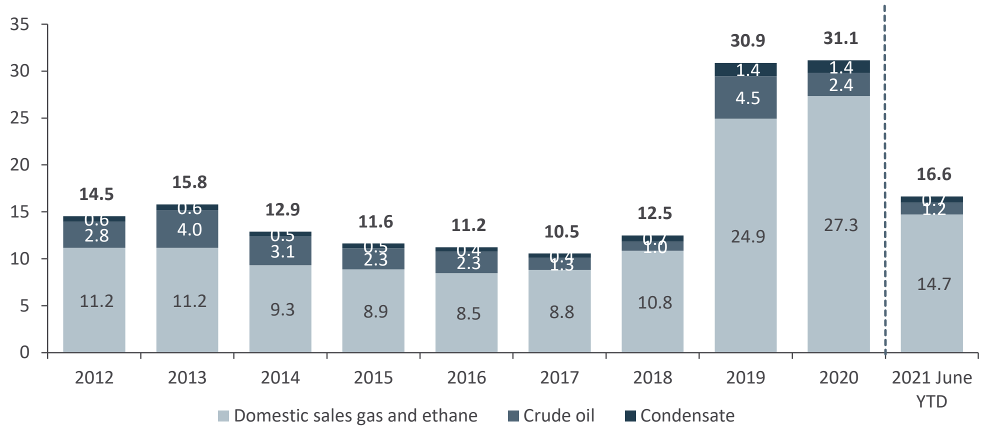
CLASSIFICATION	MMBOE
2P Developed Reserve	154.4
2P Undeveloped Reserve	99.7
2P Reserve	254.1
2C Contingent Resource	401.1

Source: Santos

1.5 Production

Annual production volumes for Santos' WA operations from 2012 to 2020 and for the first six months of 2021 are presented in the chart below.

SANTOS WESTERN AUSTRALIA – HISTORICAL PRODUCTION (NET TO SANTOS) (IN MMBOE)



Source: Santos

Over the past ten years, domestic sales gas has consistently accounted for more than 80% of the total production of Santos WA. Up to 2018, Santos WA gas production was attributable solely to its minority 45% interests in the Varanus Island and Devil Creek gas hubs. During this period, production declined slowly, reflecting progressive field depletion and (in 2013) the opening of the Macedon gas hub (then owned by BHP Billiton and Quadrant Energy), which introduced new supply into the market. Gas production grew by 23% to 10.8 mmboe in 2018 due to the commencement of two new gas supply agreements, before more than doubling in 2019 following the Quadrant Energy acquisition

Crude oil production declined more rapidly up to 2018, as a result of natural field depletion (resulting in the cessation of production from Thevenard and Mutineer-Exeter / Fletcher Finucane) and the 2015 sale of Stag following Santos' decision to divest non-core assets. Oil production declined from 4.0 mmboe in 2013 to 1.0 mmboe in 2018.

The 2018 acquisition of Quadrant Energy resulted in a significant increase in production. Domestic gas sales increased by approximately 14 mmboe per annum, as Santos acquired the other 55% interest that it did not already own in the Varanus Island and Devil Creek gas projects and a 28.6% interest in Macedon, which accounted for approximately 3.5 mmboe per annum. Oil and condensate production increased by approximately 5 mmboe per annum, principally through the acquired interests in the Pyrenees and Van Gogh oil projects, while an increased share of condensate production from the gas processing hubs contributed slightly under 1 mmboe of additional production.

As a result, Santos WA produced more than 30 mmboe per year in 2019 and 2020. Strong domestic gas demand in 2020 contributed to an increase in gas production of close to 10%. However, this was offset by the planned maintenance and temporary shutdown of the Ningaloo Vision FPSO in April 2020, resulting in a decline in crude oil production from 4.5 mmboe in 2019 to 2.4 mmboe in 2020.

Santos expects that production will exceed 30 mmboe in 2021. Gas production for the first half of 2021 increased by over 30% relative to the prior comparable period due to the commencement of a new gas supply contract with Alcoa in the middle of 2020 and higher domestic gas demand. Oil production was slightly ahead of the prior comparable period as increased production from the restart of the Ningaloo Vision FPSO was offset by disruptions caused by inclement weather.

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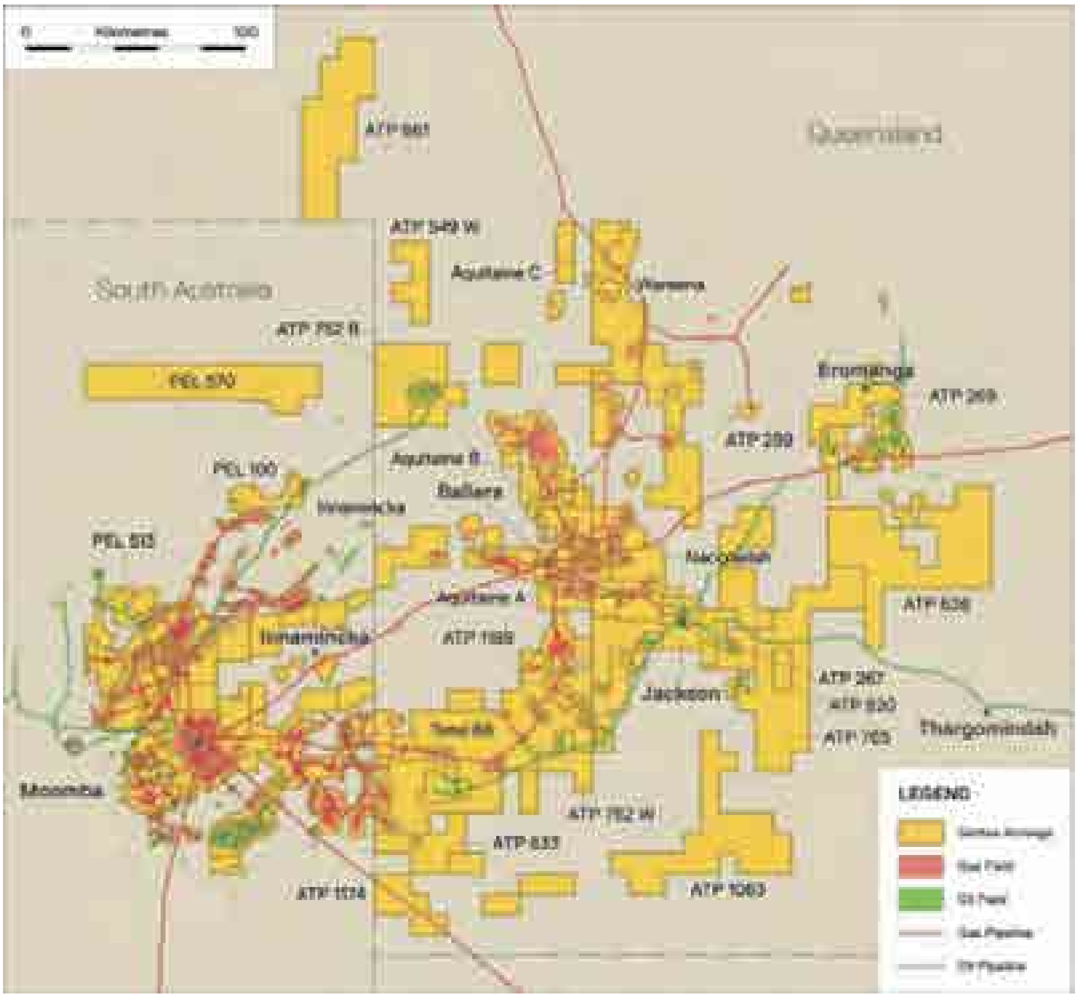
2 Cooper Basin

2.1 Overview

The Cooper/Eromanga Basin region, located across the border spanning North-East South Australia and South-West Queensland, hosts Santos's longest running operations. The company made its first discovery of natural gas with the Gidgealpa-2 well in 1963. The Moomba-1 well discovery three years later confirmed the region as a major hydrocarbon province and the first major oil discovery was made in 1970.

Santos produces natural gas, ethane, crude oil and gas liquids from the region. Production is primarily undertaken across two joint ventures, the South Australian Cooper Basin Joint Venture (SACBJV) and the Southwest Queensland Joint Venture (SWQJV). Both joint ventures are operated by Santos. Initial processing of hydrocarbons is carried out at the Santos-operated Moomba processing facility. Processed gas and liquids are then transported via pipeline to the east coast market or south to the Port Bonython processing plant (also operated by Santos) in South Australia, where gas and liquids undergo further processing before being exported or sold into the domestic market. The following map shows the major gas fields and Santos' key processing and other infrastructure in the Cooper Basin:

SANTOS COOPER BASIN OPERATIONS



Source: Santos

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Notwithstanding the mature state of the Cooper Basin operations, improvements in production technology, cost reductions and other operating efficiencies have allowed Santos to maintain and even increase production levels over the past five years. At the same time, Santos has maintained its level of 2P reserves in the Cooper Basin over the past five years through an ongoing program of exploration and appraisal.

Santos is planning a Carbon Capture and Storage (CCS) project in the Cooper Basin. The project would repurpose existing wells and reservoirs to store up to 20 Mt of carbon dioxide. On 1 November 2021, Santos announced FID to proceed with the project to store 1.7 Mt per annum.

2.2 Reserves and Resources

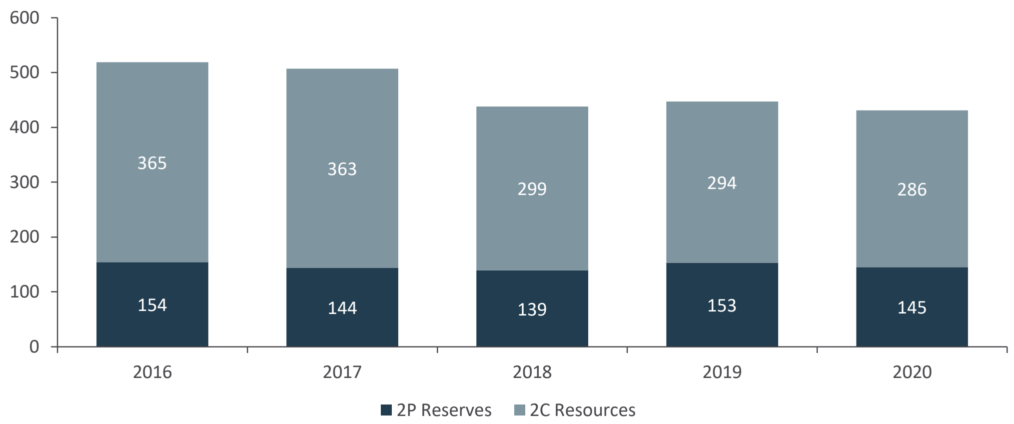
Santos's share of reserves and resources across its joint ventures in the Cooper Basin region at 31 December 2020 is summarised in the table below:

SANTOS COOPER BASIN – RESERVES AND RESOURCES (NET TO SANTOS)

CLASSIFICATION	MMBOE
2P Developed Reserve	92.6
2P Undeveloped Reserve	52.1
2P Reserve	144.7
2C Contingent Resource	285.6

Source: Santos

COOPER BASIN RESERVES AND RESOURCES (NET TO SANTOS) (MMBOE)



Source: Santos

Santos has maintained a broadly constant level of 2P reserves in the Cooper Basin over the past five years while also maintaining 2C resources at 2018 levels. This strong level of reserves and resources replacement has been achieved through:

- the introduction of alternative drilling methods such as horizontal drilling and underbalanced drilling to unlock additional reserves and resources;
- cost efficiencies achieved from introducing standardised and repeatable drilling programs with improved reliability. Vertical well costs have declined by 56% since 2016 and Santos has reduced its average unit production cost from $9.32/boe in 2017 to $7.80/boe in 2020 (after normalising for foreign exchange movements); and
- the conversion of contingent and prospective resources to reserves via exploration, appraisal and development programs.

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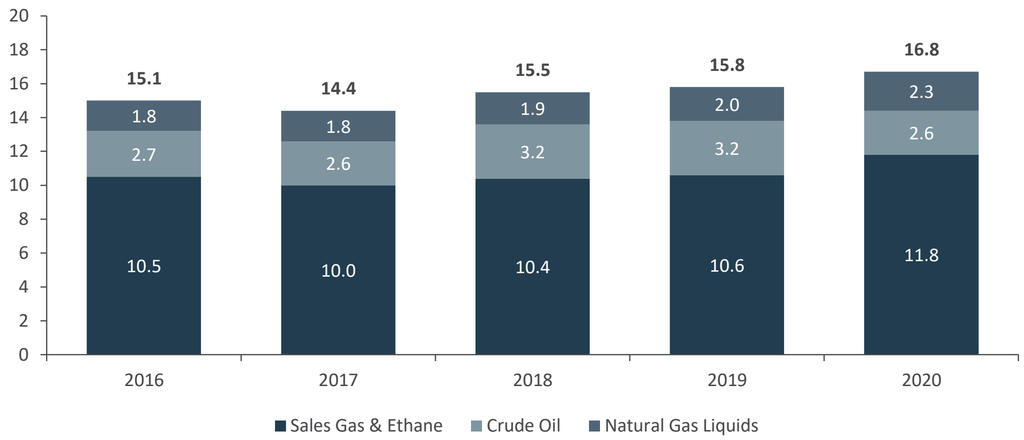
2.3 Upstream Operations

Santos's upstream operations in the Cooper/Eromanga basin region extend across 190 gas fields and 115 oil fields. To date, Santos has drilled over 3,000 wells in the region and based on current forward planning, expects another 1,150 new wells to be drilled by 2040. Gas and liquids are transported for processing to the Moomba processing plant via a network of pipelines, trunklines and flowlines of more than 7000 km in length.

Santos' production from the Cooper Basin from 2016 to 2020 is shown in the chart below.

COOPER BASIN PRODUCTION 2016 – 2020 (NET TO SANTOS) (MMBOE)



Source: Santos

The introduction of new drilling techniques and a focus on cost reduction has allowed Santos to maintain (and in 2020 to increase) production levels. Production growth in 2020 was underpinned by growth in gas and ethane production as development activity more than offset the impact of natural field decline.

2.4 Midstream Operations

Santos owns and operates two major facilities that process production from the Cooper Basin, the Moomba Processing Facility and a facility at Port Bonython. These facilities process gas and liquids from both Santos' operations and other third party production, generating stable recurrent earnings through the tolling charges earned on the processing and storage of third party volumes.

Moomba Processing Facility

The Moomba Processing Facility, which is jointly held by the SACB joint venture, is located in the Cooper Basin, approximately 800 km north of Adelaide. The facility is operated by Santos and takes in production from multiple joint ventures as well as from third-party production in the region including fields operated by Beach Energy and Central Petroleum. The plant has gas processing capacity of up to 400 TJ per day as well as gas storage capacity of approximately 70PJ. Production at the Moomba Processing Facility over the period 2016 to 2020 is shown below.

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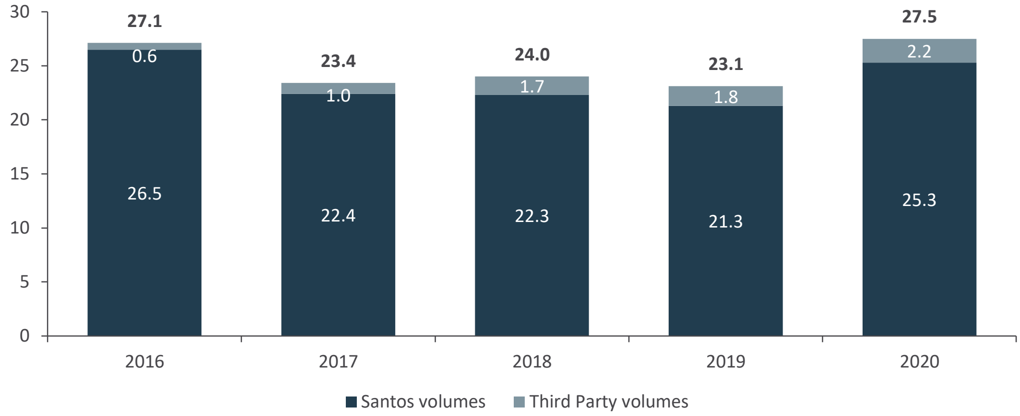
MOOMBA PLANT THROUGHPUT 2016 – 2020 (MMBOE)



Source: Santos

Gas and condensate are transported from field satellite stations to the Moomba plant via trunklines, while crude oil is transported via pipelines and trucks. The Moomba plant initially removes condensate and water from raw gas via slug catchers before further gas processing is undertaken to reduce the amount of carbon dioxide to meet gas pipeline specifications. The gas is then dehydrated via molecular sieves before liquids recovery which separates the remaining condensate, LPG and ethane. After amine scrubbing to remove hydrogen sulphide and CO2, the gas is compressed before exiting the plant into several transport pipelines.

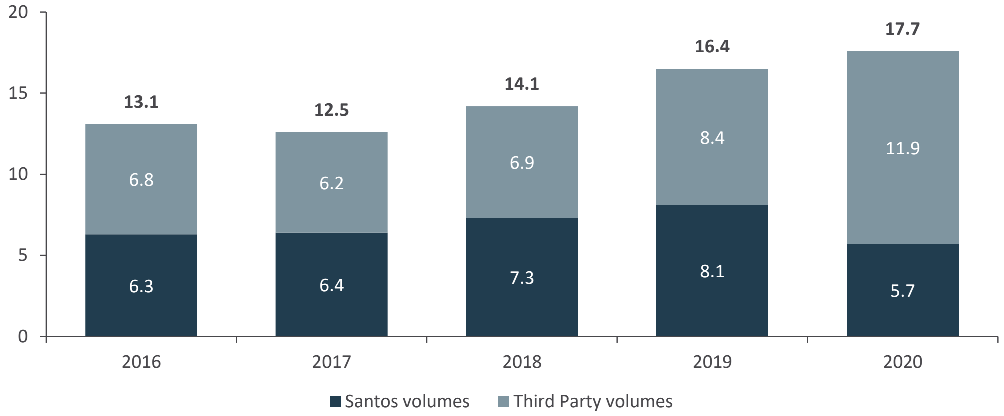
The Moomba Processing Facility is connected to the east coast gas network via the following transport pipelines:

- the Moomba to Adelaide gas pipeline (operated by Epic Energy);
- the Moomba to Port Bonython liquids pipeline (operated by Santos);
- the Moomba to Sydney gas pipeline (operated by APA Group);
- a dedicated ethane pipeline from Moomba to a petrochemical manufacturing plant in Sydney (operated by APA Group); and
- the QSN link pipeline, which connects Moomba to Queensland via Ballera and the South West Queensland pipeline (operated by APA).

Port Bonython Processing Facility

The Port Bonython Processing Facility, which is owned by the SACB joint venture and operated by Santos, is located on the Upper Spencer Gulf coast in South Australia, approximately 390 km north of Adelaide. The facility processes gas liquids and crude oil production from the Moomba facility to produce naphtha and reduced crude for export market, and LPG for domestic and export markets. The plant has a liquid processing capacity of up to 55,000 bopd. Production at the Port Bonython Processing Facility over the period 2016 to 2020 is shown below.

PORT BONYTHON THROUGHPUT 2016 – 2020 (MMBOE)



Source: Santos

2.5 Development Opportunities

Moomba Granite Wash Play

The Granite Wash Play is located in the Moomba field and covers an area of approximately 400 km^2. The play is estimated to contain a prospective resource of as much as 2.7 tcf (gross) of gas in place, with 122 bcf 2C contingent resources (gross) booked based on appraisal drilling conducted in parts of the field area to date. The opportunity is segregated into two resources areas, Moomba North and Moomba South, which are separated structurally by a syncline and reservoir distribution.

Deep Coal Play

The Deep Coal Play targets an extensive liquids-rich 'fairway' that extends across both the SACBJV and SWQJV in the Cooper Basin. Santos has booked 2C contingent resources of 75 mmboe (net to Santos) with more than 120 flow rate tests across the fairway undertaken since 2007. The next phase of exploration-appraisal drilling will involve targeting the thicker coal seams within the fairway with horizontal wells and multi-stage fracture stimulation. The first horizontal well is planned in the Beanbush field in late 2021.

Moomba Carbon Capture Storage Project

Santos has undertaken a detailed evaluation of a potential Carbon Capture and Storage (CCS) project that would utilise existing wells and reservoirs in the region to store carbon dioxide (CO2) emissions. The project has been awarded a A$15 million grant from the Federal Government Carbon Capture Use and Storage Development Fund. The Commonwealth Government has recently announced that CCS will qualify for Australian Carbon Credit Unit (ACCU) eligibility. On 1 November 2021, Santos announced FID to proceed with the project.

The project would be the lowest cost and third largest CCS project globally, initially capable of storing 1.7 Mt of carbon dioxide per year and scalable up to 20 Mt per year. Low cash operating costs of approximately $6-8 per tonne of CO2 would be achieved through the use of existing separation equipment at the Moomba Gas Plant and the reinjection of carbon dioxide into depleted reservoirs with proven rock seal for permanent storage. Development capital expenditure of approximately $110 million (Santos's net share) would be phased over a three-year period with first injection planned for 2024. In the long term, the project would be well placed to play a role in CCS for zero-emissions hydrogen projects.

Other Development Opportunities

Other potential development opportunities that Santos is currently evaluating in the Cooper Basin include the following:

- **Moomba South Patchawarra**, a development ready opportunity with approximately 17 mmboe of 2P undeveloped reserves and 48 mmboe 2C contingent resources. The project would involve low risk vertical stimulated well development close to existing infrastructure;
- **Toolebuc Shale Oil Play**, an opportunity in the SWQJV with an unrisked prospective resource of 110 mmbbl of oil;
- **Warburton Gas Play**, comprising an unrisked prospective resource of 145 bcf across five prospects. The development would utilise existing infrastructure; and
- **Kalladiena Gas Play**, comprising an unrisked prospective resource of 42.2 mmboe with the potential to produce gas and gas liquids.

3 Gladstone Liquefied Natural Gas Project

3.1 Overview

The Gladstone Liquefied Natural Gas Project is an integrated LNG project in Northeast Queensland. The project is held in a joint venture ("GLNG JV") between Santos (30%), Petroliam Nasional Berhad ("PETRONAS") (27.5%), Total (27.5%) and Korean Gas Corporation ("KOGAS") (15%). The upstream infrastructure of the project is operated by Santos. The midstream infrastructure, including the pipeline and liquefaction plant, is operated by GLNG Operations Pty Ltd ("GLNG Operations") a company owned by the GLNG JV.

The project produces natural gas from coal seams located in the Surat and Bowen basins. The gas is transported 420km via a gas transmission pipeline to Curtis Island, Gladstone, where it is liquified in two LNG trains with a combined nameplate capacity of 7.8 Mtpa. In addition to the gas sourced from GLNG's own gas fields, GLNG JV has several long-term gas supply agreements with third parties and with Santos.

The initial development concept, announced by Santos in 2007, was for a 3-4 Mtpa LNG processing train and associated infrastructure which would see coal seam gas processed and sold into export markets.[3] Santos sold a 40% stake in the project to PETRONAS in May 2008 for A$2.64 billion[4]. Ahead of project FID, GLNG JV entered into binding agreements for the sale of gas to PETRONAS and KOGAS that underpinned the development of a two train project.

FID for the project, including the development of upstream gas resources, the construction of the gas transmission pipeline and two LNG trains, was announced in January 2011. First production from the project occurred in September 2015, with the first shipment of LNG departing shortly thereafter.

The GLNG project has consistently produced at rates below its nameplate capacity of 7.8Mtpa principally reflecting lower than initially expected upstream production from GLNG's own gas fields and lower availability of third party gas supplies. Initial well productivity was below original forecasts and overall upstream gas production costs were accordingly higher than expected. The development of new production acreage was accelerated requiring additional drilling, further driving up costs during the upstream development phase.

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3 Santos ASX announcement – "Santos proposes multi-billion dollar Gladstone LNG project" 18 July 2007.

4 Based on total transaction value of $2,508m and A$:$ exchange rate of 0.95 as reported in Santos transaction announcement – "Santos and PETRONAS sign historic partnership for Gladstone LNG" 29 May 2008

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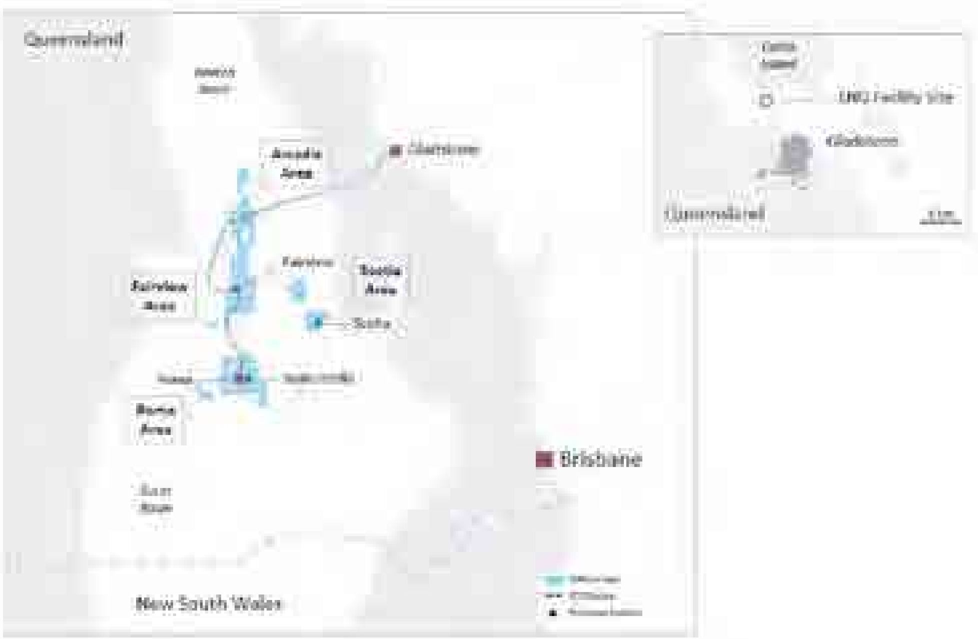
Lower than expected upstream production, from GLNG's own gas fields has in turn resulted in a greater dependence on third party gas supply. Competition for gas feedstock with the other Queensland LNG projects and the domestic gas market has limited GLNG's ability to source all the gas required to achieve nameplate production. Periods of lower oil prices, combined with the need to access third party gas, have at times constrained the GLNG JV partners' capacity to fund development of upstream infrastructure. The subsequent deferral of development plans has placed further pressure on the ramp-up of equity gas production.

Consequently, Santos has announced multiple impairment write downs of its 30% interest in GLNG, totalling nearly $3.8 billion (pre-tax) between 2016 and 2020. Following these write-downs, the recoverable amount of Santos' 30% interest in GLNG is $3,640 million as at 31 December 2020.[5]

3.2 Project Components

The following map shows the major components of the GLNG:



Source: Source: Santos

GLNG sources coal seam gas from the Fairview, Roma, Arcadia, and Scotia gas fields located in the Surat and Bowen basins in Southeast Queensland, both from tenements held by GLNG and from tenements held in joint venture with Australia Pacific Liquefied Natural Gas ("APLNG"), a joint venture between Origin Energy Limited ("Origin"), ConocoPhillips and Sinopec. In addition, GLNG sources gas from third parties, including Santos portfolio gas from Eastern Queensland and the Cooper Basin.

Santos operated approximately 1,965 producing coal seam gas wells as at 30 December 2020 and development plans indicate that it may have as many as 6,000 producing wells by 2035. Regulatory approvals allow for a maximum of 8,750 production wells and associated infrastructure. Wells are fitted with pumps to extract water for the purpose of depressurising the coal seam. As water pressure declines in

[5] As reported in Santos' 2020 annual report. The recoverable amount represents the carrying value of GLNG before deducting the present value of restoration liabilities

the coal seam, gas begins to desorb and flow to the surface via production wells. Production wells can operate for up to 30 years.

Gas is transported to processing hubs located in the Fairview, Roma, Arcadia, and Scotia gas fields via gas and water gathering lines. Following initial processing, the extracted gas is transported to the GLNG pipeline compressor station ("PCS"). The PCS is the point of aggregation for all GLNG JV upstream gas supply and the connection point to the GLNG gas transmission pipeline to Gladstone. The GLNG gas transmission pipeline is a 420km underground pipeline connecting the pipeline compressor station to the LNG facility. The day-to-day control of the pipeline is conducted from GLNG JV's Brisbane operations centre. Santos is the operator of the upstream infrastructure which includes wells, 64 high pressure and low pressure compressors across 10 hubs, 4800km of gathering and pipelines and relevant water processing infrastructure. The GLNG gas transmission pipeline is operated by GLNG Operations.

In 2020, the project's upstream operations produced 9.9 mmboe (Santos share) of natural gas, accounting for approximately 50% (Gross GNLG) of the LNG facilities' feedstock, with the remaining gas supplied by third parties and Santos portfolio gas. Gas supplied by third parties is a combination of contracted gas, principally supplied under oil price-linked contracts, and uncontracted gas. The GLNG project is integrated with Santos and third-party gas supply infrastructure, principally via the Wallumbilla gas supply hub. In 2013, GLNG JV and APLNG signed a cooperation agreement which facilitates the shared use of relevant infrastructure. As GLNG upstream production continues to ramp up, third party gas supply is expected to account for a smaller proportion of total feedstock.

The LNG plant comprises two 3.9 Mtpa[6] processing trains, two storage tanks with a combined capacity of 280,000m^3, a 360 metre long jetty with four loading arms (suitable for ships with capacity up to 220,000m^3) and other associated infrastructure. The plant is located on a 144 hectare site on Curtis Island, offshore Gladstone. An operational workforce of 160 is required to run the LNG plant and port.[7] The LNG facility is operated by GLNG Operations.

3.2.1 Reserves

The GLNG project forms part of the Queensland and NSW Asset. Santos's share of the reserves estimated for the Queensland and NSW, as at 31 December 2020, by Netherland, Sewell & Associates, Inc. ("NSAI") are summarised as follows:

QUEENSLAND & NSW PROJECT – RESERVES AS AT 31 DECEMBER 2020 (NET TO SANTOS[8])

CLASSIFICATION	MMBOE
2P Developed Reserve	108.2
2P Undeveloped Reserve	219.6
2P Reserve	327.7
2C Contingent Resource	433.9

Source: Santos

Queensland proved plus probable sales gas reserves include 1,491 PJ GLNG and 405 PJ other Santos non-operated Eastern Queensland assets.

The GLNG reserves shown above have been estimated at various Santos operated tenements in Arcadia, Fairview, Scotia and Springwater in the Bowen Basin and the Roma field in the Surat Basin.

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6 Nameplate capacity
7 As presented in Santo investor presentation – GLNG Investor Visit (25 June 2014)
8 Represents Santos 30% interest in the GLNG JV. The amounts do not include contingent resources

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3.3 Marketing

Prior to final investment decision in January 2011, GLNG JV had signed binding offtake agreements with each of KOGAS (3.5 Mtpa) and PETRONAS (3.5 Mtpa) for the sale of LNG for 20 years commencing in 2015. The KOGAS agreement is binding for the first 15 years with GLNG JV having the option to extend the agreement for a further five year period.

3.4 Development

At the time of the final investment decision in 2011, the project was estimated to have a gross development capital cost of $16 billion (Santos 30% share of development capital expenditure was estimated at $4.8 billion). The estimate included $2 billion of contingencies. The estimated gross development capital cost was increased in 2012 to $18.5 billion. The increased capital requirements reflected the acceleration of upstream gas field developments in the Fairview and Roma areas, which had previously been planned for development subsequent to first production in 2015. The project was delivered on schedule and within the revised budget. On 24 September 2015, Santos announced that the GLNG project had started producing its first LNG.

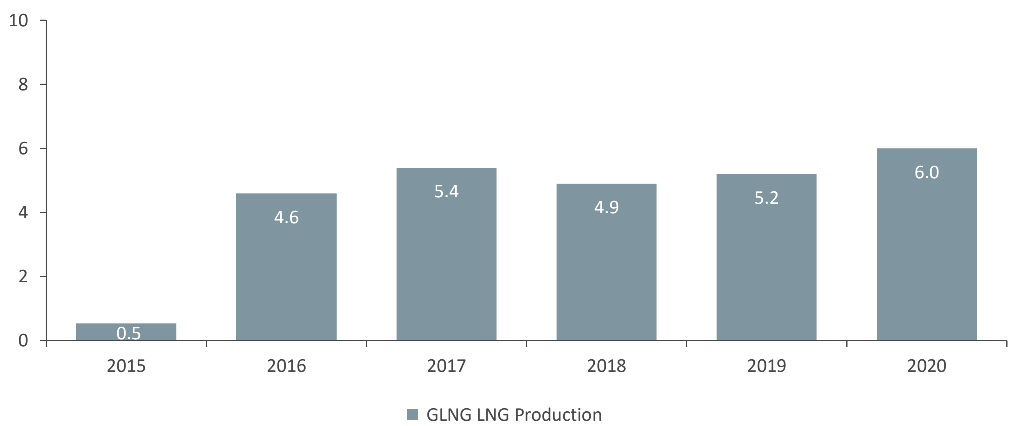
GLNG's upstream gas field interests have significant undeveloped resources. Achievement of targeted production will require the delivery of around 350 new producing wells per year, and average annual upstream sustaining capital expenditure is estimated to be $183 million over 2021-2025. Santos expects to drill approximately 3,700 new wells on behalf of the GLNG project by 2035.

3.4.1 Production

LNG Production

First LNG production at Curtis Island occurred in September 2015 with the project's first LNG shipment occurring shortly thereafter in October 2015. The project has since performed below nameplate capacity, reflecting ongoing upstream production underperformance and lower supplies of third party gas. Even record production of 6.0 Mt in 2020 was well short of nameplate capacity of 7.8 Mtpa (100%). LNG production was lower in 2018 as GLNG JV diverted natural gas originally slated for export to the domestic market. Santos expects the project to produce more than 6.4 Mt of LNG in the 2021 calendar year, of which Santos' share would be 1.9 Mt.

GLNG – LNG PRODUCTION VOLUMES (MT) (100% INTEREST)



Source: Santos Annual Reports

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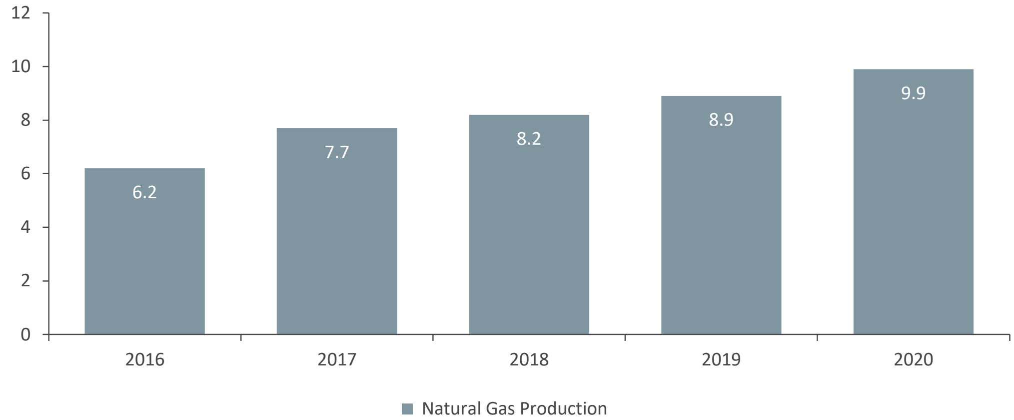
Between 2017 and 2020, GLNG's average unit upstream production costs to the wellhead were approximately $6.00/boe. Santos expects ongoing cost reductions, principally reflecting reduction in upstream drilling and related costs, including work on extending pump life, increasing gas flow rates, introducing new well designs and using fit for purpose drilling rigs, and rationalising infrastructure. Such initiatives have lowered costs per well in gas fields such as Roma by approximately 83% since initial development.

Upstream Natural Gas Production

Production of natural gas sourced from GLNG's upstream fields has steadily increased over the past five years.

GLNG – UPSTREAM PRODUCTION VOLUMES (MMBOE) (SANTOS SHARE)



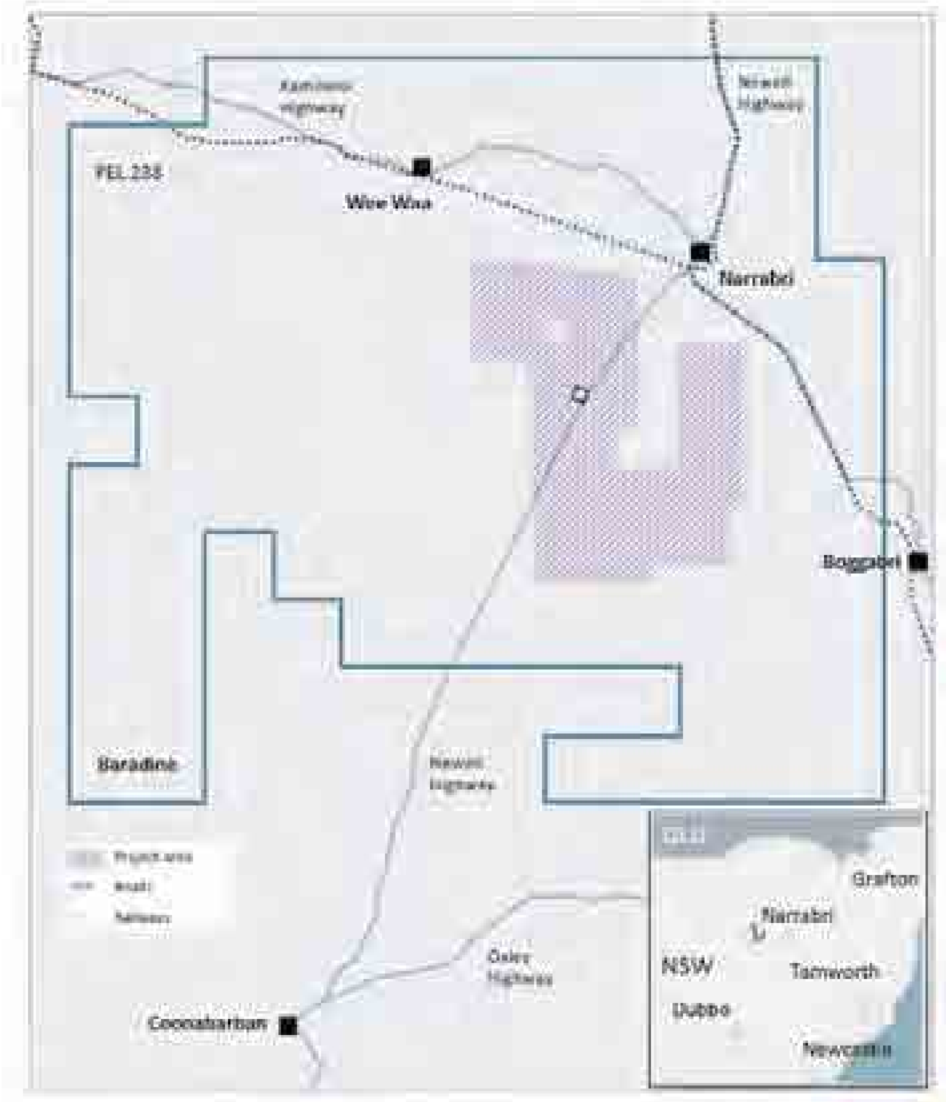
Source: Santos

Increased gas production rates have reflected the operational improvements (including improved drilling rates and well performance) described above. Santos expects upstream production volumes to continue to grow, offsetting declining third party contracted volumes.

3.5 Narrabri Gas Project

3.5.1 Overview

The Narrabri gas project is an undeveloped, long life CSG asset located south-west of the Narrabri township in the Gunnedah Basin in northern NSW. The project is held in a joint venture ("Narrabri JV") between Santos (80%) and EnergyAustralia (20%). Santos is the operator of the project. The resource is geologically continuous with the Bowen Basin.



Source: Santos

Santos initially invested in the Narrabri project during July 2009 through the acquisition of Gastar Exploration Limited's 35% project interest. Santos acquired 100% control of the project through its 2011 acquisition of the ASX-listed Eastern Star Gas Limited ("ESG"). Santos subsequently on-sold a 20% working interest in the Narrabri Gas Project and certain other ESG assets to TRUenergy (now EnergyAustralia), for A$284.3 million. Following the sell-down, Santos was the operator, and held 80% ownership, of the project.

In 2012, the Narrabri gas field was shut-in to address environmental issues. In 2014, the field was reactivated, and Santos commenced exploration and appraisal work. Limited infrastructure has been installed, including 18 producing and 14 non-producing pilot wells, a compressor station and water processing facilities. From late 2018, field production has been focused on providing gas to the Wilga Park Power Station, a 22MW gas-fired power plant acquired through the ESG acquisition, which provides power to the infrastructure across the field.

Santos commenced the first formal step in the regulatory assessment process for the Narrabri gas project in 2014. In late 2020, the Narrabri Gas Project received Environmental Impact Statement ("EIS") approval from the NSW Independent Planning Commission ("NSW IPC") and Federal approval under the Environment Protection and Biodiversity Conservation ("EPBC") Act. Since that time, Santos has been progressing activities to address EIS and EPBC consent conditions to allow the commencement of final appraisal drilling, which is required to inform the phased development at Narrabri. There has been opposition to development of the Narrabri project from the local community and activist groups. An appeal against the NSW IPC's approval of the Narrabri Gas Project was heard in August 2021.

On 18 October 2021, the appeal against the NSW Independent Planning Commission approval of the Narrabri gas project was dismissed. This enables the appraisal phase of the project to continue. Santos has committed to supply 100% of Narrabri gas to the east coast domestic market.

3.5.2 Reserves

Santos' share of reserve and resources are reported within the Queensland and NSW asset.

3.5.3 Development

In June 2019, the project underwent a major review that resulted in a revised project development plan. The plan contemplates the multi-phased development of approximately 400 production wells, which would be progressively developed and decommissioned over the estimated 25 year life span of the project. Successful completion of an appraisal program Santos intends to confirm 2C resources, acquire seismic and complete FEED studies, FID for the initial development is expected by the end of 2023. Gas from the project would be made available to the NSW market via a pipeline linking into the existing Moomba to Sydney pipeline. The pipeline, which is to be constructed and owned by APA Group, will be subject to a separate approvals process. The pipeline route has not been finalised.

3.6 Other Assets

Santos has interests in a number of onshore licences located in the Northern Territory and northern and eastern Queensland. Development of these interests, which are at various maturity levels, could potentially provide backfill gas for GLNG.

3.6.1 South Nicholson Basin

The South Nicolson Basin, located along the border of the Northern Territory and Queensland, is a multi-TCF prospective shale gas resource. The tenements are located in close proximity to existing supply infrastructure such as the Northern Gas Pipeline and Mount Isa. Santos originally acquired an interest in the tenements in October 2019 through a farm-in agreement with Armour Energy Limited ("Armour"). The agreement stipulated that Santos would become the operator of and could earn an interest of up to 70% in certain Armour-owned tenements. In December 2020, Armour announced a sale and purchase agreement whereby Santos acquired Armour's remaining 30% working interest in ATP1087, ATP1192, ATP1193, EP172 and EP177 and Armour re-acquired full ownership and operatorship of ATP1107. The project has proven gas flow to surface at the Egilabria 2 DW1 well contained within ATP1087. Santos' near-term priorities are focussed on further exploration and evaluation. A summary diagram of Santos' tenements is shown below:

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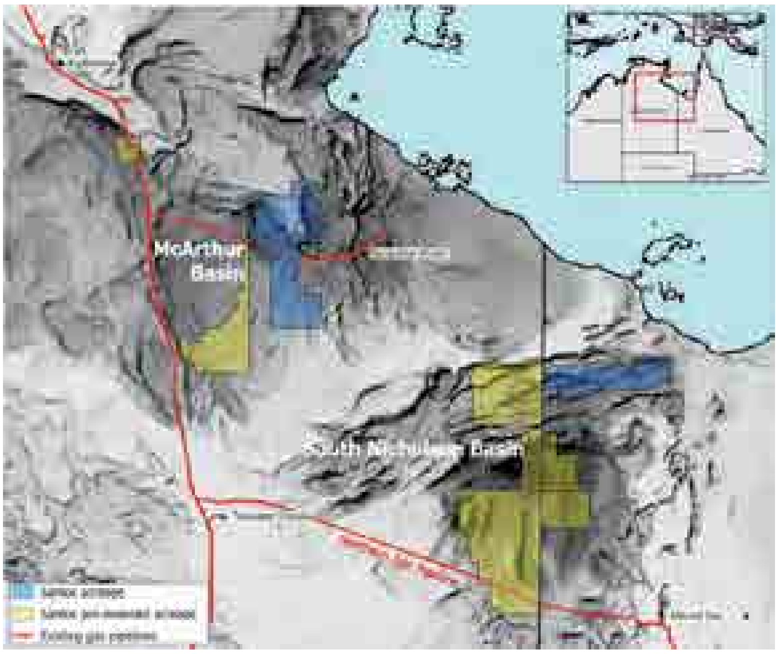


Source: Santos

3.6.2 Eastern Queensland

Santos holds interests in significant non-GLNG acreage in the Bowen Basin. The acreage contains a mixture of producing CSG assets and undeveloped CSG and Tight Gas Sands ("TGS") prospects close to existing infrastructure. Santos' working interest and operatorship vary across tenements.

Santos owns working interests of approximately 7% in the Combabula gas field and 4% in the Spring Gully gas field, both APLNG operated tenements that were developed as part of the APLNG project's upstream infrastructure. The first well was commissioned in the gas fields at Combabula in October 2014. Santos' net share of gas production is preferentially delivered to GLNG at the company's Fairview gas processing hub. Santos expects production from the fields to remain relatively constant in the near-term with its net share equating to approximately 3 mmboe in 2021.

Santos holds additional interests in undeveloped tenements in the region. Exploration to date has resulted in the estimation of a contingent resource of 1Tcf (100%) across these tenements. Any future gas produced would support GLNG production

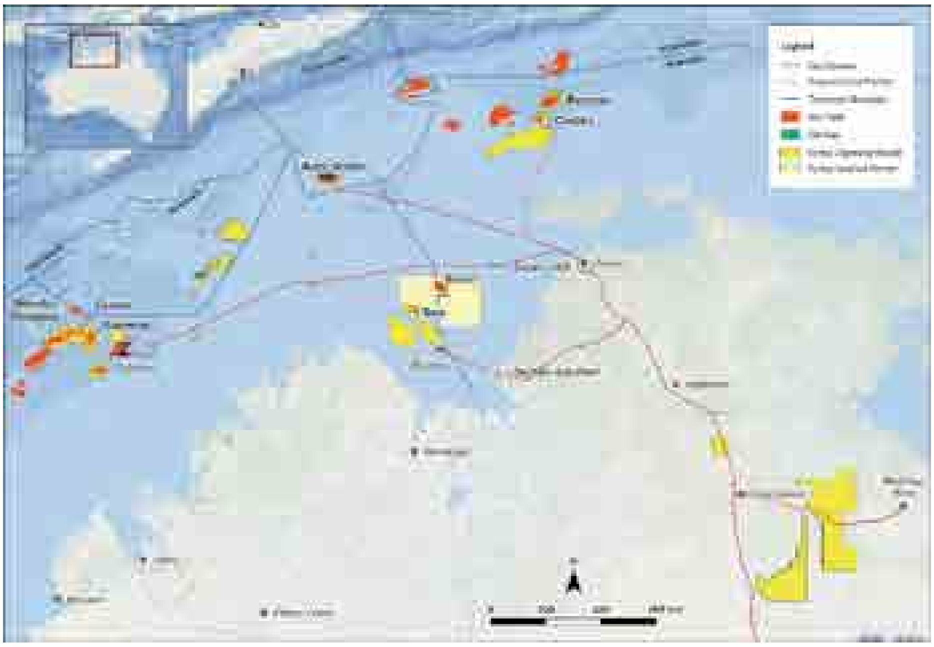
3.7 Northern Australia

3.7.1 Overview

Santos' operations in the Northern Australia region date back to 2004, when production commenced at the Bayu-Undan joint venture. With a 10.6% interest, Santos was a foundation partner in the Bayu-Undan joint venture, which was originally operated by ConocoPhillips. Processing of Bayu-Undan gas at the Darwin LNG processing facility commenced two years later in 2006. Santos' interest increased to 11.5% in 2007. In 2020, Santos acquired ConocoPhillip's Northern Australian portfolio of assets for $1.265 million plus a $200 million payment contingent on Barossa FID. Santos assumed operatorship of the assets, which included ConocoPhillips' 56.9% interest in Bayu-Undan and DLNG, a 37.5% interest in the undeveloped Barossa project and a 40% interest in the Greater Poseidon gas field. Santos subsequently sold 25% interests in each of Bayu-Undan and DLNG to SK E&S and is in the process of divesting a 12.5% interest in Barossa to

JERA Co. Following these transactions, Santos will hold a 43.4% interest in Bayu-Undan and DLNG and will have a 50% interest in the Barossa project. The location of the key fields and facilities is set out in the map below:

SANTOS NORTHERN AUSTRALIA OPERATIONS



Source: Santos

Santos' Northern Australian operations are in transition, with the Bayu-Undan gas fields approaching end of field life in 2022-2023. FID has been taken on the $3.6 billion Barossa development, which is expected to produce first gas in the first half of 2025 and to provide backfill to DLNG. DLNG will undergo a life extension project to accommodate the Barossa project.

Santos is in the process of evaluating other projects in the region that could have the potential to support an extension or expansion of DLNG. The McArthur Basin onshore shale gas play is a significant development opportunity with a potentially large resource base. Santos holds interests in discovered gas resources offshore in the Browse and Bonaparte basins. In addition, the company is currently evaluating a Carbon Capture and Storage (CCS) project through the repurposing of the Bayu-Undan reservoir at the end of its production life. This project could provide carbon storage for the Barossa project, Santos' other potential development projects, or other third-party gas developments in the region.

3.7.2 Reserves and Resources

Santos's share of reserves and resources in the Northern Australia region at 31 December 2020 is summarised in the table below.

SANTOS NORTHERN AUSTRALIA – RESERVES AND RESOURCES (NET TO SANTOS)

CLASSIFICATION	MMBOE
2P Developed Reserve	18.4
2P Undeveloped Reserve	13.9
2P Reserve	32.3
2C Contingent Resource	1,105.9

Source: Santos

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3.7.3 Producing Assets

Bayu-Undan

Bayu-Undan is a late-life producing gas and condensate field located approximately 500 km north-west of Darwin in Timor-Leste offshore waters. The asset is held through a joint venture between Santos (43.4% and operator), SK E&S (25.0%), INPEX Corporation (11.4%), Eni S.p.A (11.0%) JERA Co. (6.1%) and Tokyo Gas (3.1%). The offshore facilities comprise a central production and processing complex with a Floating Production Storage and Offloading vessel for condensate and LPG products and an unmanned wellhead platform. There are 20 production wells and two subsea water injection wells. Gas from the field is transported to the DLNG liquefaction and storage facility via a 26 inch subsea pipeline. The joint venture participants hold the same respective interests in DLNG. As at 31 December 2020, Bayu-Undan had remaining 2P reserves of 32 mmboe (net to Santos).

The Bayu-Undan field was originally discovered in 1995 and commercial production commenced in 2004. The project was originally developed in two phases by the then operator, ConocoPhillips. Phase one was a gas recycle (liquids) project which involved production of condensate and LPG whilst dry gas was re-injected into the reservoir. Dry gas supply to DLNG commenced in 2006 during phase two of the project.

A further phase three of the project was commenced in 2015 with subsea wells drilled to extend the field life. In January 2021, Santos announced FID for the Phase 3C infill drilling program. The $235 million (gross) project involves the drilling of a further three production wells to extend field life to 2023. Drilling activity has commenced, with the first two wells of the program completed and on production.

The Bayu-Undan field is subject to the maritime jurisdiction of Timor-Leste, following the ratification of the Maritime Boundary Treaty with Australia in 2019, while the subsea gas pipeline is located within Australia's maritime jurisdiction. Under the PSC with the Timor-Leste Government, 100% of the tax revenue generated by the Bayu-Undan field is received by Timor-Leste.

Bayu-Undan joint venture LNG production volumes are marketed under long term sale and purchase agreements. Cargoes not accepted by the foundation customers, Jera and Tokyo Gas, are marketed by Santos on a spot basis on behalf of the joint venture. Condensate is also sold on a spot basis while LPG is currently sold under a term contract expiring at the end of 2021. Bayu-Undan production was 14.5 mmboe (net to Santos) in 2020 and forecast to exceed this in 2021.

Santos is currently assessing the potential to convert Bayu-Undan into a carbon capture and storage facility after the end of field life, which is currently expected around 2022-2023 (refer below for further detail.) If this was to proceed, field abandonment expenditure estimated at $360 million (Santos' share) would be deferred for approximately 25 years.

Darwin LNG

Darwin LNG is a natural gas liquefaction and storage facility located at Point Wickham, in the south of the city of Darwin. The asset is operated by Santos and is held in a joint venture in the same proportions as Bayu-Undan.

The facility currently processes gas from the Bayu-Undan field and began production in 2006 when the field's dry gas production commenced. The facility includes a single LNG train with processing capacity of 3.7 Mt of LNG per annum, a storage tank with capacity of 188,000 m^3 and a loading jetty. It has delivered more than 800 cargoes of LNG to date. Following the end of Bayu-Undan field life in 2023, DLNG will undergo a $600 million life extension project. This will extend the facility life by 20 years and equip DLNG to process gas from the Barossa project, with first Barossa gas expected in the first half of 2025..

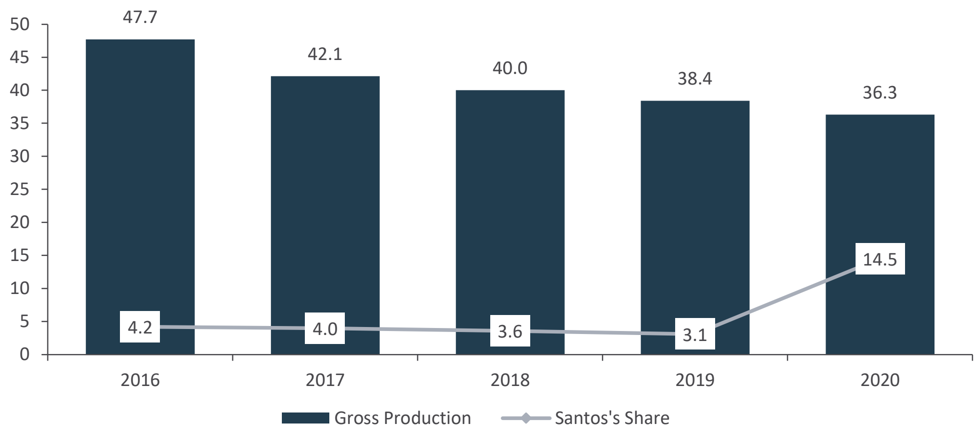
DLNG has planning approvals in place for an expansion of the facility to incorporate up to two additional processing trains with aggregate capacity of 10 Mtpa of LNG, subject to the availability of additional gas. Potential feed sources include the following:

- **McArthur Basin**, an onshore shale gas play. Santos' development concept for the resource would involve a new 4 Mtpa processing train at DLNG;
- **Petrel**, **Tern and Frigate**, offshore gas fields in which Santos has ownership interests, located 250 km west of Darwin in the Bonaparte basin;
- **Crown / Lasseter and Greater Poseidon**, gas fields located in the Browse Basin in which Santos has ownership interest (although these are also backfill candidates for Ichthys LNG); and
- other third-party gas resources located offshore in the region including Evans Shoal, Sunrise and Cash-Maple.

3.7.4 Production

Bayu-Undan production has declined steadily over the past five years as the project approaches the end of field life. Santos' net share of production increased in 2020 following the acquisition of ConocoPhillips' interest.

SANTOS NORTHERN AUSTRALIA – HISTORICAL PRODUCTION (MMBOE)



Source: Santos

3.7.5 Development and Backfill Opportunities

Barossa

Barossa is a gas and condensate field located in the Bonaparte Basin, approximately 300 km north of Darwin. The asset is a jointly held venture between Santos (62.5% and operator) and SK E&S (37.5%). Santos' interest in the venture will reduce to 50% upon completion of the planned sell-down of a 12.5% interest to JERA Co. announced in April 2020. The Barossa Project represents the largest investment in Australia's oil and gas sector since 2012 with a gross development cost of $3.6 billion and will provide backfill gas to Darwin LNG for approximately 25 years following the end of Bayu-Undan production. The nearby Caldita field will be developed along with Barossa and provide supplementary gas to DLNG. As at 31 December 2020, Barossa had 495 mmboe of 2C resources and Caldita a further 27 mmboe (both net to Santos[9]).

Barossa was discovered in 2006 with the drilling of the Barossa-1 exploration well by the original operator, ConocoPhillips. Three appraisal wells drilled in 2015 confirmed the existence of significant hydrocarbon

[9] Based on Santos's 50% interest post the 12.5% sell-down to JERA Co.

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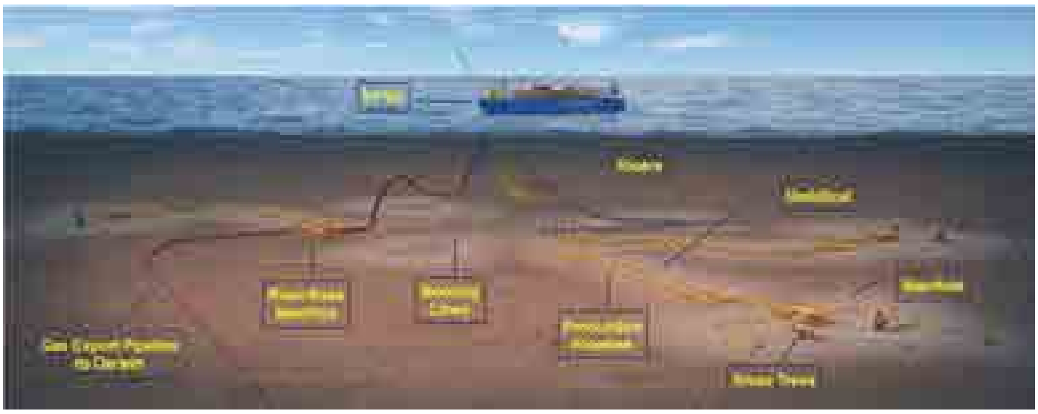
resources in the Elang and Plover reservoirs of the field. A further two appraisal wells drilled in 2017 provided greater certainty regarding the deliverability potential of the field. In early 2018, the development proposal for the offshore project was approved by the National Offshore Petroleum Safety and Environment Management Authority (NOPSEMA) and FEED contracts were awarded later that year.

Following its 2020 acquisition of ConocoPhillips' 37.5% interest in the project and assumption of operatorship, Santos announced FID on the Barossa project in March 2021. The development will comprise an FPSO vessel and nine subsea production wells. The production wells will be drilled in two phases, with six wells drilled in Phase one ahead of first gas in the first half of 2025, with the remaining three wells drilled approximately four years later. Each well will be capable of producing up to 200 mmscf per day. Gas will be transported via a 260 km subsea pipeline and tie-in to the existing Bayu-Undan export pipeline for processing at DLNG. Caldita production is scheduled to commence in 2039 and supplement production volumes until the end of field life in 2050.

The following schematic provides an overview of the key project infrastructure:



At full nameplate capacity the project is expected to deliver up to 20 mmboe per year (Santos net 50% share). Access to the DLNG export pipeline and processing plant will be provided via a Processing Servicing Agreement (PSA) and a Tie-in Agreement (TIA) with the DLNG joint venture. The tariff paid under the agreements is reflective of an appropriate rate of return on the $600 million investment required for the DLNG life extension project.

Barossa LNG volumes will be marketed at the equity level in the joint venture. Santos has signed a 10-year agreement with Diamond Gas International ("DGI"), a wholly-owned subsidiary of Mitsubishi Corporation. The contract covers 1.5 Mtpa of LNG with pricing linked to the Platts JKM™, with Santos retaining options that have the potential to provide pricing upside.

MCARTHUR BASIN

The McArthur Basin, located onshore in the Northern Territory, is a multi-tcf prospective onshore gas resource similar to US shale plays. Santos' interests are located in the Beetaloo sub-basin and are held via a joint venture between Santos (75% interest and operator) and Tamboran Resources (25% interest).

Santos originally acquired its interest in 2012, through a farm-in agreement with Tamboran Resources, in exchange for funding Phase-1 and Phase-2 exploration drilling programs. Following the lifting of the Northern Territory's three-year moratorium on hydraulic fracturing exploration in the Beetaloo Basin in 2018, Santos conducted a successful four stage fracture stimulation of the Velkerri shale gas play in the Tanumbirini-1 well, originally drilled in 2014. Subsequent flow rate testing results exceeded initial expectations for the vertical well.

The planned exploration phase involves four wells over 2022-2024.

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Bayu-Undan Carbon Capture and Storage

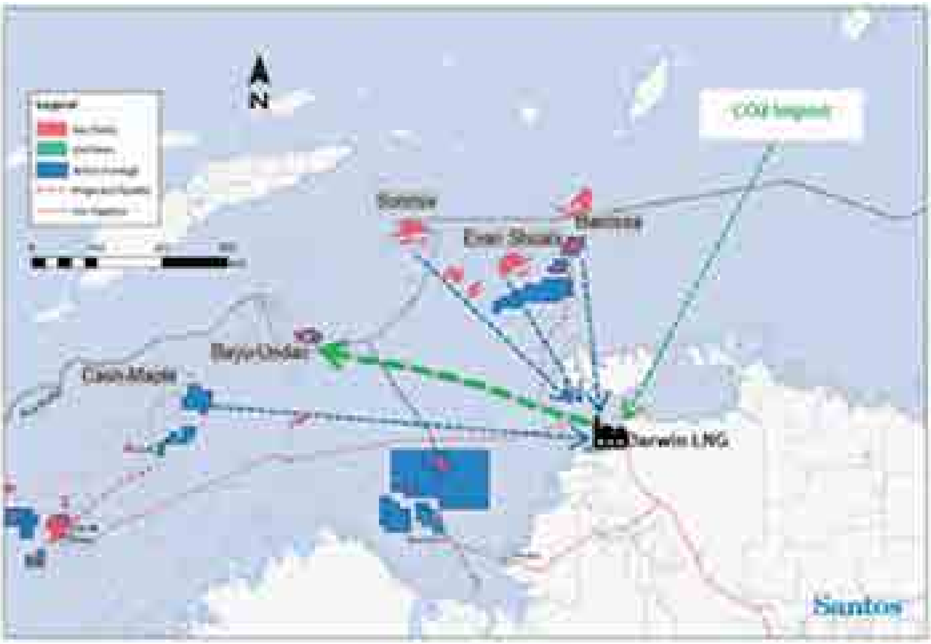
Santos is currently evaluating the development of a Carbon Capture and Storage (CCS) project through the re-purposing of the Bayu-Undan reservoir after it ceases production. Under the proposed development, carbon dioxide (CO2) produced in the processing of gas in Darwin would be transported to the Bayu-Undan reservoir via the existing Bayu-Undan to DLNG subsea pipeline. It is expected that the reservoir could accommodate approximately 10 Mt of CO_2 per annum.

Potential feed sources of CO_2 include:

- existing production out of Ichthys LNG;
- Barossa production out of DLNG once online in 2025; and
- other discovered resources in the region that may be developed including the McArthur basin onshore gas project and offshore resources including Evans Shoal, Petrel-Tern-Frigate, Greater Poseidon and Crown Lassetter.

The concept for the CCS project is shown in the diagram below.

BAYU-UNDAN CCS PROJECT CONCEPT



Source: Santos

The project concept would be to generate revenue through the creation of carbon credits as well as provide other valuable benefits for Santos, including reduction of Barossa's CO_2 emissions output, the delay of a significant proportion of Bayu-Undan decommissioning and rehabilitation costs until after the CCS project and the facilitation of further development in the region through DLNG.

Other Development and Exploration Opportunities

The majority of Santos' other exploration and development opportunities in Northern Australia are located offshore in the Browse basin. Some of these have the potential to provide backfill or expansion volumes for Darwin LNG or Ichthys LNG and could potentially be integrated into Santos's proposed Carbon Capture Storage project at Bayu-Undan. They include:

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- **Greater Poseidon**, in which Santos acquired a 40% interest and operatorship from ConocoPhillips in 2020. The field has a discovered 2C resource of 2.7 Tcf (gross);
- **Crown-Lasseter**, which is jointly held by Santos (60%) and INPEX Corporation (40%) and has a discovered 2C resource of 2.0 Tcf (gross);
- **Petrel**, **Tern and Frigate**, gas fields located 250 km west offshore of Darwin in the Bonaparte basin; and
- **Vulcan Sub-Basin**, in which Santos is targeting an emerging Triassic oil play with drilling planned during 2022 and 2023.

3.8 Papua New Guinea

Santos commenced exploration in PNG in 1987 and production from the SE Gobe oil field in 1998. Its interests in PNG primarily relate to the PNG LNG Project and SE Gobe, which are described in detail in Appendix 4 of this report. Santos has a unitised working interest of 13.5% in the PNG LNG Project, through its 24% interest in the Hides field in PDL 1. Through its 15.92% interest in PDL 3, Santos has an approximate 7.45% interest in SE Gobe. Although Santos operates PDL 3, Oil Search is the operator of SE Gobe Unit. Santos has a 10% indirect interest in the Muruk gas field in PDL 9. Santos is also involved in exploration along the Hides – P'nyang and Eastern Carbonate geological trends. In May 2019, Santos signed a Letter of Intent to acquire a 14.32% interest in P'nyang (pre government back-in) for US$187 million. The acquisition was conditional on FEED-entry for an integrated three-train LNG expansion, which ultimately did not proceed due to protracted negotiations on the P'nyang Gas Agreement. On lapse of the 2019 Letter of Intent, a non-binding MOU was signed in December 2020 agreeing to negotiate a future farm-in agreement, on terms to be agreed pending the outcome of future Gas Agreement negotiations with the State of PNG. Santos does not hold an interest in Elk-Antelope.

PAPUA NEW GUINEA – RESERVES AND RESOURCES (NET TO SANTOS)

CLASSIFICATION	MMBOE
2P Developed Reserve	116.2
2P Undeveloped Reserve	58.0
2P Reserve	174.3
2C Contingent Resource	55.3

Source: Santos

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APPENDIX 5

SELECTION OF DISCOUNT RATE

1 Overview

A discount rate in the range 8.5-9.5% has been selected as appropriate to apply to the forecast nominal ungeared after tax US$ denominated cash flows for Oil Search's and Santos' oil and gas assets. Lower discount rates have been selected for certain specific assets with low risk characteristics.

Selection of the appropriate discount rate to apply to the forecast cash flows of any business enterprise is fundamentally a matter of judgement. The valuation of an asset or business involves judgements about the discount rates that may be utilised by potential acquirers of that asset. There is a body of theory which can be used to support that judgement. However, a mechanistic application of formulae derived from that theory can obscure the reality that there is no "correct" discount rate. Despite the widespread acceptance and application of various theoretical models, it is Grant Samuel's experience that many companies rely on less sophisticated approaches. Businesses and investors often use relatively arbitrary "hurdle rates" which do not vary significantly from investment to investment or change significantly over time despite movements in interest rates. Valuation is an estimate of what real world buyers and sellers of assets would pay and must therefore reflect parameters that will be applied in practice even if they are not theoretically correct. Grant Samuel considers the rates adopted to be reasonable discount rates that acquirers would use in irrespective of the outcome of any particular model.

The discount rate represents an estimate of the weighted average cost of capital ("WACC") appropriate for these assets. Grant Samuel has calculated a WACC based on a weighted average of the cost of equity and the cost of debt. This is the relevant rate to apply to ungeared cash flows. There are three main elements to the determination of an appropriate WACC:

- cost of equity;
- cost of debt; and
- debt/equity mix.

The cost of equity has initially been derived, in the first instance, from application of the capital asset pricing model ("CAPM") methodology. The CAPM is probably the most widely accepted and used methodology for determining the cost of equity capital. There are more sophisticated multivariate models which utilise additional risk factors but these models have not achieved any significant degree of usage or acceptance in practice. However, the cost of equity is not a precise or provable number nor can it be estimated with any degree of reliability. The cost of equity capital is not directly observable and models such as the CAPM do no more than infer it from other data using one particular theory about the way in which security prices behave. The usefulness of any estimate therefore depends on the efficacy of the theory and the robustness of the data but the available tools such as CAPM involve:

- models that have questionable empirical validity (and competing formulations);
- simplifying assumptions;
- the use of historical data as a proxy for estimates of forward looking parameters;
- data of dubious statistical reliability; and
- unresolved issues (such as the impact of dividend imputation).

It is easy to overengineer the process and to credit the output with a precision that it does not warrant. The reality is that any cost of capital estimate or model output should be treated as a broad guide rather than the absolute truth. The cost of equity capital is fundamentally a matter of judgement, nor merely a calculation.

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The cost of debt has been determined by reference to the pricing implied by the debt markets in Australia and the United States. The cost of debt represents an estimate of the expected future returns required by debt providers. In determining the appropriate cost of debt over the period of the cash flows, regard was had to debt ratings of comparable companies.

Selection of an appropriate debt/equity mix is a matter of judgement. The debt/equity mix represents an appropriate level of gearing, stated in market value terms, for the assets over the forecast period. The relevant proportions of debt and equity have been determined having regard to the financial gearing of comparable companies and the oil and gas industry in general, and judgements as to the appropriate level of gearing considering the nature and quality of the cash flows.

The following sections set out the basis for Grant Samuel's determination of the discount rates for Oil Search's and Santos' oil and gas assets and the factors that limit the accuracy and reliability of the estimates.

2 Definition and Limitations of the CAPM and WACC

The CAPM provides a theoretical basis for determining a discount rate that reflects the returns required by diversified investors in equities. The rate of return required by equity investors represents the cost of equity of a company and is therefore the relevant measure for estimating a company's WACC. CAPM is based on the assumption that investors require a premium for investing in equities rather than in risk free investments (such as Australian Government Bonds and United States Treasury Bonds). The premium is commonly known as the market risk premium and notionally represents the premium required to compensate for investment in the equity market in general.

The risks relating to an asset or a business can be divided into specific risks and systematic risks. Specific risks are risks that are specific to a particular asset or business and are unrelated to movements in equity markets generally. While specific risks will result in actual returns varying from expected returns, it is assumed that diversified investors require no additional returns to compensate for specific risk, because the net effect of specific risks across a diversified portfolio will, on average, be zero. Portfolio investors can diversify away all specific risk.

However, investors cannot diversify away the systematic risk of a particular asset or business. Systematic risk is the risk that the return from an asset or business will vary with the market return in general. If the return on an investment was expected to be completely correlated with the return from the market, then the return required on the investment would be equal to the return required from the market (i.e. the risk free rate plus the market risk premium).

Systematic risk is affected by the following factors:

- financial leverage: additional debt will increase the impact of changes in returns on underlying assets and therefore increase systematic risk;
- cyclicality of revenue: projects and companies with cyclical revenues will generally be subject to greater systematic risk than those with non-cyclical revenues; and
- operating leverage: projects and companies with greater proportions of fixed costs in their cost structure will generally be subject to more systematic risk than those with lesser proportions of fixed costs.

CAPM postulates that the return required on an investment or asset can be estimated by applying to the market risk premium a measure of systematic risk described as the beta factor. The beta for an investment reflects the covariance of the return from that investment with the return from the market as a whole. Covariance is a measure of relative volatility and correlation. The beta of an investment represents its systematic risk only. It is not a measure of the total risk of a particular investment. An investment with a beta of more than one is riskier than the market as a whole and an investment with a beta of less than one is less risky. The discount rate appropriate for an investment which involves zero systematic risk would be equal to the risk free rate.

The formula for deriving the cost of equity using CAPM is as follows:

Re = *Rf + Beta (Rm – Rf)*

Where:

Re	=	the cost of equity capital;
Rf	=	the risk free rate;
Beta	=	the beta factor;
Rm	=	the expected market return; and
Rm - Rf	=	the market risk premium.

The beta for an asset or a business is normally estimated by observing the historical relationship between returns from the investment or comparable companies and returns from the market in general. The market risk premium is estimated by reference to the actual long run premium earned on equity investments by comparison with the return on risk free investments.

The formula conventionally used to calculate a WACC under a "classical tax system"[1] is as follows:

WACC = *(Re x E/V) + (Rd x (1-t) x D/V)*

Where:

E/V	=	the proportion of equity to total value (where V = D + E);
D/V	=	the proportion of debt to total value;
Re	=	the cost of equity capital;
Rd	=	the cost of debt capital; and
t	=	the corporate tax rate

The models, while simple, are based on a sophisticated and rigorous theoretical analysis. Nevertheless, application of the theory is not straightforward and the discount rate calculated should be treated as no more than a general guide. The reliability of any estimate derived from the model is limited. Some of the issues are discussed below.

Overall Validity of the Model

The CAPM has been subject to intense criticism over many years with numerous empirical studies demonstrating that it does not accurately portray movements in individual share prices and has limited explanatory power. There are also competing formulations (such as the Sharpe-Lintner, Black, Brennan-Lally, Officer or Monkhouse models) which can give different results.

In addition:

- the CAPM is a single period model rather than one developed specifically for valuing long term cash flows. It has been adapted to a multi-period model (usually annually) to calculate the value of long term cash flows. Theoretically, the analysis should use a forecast of each of the parameters for each period in question (annual is no more correct than any other period) but, typically, a long term average is assumed for the sake of practicality;
- the CAPM assumes investors are diversified and therefore are not (and should not be) concerned with the specific risk of a particular investment. Behavioural economics suggests while this may be theoretically sensible, it doesn't actually reflect how investors behave or how they price risk; and

[1] A tax system not featuring dividend imputation or other variants such as advance corporation tax (i.e. dividends are paid out of after tax income and are subject to full tax in the hands of investors).

- it ignores all investor taxes, which may or may not have an impact in the real world. Even where models do attempt to reflect taxation effects, adjustments are usually based on assumed averages which may not be accurate or appropriate given the diversity of individual tax positions.

Risk Free Rate

Theoretically, the risk free rate used should be an estimate of the risk free rate in each future period (i.e. the one year spot rate in that year if annual cash flows are used). There is no official "risk free" rate but, in developed economies such as Australia and the United States, rates on government securities are typically used as an acceptable substitute. In practice, the long term Australian Commonwealth Government Bond rate and the long term United States Treasury Bond rate are used as the most practical estimates in Australia and the United States respectively (even though rates for individual years could be interpolated). However, it should be recognised that the yield to maturity of a long term bond is only an average rate and where the yield curve is strongly positive (i.e. longer term rates are significantly above short term rates) the adoption of a single long term bond rate has the effect of reducing the net present value where the major positive cash flows are in the initial years. The long term bond rate is therefore only an approximation.

The ten year bond rate is a widely used and accepted benchmark for the risk free rate. Where the forecast period exceeds ten years, an issue arises as to the appropriate bond to use. While longer term bond rates are available, the ten year bond market is the deepest long term bond market in Australia and is a widely used and recognised benchmark. There is a limited market for bonds of more than ten years although the Australian government has more recently issued 30 year bonds in volume. In the United States, there are deeper markets for longer term bonds. The 30 year bond rate would be a better benchmark for longer term cash flows. However, long term rates accentuate the distortions of the yield curve on cash flows in early years. In any event, a single long term bond rate matching the term of the cash flows is no more theoretically correct than using a ten year rate. More importantly, the ten year rate is the standard benchmark used in practice.

Market Risk Premium

The market risk premium (Rm - Rf) represents the "extra" return that investors require to invest in equities as a whole over risk free investments. This is an "ex-ante" concept. It is the expected premium and, as such, it is not an observable phenomenon. There is no generally accepted approach to estimating a forward looking market risk premium and therefore the historical premium is used as the best available proxy measure. The premium earned historically by equity investments is usually calculated over a time period of many years, typically at least 30 years. This long time frame is used on the basis that short term rates of return are highly volatile and that a long term average return would be a fair indication of what most rational investors would expect to earn in the future from an investment in equities with a five to ten year time frame.

In the absence of controls over capital flows, differences in taxation and other regulatory and institutional differences, it is reasonable to assume that the market risk premium should be approximately equal across markets which exhibit similar risk characteristics after adjusting for the effects of expected inflation differentials. Accordingly, it is reasonable to assume similar market risk premiums for first world countries enjoying political economic stability, such as Australia, New Zealand, the United States, Japan, the United Kingdom and various western European countries.

In the United States, it is generally believed that the historical premium is in the range 4-6% but there are widely varying assessments (from 3% to 9%). For example, Damodaran's[2] latest estimate (1 October 2021) is 4.8%.

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[2] Online at stern.nyu.edu. Published by Aswath Damodaran, a professor at the Stern Scholl of Business at NYU.

Australian studies have been more limited and mainly derive from the Officer Study[3] which was based on data for the period 1883 to 1987 (prior to the introduction of dividend imputation in Australia) and indicated that the long run average premium was in the order of 8% using an arithmetic average but subject to significant statistical error. More recently, the Officer Study data has been updated to 2017[4] with the long term average declining to around 6.5%. Due to concerns about the earlier market data, emphasis is now placed on the average risk premium since 1958, which is estimated to be 6.0% ignoring the impact of imputation (where imputation credits are valued at 100% the market risk premium over the same period is 6.9%).

However, even the measurement or use of long term historical returns is subject to considerable debate:

- there are multiple different outcomes for the historical market risk premium depending on time period, basis (over long term bonds or shorter term bills), method (arithmetic or geometric averages) and estimation approach;
- the measures of historical returns typically have extremely high statistical error measures. For a, say, 6% average measured premium the "true" figure will typically lie in a range of 2-10% at a 95% confidence level;
- the methodology is inflexible and tends to fail when market conditions change materially. Market volatility is the reality of financial markets. Clearly, following the outbreak of the COVID-19 pandemic in March 2020, investors' perceptions of risk and the pricing of that risk rose significantly and rapidly. This can be demonstrated by the observable data from the pricing of lowly rated corporate bonds (which sit on the risk spectrum between risk free assets and equities) over this period. Yields to maturity rose sharply in March 2020 (albeit the increase was short lived as government stimulus and Reserve Bank of Australia support was put in place). However, long term average historical data will not flex to reflect these changes – an average of, say, 50 years of data will not move much even with 2-3 years of "new" data;
- the longer the period of measurement (and therefore the greater the "robustness" of the average) the more likely it is to reflect economic and market circumstances that have little resemblance to the present (is it really likely that investor returns prior to World War II are relevant to the kinds of returns investors expect today?); and
- the historical data also contains a logical contradiction – when the equity return required by investors is lower than the returns implied by market prices, investors respond by bidding the price of equities higher. A rising market translates to a higher measured historical risk premium, contrary to the lower return expectations driving the upwards movement in prices.

Beta Factor

The beta factor is a measure of the expected covariance (i.e. volatility and correlation of returns) between the return on an investment and the return from the market as a whole. The expected beta factor cannot be observed. The conventional practice is to calculate an historical beta from past share price data and use it as a proxy for the future but it must be recognised that:

- the expected beta is not necessarily the same as the historical beta. A company's relative risk does change over time and measured historical betas can often reflect structural changes in an industry or in the company over the time period rather than its inherent correlation to the market;

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[3] R.R. Officer in Ball, R., Brown, P., Finn, F. J. & Officer, R. R., "Share Market and Portfolio Theory: Readings and Australian Evidence" (second edition), University of Queensland Press, 1989 ("Officer Study").

[4] S. Bishop, A. Carlton and T. Pan, "Market Risk Premium: Australian Evidence", Research Paper prepared for the Chartered Accountants Australia and New Zealand Business Valuation Specialists Conference, August 2018, Department of Applied Finance, Macquarie University. This paper is based on earlier work by J.C. Handley in 2012 and T. Brailsford, J.C. Handley and K. Maheswaran in 2008.

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- the starting point is normally to measure the historical correlation of a company's share price against its local market index. However:
  - the composition of indices varies substantially between markets. For example, the Australian index is dominated by banks and resources compared to other markets; and
  - where a company is extensively traded by global investors it can be argued that the regression against an index such as the Morgan Stanley Capital International Developed World Index ("MSCI"), an international equities market index that is widely used as a proxy for the global stockmarket as a whole, is more relevant but it:
    - depends on who the "price setting" investors are;
    - can give materially different results to measures based on the local index; and
    - raises a related issue as to whether a global risk premium is also appropriate and, if so, what that global premium is;
- the appropriate beta is the beta of the company being valued rather than the beta of the acquirer (which may be in a different business with different risks). Betas for the particular subject company may be utilised but these are seldom regarded as reliable enough (and may not be available if the company is not listed). Accordingly, it is common practice to utilise betas for comparable companies and sector averages (particularly as those may be more reliable). However, none of these other companies is likely to be exactly comparable to the subject entity (e.g. it may operate in other jurisdictions with different economic drivers, regulatory regimes and benchmark index composition). In any event, the comparable company data seldom yields a tight and consistent range from which a precise estimate can be derived;
- there are very significant measurement issues with betas which mean that only limited reliance should be placed on such statistics. There is no "correct" beta. For example:
  - over the last four years Oil Search's beta as measured by the Securities Industry Research Centre of Asia-Pacific (Rozetta Institute Ltd ("Rozetta")) has varied between 0.79 and 2.67 and was measured at 2.63 at 30 June 2021 (in all cases, excluding March 2020[5]). The median beta over the four years to 30 June 2021 was 1.27 (excluding March 2020[5]);
  - the standard error of the Rozetta's estimate of Oil Search's beta has generally been in the order of 0.28 meaning that for a beta of, say, 1.27, even at a 68% confidence level, the true beta is somewhere in the range 0.99 to 1.55 (and for 95% confidence is between 0.71 and 1.83);
  - Rozetta's latest estimate of 2.63 (excluding March 2020[5]) compares to 1.72 measured by MSCI Barra Inc. ("Barra") and 2.04 measured by Bloomberg; and
  - estimates of "predicted" betas made by providers such as Barra can be significantly different to the historically calculated beta. In the case of Oil Search, its predicted beta is 1.40 compared to its historical beta (as measured by Barra) of 1.72.

  There is similar variation in the various measures of Santos' beta:
  - over the last four years Santos' beta as measured by Rozetta has varied between 1.58 and 2.64 and was measured at 2.39 at 30 June 2021 (in all cases, excluding March 2020[5]). The median beta over the four years to 30 June 2021 was 2.20 (excluding March 2020[5]);
  - the standard error of the Rozetta's estimate of Santos' beta has generally been in the order of 0.49 meaning that for a beta of, say, 2.20, even at a 68% confidence level, the true beta is somewhere in the range 1.71 to 2.69 (and for 95% confidence is between 1.22 and 3.18);

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[5] Rozetta estimates that exclude return observations for the single month of March 2020, which experienced the second largest negative values for the entire market of any month since January 1974.

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- Rozetta's latest estimate of 2.39 (excluding March 2020[5]) compares to 1.22 measured by Barra and 1.95 measured by Bloomberg; and
- Santos' predicted beta is 1.31 compared to its historical beta (as measured by Barra) of 1.22.

Debt/Equity Mix

The relevant measure of the debt/equity mix is based on market values (not book values). As beta is normally considered in the context of comparable companies as well as the subject company, the debt/equity mix should involve similar analysis. Accordingly, the relevant proportions of debt and equity are usually determined having regard to the financial gearing of the subject company, comparable companies and the industry in general as well as assessments of the appropriate level of gearing taking into account the nature and quality of the cash flow stream. However:

- a simple debt/equity mix is usually used for practicality but it represents a simplification of what are usually much more complex financial structures (e.g. hybrids, convertibles and lease obligations);
- a constant degree of leverage is typically assumed but this is seldom the case in practice;
- the debt/equity mix (measured over the same period as the historical beta is measured) can be volatile over time at an individual company level. Averages across time may give a more meaningful guide but in some circumstances this may not be appropriate;
- there is often a wide diversity of debt/equity ratios across companies in an industry. Moreover, there is often inconsistency between gearing ratios and betas (e.g. those with higher gearing may exhibit lower betas than their peers); and
- the measured beta factors for listed companies are "equity" betas and reflect the financial leverage of the individual companies. It is possible to unleverage beta factors to derive asset betas and releverage betas to reflect a more appropriate or comparable financial structure. In Grant Samuel's view, this technique is subject to considerable estimation error. Deleveraging and releveraging betas exacerbates the estimation errors in the original beta calculation and gives a misleading impression as to the precision of the methodology. Indeed, there are competing deleveraging formulae which give different results. Deleveraging and releveraging is also commonly calculated based on debt levels at a single point in time. This is incorrect as it is leverage over the same period as the beta was measured that is relevant (although this can be difficult to estimate accurately given that data points may be, at best, quarterly). Recent advice to the Australian Energy Regulator ("AER") stated that leverage adjustments were a *"worthless pursuit of spurious precision"* and recommended a raw estimate of the industry beta (if gearing is similar)[6].

Corporate Tax

The WACC calculation generally assumes a constant rate of corporate tax, typically the standard corporate rate. However, the tax position of many corporates, particularly multinationals, is usually much more complex and can change significantly over time.

Dividend Imputation

The conventional WACC formula set out above was formulated under a "classical" tax system. The CAPM model is constructed to derive returns to investors after corporate taxes but before personal taxes. Under a classical tax system, interest expense is deductible to a company but dividends are not. Investors are also taxed on dividends received.

Under Australia's dividend imputation system, domestic equity investors receive a taxation credit (franking credit) for any tax paid by a company. The franking credit attaches to any dividends paid out by a company and the franking credit offsets personal tax. To the extent the investor can utilise the franking credit to

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6 G. Partington and S. Satchell, "*Issues in releveraging beta and testing for structural breaks*", September 2017.

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offset personal tax, then the corporate tax is not a real impost. It is best considered as a withholding tax for personal taxes. It can therefore be argued that the benefit of dividend imputation should be incorporated into any analysis of value.

As a PNG incorporated entity with assets in PNG and Canada, Oil Search generates no franking credits so the issue is only relevant for Santos.

There is no generally accepted method of allowing for dividend imputation. In fact, there is considerable debate within the academic and financial communities as to the appropriate adjustment or even whether any adjustment is required at all. Some suggest that it is appropriate to discount pre-tax cash flows, with an increase in the discount rate to "gross up" the market risk premium for the benefit of imputation credits that are on average received by shareholders. On this basis, the discount rate might increase by approximately 2% but it would be applied to pre-tax cash flows. However, not all of the necessary conditions for this approach exist in practice:

- not all shareholders can use franking credits. In particular, foreign investors gain no benefit from franking credits (except in relation to withholding taxes in some cases[7]). If foreign investors are the marginal price setters in the Australian market there should be no adjustment for dividend imputation;
- not all franking credits are distributed to shareholders; and
- capital gains tax operates on a different basis to income tax. Investors with high marginal personal tax rates will prefer cash to be retained and returns to be generated by way of a capital gain.

Others have proposed a different approach involving an adjustment to the cost of equity by a factor reflecting the effective use or value of franking credits (i.e. allowing for the proportion of taxed income paid out as dividends and the utilisation by investors). The proponents of this approach have in the past suggested a factor in the range 40-65% as representing the appropriate adjustment (gamma)[8] although more recent commentary suggests a lower level (circa 25%). The gamma can be applied to the cost of capital or, alternatively, the tax charge in the forecast cash flows can be decreased to incorporate the expected value of franking credits distributed (the usual approach by regulators).

In Grant Samuel's opinion, it is not appropriate to allow for dividend imputation for business valuation purposes (including the valuation of Santos):

- the underlying concept of gamma is flawed. The gamma is meant to represent some kind of complex market weighted average but the value of franking credits is essentially binary. They have 100% value to some (or many) domestic investors and 0% to foreign investors[7]. There is nobody to whom franking credits have a value equal to, say, 50% of their face value (i.e. there is no spectrum of outcomes to determine a meaningful "weighted average");
- there is no direct evidence that imputation credits are factored into market prices of listed companies or the prices paid in acquisitions. The primary "proof" appears to be based on dividend drop off studies but these face serious questions as to reliability of data and the interpretation of the outcome never mind that it does not address risk and other issues associated with the ability to use them over the longer term;
- it is not consistent with what is happening in real world markets. The adoption of a gamma factor (of, say, 0.5) must, by definition, mean that companies in the Australian market are valued such that:

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7 Withholding tax on unfranked distributions will generally apply to portfolio investors in listed Australian entities but foreign companies (depending on their jurisdiction) are generally not subject to withholding tax on unfranked dividends of wholly owned Australian subsidiaries.

8 Under this construct the cost of equity is scaled by gamma ("δ") (i.e. *Adjusted Re = Re x l-t/(1-t(1-δ))*. Assuming the standard Australian corporate tax rate of 30% and δ = 0.5, Re is multiplied by 0.82 (i.e. 0.70 divided by 0.85).

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- domestic investors (who can use 100% of imputation credits) earn a higher return than their cost of capital; and
- offshore investors earn less than their required return.

As such there should be no offshore investors in Australian (unless they have a lower cost of capital than domestic investors through some other means). It would also suggest that overseas acquirers of businesses in Australia would not be able to compete effectively with local acquirers. Rather, the evidence demonstrates that:

- marginal sharemarket prices are not set using any value for gamma; but that
- domestic investors enjoy a higher after tax return than comparably taxed offshore investors; and

- offshore entities that gain no benefit from franking credits (except for withholding tax) are significant investors in, and acquirers of, oil and gas assets across Australia.

In summary, it is clear that dividend imputation affects returns to investors. However, the evidence gathered to date does not demonstrate or prove that franking credits are factored into the market price of listed companies or the prices paid in acquisitions. While acquirers are undoubtedly attracted by franking credits there is no clear evidence that they will actually pay extra for them or build it into values based on long term cash flows.

Specific Risk

The CAPM/WACC discount rate is designed to be applied to "expected cash flows" which are effectively a weighted average of the likely scenarios. The theoretical underpinning of CAPM is that there is no need or requirement to recognise specific (unsystematic) risks. To the extent that a business is perceived as being particularly risky, this specific risk should be dealt with by adjusting the cash flow scenarios. This avoids the need to make arbitrary adjustments to the discount rate which can dramatically affect estimated values, particularly when the cash flows are of extended duration or much of the business value reflects future growth in cash flows. In addition, risk adjusting the cash flows requires a more disciplined analysis of the risks that the valuer is trying to reflect in the valuation.

However, it is nevertheless common in practice to allow for certain classes of specific risk (particularly sovereign and other country specific risks) by adjusting the discount rate although it must be recognised that such adjustments compromise the theoretical integrity of the methodology (see Section 4). Moreover, there is little evidentiary base for measuring determining the size of any adjustments.

3 Calculation of WACC

3.1 Cost of Equity Capital

Risk Free Rate

Grant Samuel has adopted a risk free rate of 1.6%. The risk free rate approximates the yield to maturity on ten year United States Treasury Bonds in October 2021, reflecting the fact that the functional currency for both Oil Search and Santos is United States dollars.

Market Risk Premium

Grant Samuel has consistently adopted a market risk premium of 6% and believes that this continues to be a reasonable estimate. It:

- is not statistically significantly different to the premium suggested by long term historical data;
- is similar to that used by a wide variety of analysts and practitioners as well as regulators (typically in the range 5-7%); and
- makes no explicit allowance for the impact of Australia's dividend imputation system.

9

Beta Factor

Grant Samuel has adopted a beta factor in the range 1.3-1.4 for the general oil and gas assets of both Oil Search and Santos.

The historical beta factors for a range of upstream oil and gas companies have been considered in determining an appropriate beta. They have been calculated on two bases – relative to each company's home exchange index and relative to an international index (the aggregated world market for Barra and the MSCI for Bloomberg). In Grant Samuel's view, betas estimated by reference to an international index are generally more relevant than those estimated relative to the local index, because they represent a better measure of investing in the resources sector. A summary of betas for selected comparable listed companies is set out in the table below:

EQUITY BETA FACTORS FOR SELECTED LISTED UPSTREAM OIL AND GAS COMPANIES

COMPANY	MARKET CAPITALISATION[9] (US$ BILLIONS)	BARRA			MONTHLY OBSERVATIONS OVER 4 YEARS			WEEKLY OBSERVATIONS OVER 2 YEARS	
		HISTORICAL[10]	PREDICTED[11]		ROZETTA[12]	BLOOMBERG[13]		BLOOMBERG	
			LOCAL BETA	GLOBAL BETA[14]		LOCAL INDEX	MSCI[15]	LOCAL INDEX	MSCI
Oil Search	**5.7**	**1.72**	**1.40**	**1.70**	**2.63**	**2.04**	**1.91**	**1.77**	**1.36**
Santos	**9.2**	**1.22**	**1.31**	**1.51**	**2.39**	**1.95**	**1.82**	**1.71**	**1.42**
AUSTRALIA									
Woodside	13.7	1.24	1.29	1.49	1.81	1.47	1.34	1.43	1.14
Beach Energy	1.8	1.22	1.33	1.55	3.04	1.91	2.06	1.57	1.18
UNITED STATES									
ConocoPhillips	74.4	1.96	1.49	1.60		1.54	1.72	1.18	1.34
EOG Reources	39.4	2.08	1.61	1.74		1.78	1.97	1.13	1.33
Pioneer	36.5	2.05	1.55	1.66		1.62	1.79	1.13	1.30
Occidental	24.0	3.20	1.92	2.08		2.04	2.34	1.70	1.95
Hess	21.3	2.00	1.56	1.68		1.79	1.94	1.22	1.38
Devon Energy	20.0	2.72	1.87	2.01		2.57	2.81	1.54	1.70
Continental Resources	14.4	2.46	1.77	1.90		2.62	2.79	1.40	1.60
Diamondback Energy	14.0	2.88	1.98	2.14		2.19	2.41	1.59	1.80
Marathon Oil	9.3	2.71	1.92	2.09		2.49	2.71	1.32	1.50
APA	7.4	2.77	1.97	2.16		3.70	1.14	2.01	2.25
Cimarex Energy	6.6	2.11	1.64	1.76		2.09	2.32	1.25	1.40
Cabot Oil & Gas	6.4	1.21	1.20	1.30		0.40	0.39	0.78	0.73

9 Based on share prices as at 20 September 2021. Market capitalisations have been converted to US$ at exchange rates of A$1 = US$0.73, EUR1 = US$1.18, THB1 = US$0.03 and JPY1 = US$0.01.

10 Historical beta factors calculated by Barra as at 31 August 2021 over a period of 60 months using ordinary least squares regression.

11 Barra predicted beta is a "fundamental" beta based on a multi-factor model, which regresses historical company returns against the returns of a market index using company-risk and industry-risk factors, re-estimated on a monthly basis, within the regression equation.

12 The Australian beta factors calculated by Rozetta as at 30 June 2021 over a period of 48 months using ordinary least squares regression, excluding return observations for the single month of March 2020.

13 Bloomberg betas have been calculated up to 20 September 2021. Grant Samuel understands that betas estimated by Bloomberg are not calculated strictly in conformity with accepted theoretical approaches to the estimation of betas (i.e. they are based on regressing total returns rather than the excess return over the risk free rate). However, in Grant Samuel's view the Bloomberg beta estimates can still provide a useful insight into the systematic risks associated with companies and industries. The figures used are the Bloomberg "adjusted" betas.

14 Global beta is the predicted beta of the asset with respect to the aggregated world market.

15 MSCI is calculated using local currency so that there is no impact of currency changes in the performance of the index.

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EQUITY BETA FACTORS FOR SELECTED LISTED UPSTREAM OIL AND GAS COMPANIES (CONT)

COMPANY	MARKET CAPITALISATION[9] (US$ BILLIONS)	BARRA			MONTHLY OBSERVATIONS OVER 4 YEARS			WEEKLY OBSERVATIONS OVER 2 YEARS	
		HISTORICAL[10]	PREDICTED[11]		ROZETTA[12]	BLOOMBERG[13]		BLOOMBERG	
			LOCAL BETA	GLOBAL BETA[14]		LOCAL INDEX	MSCI[15]	LOCAL INDEX	MSCI
EUROPE									
Eni	44.5	1.10	1.11	1.07		1.11	1.14	1.14	1.04
Repsol	17.5	1.42	1.28	1.37		1.47	1.28	1.18	1.27
ASIA									
PTTEP	13.7	1.08	1.30	1.15		1.42	1.51	1.42	1.08
Inpex	10.1	1.20	1.25	1.25		1.81	1.53	1.21	1.19
Minimum		*1.08*	*1.11*	*1.07*	*1.81*	*0.40*	*0.39*	*0.78*	*0.73*
Maximum		*3.20*	*1.98*	*2.16*	*3.04*	*3.70*	*2.81*	*2.01*	*2.25*
Median		***1.98***	***1.52***	***1.67***	***2.51***	***1.86***	***1.87***	***1.36***	***1.35***
Weighted average[16]	***389.7***	***1.95***	***1.52***	***1.63***	***2.21***	***1.75***	***1.82***	***1.30***	***1.38***

Source: Rozetta, Barra, Bloomberg

The table shows outcomes that suggest it is extremely difficult to determine a reliable beta for oil and gas assets:

- the betas for Oil Search and Santos vary significantly depending on the measurement source (Rozetta, Barra, Bloomberg etc.) and, as discussed earlier, have varied significantly over time;
- individual company betas (for the same source/period) fall in a very wide range. For example, Barra Five Year predicted global betas generally range from 1.1 (Eni Spa) to 1.7 (Oil Search, EOG Resources, Inc ("EOG Resources"), Pioneer Natural Resources Company ("Pioneer"), Hess Corporation) and to in excess of 2.0 for several companies (Occidental Petroleum Corporation, Devon Energy Corporation, Diamondback Energy, Inc., Marathon Oil Corporation and APA Corporation);
- some individual company betas vary significantly depending on which market index is utilised (local or international) (e.g. APA Corporation);
- the betas vary materially, depending on the data measurement source (Rozetta, Barra or Bloomberg);
- the two year betas are almost all substantially lower than the four year betas. This may reflect relatively lower volatility compared to the market as a whole through the COVID-19 pandemic. However, the longer term measures may be more reflective of the true risks of the industry; and
- gearing levels vary significantly but this is not always consistent with beta factors. The United States upstream oil and gas companies generally have higher betas, reflecting, among other things, the generally higher gearing levels for those companies. However, the European upstream oil and gas companies also have relative high gearing but their betas are not as high.

However, the table does indicate that companies operating predominantly in the upstream oil and gas sector generally have betas well above 1.0 (indicating more risk than the overall market), and arguably, closer to 2.0. Intuitively, this makes sense given their exposure to commodity prices and global economic growth.

The appropriate beta factor is the expected beta but conventional practice is to use historical beta as a proxy for the future. However, historical beta is not the same as expected beta and relative risk does change over time, particularly for oil and gas companies:

16 Weighted by market capitalisation converted to United States using the following exchange rates: A$1 = US$0.73, EUR1 = US$1.18, THB1 = US$0.03 and JPY1 = US$0.01.

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- Barra does attempt to calculate "fundamental" or predicted betas based on a multi-factor regression model. Overall, Barra's predicted betas are lower than historical betas, although this is not always the case on a country by country basis, with Australian and Asian historical betas generally lower than predicted betas;
- share prices can move considerably in response to new discoveries or unexpected increases in reserves and resources for existing assets, causing greater volatility in returns relative to the market as a whole at various points in time; and
- betas are impacted by the mix of activities and the extent of exploration relative to production. Upstream oil and gas companies that have substantial producing assets generally have lower betas than companies with greater exposure to production activities.

As the discount rate is being used to value producing (or close to producing) assets (with exploration assets valued separately), a beta factor towards the lower end of the range for the comparable upstream oil and gas companies can be justified. In addition, Oil Search and Santos have more infrastructure (e.g. LNG trains) than many of the US companies).

Taking all of these factors into account as well as the nature of Oil Search's and Santos' oil and gas assets and their exposure to macroeconomic factors, Grant Samuel believes that a beta in the range 1.3-1.4 is a reasonable estimate of the appropriate beta for the oil and gas assets of both entities. There is insufficient evidence to demonstrate that Oil Search and Santos warrant difference beta factors. Oil Search is higher on some bases and lower on others and the differences are mostly around 0.1. These betas are below those of the United States peers, most of which might best be described as upstream (only) producers.

Calculation

Using the assumptions set out above, the cost of equity capital can be calculated as follows:

COST OF EQUITY CAPITAL

	LOW	HIGH
Formula	***Re = Rf + Beta (Rm – Rf)***	
Outcome	= 1.6% + (1.3 x 6%) **= 9.4%**	= 1.6% + (1.4 x 6%) **= 10.0%**

3.2 Cost of Debt

A cost of debt of 4.6%, which implies a margin of 3% over the risk free rate, has been assumed. This margin reflects:

- Grant Samuel's understanding of current market margins and:
  - is broadly consistent with margins achieved by companies of a comparable credit standing to Santos (BBB (Fitch), BBB- (S&P)) (Oil Search does not have a credit rating);
  - allows for the margin between government bonds (i.e. the risk-free rate) and lending benchmarks (i.e. interbank lending/swap rates); and
  - allows for debt issuance costs; and
- current spreads for Australian BBB bonds over Australian Government bonds of similar tenor as published by the Reserve Bank of Australia (31 August 2021):
  - 160 basis points for 10 years; and
  - 147 basis points for 7 years,

  taking into account Santos' BBB- rating from S&P;

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- Santos' April 2021 announcement that it had priced a US$1.0 billion 10 year US 144A/Regulation S bond at a fixed coupon of 3.649% (a margin of a little over 200 basis points). At the same time, Santos' debt mix includes more expensive facilities such as its share of PNG LNG project debt and leasing; and
- the cost of liquidity. Santos is carrying cash of over $2 billion and undrawn facilities of over $2 billion both of which incur a cost (that is attributable to net borrowings). This liquidity cost is an inherent cost of financing the business.

Oil Search's cost of debt is approximately 100-150 basis points higher largely reflecting a sovereign risk premium (see Section 4) but it also carries proportionately less cost from cash/undrawn facilities.

3.3 Debt/Equity Mix

In determining an appropriate debt/equity mix, regard was had to gearing levels of Oil Search and Santos and the peer group companies used in the beta analysis. Gearing levels (based on market values) for these companies for the past five years are set out below:

GEARING LEVELS FOR SELECTED LISTED OIL AND GAS COMPANIES

	NET DEBT/(NET DEBT + MARKET CAPITALISATION)								
	FINANCIAL YEAR END					CURRENT[17]	2 YEAR AVERAGE	4 YEAR AVERAGE	5 YEAR AVERAGE
	HISTORICAL 5	HISTORICAL 4	HISTORICAL 3	HISTORICAL 2	HISTORICAL 1				
Oil Search	**22.7%**	**18.8%**	**20.6%**	**23.5%**	**26.4%**	***23.6%***	***25.0%***	***22.3%***	***22.4%***
Santos	**28.2%**	**19.3%**	**23.9%**	**16.4%**	**22.0%**	***20.2%***	***19.2%***	***20.4%***	***22.0%***
AUSTRALIA									
Woodside	15.2%	14.4%	7.4%	7.9%	14.5%	*15.5%*	*11.0%*	*11.0%*	*11.9%*
Beach Energy	-22.8%	13.3%	-4.0%	0.3%	5.1%	*5.9%*	*2.7%*	*3.7%*	*-1.6%*
UNITED STATES									
ConocoPhillips	27.5%	12.8%	9.3%	7.3%	16.3%	*10.9%*	*11.8%*	*11.4%*	*14.6%*
EOG Reources	8.%	8.2%	8.2%	7.5%	10.5%	*3.5%*	*9.0%*	*8.6%*	*8.6%*
Pioneer	2.1%	2.1%	3.6%	8.6%	11.8%	*15.2%*	*10.2%*	*6.5%*	*5.6%*
Occidental	12.2%	12.6%	13.6%	56.7%	74.4%	*64.7%*	*65.5%*	*39.3%*	*33.9%*
Hess	17.3%	12.5%	25.1%	24.1%	31.3%	*23.8%*	*27.7%*	*23.2%*	*22.0%*
Devon Energy	25.6%	16.5%	16.2%	23.7%	29.3%	*22.2%*	*26.5%*	*21.4%*	*22.2%*
Continental Resources	25.6%	24.3%	26.8%	29.6%	48.3%	*23.8%*	*38.9%*	*32.3%*	*30.9%*
Diamondback Energy	-6.6%	9.9%	21.8%	26.0%	42.8%	*32.9%*	*34.4%*	*25.1%*	*18.8%*
Marathon Oil	24.6%	25.5%	25.3%	30.9%	47.8%	*30.9%*	*39.3%*	*32.4%*	*30.8%*
APA	22.9%	29.8%	43.0%	47.2%	62.6%	*51.2%*	*54.9%*	*45.6%*	*41.1%*
Cimarex Energy	6.1%	8.5%	10.6%	30.0%	34.5%	*15.3%*	*32.3%*	*20.9%*	*17.9%*
Cabot Oil & Gas	8.6%	7.3%	11.3%	12.9%	13.7%	*10.6%*	*13.3%*	*11.3%*	*10.8%*
EUROPE									
Eni	21.4%	17.9%	14.6%	25.9%	35.5%	*29.9%*	*30.7%*	*32.5%*	*23.0%*
Repsol	38.6%	32.6%	28.1%	25.9%	43.9%	*31.5%*	*39.9%*	*35.1%*	*35.8%*
ASIA									
PTTEP	-0.3%	-0.4%	-0.5%	0.0%	0.0%	*0.5%*	*0.0%*	*-0.2%*	*-0.2%*
Inpex	-2.5%	1.8%	18.0%	36.3%	56.4%	*46.7%*	*46.3%*	*28.1%*	*22.0%*
Minimum						*0.5%*	*0.0%*	*-0.2%*	*-1.6%*
Maximum						*64.7%*	*65.5%*	*45.6%*	*41.1%*
Median						***22.9%***	***27.1%***	***21.9%***	***22.0%***
Weighted average						*22.0%*	*24.1%*	*18.9%*	*18.5%*

Source: IRESS, S&P Global Market Intelligence, Bloomberg, Grant Samuel analysis

[17] Current gearing levels are based on the most recent balance sheet information and sharemarket prices at 20 September 2021.

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The table shows a very wide range of gearing levels. The debt levels should actually be the weighted average measured over the same period as the beta factor rather than just at the current point in time. Moreover, these do not always bear any relationship to the betas of the individual companies:

- in some cases lowly geared companies have equity betas towards the higher end of the range (e.g. EOG Resources or Pioneer); and
- gearing is impacted by market capitalisation at financial year end. The 2 year average gearing in particular has been impacted by market volatility associated with the COVID-19 pandemic in the months following March 2020 (and less weight has been placed on two year average gearing as a result).

Oil Search's and Santos' gearing has generally been very similar at between 20% and 22% over the past 4-5 years. This level of gearing is:

- higher than other Australian upstream oil and gas companies. Woodside Petroleum Limited ("Woodside") has lower average gearing (~11-12%) but also has lower beta (~1.2-1.5, excluding outliers). Beach Energy Limited ("Beach") has minimal gearing and a net cash position based on 5 year averages. It has a higher beta than Woodside but this is likely to reflect factors other than gearing such as size, mix of activities etc;
- consistent with the average gearing for United States upstream oil and gas companies (~18-23%, excluding the 2 year average), albeit most of the United States companies have relatively higher betas; and
- slightly below the gearing levels of European and Asian upstream oil and gas companies (~22-30%, excluding PTT Exploration and Production PCL ("PTTEP") which has no gearing or a net cash position). However, the slightly higher gearing of the European and Asian companies does not translate into higher betas, which are consistently in the range 1.0-1.5.

The selection of an appropriate gearing level is highly judgemental. Having regard to the above, the debt/equity mix has been estimated as 15-25% debt and 75-85% equity. This is regarded as being broadly consistent with a beta factor of 1.3-1.4.

3.4 Calculated WACC

On the basis of the parameters outlined above and assuming a corporate tax rate of 30%[18], the nominal WACC can be calculated to be in the range 7.9-9.0%:

CALCULATED WACC

	LOW	HIGH
Formula	***= (Re x E/V) + (Rd x (1-t) x D/V)***	
Outcome	= (9.4% x 75%) + (4.6% x (1 – 30%) x 25%) = 7.1% + 0.8% **= 7.9%**	= (10.0% x 85%) + (4.6% x (1-30%) x 15%) = 8.5% + 0.5% **= 9.0%**

18 The appropriate tax rate should be a blend of the tax rates in which the assets are located. However, as the assumed gearing level is relatively low, a higher or lower tax rate has minimal impact on the calculated WACC. The corporate tax rate is 30% in both Australia and PNG.

4 Sovereign Risk

Oil Search's assets are all based on Papua New Guinea with the exception of its investment in the Pikka exploration project in Alaska. Santos also has a significant investment in the PNG LNG Project. The question therefore arises as to whether these assets should be valued using a discount rate that takes account of the sovereign risk associated with investment in Papua New Guinea.

The assessment of appropriate discount rates for developing markets is even more problematic than developed markets. The CAPM is designed to estimate the cost of equity capital in developed markets. The first issue is currency. For a DCF analysis in local currency, the starting point is a risk free rate in that currency. Government bonds in these markets are not necessarily risk free so the alternative is to adjust mature market bond rates for inflation differentials (assuming the Fisher effect). In this case, the issue is not relevant as the functional currency is United States dollars. It is then necessary to also consider the extent of any "country risk" premium. While it is generally acknowledged that there is additional uncertainty associated with investment in developing markets (such as political instability, economic risks (e.g. higher inflation), level of sovereign debt and probability of default, currency fluctuations and government regulation (e.g. expropriation or currency controls):

- the CAPM does not explicitly allow for this additional risk. It is not simply a case of changing the inputs to reflect risk free rates and market risk premiums in the relevant developing market, not least because of their questionable reliability; and
- there is no consensus among academics or practitioners as to the best approach to estimating the equity cost of capital for companies operating in developing countries. There are several approaches (e.g. government bond spreads, credit default swap spreads, country credit ratings, relative volatility of equity market returns) but there are limitations with each approach. Widely referenced calculations such as those by Damodaran[19], whose latest estimate for Papua New Guinea is a 4.62% premium, have been subject to strident criticism (although it is one of the few easily accessible databases). In fact, there are arguments that no adjustment is necessary as these risks can be eliminated through diversification; and
- the effective exposure to country risk varies from company to company. Oil Search and Santos produce oil and gas for international export markets (with revenues earned in US$) and therefore have virtually no exposure to the domestic economy. In fact, if the PNG currency falls, they potentially benefit from a reduction in local operating costs. This exposure is very different to that of, for example, a company importing and selling goods to the local market (where currency and the domestic economy are critical). The primary risks facing Oil Search and Santos are distinctly different and include factors such as political upheaval (impacting approvals), difficulties in securing stable fiscal regimes, constraints on repatriation of profits and expropriation of assets. In this context, a single rate as suggested by Damodaran is clearly an inadequate basis for dealing with a complex issue that depends on the particular circumstances. While the risks in PNG are not trivial (and Bougainville Copper provides a stark example):
  - Oil Search has a long history in Papua New Guinea and the PNG LNG Project has been in operation since 2014;
  - government and local ownership of the PNG LNG joint venture (19% in total) and the Papua LNG Project (22.5%) is very significant; and
  - both projects are of fundamental importance to the generation of export earnings for, and the broader economic development of, Papua New Guinea. The ventures also undertake various active economic and social projects across PNG.

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19 Damodaran, Aswath, Country Risk: Determinants, Measures and Implications – The 2021 Edition (5 July 2021). The country risk premium is in addition to the equity market risk premium.

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Country risk can also change quickly as economic and market conditions change.

The factors suggest that it is extremely difficult to reliably estimate a sovereign risk premium for the Oil Search and Santos investments in Papua New Guinea.

Oil Search does have a higher overall debt margin than Santos (circa 1-1.5%) largely due to its greater exposure to PNG risk. While this is a measurable additional cost:

- debt premiums are not directly translatable into equity premiums; and
- the impact on WACC is not material (<0.3%).

In any event, it is Grant Samuel's preference, where practical, to reflect these risks through a risking of the cash flows rather than by adding a premium to the discount rate (albeit the economic effect may be similar). This is the approach that has been adopted in this report.

5 Selection of Discount Rates

Grant Samuel considers a discount rate above the calculated WACC of 7.9-9.0% to be a more appropriate measure of the cost of capital. In addition to the issues with use of CAPM to calculate the cost of equity (see Section 2 for a detailed discussion):

- measurement of the risk premium is open to debate, even at the best of times. Most practitioners opt for using a "stable" risk premium and around 6% is a relatively common benchmark. However, equity markets are inherently volatile, and the "true" risk premium rises and falls. There was considerable press and other comment that the risk premium went up at the height of the COVID-19 pandemic in March 2020 but the subsequent recovery on global equity markets and relative stability in recent months suggest much of this additional risk may have dissipated;
- strict application of the CAPM at the present time (using current parameters) gives results that are arguably unrealistically low and understate the true cost of capital (primarily because of extremely low government bond rates). While the broad expectation is that government bond rates across the globe will remain extremely low for several years as the world economy seeks to recover from the impacts of the COVID-19 pandemic. The discount rates produced by CAPM do not seem to accord with how investors set their expected returns and are often inconsistent with other measures such as the Gordon Growth Model (which is based on observable dividend yield plus a long term growth rate).

  Some academics and valuation practitioners consider it to be inappropriate to add a "normal" market risk premium (e.g. 6%) to a temporarily depressed bond yield and therefore advocate that a "normalised" risk free rate should be used. This practice has become increasingly common among broker analysts with an assumed risk free rate of around 2.5% not uncommon. Assuming a risk free rate of 2.5% would result in a CAPM WACC of 8.8-9.9%. Alternatively, there is some evidence that risk premiums are higher when risk free rates are lower (i.e. implying a more stable overall cost of equity);
- 30 year bonds issued by the United States Government are trading at yields approximately 0.5% higher than equivalent ten year bonds (the term premium for Australian bonds is slightly higher); and
- analysis of research reports indicates that brokers (that do publish their estimates) are currently adopting a WACC generally in the range 8.0-10.0% with a median of around 9.0% for both Oil Search and Santos (although some brokers are adopting a higher WACC for Oil Search than for Santos).

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Consideration has also been given as to whether there should be different discount rates for Oil Search and Santos. In addition to relative degrees of sovereign risk (see Section 4), Oil Search and Santos also have different product mixes, gearing levels and costs of debt. However:

- sovereign risk has been taken account of in the risking of cash flow scenarios;
- Oil Search's higher cost of debt is at least partly offset by its higher gearing (certainly in terms of accounting metrics) and has a minimal WACC impact;
- given the uncertainty in the measurement of other inputs to the calculation of WACC (e.g. beta factors), these other differences would have minimal overall impact on WACC (i.e. within the margin of error); and
- revenue of both companies is largely driven by the same external factors (i.e. global oil and LNG prices). They are essentially in the same business and, arguably, CAPM is best thought of in industry terms rather than trying to determine highly refined individual company estimates (given the unreliability, spread and inconsistency of the available data).

Having regard to these matters, Grant Samuel has adopted a discount rate (WACC) in the range 8.5-9.5% for Oil Search's and Santos's oil and gas assets.

Nevertheless, it is necessary to recognise that within the portfolio some assets have different risk characteristics that warrant a different discount rate. Specifically:

- cash flows from gas production sold into Australian domestic market on long term contracts with fixed or index linked pricing. These cash flows are not exposed to the vagaries of oil or oil-linked prices; and
- cash flows from operations that process gas for third parties on a "tolling" basis.

To reflect the lower systematic risk of these categories of cash flows, Grant Samuel has adopted discount rates of:

- 6.5-7.5% for gas contracts; and
- 6.0-7.0% for tolling profits.

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APPENDIX 6

MARKET EVIDENCE – COMPARABLE LISTED COMPANIES

The sharemarket metrics of selected listed oil and gas companies are set out below:

SHAREMARKET RATINGS OF SELECTED LISTED COMPANIES – OIL AND GAS INDUSTRY

COMPANIES	MARKET CAPITAL-ISATION (US$ million)	EBITDAX MULTIPLE			EBITDA MULTIPLE[1]			EBIT MULTIPLE[2]			PRICE EARNINGS MULTIPLE[3]			RESOURCE MULTIPLES		
		HISTORICAL	FORECAST YEAR 1	FORECAST YEAR 2	HISTORICAL	FORECAST YEAR 1	FORECAST YEAR 2	HISTORICAL	FORECAST YEAR 1	FORECAST YEAR 2	HISTORICAL	FORECAST YEAR 1	FORECAST YEAR 2	1P RESERVES	2P RESERVES	2P + 2C
ASX listed oil and gas peers																
Beach Energy Limited	2,385	3.4x	3.3x	3.3x	3.6x	3.3x	3.3x	8.1x	5.2x	5.5x	8.5x	7.4x	7.6x	13.65	7.37	4.71
Woodside Petroleum Ltd[4]	16,926	11.6x	5.4x	4.6x	12.1x	5.5x	4.6x	--	10.3x	7.2x	--	13.4x	9.9x	29.90	20.53	5.17
Other listed peers																
APA Corporation	9,908	8.3x	3.7x	3.7x	9.0x	3.8x	3.9x	--	6.2x	6.2x	--	6.8x	5.3x	20.04	--	--
ConocoPhillips	99,748	19.2x	5.1x	4.5x	21.6x	5.2x	4.6x	--	8.9x	7.8x	--	14.0x	10.6x	23.03	--	--
Continental Resources, Inc.	17,643	14.1x	5.3x	5.1x	14.3x	5.3x	5.1x	--	10.0x	8.8x	--	11.1x	9.3x	20.50	--	--
Coterra Energy Inc.	17,347	26.0x	8.0x	3.9x	26.6x	8.0x	3.9x	--	11.9x	5.7x	--	14.3x	6.7x	5.84	--	--
Devon Energy Corporation	27,128	23.2x	6.2x	4.9x	23.5x	6.2x	4.9x	--	11.2x	7.3x	--	13.2x	8.7x	43.49	--	--
Diamondback Energy, Inc.	19,407	15.1x	6.6x	5.0x	15.1x	6.6x	5.0x	--	8.8x	6.6x	--	10.4x	6.8x	23.66	--	--
Eni S.p.A.	50,989	8.4x	3.6x	3.1x	8.4x	3.6x	3.1x	--	6.5x	5.2x	--	11.9x	9.9x	9.28	--	--
EOG Resources, Inc.	53,984	10.7x	5.2x	4.8x	11.1x	5.3x	4.8x	--	9.5x	8.4x	--	11.4x	10.2x	17.23	--	--
Hess Corporation	25,411	15.2x	9.2x	7.1x	16.5x	9.6x	7.4x	--	15.4x	10.6x	--	40.2x	16.9x	28.08	--	--
Inpex Corporation	12,187	6.2x	3.7x	3.5x	6.2x	3.7x	3.5x	10.7x	5.2x	5.0x	--	--	--	6.26	--	--
Marathon Oil Corporation	12,867	10.1x	4.7x	4.3x	10.3x	4.8x	4.4x	--	13.8x	10.2x	--	14.2x	9.2x	16.93	--	--
Occidental Petroleum	31,308	10.3x	5.3x	4.9x	10.5x	5.4x	5.0x	--	17.2x	12.0x	--	22.0x	14.0x	24.63	--	--
Pioneer Natural Resources	45,615	28.7x	7.6x	5.1x	29.3x	7.7x	5.1x	--	12.3x	7.3x	--	14.4x	8.5x	41.42	--	--
PTT Exploration and Production	13,979	4.2x	--	--	4.3x	--	--	10.5x	--	--	17.7x	--	--	14.39	--	--
Repsol, S.A.	19,009	13.3x	3.0x	2.8x	14.1x	3.0x	2.8x	--	4.9x	4.5x	--	7.4x	6.4x	12.64	--	--

Source: S&P Capital IQ, Grant Samuel analysis

The multiples shown above are based on sharemarket prices as at 29 October 2021 and do not reflect a premium for control. All companies have a 31 December year end with the exception of Beach Energy Limited which has a 30 June year end.

The data analysed for each company included the last two annual historical results plus the subsequent two forecast years. The majority of the listed oil and gas peers observed significant declines in earnings in the most recent historical period (i.e. financial year ended 31 December 2020). As a result, the calculated earnings (e.g. EBIT, price-to-earnings, etc.) are not particularly meaningful from a valuation perspective.

Resource and reserve multiples are based on the latest disclosures for each of the listed peers, which is generally aligned with the latest financial year end date. 2P reserves and 2C resources are only disclosed by ASX-listed oil and gas peers. All other global peers only disclose 1P reserves.

---

1 Represents gross capitalisation (that is, the sum of the market capitalisation adjusted for minorities, plus borrowings less cash as at the latest balance date) divided by EBITDA. EBITDA is earnings before net interest, tax, depreciation, amortisation, investment income and significant and non-recurring items.

2 Represents gross capitalisation divided by EBIT. EBIT is earnings before net interest, tax, investment income and significant and non-recurring items.

3 Represents market capitalisation divided by net profit after tax (before significant and non-recurring items).

4 Canada, Greater Sunshine and Myanmar have been removed from the Woodside 2C resource estimates as a result of the low likelihood of development.

1

APPENDIX 7

TECHNICAL SPECIALIST REPORT BY
GAFFNEY CLINE & ASSOCIATES PTY LTD

1

Gaffney Cline

Independent Technical Specialist's Report for Oil Search Limited and Santos Limited Merger

Prepared for

Grant Samuel & Associates Pty. Limited

October 2021

Gaffney Cline

Document Approval and Distribution

Copies:	Electronic (1 PDFs)
Project No:	PY-21-2005
Prepared for:	Grant Samuel & Associates Pty. Limited

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Appendix IV: Documented JVs in which Santos carries Reserves/Resources as of 31 December 2020

Grant Samuel & Associates Pty. Limited
October 2021

1 Introduction

At the request of Grant Samuel & Associates Pty. Limited (Grant Samuel), Gaffney, Cline & Associates Pty. Ltd. (GaffneyCline) has performed a technical assessment of the petroleum assets owned by Oil Search Limited (Oil Search or OSL) and Santos Limited (Santos or STO) for their proposed merger. The merger is to be implemented by way of a Scheme of Arrangement in Oil Search. Grant Samuel appointed GaffneyCline to provide technical advice in relation to the assignment and to prepare an Independent Technical Specialist's Report (Subsidiary Assignment) that is appended to Grant Samuel's Independent Expert Report to be included in the transaction documents as part of Oil Search's submission to shareholders. The Grant Samuel appointment of GaffneyCline was a result of Oil Search's appointment of Grant Samuel to act as their Independent Expert for any transaction response requirements and the simultaneous Oil Search appointment of GaffneyCline. Oil Search are GaffneyCline's original contract holders. This Oil Search arrangement has been in place since around 2010.

GaffneyCline has advised Grant Samuel that it is independent of Oil Search and Santos for the purpose of the Subsidiary Assignment. By accepting the terms of the Subsidiary Assignment GaffneyCline confirms that it is, and has remained, independent of Oil Search and Santos for the purpose of the Subsidiary Assignment, including the preparation of this Technical Specialist's Report. Oil Search was however responsible for the fees of GaffneyCline and in undertaking the Subsidiary Assignment GaffneyCline accepted instructions exclusively from, and provided advice and reporting exclusively to, Grant Samuel.

As per Grant Samuel's assignment instructions, for each of Oil Search and Santos, GaffneyCline reviewed estimates of reserves and resources, capital costs, production profiles and operating costs for each significant producing and development asset and advised Grant Samuel as to whether these estimates, or other assumptions that GaffneyCline believed are more appropriate, were reasonable for valuation purposes. Grant Samuel also required GaffneyCline to consider different development / production scenarios in valuing each of the assets. These scenarios varied depending upon the specific issues relating to each asset and were predominantly based on extensions to current reserves with contingent and/or prospective resources and/or the potential for variations in future production rates. GaffneyCline and Grant Samuel worked together to jointly specify and define the valuation scenarios for each relevant asset based on technical briefings, data and profiles provided by Oil Search and Santos. In respect of each valuation scenario, GaffneyCline provided Grant Samuel the vetted input parameters for Grant Samuel's financial modelling. These parameters typically consisted of production profiles and annual estimates of capital and operating costs reviewed and/or updated from profiles and technical data provided by Oil Search and Santos. In addition, for each of Oil Search and Santos, GaffneyCline reviewed the portfolio of exploration interests and other early-stage petroleum assets for which it was not appropriate to prepare cash flow-based valuations and provided a valuation of those interests compliant with the 2015 Valmin Code, ASX listing Rules and PRMS 2018.

1.1 Oil Search

Oil Search is an oil and gas exploration and production company that has been operating in Papua New Guinea (PNG) since 1929. It is PNG's largest oil producer, operating all of PNG's current oil fields. Oil Search participates in two LNG projects in PNG: the producing PNG LNG project (operated by ExxonMobil) and the proposed Papua LNG project (operated by Total).

Oil Search's 29% interest in the ExxonMobil-operated PNG LNG Project has transformed the company into a significant gas producer. Santos is also a partner in PNG LNG with ~13.5321% interest. Oil Search has a 38.51 % interest in Petroleum Retention Lease 3 (PRL 3) which includes the discovered P'nyang gas field. The P'nyang Gas Agreement commercial negotiations between ExxonMobil and the PNG government were impacted by COVID-19 throughout 2020 and the discussions were scheduled to resume during 2021 with the government indicating a desire to prioritise the Papua LNG discussions with Total before finalising P'nyang. Two potential options for the P'nyang Field have been reviewed by GaffneyCline which include: backfill into the two train PNG LNG foundation project and expanding the construction of the two train Papua LNG project to three trains where an optional P'nyang train (an option studied during 2019 Pre-Feed) is considered.

The Papua LNG project, to be operated by Total, will supply two trains from the Elk-Antelope gas field in PRL 15. Oil Search has a 22.8% interest in Papua LNG. The PNG Government endorsed the Papua Gas Agreement in September 2019. In February 2021, PNG's Prime Minister Marape announced his government's strong support for the fast-tracking of the Papua LNG project. The final documents relating to the Papua Gas Agreement were executed and announced to the market on 10 February 2021 with the PRL 15 licence extended a further 5 years. Front end engineering and design (FEED) is scheduled for the first half of 2022, the final investment decision (FID) is currently due in Q4 2023 with the Papua LNG first gas planned for Q4 2027 from Papua LNG's first train. The second train is scheduled to start up in Q1 2028.

The PNG LNG Project started exporting LNG cargoes in 2014 and has consistently produced above the foundation project two-train nameplate capacity of 6.9 MT, with a gross production of 7.9 MT in 2016, 8.2 MT in 2017 and 7.4 MTin 2018. Production for 2018 declined due to the PNG earthquake in February 2018, with 1H 2018 averaging 6.1 MT and 2H 2018 averaging 8.8 MT. PNG LNG production in 2019 was 8.5 MT and 8.8 MTin 2020. The base case valuation scenario assumption is a maximum 8.6 MPTA for future years considered in this technical assessment for input into Grant Samuel's valuation analysis. PNG LNG 100% 2021 production as of 1 July 2021 was ~4.1 MT (52 LNG cargoes) with a Net Oil Search ~11.9 MMboe H1 sales equivalent. Production was affected by planned maintenance at the PNG LNG plant and the Hides gas conditioning plant, which processes gas from the onshore Hides Field that provides the bulk of the feedstock for the liquefaction plant. The maintenance, which was completed ahead of schedule, comprised work on train one, which was deferred from last year, as well as on train two.

Oil Search's PNG Net Crude Oil production was 5.02 MMstb in 2016, 3.97 MMstb in 2017 and 1.99 MMstb in 2018. Net Crude Oil production in 2019 was 1.57 MMstb due to restoration work on earthquake-damaged infrastructure. 2020 oil production from Oil Search's operated fields in PNG was 2.62 MMstb. PNG Oil production as of 1 July 2021 was ~1.4 MMstb Net to Oil Search. Total Net Oil Search H1 sales were ~13.4 MMboe when including the PNG LNG production.

Oil Search's PNG discoveries P'nyang and Muruk and the near field PNG exploration portfolio provide significant opportunities based on a gas strategy assessment defined by the foundation and expansion LNG timing and volume needs. GaffneyCline considers near field discoveries and exploration assets as key to Oil Search's future production capacity in PNG. These are evaluated in the scenarios considered as part of this report.

Oil Search acquired a 25.5% interest of the Pikka Unit and 37.5% of the Horseshoe and Hue Shale in the North Slope of Alaska (USA) in early 2018 for circa US$400 MM, increasing its equity to 51% after exercising its option in June 2019 with a further US$450 MM payment. The North Slope of Alaska is a prolific, well-established oil province with one of the largest conventional, onshore oil fields discovered in the USA in the last few decades. Oil Search's Alaskan portfolio purchase contains many appraisal and exploration opportunities with material resource upside. Current third-party independent assessments of the progressing Pikka Development project alone have estimated the discovered 2C Contingent Oil Resources at 727.6 MMstb (100% Gross).

Oil Search was in active discussion to farm down the Alaska assets during 2021. GaffneyCline has focused on the resource volumes assessed by Oil Search in this technical assessment and also discusses additional Alaska exploration potential for impact on valuation. The Phase 1 Pikka development was the primary focus for GaffneyCline's production and cost valuation scenarios for input into the Grant Samuel financial model.

Oil Search has existing contracts to provide gas to the Porgera mine gas-to-electricity plant (Hides GSA and Hides Project Co-Ordination Deed (HPCD)) which are presently under Force Majeure as a result of the Porgera mine closure and the dispute over longer term tenure between Barrick (and the Porgera parties) and the PNG Government. The GSA and HPCD expire at year end so new contracts will need to be put in place.

Oil Search's main areas of operation in PNG and Alaska (inset) are illustrated in **Figure 1.1** and **Figure 1.2**.

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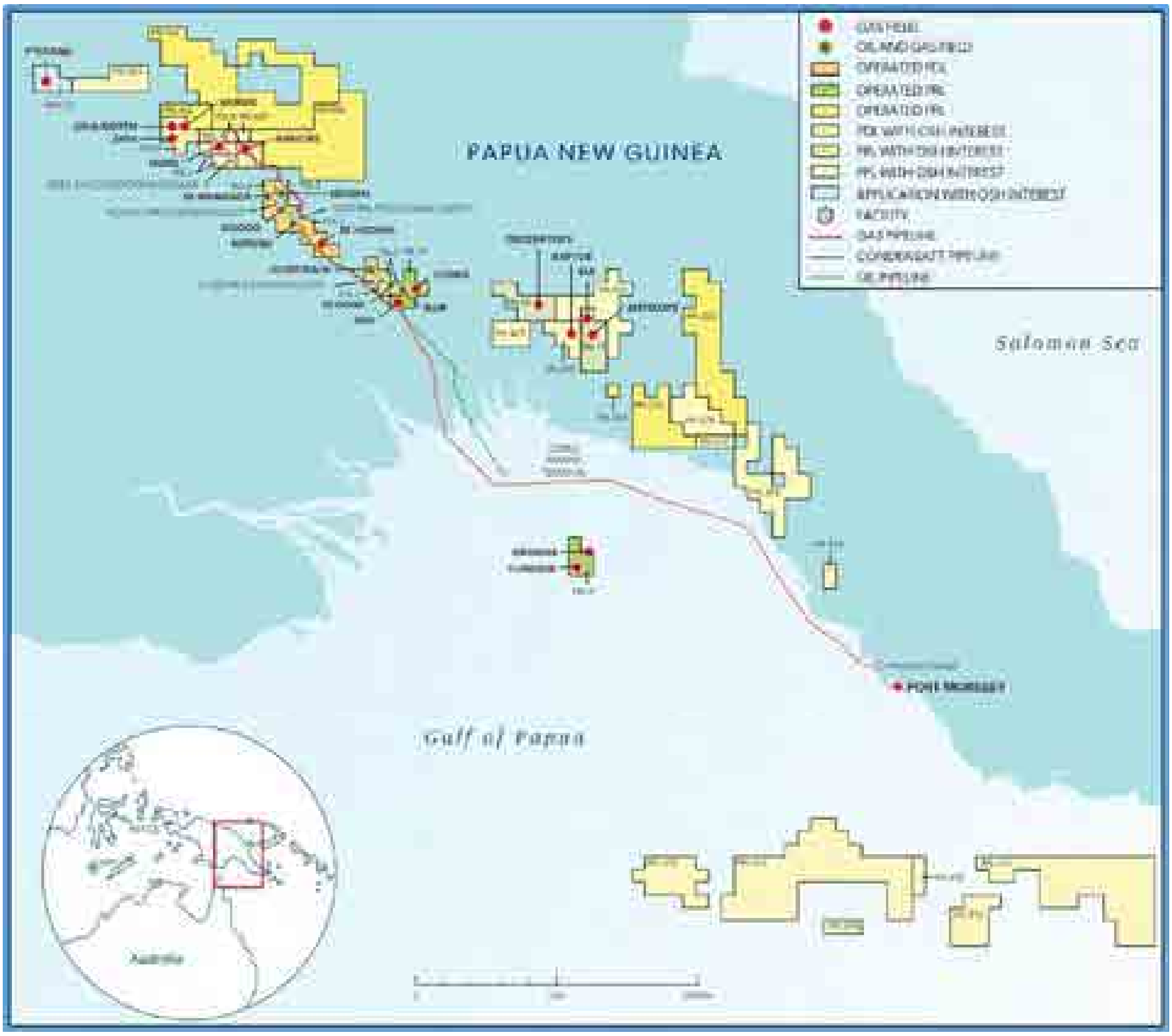
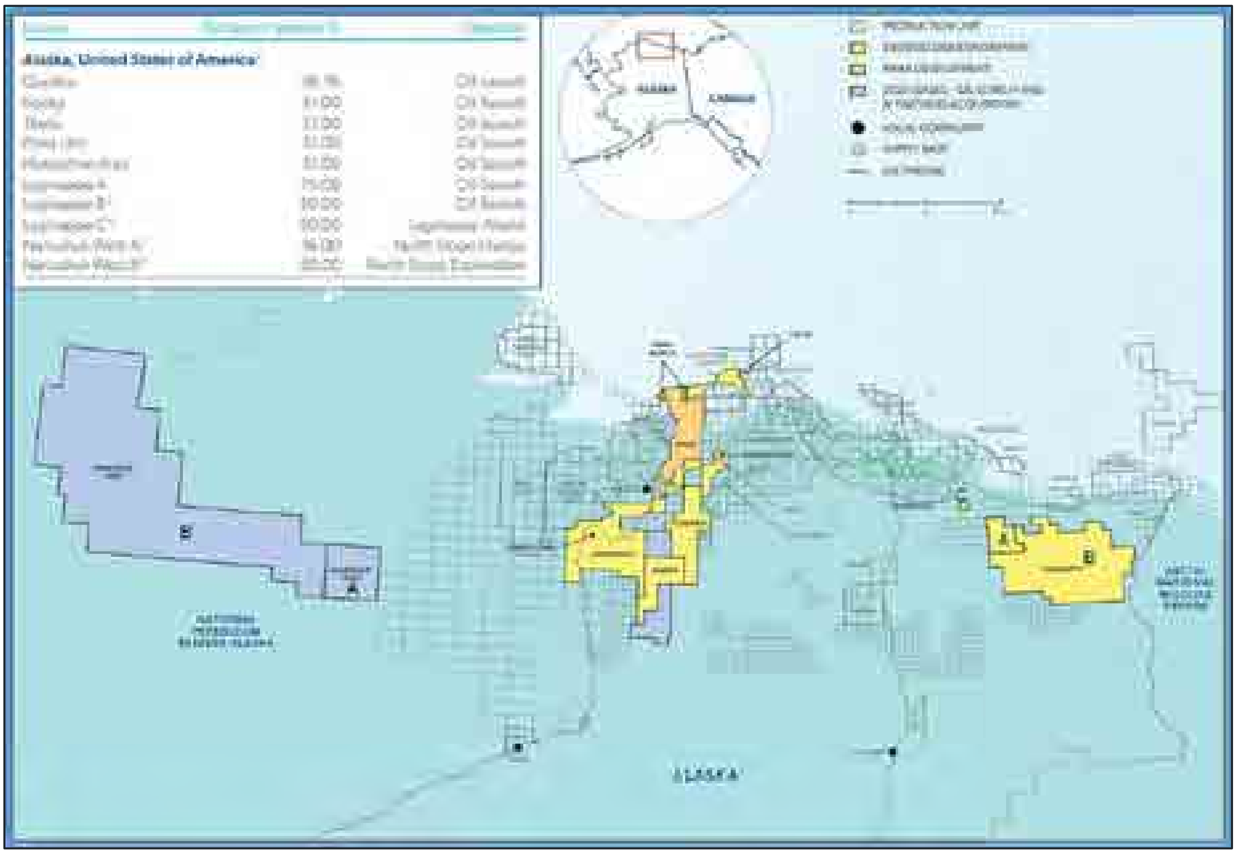
Figure 1.1: Oil Search's PNG Areas of Operation



Source: Oil Search (Modified)

Figure 1.2: Oil Search's Alaska North Slope Interests



Source: Oil Search (Modified)

GaffneyCline has focused on Oil Search's producing, discovered and exploration assets in PNG and Alaska as presented to GaffneyCline in various technical discussions since 2010 with updates for this Independent Technical work during the merger process to provide input to Grant Samuel for valuation.

1.2 Santos

Santos is Australia's largest domestic gas supplier with additional focus in the Asia–Pacific LNG arena. Santos' portfolio of producing natural gas and oil assets is in Western Australia, Cooper Basin, South East Queensland, New South Wales, Northern Australia, Timor-Leste and Papua New Guinea. Additional Santos exploration focus exists in the McArthur and South Nicholson basins onshore Australia (**Figure 1.3**, **Figure 1.4** and **Figure 1.5**). Santos has stated in various releases "*that it intends to grow its clean fuels capability as customer demand evolves for zero-emissions LNG, hydrogen and other products through carbon capture and storage (CCS), nature-based offsets, energy efficiency and use of renewables in its operations".* GaffneyCline has focused on Santos' producing, discovered and exploration assets as presented to GaffneyCline in various technical discussions during this merger process (with additional technical data provided via the Ansarada data exchange platform and/or directly from Santos) and in the Santos Annual Report (2020) to provide input to Grant Samuel for valuation. GaffneyCline has also opined on Santos' CCS projects for technical input into the valuation with specific focus on the most mature project in Moomba, South Australia.

Western Australia

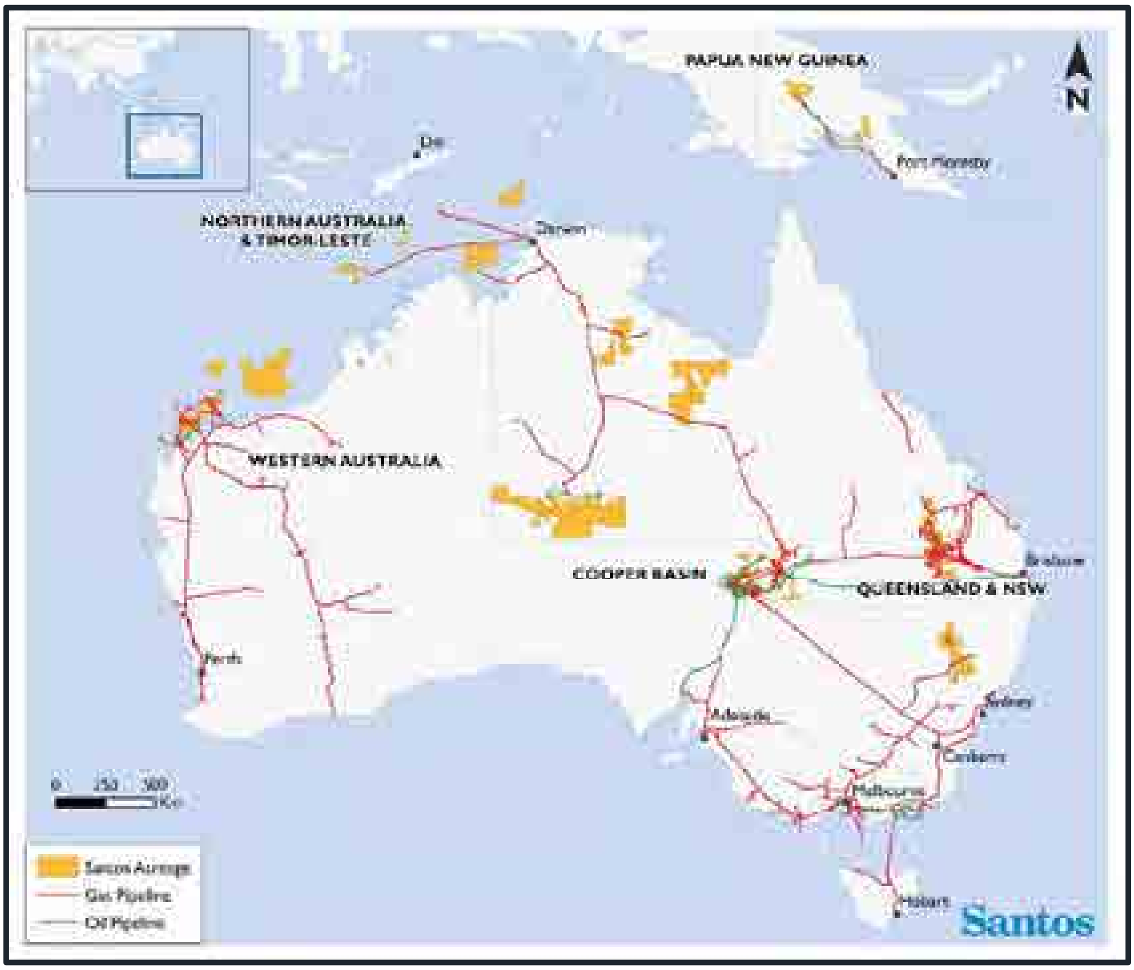
Santos is a producer of domestic natural gas in Western Australia and is also a producer of oil and natural gas liquids. Santos' Western Australian assets include operated production and near-field development along with additional exploration. These assets include 100% ownership and operatorship of the Varanus Island and Devil Creek domestic gas hubs, a 28.6% interest in the Macedon gas hub and a position in the prospective Bedout Basin. Santos is targeting a Final Investment Decision (FID) for a potential oil and liquids development of the Dorado Field (Santos 80% interest) in the Bedout Basin for mid-2022 with first production in 2026. Further drilling is also planned on the Dancer, Yoorn, Apus and Pavo prospects in 2021/2022. Santos' reported Western Australia 2020 Production and Sales Volume was 31.1 MMboe. Santos' gas production in Western Australia was up 10% to 159 PJ due to strong customer demand. Crude oil production was 2.4 MMbbl, lower than the previous year due to the Ningaloo Vision FPSO (Van Gogh, Coniston and Novara Fields) being off station for planned shipyard maintenance. Western Australia 2021 Production and Sales as of 1 July 2021 were ~16.7 and 16.5 MMboe respectively.

Cooper Basin

The Santos' Cooper Basin asset produces natural gas, gas liquids and crude oil with gas primarily sold to domestic retailers, industry and for liquefied natural gas. Santos through various management presentations and in their annual report, have stated that the Cooper basin strategy is to deliver production growth by being a low-cost business, increasing reserves through additional drilling targeting ~100 wells per year with 4 drilling rigs to sustain their reserves replacement ratio. Santos also state they are investing in new technology to lower development and exploration costs through low-cost efficient drilling. Operating 125 compressors across 28 satellites, they are demonstrating an increased utilisation of infrastructure with additional integrated operation centres. Santos provided information indicating that the Moomba and Port Bonython plants (Santos 66.7% interest) are being optimised via remote operations, digitisation and collaboration to achieve cost savings. FID has been announced on the 1.7 million tonne per annum Moomba CCS project. The Cooper Basin 2020 production was 16.8 MMboe with a Sales volume 24.2 MMboe. Santos' share of sales gas and ethane production of 68.5 petajoules (PJ) was 11% higher than the previous year (61.5 PJ) as new development activity offset the impact of natural field decline. Santos' share of crude oil production of 2.6 MMbbl was 17% lower than the previous year due to lower development activity due to lower oil prices and natural field decline. Cooper Basin 2021 production as of 1 July 2021 was ~7.9 MMboe with a sales volume of 10.9 MMboe.

Gaffney Cline

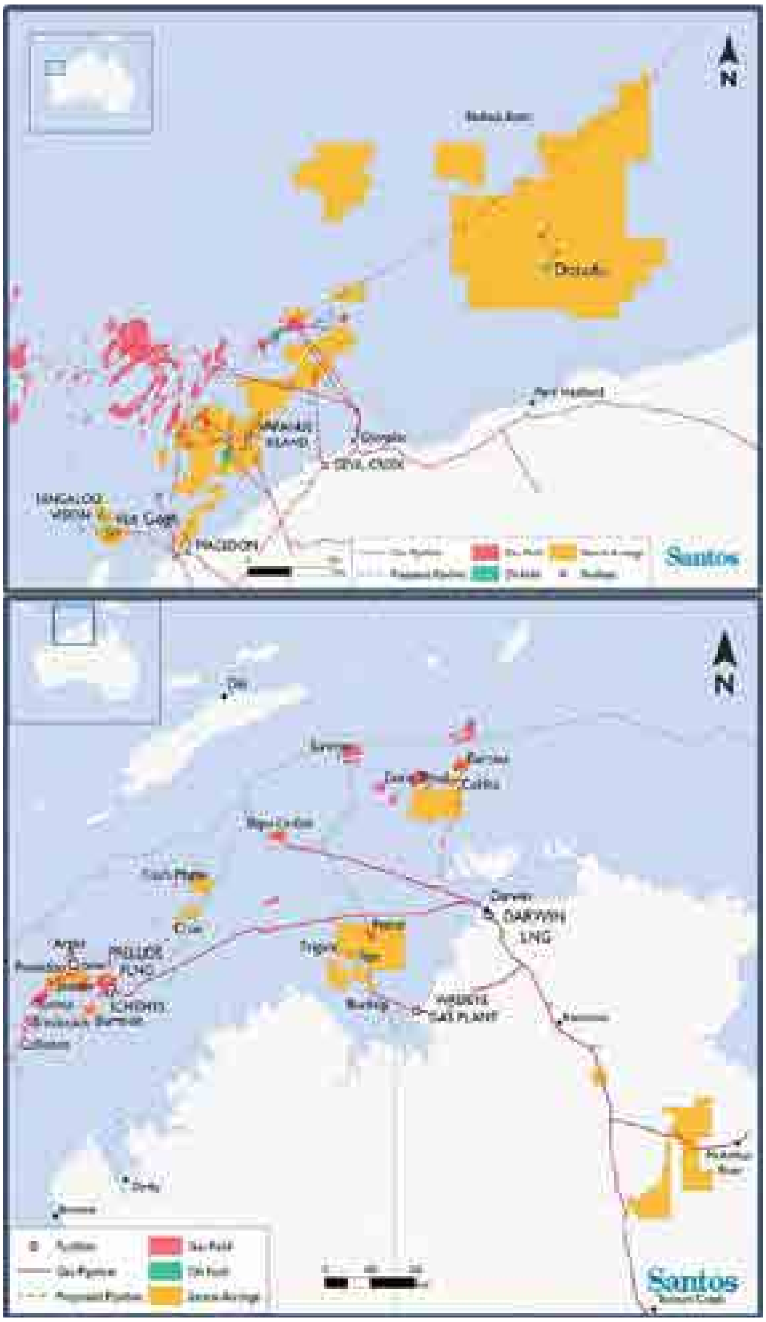
Figure 1.3: Summary of Santos Areas of Operation



Source: Santos

Gaffney Cline

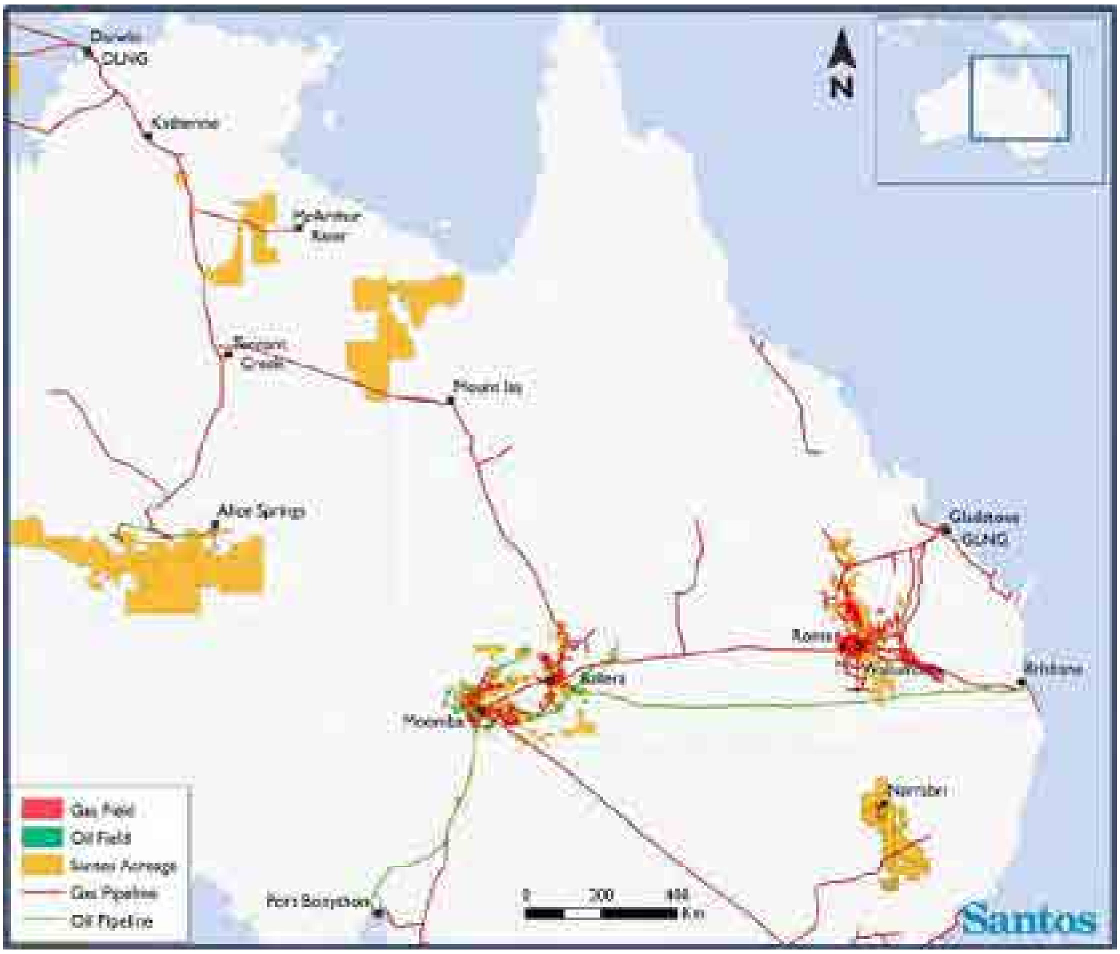
Figure 1.4: Western Australia, Northern Australia and Timor-Leste



Source: Santos (Modified)

Gaffney Cline

Figure 1.5: Onshore Australia



Source: Santos

Queensland and NSW

The GLNG facility produces liquefied natural gas (LNG) from coal seam gas (CSG) in the Bowen and Surat basins for export to global markets from the LNG plant at Gladstone. Santos has a 30% interest in GLNG. The LNG plant has two LNG trains with a combined nameplate capacity of 7.8 MTPA however with only ~6.2 MTPA being utilised currently. Production from Train 1 commenced in September 2015 and Train 2 in May 2016. GLNG feed gas is sourced from GLNG's upstream fields, contracted Santos equity gas, Santos portfolio gas, contracted third party gas and third-party uncontracted gas. GLNG have drilled ~2,304 wells to September 2021 with ~4,350 additional wells scheduled by Santos to be online by 2035.

The LNG plant produced six million tonnes of LNG in 2020 and shipped 101 cargoes. Annual LNG production was higher than the previous year (5.2 million tonnes) due to the ramp-up in GLNG upstream equity gas supply. Queensland and NSW 2020 production overall was 13.4 MMboe with a Sales volume of 22.0 MMboe. The LNG plant produced 3 million tonnes in the first half of 2021, 3% higher than the prior corresponding period, and shipped 51 cargoes (2020 first half 51 cargoes). QLD Operated by Others (OBO) production was 1.39 MMboe whilst minor Narribri production for the local power plant produced ~0.08 MMboe for a total Queensland and NSW H1 2021 production of 6.72 MMboe and a Sales Volume of 10.7 MMboe. Santos indicates in their public reporting that they want "*to build GLNG gas supply through upstream development, seek opportunities to extract value from existing infrastructure and drive efficiencies to operate at lowest cost".* Santos is also progressing the proposed Narrabri domestic gas project in NSW. The project received environmental approvals from the state and federal governments in 2020.

Northern Australia and Timor-Leste

Santos' business in Northern Australia and Timor-Leste is mainly focused on the Bayu-Undan/Darwin LNG (DLNG) project and the future Barossa development. DLNG has been producing since 2006 with the LNG and gas liquids exported to global markets with Barossa planned to backfill gas to DLNG. The first Barossa LNG Cargo is scheduled for 1H 2025. Preliminary planning is also underway to repurpose Bayu Undan for CCS potential.

The DLNG plant has a single LNG train with a 3.7 MTPA capacity. In 2020, production was three million tonnes of LNG and 48 cargoes were shipped. In May 2020, Santos completed the acquisition of the ConocoPhillips assets in Northern Australia and Timor-Leste, including DLNG, Barossa and Poseidon. The acquisition increased Santos' interest in DLNG to 68.4% and Barossa to 62.5%, and Santos operates both projects. Santos' interest in DLNG is 43.4% having completed a sell-down to SK E&S and in Barossa will reduce to 50% upon the planned 12.5% sell-down to JERA.

The final investment decision on Barossa was taken in March 2021 and extends DLNG's life by 20 years. Northern Australia and Timor-Leste 2020 production was 14.5 MMboe with a sales volume 14.6 MMboe. Net Santos H1 2021 production was 10.0 MMboe and a sales volume of 10.2 MMboe.

Santos is also actively exploring the onshore gas potential of the McArthur Basin and South Nicholson basins onshore Australia. This is also considered in this report.

PNG

Santos' business in PNG also includes a share of the PNG LNG project with Oil Search as a JV partner. Santos has a 13.5321% interest in PNG LNG. As discussed, the LNG plant produced a record 8.8 million tonnes of LNG in 2020. LNG production was higher than the previous year (8.5 million tonnes) due to high plant uptime and throughput. Santos' strategy in PNG is to work with its partners to align interests, and support and participate in backfill and expansion opportunities at PNG LNG. PNG LNG Net Santos 2020 production was 13.2 MMboe with a sales volume 12.5 MMboe. As stated, the LNG plant produced 4.1 million tonnes in the first half of 2021, 6% lower than the prior corresponding period due to planned maintenance and shipped 52 cargoes (2020 first half 57 cargoes). Net Santos H1 2021 production was 6.1 MMboe and a Sales Volume of 5.8 MMboe.

2 Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by Oil Search and Santos, the limited scope of engagement, and the time permitted to conduct the evaluation. This document must be considered in its entirety.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that the actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by, or at the direction of, Oil Search and Santos and/or obtained from the public domain and has accepted the accuracy and completeness of these data. GaffneyCline has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GaffneyCline has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 (see **Appendix II**).

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resources estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resources estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMstb or MMBbl). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf) and are either volumes of full well stream raw gas with the application of an economic limit test or sales gas depending on the Operator/Company asset. For sales gas reporting an allocation has been made for fuel and process shrinkage losses (or Consumed in Operations (CiO)). For full well stream raw gas the volumes have been reported with application of the economic limit test however the CiO are accounted for in the Operator's provided economic model. Standard conditions are defined as 14.7 psia and 60° Fahrenheit. Oil Search provided 100% Gross numbers for analysis of their financial models whilst Santos financial models were provided in Net numbers. For consistency purposes GaffneyCline has maintained the operators reporting and financial modelling structure.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions made by Oil Search and Santos or others (e.g. Independent 3rd party Reserves and Resource reports) in preparing and utilising estimates of reserves and resources. GaffneyCline performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

Definition of Reserves and Resources

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have been reviewed within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any Net Present Value (NPV) analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development" (per PRMS).

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analogue developments in the earlier phases of exploration.

There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resources volumes are presented as unrisked.

Reserves net to Oil Search and Santos are quoted as Net Revenue Interest Reserves, reflecting the concession contract terms applicable to the asset. Contingent Resources and Prospective Resources are presented at a gross field level and a net working interest level, as the development plans are not yet sufficiently mature for net entitlements to be estimated.

GaffneyCline's scope of work did not extend to a site visit and inspection of Oil Search's or Santos' producing and development assets. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operations.

This report has been prepared based on GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licences and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Use of Net Present Values

It should be clearly noted that Net Present Values (NPVs) provided herein, or developed by others utilising GaffneyCline's production and cost valuation scenario profiles that are contained in this report do not represent a GaffneyCline opinion as to the market value of the subject properties, nor any interest in them.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves and resources risk for example: that Reserves or Contingent Resources may not be realised within the anticipated timeframe for their exploitation; perceptions of economic and sovereign risk, including potential changes in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the production and cost valuation scenario profiles and any resulting NPVs presented in the GaffneyCline report or any other document to which the GaffneyCline report is appended.

For Exploration assets, GaffneyCline has derived an opinion of value using a combination of methods depending on the area and available data. This included the expected monetary value (EMV) approach, comparable transactions and sunk exploration costs. Such value is reported separately, without including individual production and cost profiles.

Qualifications

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with both Grant Samuel, Oil Search and Santos. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

3 Methodology

Oil Search and Santos have provided GaffneyCline with Reserves and Resources estimates prepared by both companies and third-party consultants, for their oil and gas assets in each company's operating area.

For Oil Search, this has occurred during regularly held workshops since 2013 to inform GaffneyCline of the status of Oil Search's assets in case a corporate transaction is triggered. Oil Search also provided GaffneyCline with access to its extensive technical data supporting their Base/2P/2C Case Reserves and Resources estimates for GaffneyCline to carry out independent technical audits of the data and adjust production and cost valuation scenario profiles where/if GaffneyCline considers it necessary. This information was received during workshop presentations carried out in March and August 2013, December 2015, September 2017, December 2019 (in both Alaska and Sydney) and February 2020 to inform the GaffneyCline technical group of the status of all the Oil Search projects. These regular preparatory workshops and subsequent GaffneyCline working data sessions have allowed GaffneyCline's technical group to monitor and update GaffneyCline's technical and commercial analysis in preparation of this Independent Technical Specialist's Report. This process has also allowed GaffneyCline to opine on the veracity of the estimates and production and cost valuation scenario profiles proposed by Oil Search.

All of the Santos assets have been reviewed as part of this merger assignment focusing on the technical presentations and data provided by Santos. GaffneyCline technical staff also relied on their experience with Santos' assets based on separate audit engagements over many years (since at least 2008). In the past 5 years, GaffneyCline have completed audits on Santos' PNG assets, Santos' Northern Australian assets, Bayu Undan and a subset of Santos' Western Australian assets.

The work presented in this report represents valuation scenario profiles adopted and/or modified by GaffneyCline from valuation scenarios and associated static/dynamic and production data presented by Oil Search and Santos. Where GaffneyCline opined that the presented valuation scenario profiles required modification, GaffneyCline made these modifications and presented the modified profiles to Grant Samuel. Where GaffneyCline opined that the presented valuation scenario profiles were reasonable they were adopted from Oil Search/Santos provided profiles. Details are included in the body of this report per individual asset.

In reviewing the Reserves and Resources volume estimates utilised in the valuation scenario profiles, GaffneyCline's remit was not to undertake a complete 'from the ground up' independent assessment of all the assets and therefore duplicate work carried out by other third-party organisations and Oil Search/Santos technical groups. Full independent assessments generally require investigating all technical elements in accordance with the definitions and guidelines set out in the June 2018 Petroleum Resources Management System (PRMS) developed and promulgated by the Society of Petroleum Engineers and others, to capture the full uncertainty range. However, GaffneyCline has reviewed sufficient information and carried out sufficient technical analysis as part of an audit and due diligence approach to opine on the reasonableness of the Reserves and Resources estimates carried out by the operating companies and other third-party organisations (including GaffneyCline for various assets). A discussion of the actual technical work carried out by GaffneyCline is included in the subsequent sections along with the description of the assets. This process allowed GaffneyCline to deliver production and cost valuation scenario profiles for assets that have Reserves and more mature Contingent Resource assets for valuation by Grant Samuel.

GaffneyCline has provided Base Case production and cost valuation scenario profiles to Grant Samuel based on predominantly a technical reconciliation of 2P/2C data/models and reported volumes of defined projects with details included in subsequent sections of this report. Given the large portfolio of assets, specific exceptions do exist. GaffneyCline focused on operator development plans and well counts for all projects. In GaffneyCline's view the Base Case represents a reasonable best or expectation case of future developments and performance upon which to base a valuation.

Stretch Case scenarios were also requested by Grant Samuel. These cases have been provided based on a review of Oil Search and Santos data with consideration of either alternate production scenarios depending on the geological region (such as 3P and/or 3C volumes), an alternate view of cost valuation scenario profiles or a combination of both. There are assets where the case put forward by the respective operator has also been accepted as a Stretch Case by GaffneyCline to assist Grant Samuel to bracket their valuation range process. The Stretch Case represents a more optimistic or upside view of future developments in GaffneyCline's view.

GaffneyCline has assessed Contingent Resource projects by technically reviewing the applicable volumes with respect to the proposed development plan that GaffneyCline believes is most likely to be sanctioned. Rather than applying a Chance of Development on all defined Contingent Resources, GaffneyCline investigated assets with Contingent Resources in the Development Pending, Development on Hold and Development Unclarified sub-project maturity classes as per PRMS to include technically viable volumes in subsequent cash flow analysis based on the specific area of operation and history of the asset and area. This is discussed in more detail in the body of this report per asset. Contingent Resource Not Viable projects are not included in valuation scenario profiles provided to Grant Samuel.

Oil and gas assets where Contingent Resources based on current technical and commercial information are considered immature and hence too uncertain to construct production and cost valuation scenario profiles by the operator have been evaluated utilising an alternative method. GaffneyCline has assessed and recommended a unit value multiplier expressed in US$ per MMscf and/or US$ per Boe to Grant Samuel based on a review of comparable transactions cross checked against resent projects that have received FID (e.g., Barossa). For these assets an additional explanation for the basis for this unit value and its associated commercial risk factor is provided in the body of the report. This allowed a value of the Resources to be recognised while acknowledging that the development of these Resources is less certain than that of Reserves and more mature/likely Contingent Resources.

In assessing a value for Oil Search and Santos exploration acreage GaffneyCline considered the following elements in the valuation process:

1. Recent transactions for assets that ideally lie within or adjacent to the licence area under review and are considered to be comparable
2. Where an area contains well defined prospects in a mature play which are scheduled to be drilled in the near term (5 years), a method based on Expected Monetary Value (EMV) has been considered.
3. Estimates of the expenditures to date, future commitments and Oil Search and Santos efforts to obtain farminees were also considered.

The above elements were reviewed to formulate the final value or value range. Useable data does not always exist for all the above items and therefore GaffneyCline explains the inputs in specific cases given the varied portfolio of assets owned by both companies. This is discussed in the body of the report in the relevant exploration sections.

Production and Cost profiles included for specific assets are aggregated by GaffneyCline due to the declared commercial sensitivities by either Oil Search or Santos and this is stated in the relevant sections in the body of this report. GaffneyCline was not in a position to opine on the commercially sensitive nature of the profiles.

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4 Oil Search Assets

4.1 Executive Portfolio Overview

Oil Search's major petroleum holdings are primarily located in PNG and Alaska. The PNG assets include an extensive spread of oil and gas production and exploration licenses. In 2020 Oil Search produced 29.02 MMboe from PNG with 27.95 MMboe produced in 2019. This compared to 25.21 MMboe in 2018 and 30.31 MMboe in 2017. The 2018 production was affected by the PNG Highlands earthquake which resulted in the temporary shut-in of production.

Oil Search's main asset is its 29% interest in the PNG LNG Project operated by ExxonMobil PNG Limited, an ExxonMobil subsidiary. The PNG LNG Project commenced production in early 2014 with the first cargo shipped on 25 May 2014. The production rate during 2019 was 8.5 MTPA, 23% higher than the 6.9 MTPA nameplate capacity. In 2020 the production rate reached a record of 8.8 MTPA.

The PNG LNG Associated Gas Optimisation (AGO) project is an accelerated gas delivery from the oil fields with upgrades to the Kutubu Central Processing Facility (CPF) and increasing production via the Agogo Processing Facility (APF) for the two-train foundation project. The Angore valuation scenario profile start-up date is 2024 with the CPF upgrade and APF tie-in scheduled to come online as ullage opens up later in the decade for the Base Case two train scenario profile utilised for valuation. Furthermore in the Base Case, the P'nyang discovery will also be utilised in the foundation project as backfill and is currently scheduled for early 2030s, while the Juha Field and the Muruk discovery are currently scheduled for start-up in early 2040s. GaffneyCline has modified and/or accepted the scheduling based on the GaffneyCline individual field volume estimates for input into the valuation process. There is also a possibility to utilise the P'nyang Field to supply an additional train in an upside scenario and this has also been considered in this technical work to provide appropriate production and cost valuation scenario profiles for valuation for a Stretch Case requested by Grant Samuel. In this case the APF project is delayed to suit ullage requirements for the foundation PNG LNG project. GaffneyCline considers these technical outcomes as reasonable with appropriate scenario profiles provided for valuation analysis and range. This is discussed in more detail in subsequent sections.

Oil Search and joint venture partners are pursuing LNG expansion with the construction of up to two new LNG trains at the PNG LNG site operated by ExxonMobil. The Elk-Antelope Fields which will supply the Papua LNG Project operated by Total have been technically reviewed by GaffneyCline with a technical analysis of the discovered assets presented in the body of this report. The volumes are deemed sufficient to underpin the proposed expansion. The FID is currently due in Q4 2023 with Papua LNG first gas planned for Q4 2027 from Papua LNG's first train. The second train is scheduled to start up in Q1 2028 and these timings are reflected in the production scenario profiles utilised for valuation.

Planned expansion train capacity is between 3.0 MTPA in the Base Case and 3.4 MTPA in the Stretch Case. GaffneyCline has reviewed and generally accepted the Oil Search production scenario profiles leading to this level of LNG production based on the historical performance of the foundation project. However, for both Papua LNG and the foundation projects, GaffneyCline has constructed a Base Case valuation scenario profile for submission to Grant Samuel. The volumes and valuation scenario profiles are discussed in later sections. Stretch Case valuation scenario profiles are based on Oil Search provided profiles vetted by GaffneyCline and utilising GaffneyCline updated costs (e.g. CAPEX, OPEX escalation).

Oil Search's approach involves aggregating gas reserves and resources in the PNG Highlands to underpin the foundation PNG LNG Project and expansion. Confidence in the available volumes can be demonstrated by Oil's Search's reserves as of 31 December 2020. Year on year changes for reserves predominantly reflect production, with minor revisions attributable to changes in LNG project phasing, consistent with the latest development plans, and changes to economic end of field life from Oil Search's updated corporate economic assumptions. GaffneyCline has reviewed the data comprising the static and dynamic models that underpin Oil Search's reserves and resources along with any available third party reports and in general concurs with the reasonableness of the estimates as documented in the body of this report. GaffneyCline's due diligence checks of the 2P and 2C estimates for the declared reserves and resources are generally within the 10% SPE audit standards. GaffneyCline valuation scenario profiles, where stated in the body of the report, are incorporated if applicable.

Oil Search and its partners are confident that Elk-Antelope has sufficient gas resources to underpin the additional LNG trains. There are additional upside volumes (in the 3C case) and exploration potential to extend the production profiles for the two new trains. GaffneyCline's technical analysis confirms that such production extensions are reasonable. An example of the exploration potential is the Wildebeest Prospect. This is a 4-way closure created by a carbonate drape/growth over a basement high with potential reef facies as per the Antelope discovery. GaffneyCline has estimated a Geological Chance of Success (GCoS) of 20%. Oil Search's P50 volume estimate for Wildebeest is similar to that of the Elk/Antelope Fields. GaffneyCline has independently reviewed the resource volumes that underpin the two additional LNG Trains and the robust project economics and considers the volumes and project appropriate for valuation.

In late 2016, the Muruk 1 exploration well and side-tracks (ST1, 2 & 3) discovered gas in the Oil Search operated PPL 402 block immediately to the east of the ExxonMobil operated PDL 9 block, which includes the Juha and Juha North discoveries. The wells found gas in the primary Toro Reservoir target in both the hanging wall (tested by boreholes ST1 & ST2) and footwall (tested by borehole ST3) of the Muruk structure. Muruk is located on trend from the Hides Field, approximately 21 km from the nearest PNG LNG infrastructure. The Muruk 2 appraisal well in PDL-9 was completed in May 2019 in the footwall of the structure, the well tested gas in the Toro A formation at 16.5 MMscf/d through a 53/64" choke during an 8-day flow test. The Muruk discovery has reduced the uncertainty of several prospects and leads on trend with, and with attributes similar to Muruk. These include the Karoma Prospect, which is scheduled to be drilled in 2024, demonstrating sufficient near field exploration upside to support backfill of the PNG LNG foundation trains and potential expansion in the Stretch Case scenario analysis for valuation.

Oil Search's Alaskan portfolio purchase contains many appraisal and exploration opportunities. It includes the Pikka Development (Oil Search 51%), the Pikka Satellites - Pikka East and North (with Thetis, Oil Search 51%), the Horseshoe Expansion (Oil Search 51%) the Kooka (Oil Search 51%) and Quokka (Oil Search 38.76%) areas along with, Lagniappe A (Oil Search 75%) and the Lagniappe B & C (Oil Search 50%) areas. Oil Search also holds non-operated working interests in additional areas as indicated on **Figure 1.2**. The Pikka Phase 1 development, focusing initially on the ND-B well site, will comprise 22 producer wells, 21 water injection wells, 1 cuttings injection well and one produced water disposal well. Produced fluids will flow to a new facility with a capacity of 80,000 bopd. Phase 1 will also include a new-build sea-water treatment plant and pipeline to treat and deliver water for production enhancement. Supporting infrastructure will include the Nanushuk Operations Pad (NOP). Phase 1 FID is currently planned for H1 2022 provided Oil Search satisfy pre-conditions for funding and risk allocation with production targeted for 2025.

The Pikka Satellites - Pikka East and North (with Thetis) and the Horseshoe, Kooka and Quokka areas are near field exploration and appraisal opportunities with potential to expand/extend the core development depending on the results of the Pikka Development or provide standalone opportunities. The exploration and new business areas will assist in optimising the acquired portfolio and will allow Oil Search to prioritise prospects and leads. Oil Search's activities during the 2019/2020 Alaska exploration season yielded discoveries from all three well penetrations, Mitquq 1, Mitquq 1 ST1 (Pikka East), and Stirrup 1 (Horseshoe). The exploration program improved Oil Search's understanding of the geology and potential productivity of the Nanushuk play that is central to their North Slope lease portfolio and enabled GaffneyCline to update the expected producibility of the Pikka phased development and the associated production type curves to support Oil Search's resource estimates.

GaffneyCline has independently reviewed Oil Search's resource volumes that underpin the Pikka Phase 1 Development and considers them reasonable. GaffneyCline's 2C Phase 1 estimate (100% gross) was 366 MMstb. The main contingencies are technical and depend on the production rates achieved during Phase 1 execution scheduled for 2025, which will in turn determine the extent of the phased development, and the eventual well numbers drilled. Oil Search's approach is to use the Phase 1 Pikka revenues to support the full field development and the associated ~968 MMstb 2C Gross resource potential.

GaffneyCline has provided all the 2C Contingent Resource volumes for valuation to Grant Samuel by utilising the phases and project maturation and sub-classes with an appropriate time value adjustment and chance of development for their consideration. The chance of development is applied to risk adjust projects for not being materialised or significantly delayed from the Phase 1 base scenario considered by GaffneyCline. This is due to the fact that to date they do not currently have a commercially producing asset on the North Slope.

A summary of the Reserves and Contingent Resources net to Oil Search as of 31 December 2020 are presented in **Table 4.1** and **Table 4.2** as listed in the Oil Search 2020 Annual Report. GaffneyCline has conducted an independent due diligence review of the hydrocarbon volumes for the assets in **Table 4.1** and **Table 4.2** as of 31 December 2020 based on technical and other information made available to GaffneyCline concerning these property units. GaffneyCline is of the opinion that the volumes for the assets Net to Oil Search, are in the aggregate, a reasonable estimate of Oil Search's Reserves and Contingent Resources as of 31 December 2020. For individual assets GaffneyCline has updated Reserve volumes to account for production performance to align the valuation scenario profiles to the effective date of the transaction which is 1 July 2021.

Table 4.1: Oil Search's Net Oil and Gas Reserves as of 31 December 2020

Reserve Category	Project/Field	Hydrocarbon Reserves Net to Oil Search's Revenue Interest		
		Total	Developed	Undeveloped
1P Oil & Condensate (MMstb)	PDL 2 – Kutubu	8.3	7.0	1.4
	PDL 2/5/6 – Moran Unit	4.9	3.6	1.3
	PDL 4 – Gobe Main	0.01	0.01	-
	PDL 3/4 – SE Gobe [5]	-	-	-
	PNG LNG Project [6]	34.7	23.2	11.5
	TOTAL	**48.0**	**33.8**	**14.3**
1P Gas (Bscf)	PDL 3/4 – SE Gobe [5]	-	-	-
	PNG LNG Project [4,6]	1,735.9	1,232.0	503.9
	TOTAL	**1,735.9**	**1,232.0**	**503.9**
2P Oil & Condensate (MMstb)	PDL 2 – Kutubu	13.7	11.0	1.4
	PDL 2/5/6 – Moran Unit	8.5	6.2	1.3
	PDL 4 – Gobe Main	0.01	0.01	-
	PDL 3/4 – SE Gobe [5]	0.02	0.02	-
	PNG LNG Project [6]	38.8	25.8	13.0
	TOTAL	**61.0**	**43.1**	**18.0**
2P Gas (Bscf)	PDL 3/4 – SE Gobe [5]	5.4	5.4	-
	PNG LNG Project [4,6]	1,955.0	1,356	599.0
	TOTAL	**1,960.4**	**1,361.4**	**599.0**

Notes:
1. Totals may not add due to rounding
2. Kutubu and Moran oil fields proved Reserves (1P) and proved and probable (2P) Reserves are as certified by independent auditor Netherland, Sewell & Associates, Inc. (NSAI) in 2017. 1P and 2P PNG LNG Project Reserves are based on Contingent Resources estimates prepared in 2019 by independent auditor, NSAI. Gobe Main and SE Gobe 1P and 2P Reserves are based on Oil Search 2019 technical estimates. All Reserves estimations use Oil Search's corporate assumptions to calculate economic limit.
3. Crude oil, and separator and plant condensates.
4. For the PNG LNG Project, shrinkage has been applied to raw gas for the field condensate, plant liquids recovery and fuel and flare.
5. Due to planned well work activities and the renegotiation of pricing with PNG LNG, SE Gobe is now expected to be cash flow positive on a 2P basis in the medium term. These assessments use Oil Search's 2020 technical estimates and Oil Search's current corporate economic assumptions and remain based on third party wet gas sales to the PNG LNG Project at the Gobe plant outlet at the post-sales agreement field interest of 22.34%.
6. PNG LNG Project Reserves comprise the Kutubu, Moran, Gobe Main, SE Hedinia, Hides, Angore and Juha Fields. Minor volumes associated with proposed domestic gas sales have been included as part of PNG LNG reserves.
7. Hides Reserves associated with the GTE Project under existing contract. Due to the issues with the Porgera Mine through 2020 and the continued uncertainty of resumption of operations in 2021, no reserves are booked for Hides GTE.

Table 4.2: Oil Search's Net Oil and Gas Contingent Resources as of 31 December 2020

Resource Category	Project/Field	Hydrocarbon Resources Net to Oil Search's Working Interest
		Total
2C Oil & Condensate (MMstb)	PNG LNG Project Fields oil and condensate	2.1
	Other PNG oil and condensate [2]	51.5
	Alaska – Pikka Unit oil and condensate [3]	391.5
	Alaska – Other oil and condensate [3]	102.1
	TOTAL	**547.2**
2C Gas (Bscf)	PNG LNG Project Fields Gas	142.0
	Other PNG Gas [2]	3,814.4
	TOTAL	**3,956.4**

Notes:
1. Contingent Resources are quantities of petroleum estimated to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. There may be a chance that accumulations containing Contingent Resources will not achieve commercial maturity.
2. Other gas, oil and condensate Resources comprise the Company's other PNG fields including Elk-Antelope, SE Mananda, Juha North, P'nyang, Iehi, Cobra, Flinders, and Muruk and may also include Resources beyond the current economic limit of producing oil and gas fields. These gas Resources may include fuel, flare, and shrinkage depending on the choice of reference point.
3. Alaskan oil and condensate contingent resources comprise the Company's 51% working interest before royalties in Alaskan assets, incorporating the Nanushuk and satellite reservoirs. All 2C contingent resources are based on contingent resources as certified in 2019 and 2020 by independent auditor, Ryder Scott.

Oil Search provided descriptions of each of the PNG producing oil assets in **Figure 4.1**, the PNG LNG Train 1 and 2 foundation project performance as well as the planned backfill utilising the P'nyang and Muruk discoveries in the Base Case. A possible Train 3 expansion utilising feedstock from P'nyang in the stretch case to bracket the valuation scenario profiles and subsequent cash flow evaluation has also been provided to Grant Samuel for consideration.

The Papua LNG Project, which will also make use of the current PNG LNG site, will include two additional trains. The expansion trains are yet to reach FID but are considered likely to proceed based on the PNG discovered fields to date and the public statements identifying the level of development planning by the joint venture partners. The PRL 15 (Papua) and PRL 3 (P'nyang) joint ventures have, in the past three years, sought to mature a three-train brownfield LNG expansion in PNG. Due to PNG Government PRL 3 negotiation issues, the value and logic for integrating the three-train project has diminished. As 2020 progressed, stakeholders agreed that the Papua LNG project should progress with a two-train expansion, independently of the P'nyang project. However, the option for a three-train expansion remains a viable option and is considered in the Stretch Case scenario.

For the PNG assets, Oil Search has developed and provided Base and Stretch Case production valuation scenario profiles, capital and operating cost valuation scenario profiles for each of its major PNG assets along with the status of each asset and future development plan and schedule. Technical models (e.g. Petrel and Eclipse models), general well information and maps were provided on Oil Search's inventory of current discoveries along with technical details of their exploration prospects and leads, both near existing developments and discoveries and in greenfield areas. GaffneyCline has reviewed these valuation scenario profiles and generally considered them reasonable with adjustments as stated in the body of this report.

All production valuation scenario profiles were provided on a 100% interest basis and maintained the Oil Search nomenclature of raw gas produced with the Oil Search economic model accounting for all shrinkage. Commercial and cost information is considered to be sensitive and not included in detail even though reviewed by GaffneyCline.

For Oil Search's Alaska asset, and specifically the Pikka Phase 1 development, GaffneyCline has reviewed Petrel models, simulation models and well test data to create GaffneyCline type curves and subsequent technical risking criteria. GaffneyCline has accepted the Oil Search 2C Contingent Resource volumes for the evaluation. Discovered pools within reach of the Pikka development have also been considered for risking and this is discussed in the body of this report.

Appendix III includes a list of Oil Search's provided Licence holdings utilised for valuation input in this report. GaffneyCline has not undertaken an independent verification of these Licence interests.

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Figure 4.1: Oil Search's PNG Assets

Source: Oil Search

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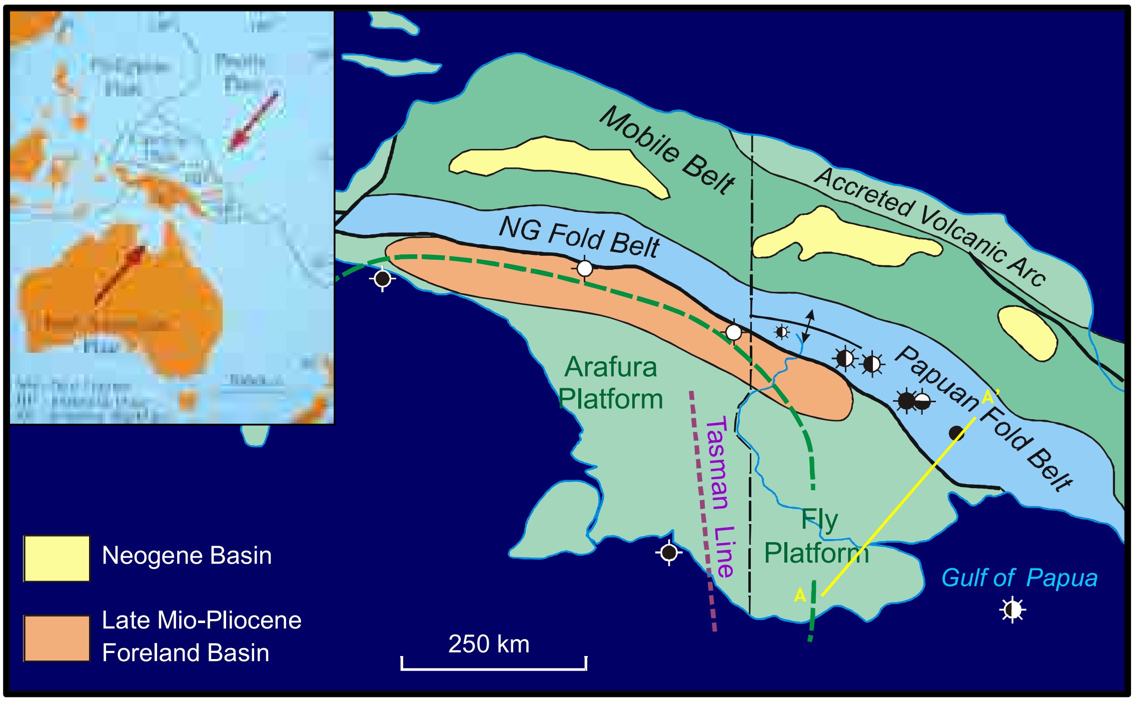
4.2 Oil Search PNG LNG

4.2.1 PNG Geology

Geologically, PNG lies on the northern margin of the Australian Continental Plate. The country has five sedimentary basins lying both onshore and offshore, with diverse tectonic settings and totalling an area of 594,260 km^2. The Papuan Basin which stretches across both PNG and Australian territory is the largest of the five and is a structurally complex sedimentary basin which began developing in the Late Triassic to Early Jurassic. The basin lies on the northern margin of the Australian Plate and is made up of three structural provinces; the Stable Platform, the Foreland Basin and the Fold Belt which run roughly parallel along the north west to south east axis of the island and become more structurally complex to the north (**Figure 4.2**). The Papuan Basin is the most explored of PNG's sedimentary basins, it is considered a mature basin and has an exploration history going back to 1913. Numerous hydrocarbon fields occur along the leading edge of the Fold Belt in a region known as the PNG Highlands and several oil fields have been developed including Kutubu (Hedinia, Iagifu, Usano), Agogo, SE Gobe and Gobe Main, SE Mananda and Moran.

Figure 4.2: Structural Setting of the Papuan Basin



Source: Oil Search

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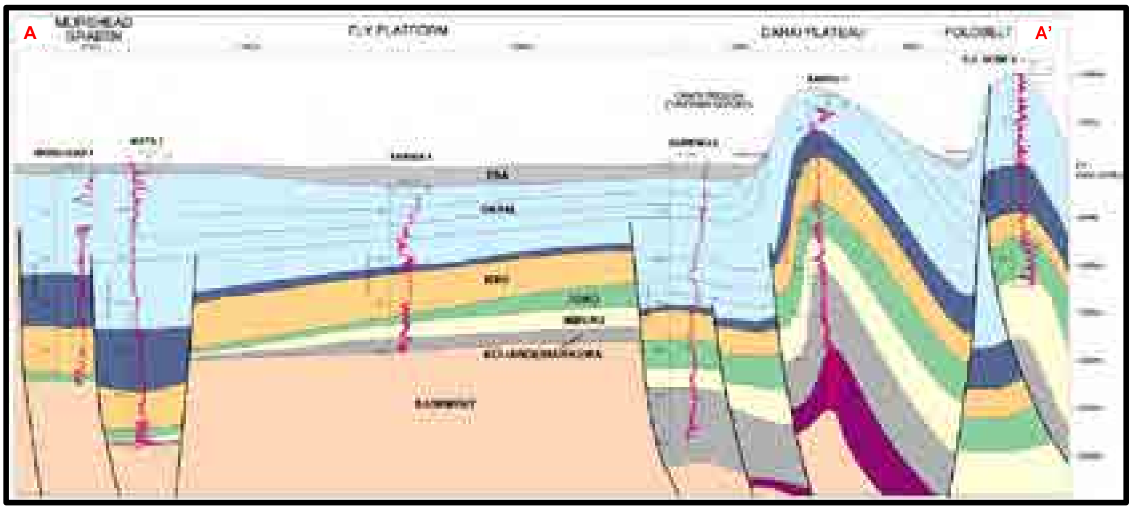
The Basin sits on a basement of Upper Palaeozoic rocks that were deformed and intruded during the Early Triassic New England Orogeny. During the Late Triassic to Early-Middle Jurassic the area experienced extension and rifting resulting in the deposition of the fluvial and deltaic syn-rift sediments of the Magobu Sandstone and coal measures, the Barikewa and Koi-Iange Shales as well as the Kana Volcanics. These syn-rift sediments are possible source rocks for some fields in the fold belt. Post-rift thermal sag during the Late Jurassic led to the flooding of the basin and deposition of transgressive and regressive cycles. During this period, the transgressive deltaic-marine mudstones of the Imburu Formation were deposited interbedded with the regressive Digimu, Hedinia and Iagifu sandstone units. The Imburu Formation is the primary source rock in the fold belt while the interbedded sandstone units act as secondary reservoir targets. Overlying the Imburu Formation is the main reservoir unit; the Toro Sandstone which was deposited as shallow marine tidal and/or barrier bar sands and is overlain by the Ieru Formation containing the informal Hatio, Ubea, Giero, Bawia, Juha and Alene Members. The Ieru Formation is regionally widespread and is a proven seal for the Toro sandstone. Sedimentation continued into the Late Cretaceous when uplift related to the breakup of the Tasman and Coral Sea resulted in erosion and removal of Late Cretaceous sediments from the fold belt, foreland basin and stable platform.

Backarc and foreland deposition related to flooding during the Oligocene resulted in the deposition of the Darai Limestone. This ceased in the Late Miocene due to compression and uplift which resulted from the collision of the Australian and Pacific plates and created the complexly deformed Papuan Fold Belt. The Era formation overlies the Darai Limestone and was derived from the erosion of sediments from the rising fold belt that prograded across the limestone shelf. A cross section showing the main stratigraphic units and the typical structure of the Papuan Basin is shown in **Figure 4.3**. A Stratigraphic column for the basin is presented in **Figure 4.4**.

Figure 4.3: Structural Cross Section through PNG



Source: Oil Search

Note: See Figure 4.2 for section location

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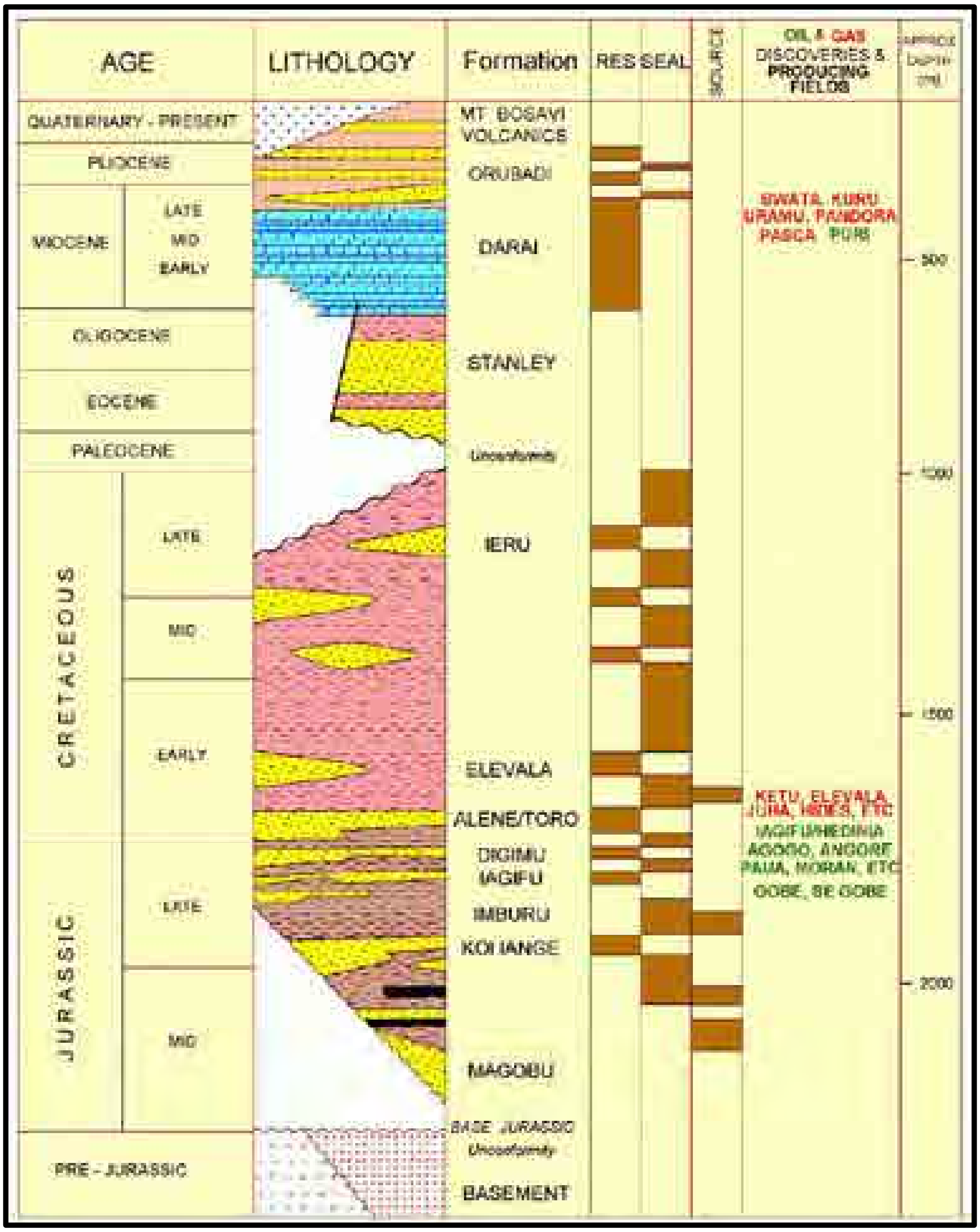
Figure 4.4: Generalized Stratigraphy of the Papuan Basin



Source: Oil Search

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4.2.1.1 PNG Onshore Fields and Discoveries Overview

The vast majority of producing and discovered fields in PNG are found along the leading edge of the Fold Belt in southeast - northwest trending structural traps which formed during compressive tectonics from the Late Pliocene to the present and resulted in a surface topography which approximately represents structures at reservoir depth. The surface is covered by dense rainforest and rugged topography formed of mostly karstified limestones of the Oligocene to Miocene age Darai Formation and these conditions provide challenges for both surface operations and also a major impediment to obtaining quality seismic data for imaging the subsurface.

The main reservoir in the Fold Belt is the Early Cretaceous Toro Sandstone which is a regionally extensive sandstone with good reservoir properties and has been interpreted as tidal and/or barrier bar sands deposited in a shallow sea. The Toro Formation is the reservoir in which most of the oil and gas discoveries have been made in PNG to date. Secondary reservoirs in the area which tend to have greater lateral and vertical variability are composed of the members of the Imburu Formation, i.e. the Upper Jurassic to Early Cretaceous Digimu and Emuk Sandstones. The Middle Jurassic Koi-Iange Formation also contains some sandstone intervals and is also a potential reservoir target. The seal for the Toro sandstone is the regionally extensive Ieru Formation which forms the seal to the majority of discoveries in PNG while the secondary reservoirs are sealed by intraformational seals.

The marine shales of the Jurassic aged Imburu, Magobu, Koi-Iange and Barikewa Formations are the main source rocks for the onshore discoveries. Recent studies have shown that Cretaceous-aged source rocks are also capable of generating hydrocarbons and are likely to have wide geological distribution, thereby enhancing the source rock potential of the basin. Hydrocarbon generation and migration is likely to have begun in the Late Pliocene coincident with the onset of tectonic compression.

Onshore PNG has a long history of exploration which was initially hindered by poor quality seismic data and the first exploration was undertaken largely based on surface mapping. The first small gas discoveries were made in the 1950's followed by gas condensate discoveries in the 1960's. The first significant oil discovery was made in 1986 at Kutubu which came on stream in 1992. The Kutubu discovery has been followed by more recent analogous discoveries in the PNG Highlands. The oil discoveries and the majority of gas discoveries have been located within structures in the Fold Belt. Smaller amounts of gas have been discovered in the Foreland.

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4.2.2 PNG LNG Overview

Oil Search and Santos have a 29.0033% and ~13.5321 %interest respectively in the PNG LNG Project which is considered a world scale two train LNG development operated by Esso Highlands Limited, an ExxonMobil subsidiary. The other equity holders are ExxonMobil (33.2%), Kumul/MRDC (19.6%) and JX Nippon Oil Exploration (4.7%). The Coordinated Development and Operating Agreement (CDOA) governs equity interest and project operations including upstream oil and gas. This agreement governs rights, duties and powers of the Operator and the Operating Committee.

The original two-train PNG LNG foundation project was designed for 6.9 MTPA which equates to approximately 90 cargos per year. After various debottlenecking projects on the LNG plant capacity, the 2020 production was 8.8 MTPA with ~116 cargos. In early 2018, the PNG LNG and Papua LNG joint ventures agreed on an integrated development concept for construction of new LNG capacity, which will double the number of trains to four with an option for a fifth train to process gas from P'nyang also possible, but less likely given the current intentions of the participants in P'nyang and PNG LNG.

The majority of the gas for the PNG LNG Project is currently sourced from the Hides gas field (~90%) and is supplemented by Associated Gas from the Kutubu (~5.8%), Gobe Main (~3.2%) and SE Gobe (~1.1%) oil fields tied-in via the Gobe Production Facility (GPF) and the CPF. . All of the fields contributing to the LNG project are located in the Southern Highlands and Western provinces of PNG. In excess of 11 Tcf of gas and ~200 MMbbl of associated liquids are expected to be produced over the foundation project life based on current estimates. Individual PNG LNG contributing fields are discussed in more detail in Section 4.2.3.

The gas is conditioned in the PNG Highlands and then transported by gas pipeline to the LNG plant located approximately 20 km northwest of Port Moresby prior to loading onto ocean going tankers to be shipped to international gas markets. Four ships operate with two of the LNG transport vessels provided by the PNG LNG Project while the other two vessels are supplied by the end customers.

4.2.2.1 Project Facilities

The Project Facilities with potential expansion are schematically summarised in **Figure 4.5** and are mainly comprised of the following:

- Upstream Facilities: existing and new wellpad facilities (Angore, Muruk, Juha etc); the Hides Gas Conditioning Plant (HGCP); and upstream infrastructure.
- Project Pipeline including: onshore pipelines (292 km); and an offshore pipeline (407 km). With the inclusion of condensate lines the total pipeline length is ~ 800 km)
- Tie-in of Associated Gas from existing oil production facilities; and
- The LNG Plant (Trains 1 and 2) and associated infrastructure including two LNG Tanks with each having a capacity of 160,000 m^3. Marine Facilities with an LNG Jetty length of 2.4 km.

The well stream products from the Primary Gas Fields are transported from individual well pads to the HGCP for gas conditioning, condensate removal, produced water removal and compression. Associated Gas is fed into the onshore portion of the Project Pipeline via tie-ins from the existing Associated Gas Fields. Gas is transported to the LNG Plant near Port Moresby via the Project Pipeline.

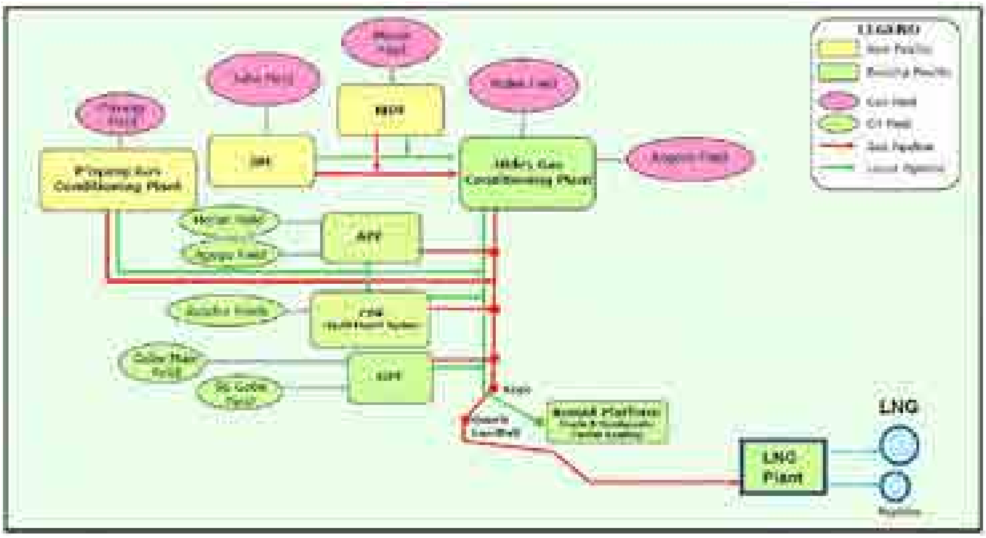
The separated field condensate is transported via pipeline to the existing Kutubu CPF where it is blended with existing crude oil, stored and exported via the existing Kutubu Pipeline System (KPS). The existing export system, while not part of the Project, includes work programs that have been put in place to ensure that the KPS continues to operate reliably for the life of the T1/T2 Project.

The majority of the Upstream Facilities utilised by the PNG LNG Project are/will be new developments. Some existing oil production facilities are also used to supply Associated Gas to the Project. These existing oil production facilities are not part of the Project. However gas export upgrades to existing facilities undertaken and paid for by the PNG LNG Project in connection with the supply of Associated Gas are part of the PNG LNG Project.

The pipeline network transports gas from the individual wellpad facilities to the HGCP and on to the LNG Plant, and Liquids from the HGCP to the Kutubu CPF. The pipeline facilities consist of an onshore pipeline network and an offshore pipeline (together, the "PNG LNG Project Pipeline") with the interface between the two sections being located at the landfall of the offshore pipeline at the Omati River. Approximately one-third of the onshore portion of the PNG LNG Project Pipeline is constructed along the existing crude oil pipeline corridor.

The Project Pipeline for PNG LNG is indicated in **Figure 4.5.**

Figure 4.5: PNG LNG Foundation Facilities and LNG Expansion System Description Summary



Source: Oil Search

Foundation T1/T2 SPA Agreements

The LNG sales and purchase agreement (SPA) contracts consist of four key customers with 20 year take or pay contracts which total ~95% of the nameplate capacity. The ~6.6 MTPA is currently contracted to customers from China (Sinopec -2 MTPA), Taiwan (CPC -1.2 MTPA) and 2 from Japan (JERA -1.8 MTPA and Osaka Gas -1.5 MTPA). A SPA with BP for ~0.9 MTPA exists, which commenced in August 2018. A four-year SPA with Unipec for 0.45 MTPA, which commenced in April 2019. The remaining quantity is sold on the spot market.

ExxonMobil is responsible for marketing the LNG while the condensates are marketed by Oil Search with the exception of the ExxonMobil equity share of the liquids.

4.2.2.2 T1/T2 Production Upgrades

The foundation PNG LNG Project has consistently produced above the project two-train nameplate capacity of 6.9 MTPA, with gross production in 2016 of 7.9 MT, 8.2 MT in 2017 and 7.4 MT in 2018 (lower due to the PNG earthquake in February 2018, with 1H 2018 averaging 6.1 MT and 2H 2018 averaging 8.8 MT). PNG LNG Production in 2019 was 8.5 MT and 8.8 MT in 2020.

The LNG plant underwent a successful debottlenecking / high-rate trial in 2015 and 2018 with modifications leading to the increase in production.

4.2.2.3 PNG LNG Expansion to 3 Trains (Stretch Case)

For the Stretch Case, GaffneyCline has assumed the P'nyang 3rd Train (~4.5 Tscf Technically Recoverable Resources (TRR) as estimated by Oil Search) begins production in 2028. The APF timing is revised to suit ullage requirements in 2031 for backfill into PNG LNG. The Muruk discovery (2037) is also available for future backfill and is currently scheduled as indicated and included in the GaffneyCline scenario profiles for evaluation. Given the experience of the foundation project, planned expansion train capacity is 3.0 – 3.4 MTPA. In the Base Case P'nyang is included as backfill to the foundation project from 2034.

4.2.2.4 Associated Gas Optimisation (AGO) Project

The export of oil field AG production from Kutubu, Agogo and Moran will occur within existing PDLs and licence variations will be submitted for the modified facilities. Production will occur from two enhanced existing production facilities (CPF & APF). Gas re-injection will cease as part of this project. AGO has plans to increase the overall AG contribution to the PNG LNG System to up to ~440 MMscf/d (annual average), subject to PNG LNG requirements. Tie-in will occur to the existing PNG LNG upstream infrastructure making use of existing production facilities with established infrastructure, logistics and community relationships. For the Base Case, GaffneyCline has assumed the CPF upgrade is scheduled for 2026 and the APF tie-in is scheduled for 2027.

4.2.2.5 PNG LNG (T1/T2) Production Profiles

The majority of forecast hydrocarbon volumes supplying the PNG LNG (T1T2) project comprise non-associated gas (NAG) assets which are currently non-producing. The key technical uncertainties concerning supply volumes therefore comprise volumetric calculation parameters and recovery factor assessments which is discussed in subsequent sections.

GaffneyCline's independent volumetric calculation and checks for Base Case Full Wellstream Gas after ELT is applied for the fields supplying the PNG LNG (T1T2) are summarised and presented in **Table 4.3** below.

The major differences between the Oil Search and the GaffneyCline Full Wellstream volumes are for Hides, Angore and Juha. Angore has a large degree of uncertainty and GaffneyCline is closely aligned with NSAI for the Base Case estimates. Overall, GaffneyCline considers the Oil Search volumes and associated profiles as reasonable representations for the foundation project based on GaffneyCline's technical analysis that are within the audit tolerance of 8% (Oil Search being 8% higher). The GaffneyCline profiles have been provided for valuation to Grant Samuel in the Base Case. The Expansion fields for P'nyang and Muruk in the Base Case are the same as the Oil Search volumes based on the GaffneyCline technical checks.

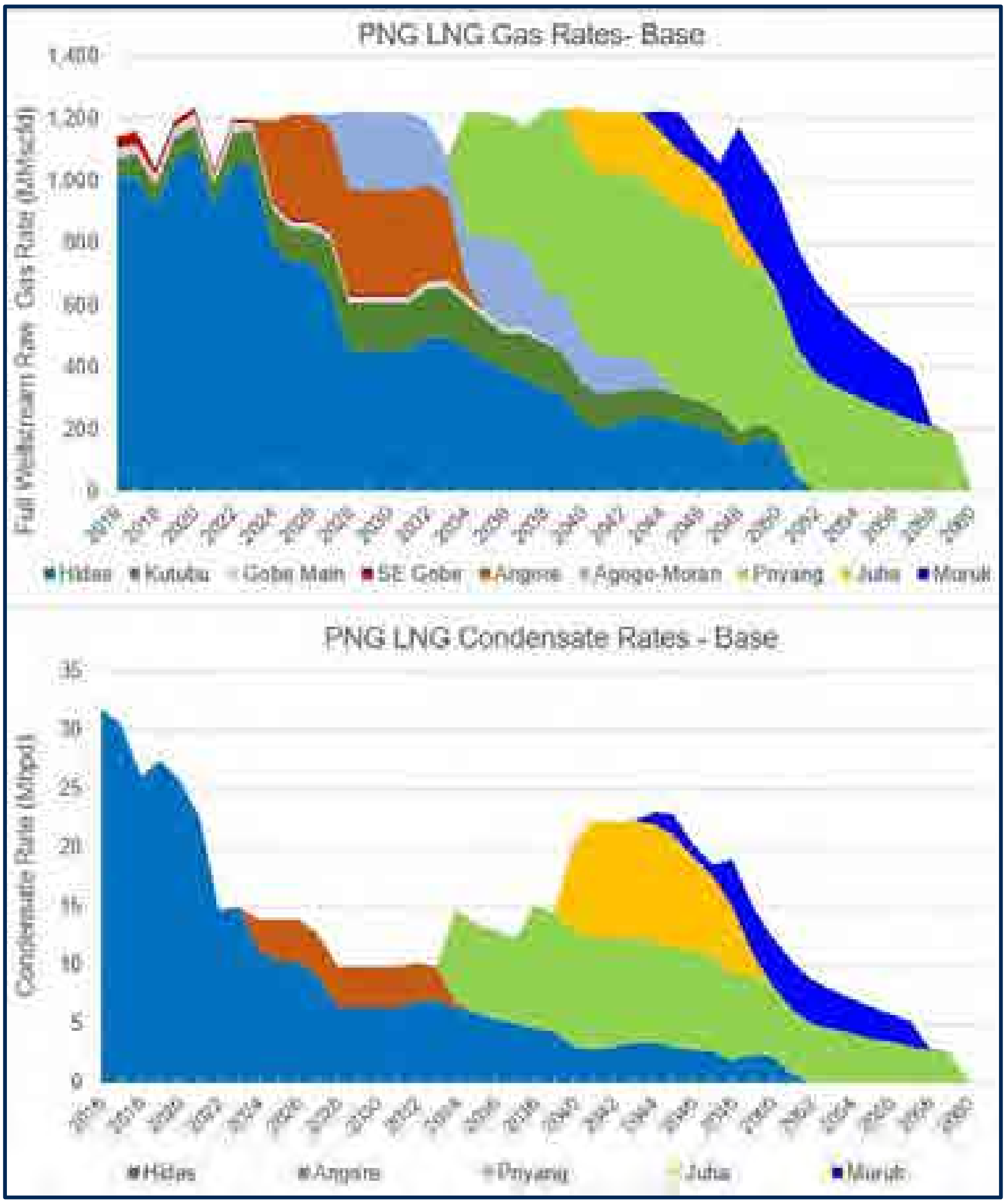
Table 4.3: 100% Estimates PNG LNG Project (Trains 1 and 2) Base Case (Bscf) as of 1 July 2021 Full Wellstream Raw Gas

Field	GaffneyCline Full Wellstream (Bscf)	GaffneyCline Year Online Assumption	Equivalent Oil Search Reserve/Resource Category
Hides	4,698	Producing	Producing 2P
Angore	1,174	2024	2P Undeveloped
Juha	579	2040	2P/2C Undeveloped
Kutubu	1,236	Producing	Producing 2P
Gobe Main	141	Producing	Producing 2P
SE Gobe	42	Producing	Producing 2P
Agogo-Moran	1,138	2027	2P Undeveloped (Gas Cap)
Foundation PNG LNGT1/T2 Gas Fields	**9,008**		
P'nyang	4,239	2034	2C
Muruk	1,093	2044	2C

Notes:
1. GaffneyCline Full Well Stream Raw Gas Volumes with ELT applied (Fuel and Flare not accounted for)
2. The economic model utilised by Grant Samuel (as provided by Oil Search accounts for the Fuel and Flare components)
3. Juha Volumes as per foundation project sanction are considered 2P by Oil Search. Santos considers these volumes as 2C. GaffneyCline has considered them for profiles appropriate in Grant Samuel's valuation analysis in the Base Case

Figure 4.6 depicts the GaffneyCline Base Case production profiles for the Full Wellstream Raw Gas (MMscfd) and Condensates (MBpd).

Figure 4.6: Oil Search Raw Gas and Condensate Base Case Production Valuation Scenario Profiles PNG LNG Project T1/T2



4.2.2.6 PNG LNGT1/T2/T3 and Papua LNG (T4/T5) Expansion Production Profiles (Stretch Case)

GaffneyCline's independent volumetric estimation checks against the mid case models and subsequent data and 3rd party reports has provided confidence for the Stretch Case Recoverable Full Wellstream Gas. These volumes are analysed in the context of the fields supplying the PNG LNG foundation and expansion (3rd Train consideration (T3)) provided by Oil Search. The volumes are summarised and presented in **Table 4.4** below. Technical discussions regarding GaffneyCline's analysis for specific fields are presented in **Section 4.2.3**. GaffneyCline considers the Oil Search Full Wellstream Raw Gas volumes for the Stretch Case as reasonable for evaluation purposes given the similarity in overall estimates against additional 3P, 2C/3C scenarios with only the Hides Footwall (FW) included for a Stretch Case consideration from the exploration seriatim. The Hides FW has been penetrated with residual gas shows in the water leg and simulation analysis demonstrating a Stretch Case likelihood of a connected volume. Other assets are discussed in subsequent sections.

Table 4.4: 100% Estimates PNG LNG Project (Trains 1 and 2) Stretch Case (Bscf) as of 1 July 2021 Full Wellstream Raw Gas

Field	Oil Search Full Wellstream (Bscf)	Year Online Assumption
Hides	5,911	Producing
Angore	2,090	2024
Juha	717	2043
Kutubu	1,404	Producing
Gobe Main	51	Producing
SE Gobe	23	Producing
Agogo-Moran	952	2031
Juha North	550	2043
Foundation PNG LNGT1/T2 Gas Fields	11,698	
Pnyang	5,605	2028
Muruk	2,910	2037

Notes:
1. GaffneyCline Full Well Stream Raw Gas Volumes with ELT applied (Fuel and Flare not accounted for)
2. The economic model utilised by Grant Samuel (as provided by Oil Search accounts for the Fuel and Flare components) which GaffneyCline considers reasonable
3. Juha Volumes as per foundation project sanction are considered 2P by Oil Search. Santos considers these volumes as 2C. GaffneyCline has considered them for profiles appropriate in Grant Samuel's valuation analysis in the Base Case
4. Juha North Volumes are also considered given the additional information gained by the Muruk wells de-risking this culmination in a Stretch Case scenario (Section 4.2.3.)
5. The P'nyang train will be owned by the P'nyang Joint Venture under a different ownership structure to PNG LNG

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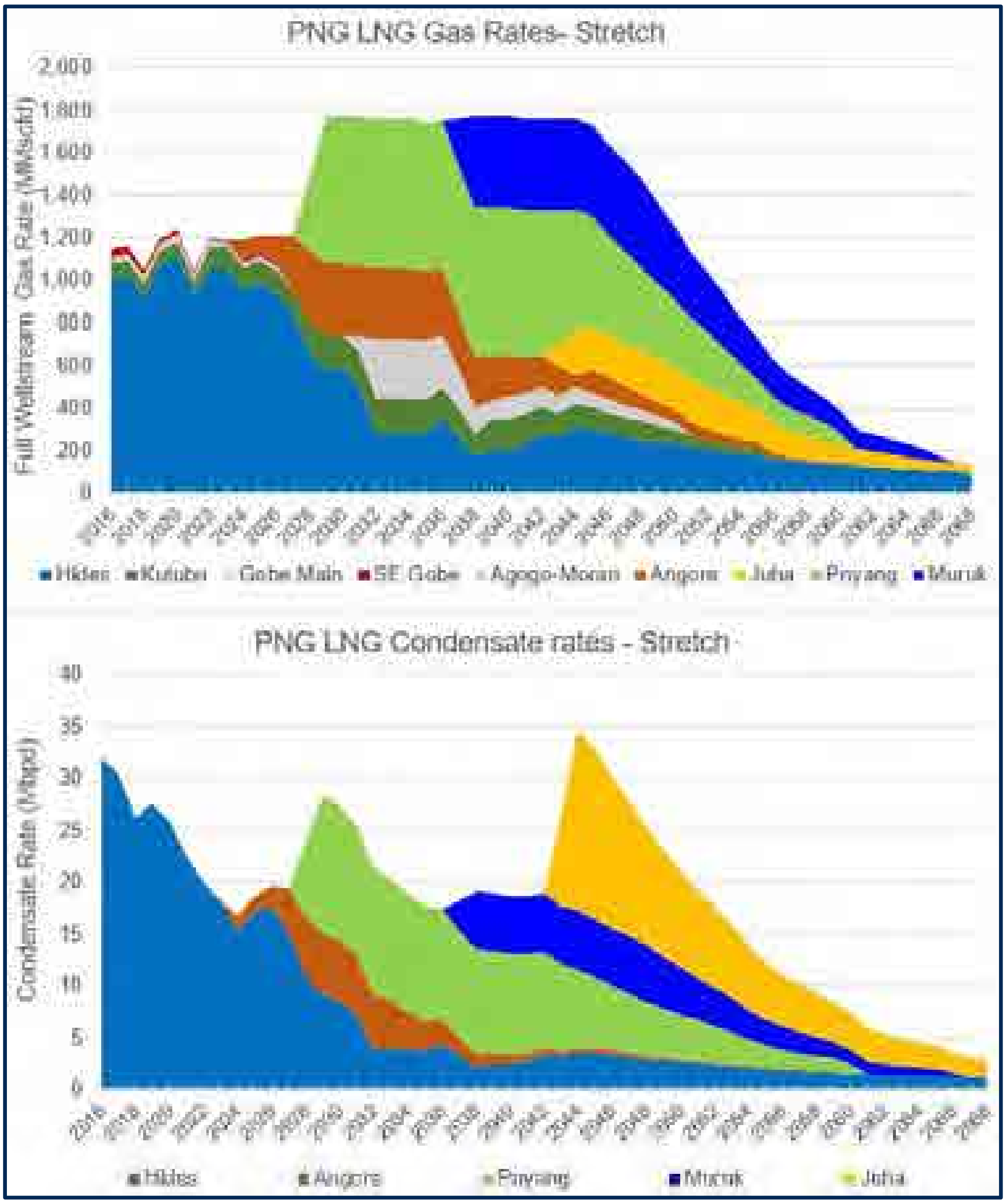
Figure 4.7 depicts the Oil Search Stretch Case production profiles for the Full Wellstream Raw Gas (MMscfd) and Condensates (MBpd).

Figure 4.7: Oil Search Stretch Case Production Valuation Scenario Profiles PNG LNG Project T1/T2



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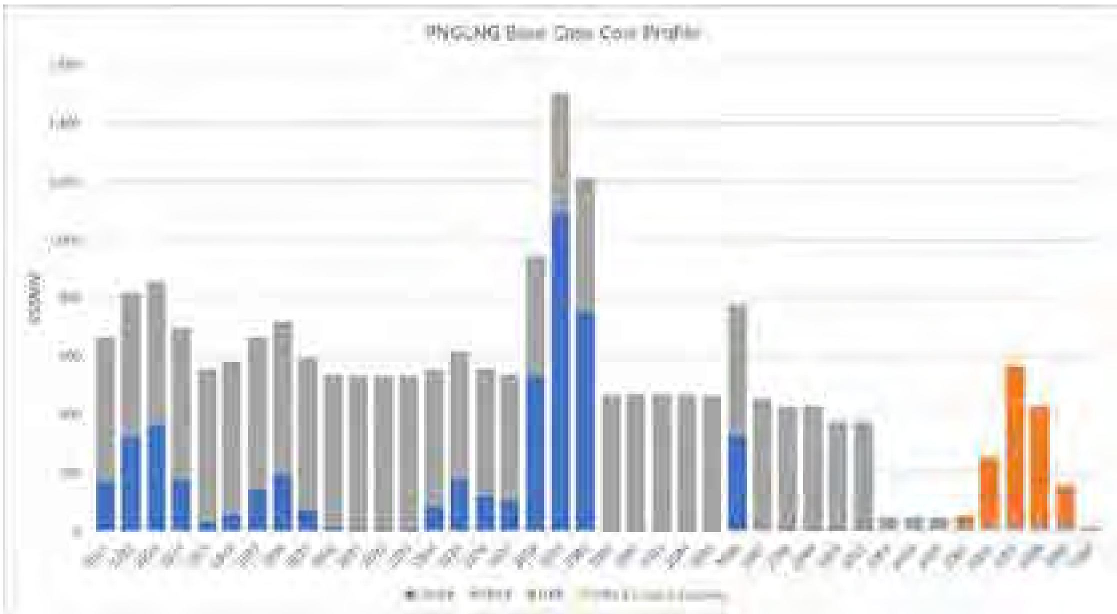
4.2.2.7 CAPEX and OPEX Valuation Scenario Summary

Oil Search has consolidated the PNG LNG Operator's expenditure estimates and their own estimates into a single integrated inputs spreadsheet. This inputs sheet consolidates the raw gas profiles by field, Exploration & Appraisal spending, Development CAPEX and DRILLEX, Late Life CAPEX, OPEX and ABEX. GaffneyCline's updates to these input profiles have been provided reflecting GaffneyCline's adjusted volumes by rescheduling the costs with appropriate reallocation. GaffneyCline has phased the Decommissioning and Restoration (D&R) costs over 5 years following the end of production. GaffneyCline has also recommended 2% p.a. cost escalation for NPV analysis utilising the Oil Search model. For the Stretch Case GaffneyCline has removed the Oil Search assumed savings or de-escalation with the addition of a Hides FW CAPEX adjustment. A 2% p.a. escalation was also recommended for application utilising the Oil Search Model and the GaffneyCline adjustments. GaffneyCline's Base Case valuation scenario profile is given in **Figure 4.8** and Stretch Case profile is given in **Figure 4.9**.

Figure 4.8: GaffneyCline's Base Case Cost Valuation Scenario for PNG LNG T1/T2 (US$ MM, 100%, RT2021)



Note: 2% p.a. escalation for costs represented above is recommended for application in the financial model

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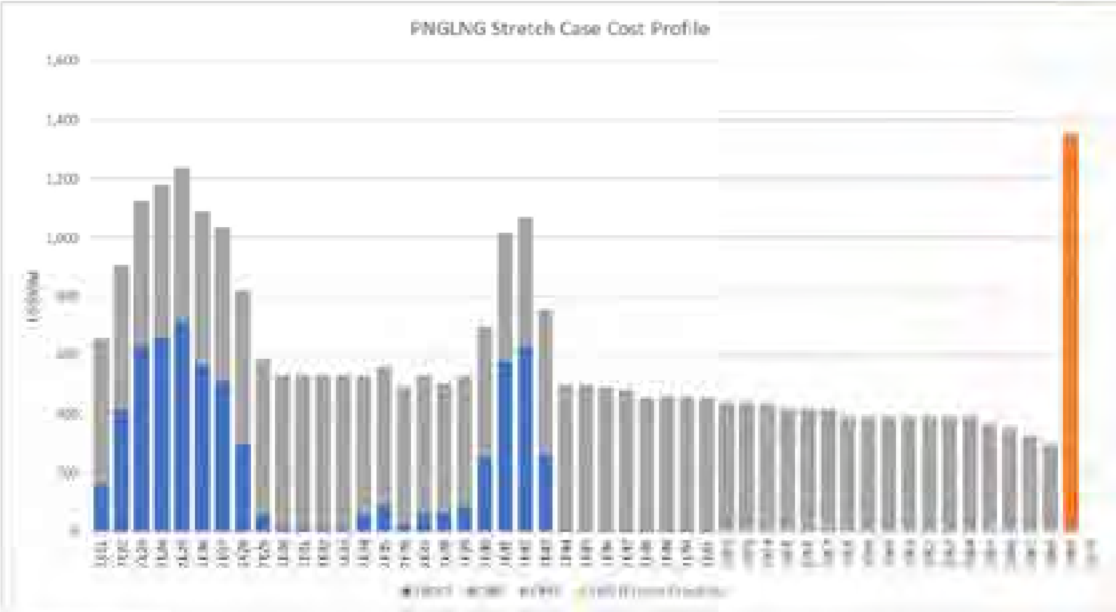
Figure 4.9: GaffneyCline's Stretch Case Cost Valuation Scenario for PNG LNG T1/T2 (US$ MM, 100%, RT2021)



Note: 2% p.a. escalation for costs represented above is recommended for application in the financial mode

4.2.2.8 PNG LNG Economic Limit Test (ELT)

GaffneyCline confirms that the reported Oil Search Reserves volumes for PNG LNG are reasonable, based on GaffneyCline's independent ELT tests. All subsequent volumes reported by GaffneyCline are full well stream raw gas with the application of ELT. Fuel and other shrinkages (CiO) are accounted for in the Oil Search financial model which GaffneyCline considers reasonable for the purposes of this work.

4.2.3 PNG LNG Fields

4.2.3.1 Hides Overview

Table 4.5: Hides Summary

Field Data	
Permits	PDL 1, PDL 7 and PDL 8
Location	Southern Highlands, 80 km northwest of Kutubu Central Processing Facility
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	PDL 1 16.66%, PDL 7 40.69%, PDL 8 40.69%
Santos Permit Interests	PDL 1 19.37%
JV Partners	ExxonMobil (Operator) 33.2 %, Kumul/MRDC (19.6%), Santos (13.5 %), JX Nippon Oil Exploration (4.7%)
Discovery Date	Hides 1 1987
First Production	March 2014 (PNG LNG), 1991 Hides Gas to Electricity project (Porgera Gold Mine)
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	4,698 Bscf Base, 5911 Bscf Stretch
Gross Condensate	67 MMBbl Base, 89 MMBbl Stretch
Status/Chance of Development	Producing

The Hides Field straddles mostly PDL 1 and PDL 7 Blocks in the PNG Southern Highlands, approximately 80 km northwest of the Kutubu Central Processing Facility (**Figure 4.10**). The field was discovered in 1987 with the drilling of Hides 1 and contains natural gas in four main reservoir intervals: Toro A, Toro B, Toro C and Upper Imburu. The field is formed of a southwest verging, partially fault dependant anticline with ~2,000 m of structural relief. The Lowest Known Gas (LKG) is in Hides-4 at 1,509 m TVDss, Highest Known Water (HKW) from the Hides PWD-1 is at 2,215 m TVDss with an estimated most likely Gas Water Contact (GWC) at approximately 2,100 m TVDss.

The reservoir interval is dominated by relatively clean quartz sandstones which are interpreted to have been deposited under shallow marine to offshore conditions. Average porosities range from 7-10% with permeability up to 800 mD. The central well cluster (Hides 1, 2, 3 and 3ST1) show little variation in reservoir characteristics between wells. The Hides 4 well, 12 km to the southeast exhibits a general improvement in reservoir quality within the Imburu, Toro B and Toro C sands indicating deposition in a more proximal setting. The Toro A sand is thinner at Hides 4 with a gradational base, indicating more distal deposition. While intra-formational shales separate each of the Toro sands, pressure data indicates the whole of the Toro is in communication.

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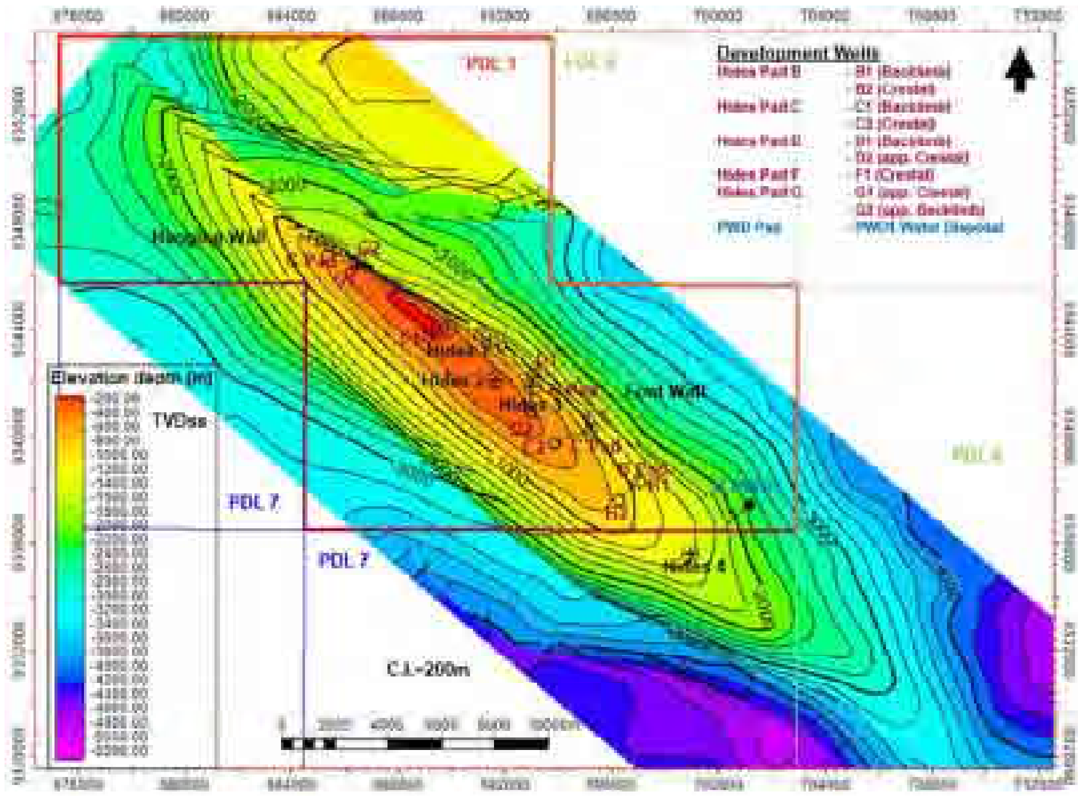
The Hides foot wall well is in the planning by the PNG LNG partners with no firm decision to date. Both Oil Search and Santos have included the Hides Footwall gas volumes in their exploration inventory based on the evidence from the hanging wall performance and the pressure response in the Hides PWD-1 well. Pressure monitoring of PWD-1 drilled in the footwall indicates a potential connection to the hanging wall which was drilled as a produced water disposal well. GaffneyCline's technical view, at this stage, is that there is a high Geological Chance of Success (GCoS) to make a discovery in the foot wall due to formation pressures indicating a water gradient and the MDT fluid analyser indicating mud filtrate with some residual gas and the simulation analysis indicating that the hanging wall history match requires foot wall gas. In addition, it is difficult to make a case for an isolated footwall given the requirement for multiple sealing faults that are not mapped on seismic.

Figure 4.10: Top Toro Reservoir Structure Map Showing Drilled Appraisal and Development Wells



Source: Santos Geological Model

4.2.3.1.1 Hides Development

The active well count for the PNG LNG project in the Hides Field is nine gas production wells (from pads B, C, D, F and G) and 1 water disposal well (**Figure 4.10**) drilled from 2012 to 2015. Hides 1 initially started producing small gas volumes for the Porgera gas to electricity (GTE) project in 1991 followed by Hides 2 in 1992 (approximately 13 MMscfd) prior to PNG LNG start up in March 2014 with a gas production rate of approximately 1000 MMscfd. Hides 3 and 4 have never been put on production. Since April 2020 the GTE project is no longer receiving any gas.

The Northern most Hides G1 and G2 wells drilled in 2014 clearly show pressure decline in line with the Hides production wells to the south indicating a connected tank for the hanging wall region. The cumulative raw gas produced as of 1 July 2021 is ~2514 Bscf.

As of 2020, the 9 Hides producers are providing the initial "swing" capacity in the PNG LNG system until Angore comes online. The Hides Gas Conditioning Plant (HGCP) acts as a gathering hub. It was initially planned to facilitate Angore and Juha and now the new Muruk discovery. The facility limit is at ~1,200 MMscf/d currently. Future development includes the Hides booster compression with the separator pressure reduced to 160 psig.

4.2.3.1.2 GaffneyCline Technical Review

<u>Geology and Geophysics Discussion</u>

The Operator ExxonMobil and the JV partners Oil Search and Santos have all completed full field modelling studies with a high confidence in the EUR estimates based on the significant production data (~30% of GIIP) that is available, and the long-term build-up post the earthquake shutdown to calibrate the history match. GaffneyCline has technically reviewed the Petrel Geological models provided by both Oil Search and Santos to estimate GaffneyCline's Gas Initially In-Place (GIIP) estimates and range as per **Table 4.6**. Exxon the operator utilise NSAI a 3rd party auditor to estimate their PNG LNG available resources by field and these in-place resource numbers are within tolerance of GaffneyCline's numbers. GaffneyCline has previously audited the same project for Santos, so is familiar with the technical aspects of the project.

Due to the complexity of the PNG fold belt with the thrusted structural environment and karsted surface limestones along with the dense rainforests, the acquisition of seismic data is difficult, and the quality varies from poor to fair. Various vintages of seismic data acquisition and processing is available and generally the operator and the JV partners Oil Search and Santos rely on structural interpretation and volumetric assessments aided by balanced cross section derived in an integrated workflow that rely on seismic data, surface data, well logs and dipmeter/well resistivity images. GaffneyCline has reviewed this work in the past as well as for this project to opine on the input parameters for the GIIP estimates tabulated below. Independent Petrel models were not constructed by GaffneyCline for the estimates, but the various models made available were evaluated to extract parameters for a 1D-Monte Carlo workflow to estimate the GIIP range. Reservoir properties (e.g. porosity, Sw) were generally accepted due to GaffneyCline's previous audit work that deduced that analysis to be reasonable.

Table 4.6: Comparison of Technical Analysis of GIIP for the Hanging Wall of the Hides Field

Company	GIIP (Bscf)		
	Low	Best	High
NSAI 2019	7,550	7,712	8,009
GaffneyCline	7,232	7,691	8,173

The Hides foot wall (FW) exploration volumes have also been analysed utilising an average between a 1D deterministic and 1D probabilistically methodology yielding a wider range of in-place resource volumes of between 813 - 1,203 - 1,524 Bscf. The FW prospect GCoS is relatively high at 0.45 (where the risk factors such migration, reservoir quality, seal effectiveness and trap evaluation have a high degree of confidence). The Hides FW is therefore recommended for consideration in the valuation of Hides and the PNG LNG longer term available gas volume stream in the Stretch Case. GaffneyCline Stretch Case volumes included for the Hides FW are 842 Bscf and 15 MMBbl of Condensates.

<u>Reservoir Engineering Discussion</u>

In line with the production reconciliation nature of the analysis, GaffneyCline considered the Produced gas and condensate profiles from all of the available models and reports. These models/reports are authored by three independent sources (Oil Search/Santos/NSAI), and so should represent a good view of the range of uncertainty in the profiles. GaffneyCline has also audited PNG LNG for Santos over previous years.

<u>Key Assumptions, Risks, Uncertainties and Opportunities</u>

The 2P estimates have been generally consistent for this asset between auditors given the volume produced so the assumption for valuation is the GaffneyCline estimated 2P profile as of 1 July 2021. The additional upside exploration potential of the Hides FW has also been considered in the profiles in the Stretch Case (3U case).

<u>Chance of Development</u>

The Chance of Development of the Hides FW is considered certain if discovered.

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4.2.3.2 Angore Overview

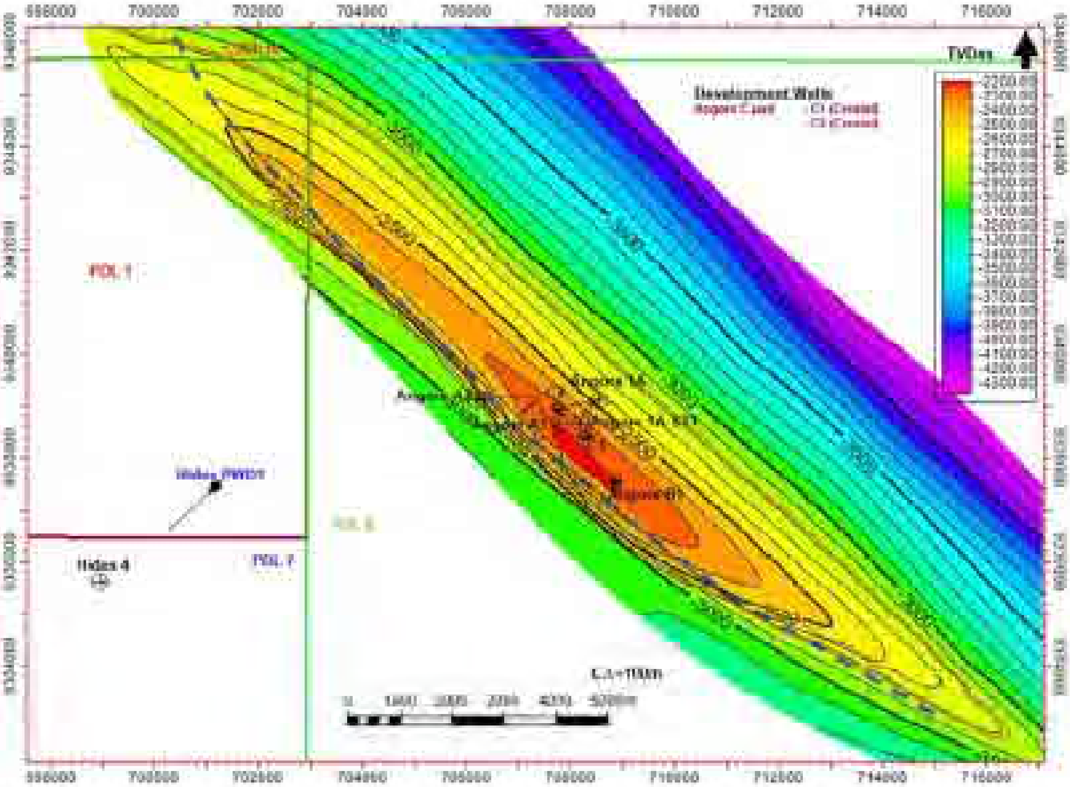
Table 4.7: Angore Summary

Field Data	
Permits	PDL1 and PDL 8
Location	Southern Highlands, 50 km northwest of Kutubu Central Processing Facility
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	PDL 1 16.66%, PDL 8 40.69%
Santos Permit Interests	PDL 1 24.025%
JV Partners	ExxonMobil (Operator) 33.2 %, Kumul/MRDC (19.6%), JX Nippon Oil Exploration (4.7%)
Discovery Date	Angore 1A 1990
First Production Schedule	Scheduled for H2 2024
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	1,174 Bscf Base, 2090 Bscf Stretch
Gross Condensate	13 MMBbl Base, 23 MMBbl Stretch
Status/Chance of Development	Approved For Development

The Angore gas field is located in PNG's Central Highlands predominantly in PDL 8, approximately 8 km northeast of the Hides Field and 50 km northwest of the Kutubu Production Facility. The field was discovered in 1990 by the Angore 1A well (**Figure 4.11**). The well encountered gas and condensate within the Toro and Upper Imburu sandstones. A DST conducted at several intervals over the reservoir section flowed gas to surface at a maximum rate of 16 MMscfd with 269 Bbld condensate per interval. The well indicated a lowest known gas (LKG) of -2,420 m TVDss and a gas column of 120 m. The Angore-B1 well drilled in 2014 on the back limb and was a failed appraisal well due to pore pressure issues in the Upper Ieru resulting in poor borehole stability.

The Pad A wells (A1 and A2) were drilled in 2015 with Angore A1 in a crestal location approximately 500 m west of Angore 1A intersecting the Toro and Digimu Reservoirs. The Angore A2 forelimb well drilled through the Toro reservoirs on the hanging wall, crossed the field boundary fault near the base of the Toro reservoirs and above the faulted-out Digimu reservoir, with the well intersecting a repeat Upper Toro reservoir on the footwall encountering residual gas and formation water. The LKG from the A2 wells logging run is 2,538 m TVDss in the A2 hanging wall penetration and the HKW is 2,877 m TVDss in the A2 footwall penetration. The most likely GWC of 2,820 m TVDss is derived from the intersection of the gas pressure gradient in the Angore Field hanging wall and the water pressure gradient in the A2 footwall well. There has been no production from the field.

Figure 4.11: Top Toro Reservoir Structure Map Showing Drilled Appraisal and Development Wells



Source: Exxon Operator Geological Model

4.2.3.2.1 Angore Development

The key uncertainty for Angore is the structure with the reservoir properties similar to Hides (Porosity is 7 to 8%, Permeability 10 to 100's mD). The field is located to the east of Hides with development planned via a tie-back to the HGCP. The development concept includes two production wells from a single pad (Pad C with C1 and C2 crestal wells) targeting 330 MMscf/d with a 14" wet gas pipeline and 2" MEG line to the HGCP. Pigging facilities are included with communications/power supplied by HGCP.

4.2.3.2.2 GaffneyCline Technical Review

Geology and Geophysics Discussion

The Operator ExxonMobil and the JV partners Oil Search and Santos have completed their individual full field modelling studies of the undeveloped field. GaffneyCline has technically reviewed the Petrel Geological models provided by both Oil Search and Santos to estimate GaffneyCline's Gas Initially In Place (GIIP) estimates in the Best Case as per **Table 4.8**. ExxonMobil the operator utilise NSAI a 3rd party auditor to estimate their PNG LNG available resources by field and these in-place resource numbers are within tolerance of GaffneyCline's Best Case number.

Table 4.8: Comparison of Technical Analysis of GIIP for the Hanging Wall of the Angore Field

Company	GIIP (Bscf)		
	Low	Best	High
NSAI 2019	1,355	1,546	1,716
GaffneyCline	-	1,677	-

Reservoir Engineering Discussion

The 2P estimates have been generally consistent for this asset between auditors so the assumption for valuation is the GaffneyCline verified 2P profile as of 1 July 2021. The additional upside potential due to the structural uncertainty based on the limited well coverage and fluid contact range has allowed GaffneyCline to review the 3P case provided by Oil Search (2090 Bscf) and accept it as a Stretch Case even if larger than the 3rd party auditor volumes.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2P estimates have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case.

Chance of Development

This project is approved for development and is scheduled for production start-up in H2 2024.

4.2.3.3 Juha Overview

Table 4.9: Juha Summary

Field Data	
Permits	PDL 9
Location	Southern Highlands, 50 km northwest of Kutubu Central Processing Facility
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	PDL 9 24.42 %
JV Partners	ExxonMobil 43.4%, State Entities 22.5%, Nippon 9.7%
Discovery Date	Juha 1X 1983
First Production Schedule	Scheduled for 2040 (Juha), 2043 Juha North (Stretch after Muruk)
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	579 Bscf Base, 1,267 Bscf Stretch (Juha and Juha North)
Gross Condensate	29 MMBbl Base, 64 MMBbl Stretch
Status/Chance of Development	Oil Search: Justified For Development

The Juha gas field is located in the Central Highlands of PNG in block PDL 9, approximately 35 km northwest of the Hides Field. The Juha structure is a broad NW-SE trending anticline with 800 m of relief and lying immediately in front of the first major thrust front of the PNG Foldbelt. The structure formed in response to the inversion of normal faults and has subsequently been modified by thrusting. The field was discovered in 1983 by the Juha-1X well which found gas in the Toro sandstone. A total of four wells have been drilled on the field. Juha-1X, -2X (1984) and -3X (1985) intersected gas in the Toro sandstone, Juha-5X (2007) was drilled 478 m down dip from the LKG intersected at Juha-3X (-2,442 m TVDss) and encountered a water bearing Toro sandstone. A GWC has been interpreted from RFT pressure data at -2,486 m TVDss. Pressure data indicates that all reservoir units are in communication across the field over a distance of approximately 13 km between Juha-1X and Juha-3X (**Figure 4.12**). Juha-4X was drilled in 2006 and was side-tracked due to mechanical issues (Juha-4XST1). Juha-4XST1 penetrated a separate fault block in the NE area known as Juha North.

The reservoir at Juha is approximately 100 m thick and composed of very clean quartz arenites with low clay content in three individual shallow marine cycles. Quartz overgrowth and pressure contact dissolution of grains has reduced the reservoir quality in comparison to the Hides field. Porosities range from 3-10% with a 7% average.

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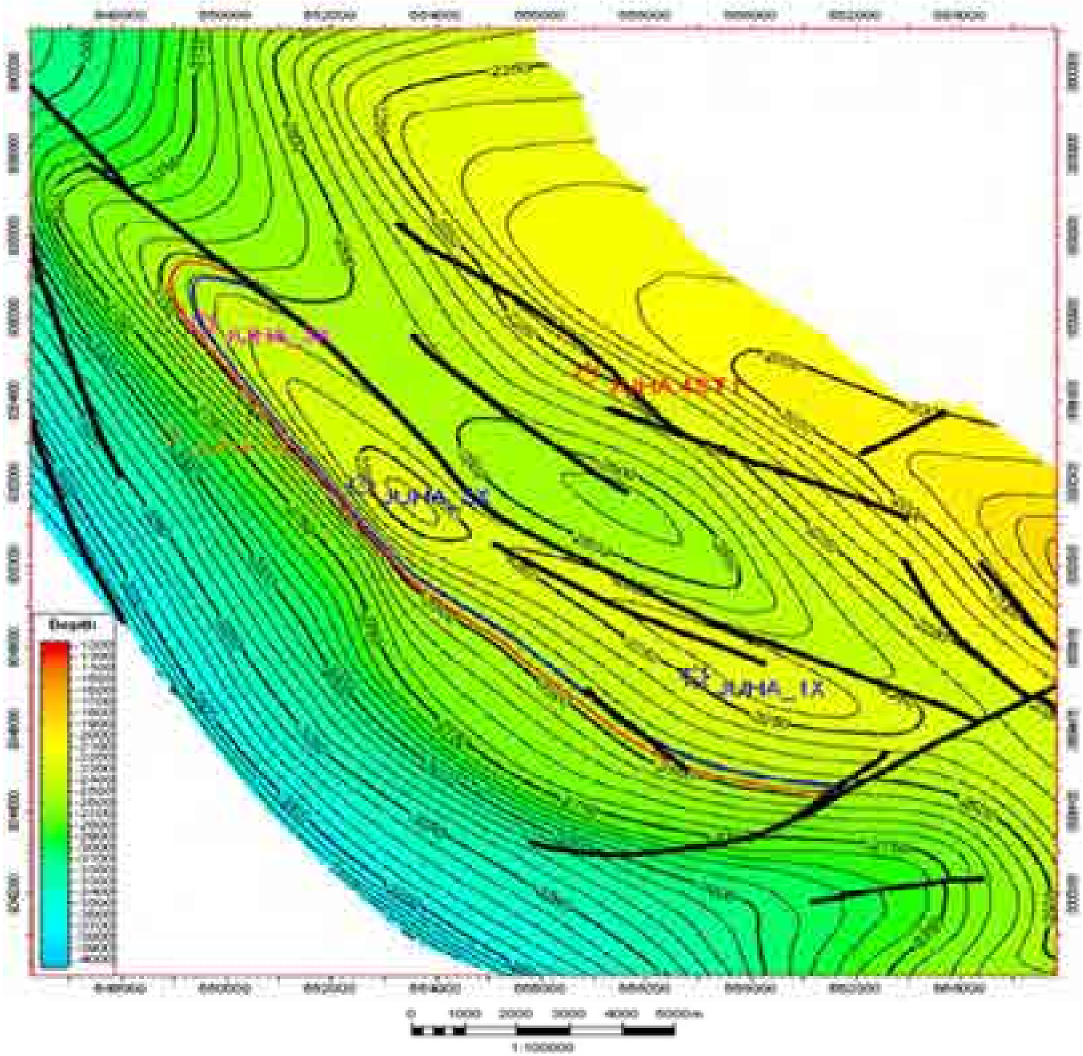
Figure 4.12: Juha Field



Source: Oil Search

4.2.3.3.1 Juha Development

There has been no development production from the field to date, the field is part of the PNG LNG Project and is planned to go on stream in 2040 based on current assessments and production profiles in the Base Case. Export will occur from the Juha Gas Conditioning Plant (separation, dew pointing and compression) at ~200 MMscf/d via a 14" gas and 8" liquids export pipeline to HGCP. Following the successful drilling of the Muruk Field, Juha may possibly be tied-back via Muruk leading to a significant reduction in development costs. This is considered in the Oil Search Stretch/High Case with a tie-in to the Muruk-HGCP export pipelines. The conceptual development plan includes the drilling of 4 wells in Juha and two wells in Juha North from two well pads.

4.2.3.3.2 GaffneyCline Technical Review

Geology and Geophysics Discussion

During previous workshops, Oil Search provided an ExxonMobil Petrel model which was consistent with the available acquisition data provided at that time and formed the basis of GaffneyCline's GIIP estimate checks in 2013. The modelled reservoir distributions were reasonable when compared to the petrophysical and engineering data. The GaffneyCline Mid Case GIIP computation based on the provided Petrel model in 2013 was 832 Bscf. The data previously reviewed supported the ExxonMobil GIIP rather than the newer NSAI GIIP in **Table 4.10** due to the older version processed seismic data. Between 2014 and 2015 ExxonMobil carried out Pre SDM seismic processing to update the seismic interpretation and structural view of the field. No new well data has become available. GaffneyCline reviewed the NSAI work performed and accepted NSAI's updated 2019 GIIP estimates as a reasonable basis for valuation.

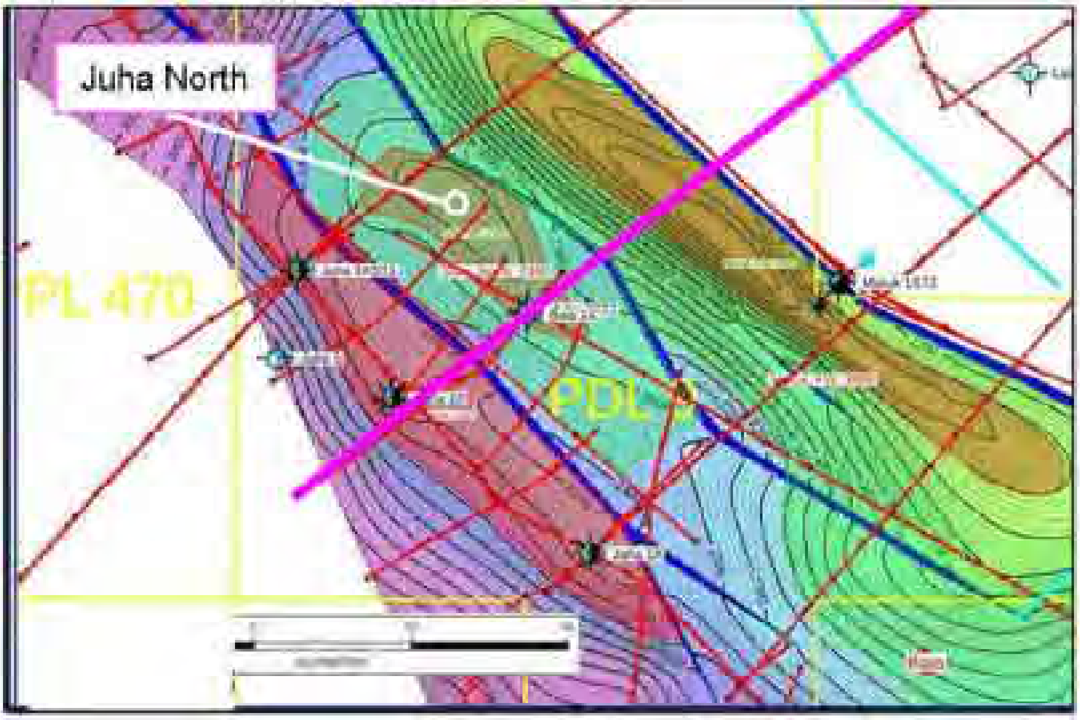
Table 4.10: Comparison of Technical Analysis of GIIP for the Juha Field

Company	GIIP (Bscf)		
	Low	Best	High
NSAI 2019	712	739	791
GaffneyCline	-	832	-

GaffneyCline has also undertaken a review of the volumetrics for Juha North (**Figure 4.13**) based on data provided by Oil Search which included log and pressure data for both the Juha North and Muruk wells together with seismic data and Oil Search's interpreted reservoir surfaces. To calculate GRVs, GaffneyCline has used the GDT for its P90 calculation of -2,266 and -2,306.5 m TVDss for the Toro A and Toro C reservoirs respectively. For its P10 GRV calculation, GaffneyCline has used a P10 GWC based on Oil Search's extrapolation of the Juha-4XST1 gas gradient to the Juha-5X water gradient. For the P50, GaffneyCline has calculated a P50 based on a lognormal distribution around its P90 and P10 GRVs.

GaffneyCline

Figure 4.13: Juha North Field



Source: Oil Search

GaffneyCline has also calculated its own independent reservoir parameters. GIIP volumes have been estimated using a 1D Monte Carlo simulation. GaffneyCline's estimates of full field GIIP are summarised in **Table 4.11.**

Table 4.11: GaffneyCline's Estimates of Full Field and On-block GIIP for Juha North

Estimate	GIIP (Bscf)		
	P90	P50	P10
Full Field	233.0	396.1	690.7

Reservoir Engineering Discussion

A volumetric approach has been utilised for Juha/Juha North assessment consisting of geological models in combination with a 1D Monte Carlo assessment.

Table 4.12: Comparison of Technical Analysis of EUR for Juha

Company	Gross EUR (Bscf)		
	Low	Best	High
NSAI 2019	538	579	626
GaffneyCline	-	582	-

Key Assumptions, Risks, Uncertainties and Opportunities

The 2P estimates for Juha have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case. Juha North is considered a Stretch valuation case scenario utilising the Juha North P10 estimate in addition to an Oil Search P50 Juha estimate (which is aligned towards a P10 outcome).

Chance of Development

This project is justified for development and is scheduled for production start-up in 2040. Juha North is considered for development in the stretch side given the successful drilling of Muruk.

4.2.3.4 Kutubu Complex

Table 4.13: Kutubu Summary

Field Data	
Permits	PDL 2 and Pipeline Licence-2 (PL 2).
Location	Southern Highlands, 50 km northwest of Kutubu Central Processing Facility
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	60.04%
JV Partners	ExxonMobil 14.5%, State Entities 6.8%, Merlin Petroleum Company (Nippon) 18.7%
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	1,236 Bscf Base, 1404 Bscf Stretch
Status/Chance of Development	Producing

The Kutubu Oil Project is PNG's first commercial oilfield development. It is located in PDL 2 in the Southern Highlands of PNG and takes its name from nearby Lake Kutubu. Oil was first discovered at Kutubu in the Iagifu sandstone structure in 1986 and commercial production commenced in June 1992. The Kutubu Oil Project is made up of the Iagifu-Hedinia, Usano and Agogo Fields which are a series of structural traps in the PNG fold belt (**Figure 4.14**).

The Iagifu-Hedinia Field comprises interrelated fold and thrust structures. The structure is formed of two northwest to southeast trending anticlines, Iagifu in the north and Hedinia in the south. The Iagifu anticline is bound to the north by a back thrust fault while the Hedinia Field is bounded to the southwest by a frontal thrust fault. The two anticlines are separated by a structural saddle and further separated from the Usano Field to the south east by a northeast - southwest trending fault. Productive oil reservoirs include the Toro, Digimu, Hedinia and Iagifu sandstones.

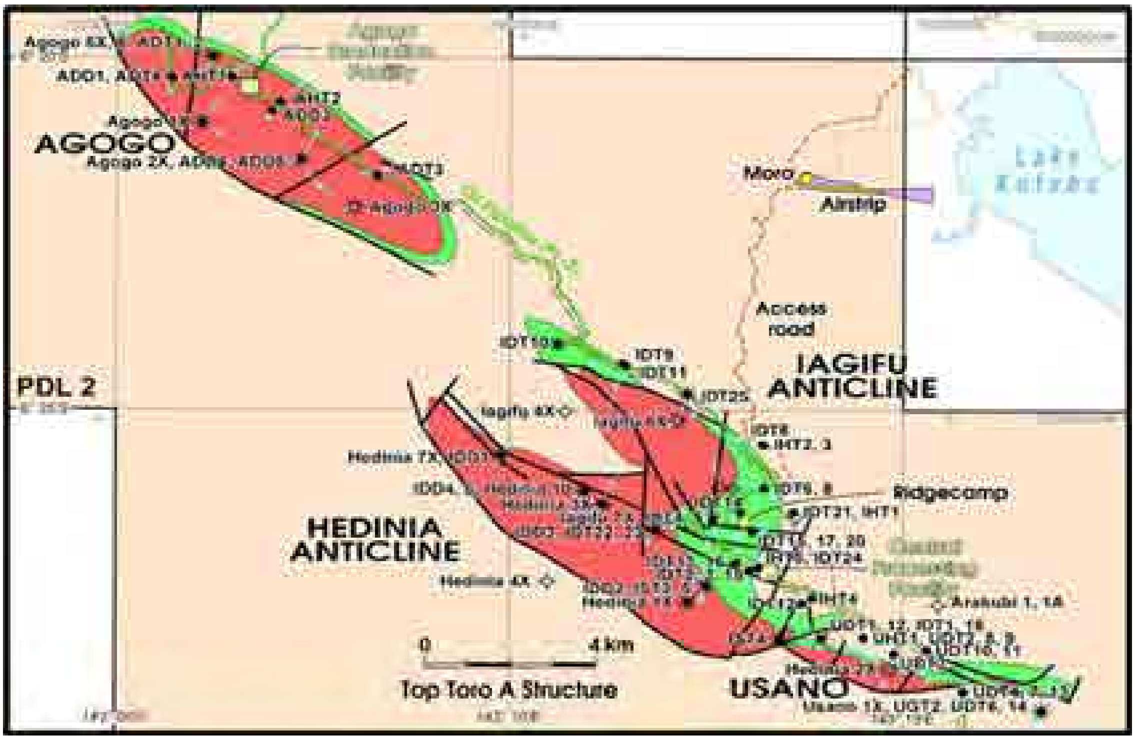
The Usano Field comprises two structural closures; west and a northeast hanging wall closures which are dip closed to the northeast. Both structures contain an oil rim below free gas caps. Productive reservoirs are the Toro A, B and C.

The Kutubu development comprises a network of wells that produce oil from the Iagifu-Hedinia and Usano and Agogo Fields, a gathering system and on-site processing facilities; the Agogo (APF) and Central Processing Facilities (CPF) and supporting infrastructure (**Figure 4.14**), as well as a 270 km export pipeline to the coast and a marine loading terminal in the Gulf of Papua. The pipeline operates under Pipeline Licence 2 (PL 2), while the oilfield operates under Petroleum Development Licence 2 (PDL 2). Both licences were issued in December 1990 for a term of 25 years and were extended in December 2009 until December 2035. Oil Search provided profiles for the PL 2 licences which at this stage GaffneyCline considered reasonable

Production from the Kutubu Field peaked in 1993 at 125,000 bopd. The Kutubu Oil Project is well into its decline phase due to natural field depletion. Efforts over the past several years to arrest the production decline have been very successful with additional production resulting from the drilling of development wells at Kutubu and Usano.

Gaffney Cline

Figure 4.14: The Kutubu Development Project



Source: Oil Search

4.2.3.4.1 Kutubu Complex Gas

The Iagifu and Hedinia structures within the Kutubu Complex (the "Iagifu/Hedinia Field" or Main Block Toro (MBT)) account for greater than 90% of the hydrocarbons produced in the Kutubu Complex. The Kutubu Complex contributed an average of 70 MMscf/day to the PNG LNG Project during 2019 based on production profiles provided by Oil Search.

The majority of the reservoirs have large gas caps over thin oil rims and the drive mechanism is predominantly gas cap expansion. All of the fields have gas injection in place, with six wells currently being used to provide pressure support. There are 48 active wells in the Iagifu/Hedinia Field. Each of these wells has a defined utility for gas production, gas injection or water injection in the complex's gas development plan. The complex's gas development plan also proposes the use of the existing wells' flowlines for gas production.

In 2015, Oil Search commenced work on the Associated Gas Acceleration (AGAA) opportunity, a project designed to accelerate the volume of gas being delivered from the Kutubu Fields, together with the Agogo and Moran Fields to the PNG LNG Project. One of the key drivers was the desire to economically maintain upstream gas production given the strong performance of the PNG LNG Project. In 2016, Oil Search, together with the PNG LNG Operator and other JV partners completed the AGAA study, identifying the preferred way to optimise production from these fields by increasing the capacity of the CPF.

GaffneyCline technical review involved confirming the structural complexity of the field via a review of the seismic and well results presented in the FDP report and Oil Search Petrel model. The Mid Case reservoir distributions are considered reasonable as presented in the geological model. The GaffneyCline Mid Case GIIP computation for the Main Block Toro (MBT) based on the provided Petrel model is 1,141 Bscf (with the Simulation model indicating 1,043 Bscf) for the gas cap +275 Bscf for solution gas (as estimated from the Oil Search simulation model). The STOIIP for the MBT was estimated from the model to be 357 MMstb.

The data supports the Oil Search GIIP rather than the NSAI GIIP however recognises that with such complexity the range is very important.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2P estimates for Kutubu have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case. The Oil Search Stretch Case of 1415 Bscf is considered reasonable by GaffneyCline.

4.2.3.5 Agogo Overview

Table 4.14: Agogo Summary

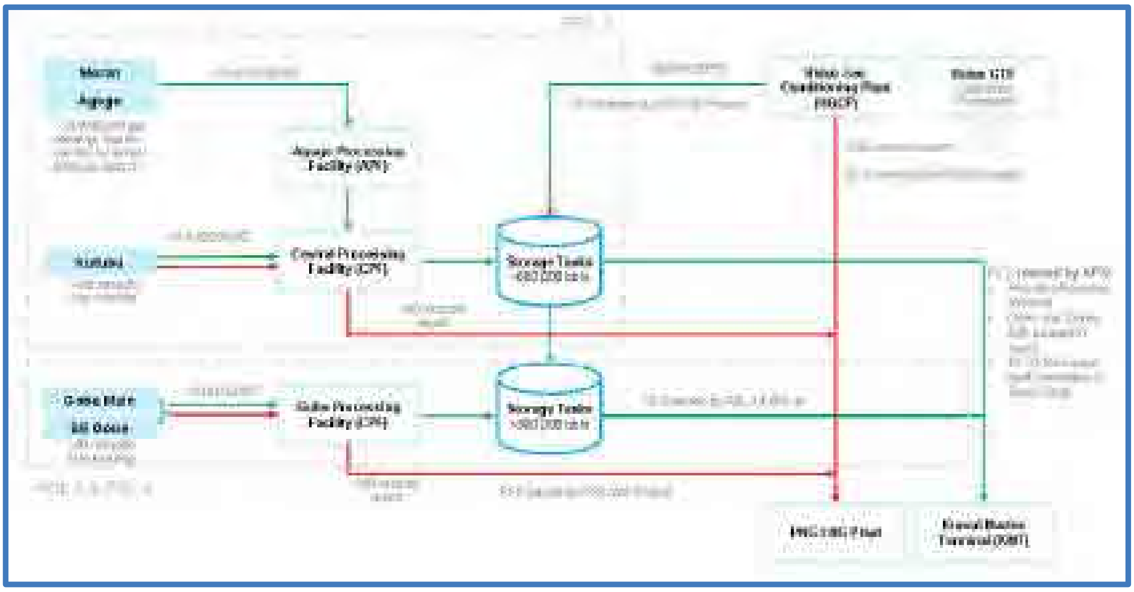
Field Data	
Permits	PDL 2 and Pipeline Licence-2 (PL 2).
Location	Southern Highlands, 50 km northwest of Kutubu Central Processing Facility
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	60.04%
JV Partners	ExxonMobil 14.5%, State Entities 6.8%, Merlin Petroleum Company (Nippon) 18.7%
Valuation Scenario Volumes as of 1 July 2021	
GaffneyCline Profile Basis	Technical reconciliation against 2P profiles utilising Oil Search model and 3rd Party auditor reference
Gross Raw Gas	752 Bscf Base
Status/Chance of Development	Approved for Development 2027

The Agogo Field (**Figure 4.15**) is also a northwest-southeast trending anticline which lies 5 km to the northwest of and on trend with the Iagifu-Hedinia structure. Producing reservoirs include the Toro, Digimu and Hedinia sands. The Iagifu reservoir is non-producing; however, logs, DST's and production tests confirm oil potential. Gas production from the Agogo reservoirs is currently re-injected into the Toro and Digimu reservoirs in the Agogo Field and at the Moran Field and will subsequently be used in the PNG LNG project. As the Toro and Digimu Reservoirs have been depleted, certain wells have been deepened and recompleted to exploit the Hedinia and Iagifu Reservoirs.

Towards the end of 2009, an Agogo development well was deepened to test an exploration target and discovered oil in a previously untested footwall forelimb compartment. Intervals within the footwall forelimb were flow tested in early 2010 and produced oil from the Digimu interval. The well was placed on production in 2010 and has since produced at sustained rates. The Agogo forelimb was successfully appraised by the Agogo 6 and Agogo 7 wells, confirming the presence of oil and gas in the forelimb Toro sands. The recovery of oil from the footwall forelimb has opened up a new play fairway in the Fold Belt and has upgraded the potential of similar footwall structures that are mapped on trend and in adjacent acreage.

The Agogo development comprises a network of wells that produce oil from the Agogo Field, a gathering system and on-site processing facilities; the Agogo (APF) and Central Processing Facilities (CPF) and supporting infrastructure (**Figure 4.15**), as well as a 265 km export pipeline to the coast and a marine loading terminal in the Gulf of Papua. Oil Search estimated average production in 2019 at 1,918 bopd.

Figure 4.15: Simplified Schematic of the PNG Oil Operations



Source: Oil Search

4.2.3.5.1 Agogo Complex Gas

The Agogo Field is located to the northwest of the Iagifu/Hedinia Field. Currently, gas from the Agogo Field is used for pressure support in both the Agogo Field and Moran Field, with small amounts used for fuel, flare and gas lift. There are 10 active wells in the Agogo Field, including two gas injection wells. Each of these wells has a defined utility for gas production or re-injection in the field's gas development plan. The field's gas development plan includes the use of the existing wells' flowlines for gas production.

4.2.3.5.2 GaffneyCline Technical Review of Agogo Gas

GaffneyCline confirmed the structural complexity of the field via a review of the seismic and well results presented in the FDP report and Oil Search Petrel model. The Mid Case reservoir distributions are considered reasonable as presented in the geological model. The 2014 GaffneyCline mid case GIIP computation for Agogo based on the provided Petrel model was 0.79 Tscf whilst the current NSAI 2016 Audit GIIP volume of 0.87 Tscf. Given the additional production and drilling results GaffneyCline has accepted the Oil Search and NSAI volumes.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2P estimates for Agogo have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case. Oil Search's Stretch Case gas volume is lower than the GaffneyCline Base and has been accepted in the integrated PNG LNG Stretch Case volumes.

4.2.3.6 Moran Overview

Table 4.15: Moran Summary

Field Data	
Permits	PDL 2 , PDL 5 and PDL 6
Location	Southern Highlands Province, 480 km north-west of Port Moresby
PNG LNG Project Interest	Oil Search 29.0033%, Santos 13.5321%
Oil Search Permit Interests	Oil Search owns a 60.05% interest in PDL 2, 40.69% interest in PDL 5 and 71.07% in PDL 6, giving it a 49.51% interest in the Greater Moran Unit.
JV Partners	PDL 2; ExxonMobil, held through Ampolex (PNG Petroleum) Inc & Merlin Pacific Oil Company Limited (14.52%), Merlin Petroleum Company (NEOX) (18.69%) and Petroleum Resources (6.75%). PDL 5; ExxonMobil, held through Esso Highlands Limited (36.81%), EDA (Petromin) (20.05%) and Petroleum Resources (2.00%) PDL 6; ExxonMobil, held through Ampolex (PNG Petroleum) Inc (18.36%), Merlin Petroleum Company (NEOX) (8.57%) and Petroleum Resources (2.00%)
Operator	PDL 2; Oil Search (PNG) PDL 5; ExxonMobil (Esso Highlands Limited) PDL 6; Oil Search (PNG) Moran Unit; Oil Search (PNG)
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	386 Bscf Base
Status/Chance of Development	Approved for Development 2027

The Greater Moran Oil Project straddles (**Figure 4.16**) three licence areas: PDL 2, PDL 5 and PDL 6 and is located in the Southern Highlands Province, 480 km north-west of Port Moresby. The structure is formed of a northwest to southeast trending plunging anticline which is bound to the southwest by a thrust fault. The forelimb of the anticline is overturned with reservoir sections repeated while both oblique and parallel to strike faults compartmentalise the reservoir with fault blocks having different contacts. The productive reservoirs are the Toro C and Digimu, which are separated vertically by the marine shales of the Upper Imburu Formation, and the two reservoirs constitute separate accumulations. The Toro C has porosities of between 11-14% and hydrocarbon saturations of 65-75%. The Digimu has porosities, which range between 12-16% and saturation of 75-85%. The Upper Cretaceous Ieru Formation provides seal for the Toro C and by the Upper Imburu shales for the Digimu.

The first Moran well was drilled in June 1996 with oil discovered in September 1996 when the Moran-1X sidetrack well (which is located within PDL 2), encountered oil-bearing sands. Production commenced from the field in January 1998 by way of an Extended Well Test (EWT) program, producing oil from the Moran-1X, -2X and -5 wells, all of which are located within PDL 2. A EWT on Moran-4 located in PDL 5 (PPL 138) commenced production in April 2000.

In March 2001, the Central Moran Unit Agreement between the PDL 2 and PDL 5 joint venture partners was executed, and full field development of the Central Moran Project was completed in September 2002.

The Central Moran Oil Field has been developed as a single Unit with ownership of the Unit in the proportion of 45% by PDL 2 and 55% by PDL 5. The Central Moran Project was designed and installed based on an oil production capacity of up to 24,000 bopd; a gas injection capacity of up to 105 MMscfd; and oil recovery by injection of the Moran solution gas supplemented by Agogo gas to maintain reservoir pressure.

The Moran PDL 5 participants pay a tariff to the PDL 2 and PL 2 partners for processing and transporting crude through the Kutubu system.

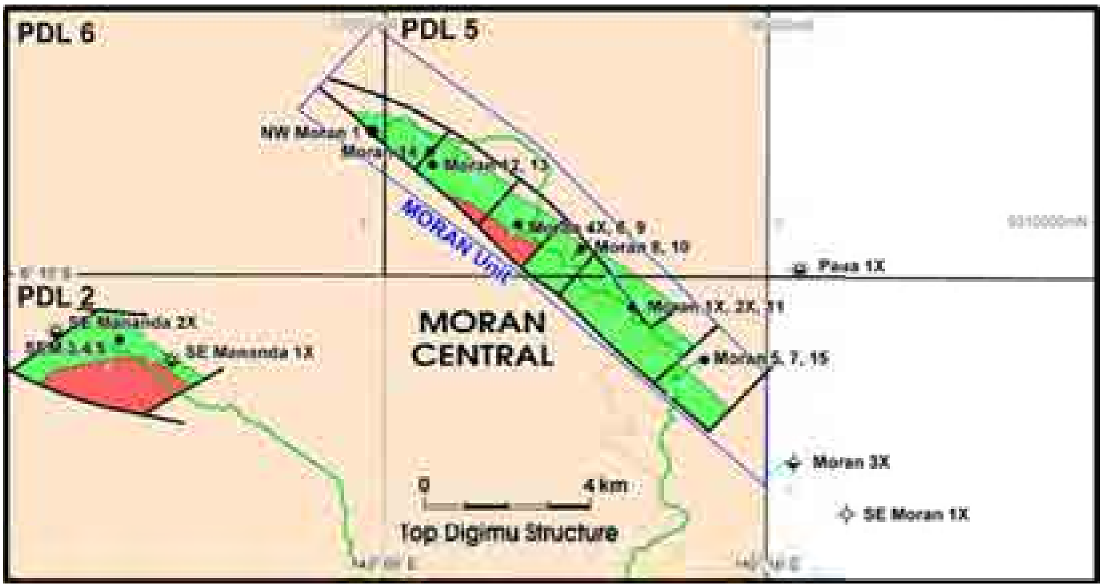
In late 2003, NW Moran, an extension of the Moran Field towards the northwest, into PPL 219, was discovered. In September 2005, an Extended Production Test (EPT) of the NW Moran-1 well commenced, following the construction of a 23 km pipeline linking NW Moran into the APF. This, together with infrastructure debottlenecking, additional infill wells and success in re-pressurising the Moran reservoir due to improved facility reliability resulted in an increase in production rates.

In late 2006, the PDL 2, PDL 5 and PPL 219 (now PDL 6) joint venture partners agreed to establish a single Greater Moran Unit across the Moran and NW Moran Fields. The unitisation split is 55%, 44%, 1% to PDL 5, PDL 2 and PDL 6 respectively, giving Oil Search a 49.51% interest in the Unit. A Production Development Licence over the NW Moran Field, PDL 6, was awarded in 2008.

In 2016, gross production from the Moran Field averaged 9,068 bopd which represented a 5% increase from 2015 levels. The production increase was attributed to bringing several wells, including NW Moran-1ST1, Moran-2XST3 and the Moran-1XST4B Block back on stream during 2015 coupled with a zone change to the Toro in Moran-15ST1 which significantly enhanced production. The Oil Search operated oil production was impacted in 2019 by 2018 earthquake-related issues, including delays in return-to-service, unplanned facilities outages requiring repairs and landowner access issues. Reconstruction from earthquake continued into 2019 where one of two pipelines were repaired enabling tie-in of the Moran-15ST2 well. Work was also completed on a new pipeline to NW Moran which was completed in 2020.

Gaffney Cline

Figure 4.16: Moran Oil Field



Source: Oil Search

4.2.3.6.1 Moran Gas

The Oil Search simulation model GIIP matched Oil Search's reported in-place number (445 Bscf) which is similar to the 2019 NSAI (483 Bscf) number. Based on GaffneyCline's review GaffneyCline has accepted the latest NSAI EUR volumes as reviewed (386 Bscf). This gas is scheduled for export into PNG LNG through the APF as determined by the Associated Gas Optimisation opportunity.

<u>Key Assumptions, Risks, Uncertainties and Opportunities</u>

The 2P estimates for Moran have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case. Oil Search's Stretch Case is lower than the GaffneyCline Base and has been accepted in the integrated PNG LNG Stretch Case volumes.

4.2.3.7 Gobe and SE Gobe Overview

Table 4.16: Gobe and SE Gobe Summary

Field Data	
Permits	PDL 3 encompassing the central part of the SE Gobe Field, and PDL 4 encompassing the Gobe Main Field, the south-eastern and north-western parts of the SE Gobe Field and the Saunders Field. PL3
Location	Gulf and Southern Highlands Provinces, 85 km southeast of the Kutubu Oil Project.
Oil Search Permit Interests	PDL 3 36.36% and PDL 4 10.0% giving it a 10.0% interest in the Gobe Main Field and a 22.34% interest in the SE Gobe Field.
JV Partners	PDL 3: NPCP Oil Company Pty Limited (45.72%), Santos (held through Barracuda Ltd) (15.92%), Petroleum Resources (Gobe) Ltd (2.0%). PDL-4: Merlin Petroleum Company (73.48%), ExxonMobil, held through Ampolex (Highlands) Ltd (14.52%), Petroleum Resources (Gobe) Ltd (2.0%).
Operator	Oil Search Limited operates the Gobe Main and SE Gobe Felds and is operator of PDL 4. Santos operates PDL 3.
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	Gobe Main 141 Bscf, SE Gobe 42 Bscf.
Status/Chance of Development	Producing

The Gobe Oil Project comprises two producing oil fields, the South East (SE) Gobe oil field and the Gobe Main oil field (**Figure 4.17**). The fields lie in the PNG Foldbelt approximately 85 km to the southeast of the Kutubu Complex. SE Gobe was discovered in early 1991. The SE Gobe discovery was significant because for the first time commercial quantities of oil were found in the Iagifu sandstone. Prior to this, the majority of oil was discovered in the Toro sandstone. The Gobe Main Field was discovered in December 1993 and is located 5 km to the northwest of the SE Gobe Field.

The SE Gobe Field is a northwest - southeast trending anticline and oil was discovered in the Upper and Lower Iagifu sandstones. The Gobe 2X well, at the NW end of the SE Gobe anticline, also confirmed the presence of producible hydrocarbons from the Hedinia sands. The Iagifu reservoir is formed of a coarsening upwards series of shoreface to estuarine sands which increase in reservoir quality upwards and have a total stratigraphic thickness of 70-100 m. The reservoir is continuous over the entire field and the best reservoir properties are found in Iagifu A of the Upper Iagifu with 70-85% Net to Gross (NTG), 16-18% porosity and permeability ranging from 6-800 mD.

The Gobe Main Field is an analogous northwest–southeast trending anticline which lies on trend with SE Gobe. Oil was discovered in the Upper and Lower Iagifu sandstones. In Gobe Main, the majority of the STOIIP is contained within the Lower Iagifu which ranges in thickness from 45-80 m and is composed of stacked progradational clastics deposited in a shallow marine environment. The reservoir is continuous across the field and has good reservoir characteristics with NTG of 80-90%, average porosity of 17% and permeabilities ranging from 70 to 1,000 mD. Compartmentalisation is evident from pressure data and variation in contacts between fault blocks. Most fault blocks contain both oil and overlying gas cap. Oil Reserves in Gobe Main are also contained in the Iagifu sandstone.

The Gobe Main Field is wholly located within Petroleum Development Licence 4 (PDL 4), while SE Gobe straddles the boundary of PDL 4 and adjoining PDL 3. Originally, 55% of SE Gobe oil reserves were attributed to PDL 4 and the balance to PDL 3. Following subsequent re-determinations, the revised and final oil and gas split is 46.8% in PDL 3 and 53.2% in PDL 4 with no further changes possible.

Oil is exported via an 8 km pipeline which joins the Gobe Processing Facility to the Kutubu Export Pipeline and marine loading terminal in the Gulf of Papua. The Gobe Project pays a tariff to the PDL 2 and PL 2 participants for the use of the export pipeline and infrastructure. The construction of infrastructure and production facilities for the Gobe Oil Project was completed in early 1998 and the first crude oil flowed from the Gobe Main Field in March 1998 and from the SE Gobe Field in April 1998.

Production peaked in December 1998 at 18,500 bopd from SE Gobe and at 20,000 bopd from Gobe Main in September 1999. In early 2005, the SE Gobe-11 well discovered an oil column in an undrained area of the SE Gobe Field, located between Saunders and SE Gobe. An appraisal/development programme took place during 2006 to exploit this area. Both fields are now in their decline phase, but active well management and facility optimisation is ongoing, to mitigate the fields' natural decline rates.

Gaffney Cline

Figure 4.17: Gobe and SE Gobe Oil Fields

Source: Oil Search

4.2.3.7.1 GaffneyCline Technical Review of Gobe Gas

Due to the smaller contributing volumes to the overall PNG LNG Project GaffneyCline performed a high level review of the volumes and considered the NSAI range to be reasonable.

4.2.3.7.2 SE Gobe Gas

The field straddles two production license areas. Oil Search has a working interest of 36.36% in PDL 3 in which Santos is the Operator. SE Gobe gas is sold as third party gas to the PNG LNG Project given that SE Gobe is not unitised into the PNG LNG Project.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2P estimates for Gobe and SE Gobe have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case.

4.2.3.8 Hides Gas to Electricity Project

The Hides Gas to Electricity project (HGTE) in PDL 1 (100% Oil Search) has supplied the Porgera Gold Mine power plant with gas and relatively small volumes of naphtha, condensate and diesel since 1991. A volume of 6.2 Bscf was supplied to the mine in 2016 and 2017, while in 2018 and 2019, 5.1 and 5.8 Bscf was supplied. Oil Search have indicated that the existing contracts (Hides GSA and Hides Project Co-Ordination Deed) are presently under Force Majeure as a result of the mine closure and the dispute over longer term tenure between Barrick (and the Porgera parties) and the State. The GSA and HPCD expire at year end so new contracts will need to be put in place.

Production was previously piped (PL 1 pipeline license 100% Oil Search) from the Hides 1 and 2 wells to the gas processing facility adjacent to the Porgera JV Power Plant.

GaffneyCline does not recommend inclusion of this project into valuation for this work and provides a summary for completeness.

4.2.4 PNG Gas Expansion Fields

4.2.4.1 P'nyang Overview

Table 4.17: P'nyang Summary

Field Data	
Permits	PRL 3
Location	PNG Highlands, 100 km north west of Juha Field and along trend from other major fields such as Hides, Kutubu and Gobe
Oil Search Permit Interests	38.51% (Prior to PNG Government Entry)
JV Partners	ExxonMobil 48.99%, JX Nippon 12.5%
Operator	Exxon Mobil
Discovery Date	P'nyang-1X 1990
First Production Schedule	Valuation Scheduling for 2034
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	Base 4239 Bscf, 5,605 Bscf Stretch
Status/Chance of Development	Development on Hold

The P'nyang Field is located in the PNG highlands, 120 km northwest of the Juha Field and along trend from other major fields such as Hides, Kutubu and Gobe. The field is a southeast - northwest trending faulted anticline. It was discovered in 1990 by the drilling of the P'nyang-1X well which discovered gas in the Toro, Digimu and Emuk reservoirs which were intersected from -826 to -1,030 m TVDss. Three further wells and sidetracks have since been drilled to appraise the field which is split into two main fault blocks, the P'nyang Fault Block and the P'nyang South Fault Block. Pressure data shows that the fault blocks are not in communication (**Figure 4.18**). This is supported by the interpretation of the 11 2D seismic lines acquired between 2011 and 2017.

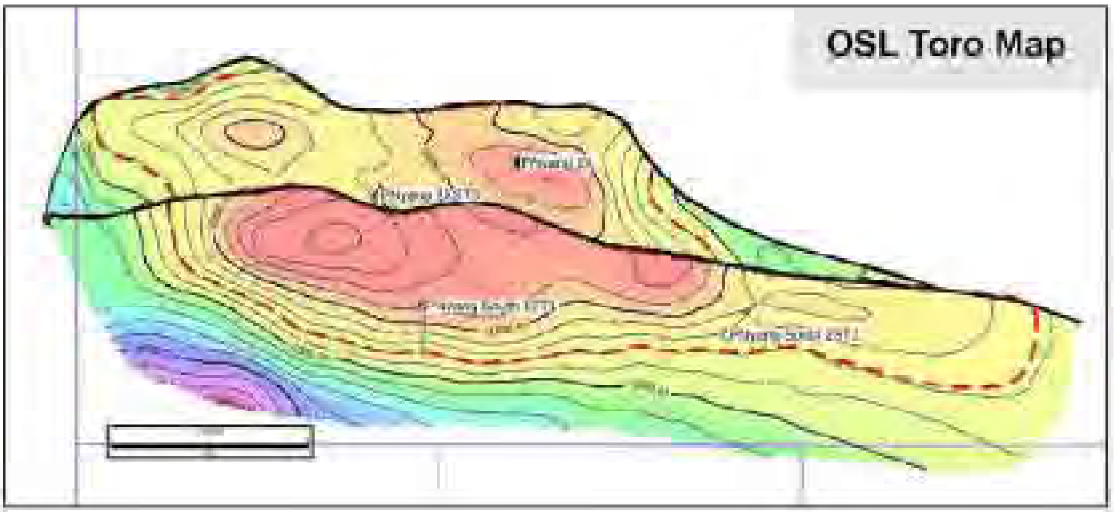
P'nyang-2X was drilled in 1991 on the northern forelimb approximately 3.7 km southwest of P'nyang-1X with the objective of establishing the fluid contacts. Toro, Digimu and Emuk reservoirs were intersected from -1,052 to - 1,260 m TVDss with the LKG at the base of the Emuk reservoir established at -1,260 m TVDss. The well was plugged back and side-tracked to the southwest, however there were two failed sidetracks (ST-1 and 2). P'nyang-2XST-3 was deviated approximately 0.5 km southeast of the original hole intersecting the Toro, Digimu and Emuk reservoirs from -1,177 to -1,480 m TVDss.

The vertical P'nyang South-1X well was drilled in 2012 and intersected the Toro, Digimu and Emuk reservoirs from -898 to - 1,084 m TVDss. The well established a LKG at the base of the Emuk reservoir at -1,083 m TVDss. P'nyang South-1XST1 was also drilled in 2012, 1.1 km south and downdip of the P'nyang South-1X original hole to appraise the fluid contacts. The Toro and Digimu reservoirs were intersected from -1,279 to -1,341 m TVDss. A GOC depth of -1,281 m TVDss near the top of the Toro A reservoir was estimated from RFT pressure and fluid samples. The P'nyang South-2XST1 well was drilled in 2017 as an appraisal well (original well abandoned due to hole conditions) approximately 8.5 km east of P'nyang South-1X. The Toro, Digimu, and Emuk reservoirs were intersected from -1,112 to -1,304 m TVDss. Nine gas samples on a common pressure gradient over Toro A, B, C and the Digimu reservoirs were taken. Seven water pressure measurements that lie on a common aquifer pressure gradient over the Emuk Reservoir were also taken. The Toro A, B, C and Digimu reservoirs have a single pressure gradient with the LKG at the base of the Digimu Reservoir at -1,268 m TVDss and HKW at the top of the Emuk reservoir at -1,283 m TVDss. The MDT data was consistent with the GOC depth of -1,281 m TVDss estimated from the P'nyang South-1X and P'nyang South-1XST-1 well.

A DST was performed for the P'nyang-1X Emuk reservoir measuring a rate of 13.7 MMscf/d with 253 bcpd and 13 bwpd with an absolute open flow (AOF) gas rate of 73.7 MMscf/d. The P'nyang-2XST3 well DSTs included tests in the Emuk and Toro B reservoirs. The Emuk DST tested formation water, while DST 2 tested gas from the Toro B Reservoir at a rate of 9.4 MMscfd with 177 bcpd and 12 bwpd with an AOF gas rate of 44.4 MMscfd. In both successful DST cases water recovered during the tests was interpreted as water condensation and not formation water.

The structural interpretation of P'nyang and subsequent volumetric estimates of the reservoirs is derived utilising an integrated approach. Balanced geological cross sections, 2-D seismic data, surface outcrop and image data, Darai limestone strontium ratios, well logs and dipmeter data, formation pressure gradient, and fluid property data are utilised by the Operator as well as Oil Search to define the P'nyang North and South areas. The data supports the two structural compartments and the separate fluid contacts with additional non-sealing faults also in existence with interpreted minor fault displacements allowing for reservoir layer juxtaposition and fluid column communication.

Figure 4.18: Oil Search Top Toro Depth Structure Map



Source: Oil Search

GaffneyCline

4.2.4.1.1 *GaffneyCline Technical Review of P'nyang Gas*

GaffneyCline has reviewed relevant geological, geophysical, petrophysical and engineering data provided by Oil Search and has undertaken an independent assessment of Contingent Resources for the P'nyang Field.

GaffneyCline has previously reviewed the P'nyang Field in 2013 and 2015 independently for volumetric estimation. Since GaffneyCline's last review in 2015, an additional 2 seismic lines have been acquired and all seismic data has been re-interpreted. The additional well drilled in 2017-18 (P'nyang South-2XST1) and the re-interpretation has led to the identification of two distinct compartments as per **Figure 4.18** which GaffneyCline confirms. The new interpretation has resulted in approximately a 10% increase in GRV for the total field.

An additional change since GaffneyCline's 2015 review is an update the NTG ranges used for each reservoir which has resulted in significantly higher NTG being used in Oil Search's latest static model. GaffneyCline reviewed the ranges used and found that in part this is due to different base reservoirs being incorporated into the model which exclude the Imburu Shale Formation. Reservoirs are consequently slightly thinner but with higher NTG. The increase in NTG is also attributed to different porosity cut-offs being used. In GaffneyCline's 2015 review a 10% porosity cut-off was applied while in Oil Search's latest model a 5% cut-off is used.

GaffneyCline's assessment has taken into account alternate structural interpretations and depth conversions along with independent GaffneyCline petrophysical and engineering analysis. The addition of the P'nyang Fault splays, together with the higher NTG has resulted in a significant increase in GIIP. To test this, technical data was incorporated into a one dimensional Monte Carlo simulation to compute the GIIP and Contingent Resources of the P'nyang Field. GaffneyCline has been able to reconcile the GIIP volumes included in Oil Search's latest static model. In GaffneyCline's review it found both the increases in GRV and NTG are within an acceptable range. GaffneyCline therefore accepts the Base and Stretch/High Case TRR utilised by Oil Search in the valuation production profiles as they are consistent with NSAI's independent estimates (3.5 - 4.4 - 5.4 Tscf) and correlate to GaffneyCline's previous range after accounting for the newest seismic and well data.

4.2.4.1.2 *P'nyang Development*

The development of P'nyang will include production from 3 well pads and a spine line to the P'nyang Gas Conditioning Plant (GCP). The plant will provide separation, stabilisation, produced water treatment (evaporation), gas compression, and condensate export with additional scope for late life booster compression. The pipeline will be a dry gas pipeline connecting to the PNG LNG pipeline at Kutubu with a parallel condensate pipeline to the oil facility at the Kutubu CPF. CO_2 and N_2 is expected to be handled downstream.

Key Assumptions, Risks, Uncertainties and Opportunities

The P'nyang Field comprises a discovered and appraised gas and condensate supply asset with a notional Field Development Plan. P'nyang negotiations resumed in 2021 and recently culminated in the signing of a Heads of Agreement on 27 September 2021 which captures key fiscal, regulatory and licensing terms. Discussion to finalise terms of the Gas Agreement with the PNG government are currently underway.

The Early Project Definition (EPD) Phase 1 was completed in 2019 (pre-FEED) by Advisian which included matured engineering work and reduced uncertainty based on their experience as a contractor in PNG. ExxonMobil's involvement in the asset has led to assured engineering deliverables based on their foundation project experiences.

Chance of Development

This project is categorised as "Development on Hold" pending discussions with the PNG Government. GaffneyCline believes the timing of the projects in the Base (2034) and Stretch Cases (2028) appropriately risks the volumes for valuation.

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4.2.4.2 Muruk Overview

Table 4.18: Muruk Summary

Field Data	
Permits	PDL 9 & PPL402
Location	Central Highlands approximately 110 km north west of Kutubu Central Processing Facility
Oil Search Permit Interests	PDL 9 24.42 %, PPL 402: 37.5%
Santos Permit Interests	PPL 402: 20%
JV Partners PDL 9	ExxonMobil, State Entities, Nippon
JV Partners PPL402	Exxon Mobil
Discovery Date	Muruk 1 2016
First Production Schedule	Valuation Scheduling for 2044 (Base) 2037 (Stretch)
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	Base 1081 Bscf, 2910 Bscf Stretch
Status/Chance of Development	Development on Hold

In late 2016, the Muruk-1 exploration well (**Figure 4.19**) and side-tracks (ST1, 2 & 3) discovered gas in the Oil Search operated PPL 402 block immediately to the east of the ExxonMobil operated PDL 9 block which includes the Juha and Juha North discoveries. The wells found gas in the primary Toro Reservoir target in both the hanging (tested by boreholes ST1 & ST2) and footwalls (tested by borehole ST3) of the Muruk structure.

The Muruk-2 appraisal well completed in May 2019 in the footwall structure in PDL 9, as per the Muruk-1ST3 borehole, tested gas in the Toro A formation at 16.5 MMscf/d through a 53/64" choke during an 8 day flow test. The Muruk structure is a northwest–southeast trending thrusted anticline which lies up-dip of Juha and on trend with Hides. The structure is likely to be dip closed to the northwest and southeast while closure to the southwest and northeast is likely to be a combination of dip and fault closure. The structure is covered by sparse 2D seismic data with four dip lines and two strike lines which are of poor quality.

The Muruk-1ST3 well penetrated a separate fault block from the other Muruk wells with Muruk-1, ST1 and ST2 penetrating the hanging wall of the thrust fault (Muruk A) and Muruk-1ST3 penetrating the footwall (Muruk B) (**Figure 4.19**). The two structures are not in communication. Analysis of downhole fluid samples recovered to surface indicates gases of different composition.

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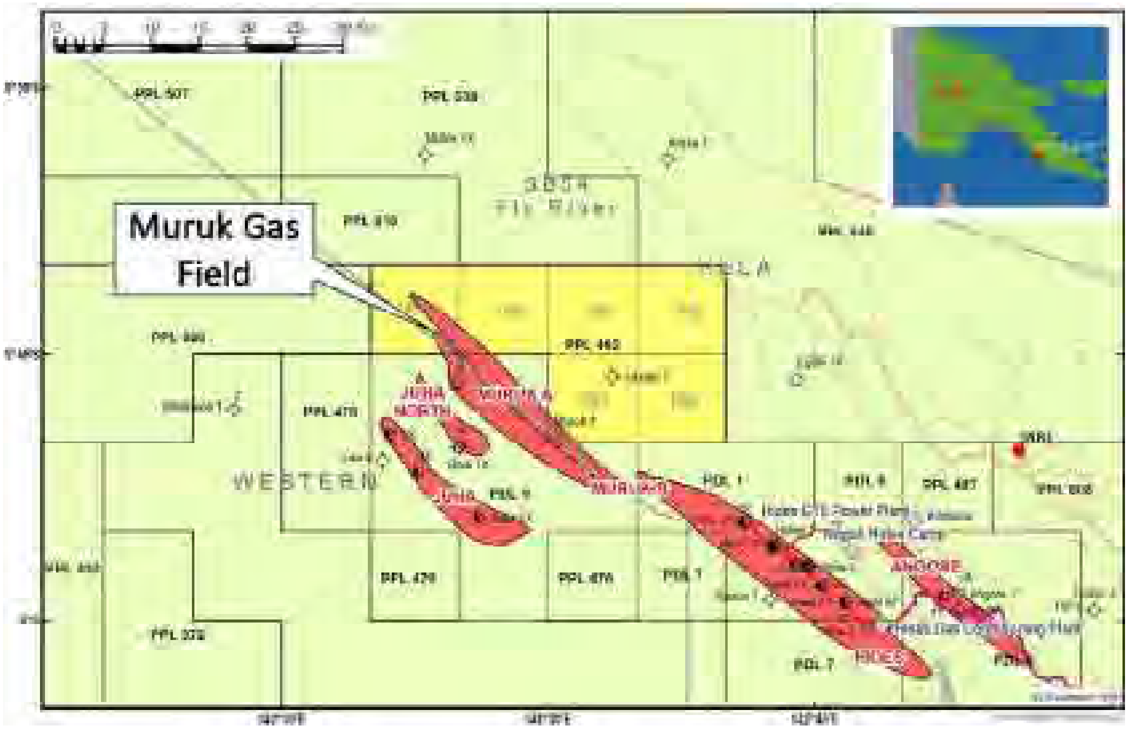
In Muruk A, the Muruk-1ST1 and ST2 wells penetrated a GDT and also obtained water pressure data enabling a likely GWC to be established. The Muruk B structure is the larger of the two and there is also more uncertainty in the fluid contact. The Muruk-1ST3 well did not penetrate a contact but established a GDT. Muruk carries a wide range in GWC due to the uncertainty in log interpretation and pressure measurements. The Muruk A sheet (**Figure 4.19**) water pressures were obtained in a low mobility reservoir while the Muruk B sheet water pressures were obtained in a highly invaded reservoir with the additional complexity of log saturations impacted by invasion. For the Muruk A sheet, Oil Search utilised the contacts of -540 and -1,450 m TVDss respectively for the Base and High Case. The base depth is taken from the GDT in Muruk-1ST1/2 while in the High Case Oil Search assume invalid pressure interpretation or perched water and the Muruk-1 gas gradient projected to the Juha-5X water gradient. For the Muruk B sheet, Oil Search utilised the contacts of -1,270 and - 2,000 m TVDss respectively for the base and high case. The Base Case is based on the Muruk-2 logs and the midpoint water gradient between Juha and Hides pressures, whilst the Oil Search High Case utilised the maximum possible GWC using the Juha-5X water gradient and the Muruk gas gradient.

Figure 4.19: The Muruk Field



Source: Oil Search

The field lies 22 km northwest of the nearest PNG LNG Project infrastructure and adjacent to the Hides and Juha gas fields. The Base Case development assumes tie-in to Juha-HGCP export pipelines post Juha development. The Stretch/High Case CAPEX assumes Muruk is developed prior to Juha bearing the cost of a pipeline to HGCP with future phase CAPEX for booster compression and Phase 2 drilling and includes 5 additional wells to enable a recovery of larger resource volume and larger export compression capacity.

4.2.4.2.1 GaffneyCline Technical Review of Muruk Gas

GaffneyCline was provided with a data pack which included a Petrel project. Due to the sparsity and quality of data, there is significant uncertainty in the structure as identified by Oil Search. GaffneyCline reviewed the original data and estimated a TRR of 1,630 Bscf which falls within the Oil Search Base and Stretch/High Cases. On this basis GaffneyCline has accepted the Oil Search volumes for valuation purposes.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2C estimates for Muruk have been generally consistent for this asset between auditors as indicated in the previous sections and are the basis for the production profile in the valuation case.

Chance of Development

This project is assessed as "Development on Hold" pending discussions with the PNG Government. GaffneyCline believes the timing of the projects in the Base (2044) and Stretch Cases (2037) appropriately risk the volumes for valuation.

4.3 Oil Search PNG Oil Fields

The producing oil assets include Kutubu and Agogo (60%), the Moran Unit (49.5%), Gobe Main (10%), and SE Gobe (22.3%) Fields (**Figure 4.1**) and these are described in later sections. The operated oil fields also account for approximately 22% of the overall gas in the foundation PNG LNGT1/T2 project. For 2021 they will account for approximately 10% with Hides contributing the remaining ~90%. Net Crude Oil production in 2019 was 1.57 MMstb and 2.62 MMstb in 2020 according to the Annual Reports. In 2020 the focus continued on restoration of earthquake-damaged infrastructure. This involved the completion and return to service of significant process facilities with the majority of remaining repairs around the APF and Moran Field infrastructure. Restoration of Moran production was key, providing almost half of Oil Search's total production (~8-10,000 stb/d) by early 2021 with the Kutubu complex also providing significant production (~8,000 stb/d), primarily from Usano by mid-2021.

Oil Search has focused on optimisation of existing wells and facilities, combined with maximizing contributions from recent development wells and workovers as well as keeping a Contingent Resources seriatim active to plan their development drilling to maintain production. Oil Search's current production is attributable to development wells drilled since 2008 with workovers conducted over the same period contributing further significant portions.

Given the complex geology, topography and operating conditions of the PNG Fold-belt, Oil Search has relied on a probabilistic forecasting tool which has been documented in an SPE paper (SPE 158347) using Monte Carlo simulation that incorporates assessments of all major variables and takes into account historical performance. GaffneyCline considers the methodology appropriate in the complex PNG Highlands environment based on GaffneyCline's review of its historical forecasting capability. This forecasting accuracy has been evaluated over the various workshops held between Oil Search and GaffneyCline and subsequent analysis performed by GaffneyCline.

Oil Search met the 2020 production forecast despite deferment of infill drilling (IDT D), coiled tubing projects and operational challenges related to COVID-19.

The production performance was primarily due to:

- Better than expected Moran 15 performance (2019 infill well)
- Early reinstatement of Northern Moran wells
- Better than expected Agogo 7 performance
- Good facility uptime with stable operations
- 2020 production within the original probabilistic range of P10 to P90 (set late 2019 pre-pandemic) validating the Probabilistic forecasting process

4.3.1 PNG Oil Production Profile Summary

The Oil Search production profiles include a combination of Reserves and Contingent Resources for the producing oil assets. The individual fields are discussed separately in the PNG LNG section as they also contribute gas to the LNG facility.

The Oil Search Incremental production profiles for all identified "Oil Hopper" opportunities incorporate the following considerations utilising the probabilistic forecasting tool to assess the remaining oil potential:

- Base Case
  - Incremental/Business Plan utilising 2P Reserves Volumes. This includes opportunities with a moderate to high level of maturity and for which there is a high confidence that they will be implemented within the next few years
  - High Graded Contingent Resource Hopper-Opportunities (2C Volumes) where there is a higher chance of commerciality. High potential opportunities with moderate to high level of maturity. GaffneyCline has adjusted this profile based on past performance after review for valuation.
- Stretch Case
  - Incremental/Business Plan utilising 3P Reserves Volumes. This includes opportunities with a moderate to high level of maturity and for which there is a high confidence that they will be implemented within the next few years.
  - Full Hopper Opportunities (3C Volumes) where there is a lower chance of commerciality (not including Non-Viable projects). These opportunities are required to capture an upside potential for both infill and appraisal. Oil Opportunities with a cost above US$30/Bbl are excluded using a P10 EUR estimate. This is provided to bracket the valuation range.

The Incremental Reserves and Contingent Resource Hopper provides data to the probabilistic forecasting tool where the Hopper is the collation point for all proposed activities/opportunities along with current view of ranges on production rates, EUR, costs, and classification. The Oil Search profiles are split into "buckets", based on PRMS project maturity sub-classes. All profiles are run without any risking applied to project maturity - however a full range of production uncertainty is output.

4.3.1.1 GaffneyCline Technical Review of Profiles

GaffneyCline audited and revised as needed at field-level, Base Case gas and oil profiles for the following fields: Kutubu, Agogo, Moran, Gobe and SE Gobe.

This audit considered all of the available forecasts and associated data from various sources as listed in **Table 4.19**. An acceptable comparison of forecasts was possible, though it was not perfect because the estimators group fields together in different ways.

Table 4.19: Data Sources Considered in the Audit of Production Profiles

Data Type	Author	Date	Notes
Production Profiles	Santos	2021	Economic Model
	Oil Search	2016/2017/2019/2021	Economic Model
Reserves Assessments	NSAI	2017	Kutubu and Moran Oil Fields
	NSAI	2019	PNG LNG associated gas
Production Data	Oil Search	Until April 2021	All Fields
Dynamic Models	Santos	2020/2021	Kutubu and Agogo

The GaffneyCline Due Diligence focused on a production level reconciliation of performance data from static/dynamic models. GaffneyCline opined on the reasonableness of the profiles from Oil Search, based on a comparison of all available forecasts from previous years with actual production in these years. This approach was facilitated by the availability of four forecasts from Oil Search from 2016 until 2021, coupled with production data until April 2021.

For the major fields of Kutubu and Agogo, the decline in oil rate from 2016-2021 suggests that the level of field activities was minimal, whereas profiles from Oil Search over this period all predicted an increase in oil rate from the implementation of activities utilising the Oil Search Hopper. Given this history, GaffneyCline adjusted the future level of activities proposed by Oil Search, and therefore has adopted profiles that give some credit for future activities given the recent sustained higher oil prices, but that are lower than the 2021 oil profiles from Oil Search.

For the other producing fields, dominated by Moran, the oil profiles and oil production history do correspond, and so GaffneyCline accepted the 2021 oil profiles from Oil Search.

For all producing fields, GaffneyCline predominantly accepts the 2021 gas profiles from Oil Search, as these are dominated by gas-cap blowdown of the major fields of Kutubu, Agogo and Moran. The profiles from Oil Search over the years have not changed other than the timing of the blowdown in line with the need for this gas to back-fill the major gas fields.

Kutubu, Agogo and Moran are the significant fields for oil, whilst Kutubu dominates for gas. Gobe and SE Gobe are expected to reach the end of their field lives within a few years.

GaffneyCline has adjusted the cost profiles for the Base Case (**Figure 4.20**) and accepted the Oil Search Stretch Case as indicated in **Figure 4.21** which considers Oil Search cost savings for Decommissioning and Restoration activities. Cost phasing has been adjusted, where necessary, to reflect the field development timings.

Table 4.20: GaffneyCline Estimates of Gross Recovery by Field from 1 July 2021

Field	Oil (MMstb)
Kutubu	25.0
Agogo	17.6
Moran	21.8
Gobe	0.1
SE Gobe	0.1
TOTAL	**64.5**

Note: H1 2021 Volumes subtracted from GaffneyCline adjusted profiles for valuation input

Figure 4.20: GaffneyCline Base Case Oil Profiles

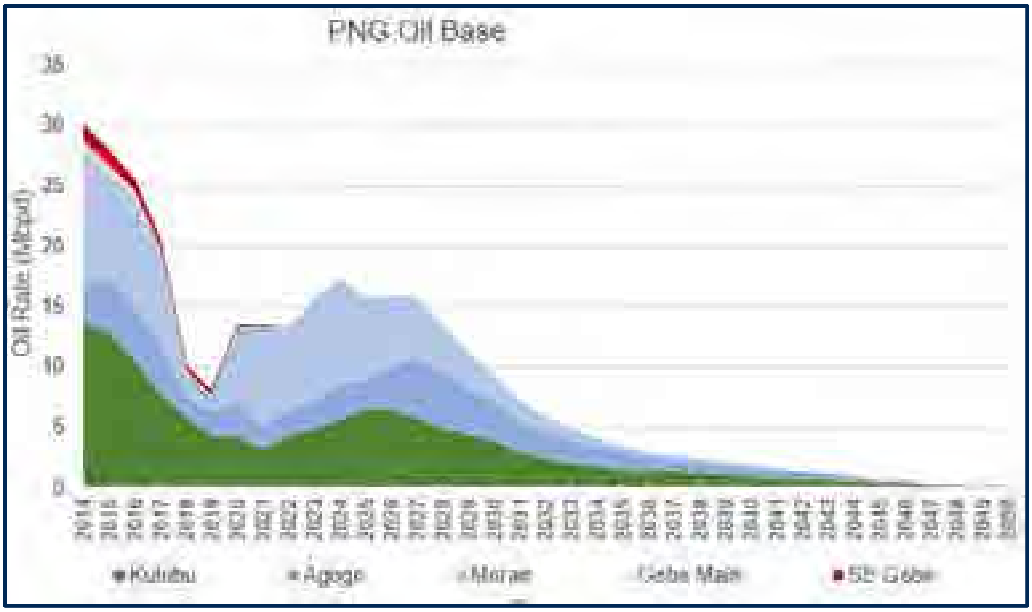


Figure 4.21: Oil Search Stretch Case Oil Profiles

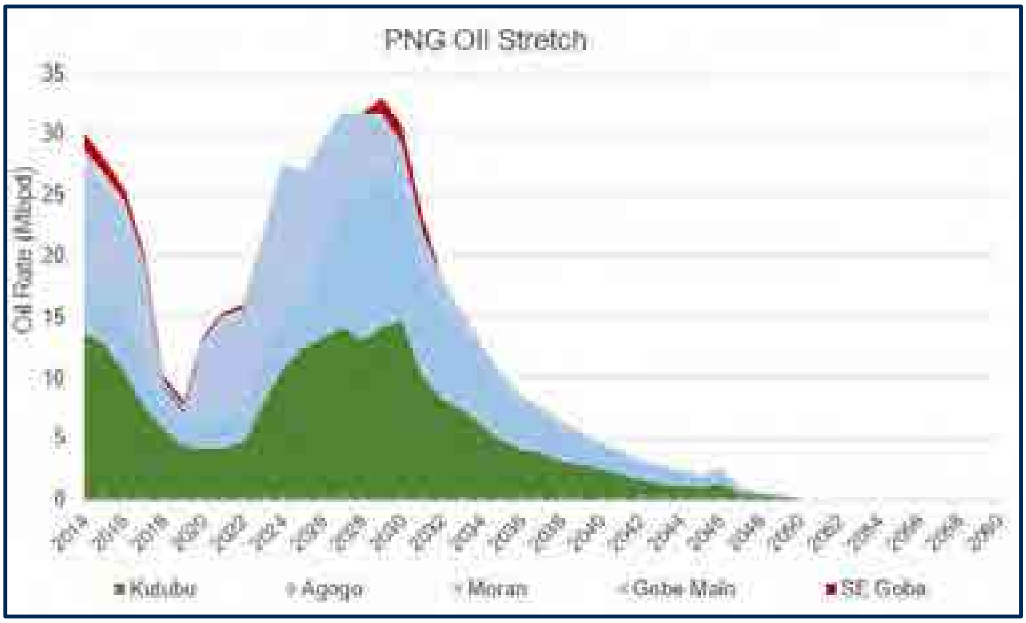
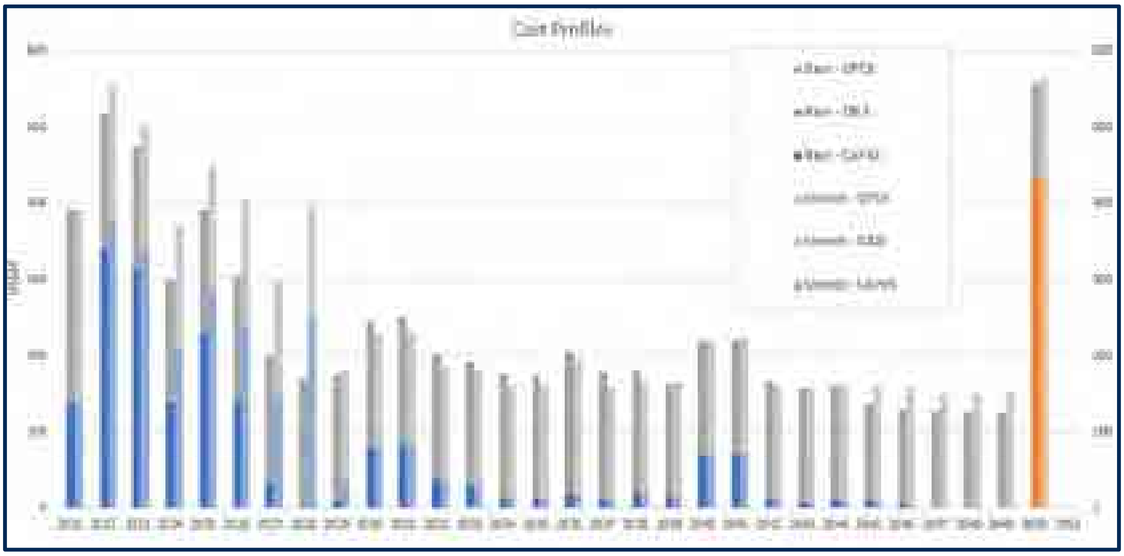


Figure 4.22: GaffneyCline's Base and Stretch Case Cost Profiles for PNG Oil (US$ MM, 100%, RT2021)



Note: 2% p.a. escalation for costs represented above is recommended for application in the financial model. OPEX/CAPEX profiles are on a gross basis (pre allocation to PNG LNG)

4.4 Oil Search Papua LNG Project

4.4.1 Elk-Antelope

Table 4.21: Elk-Antelope Summary

Field Data	
Permits	PRL 15
Location	The Elk/Antelope Fields lie at the junction of two dominant fold bend trends, the Papuan Fold Belt to the west and the Aure Tectonic Belt to the east.
Oil Search Permit Interests	22.83% (Prior to PNG Government Entry)
JV Partners	Total 40.13%, ExxonMobil 36.54%, Other 0.5%
Operator	Total
Discovery Date	Elk discovery well was drilled in 2006
First Production Schedule	Valuation Scheduling for 2027
Valuation Scenario Volumes as of 1 July 2021	
Gross Raw Gas	6350 Bscf , Stretch 8542 Bscf (OSL 3C + Mule Deer)
Gross Condensate	45 MMBbl, 77 MMBbl
Status/Chance of Development	Development Pending

The Elk discovery well was drilled in 2006 by InterOil and tested gas at a rate of 21.7 MMscfd from fractured Miocene-age carbonates. The Elk structure was further delineated by the Elk-2 well, although this was drilled below the GWC. The Elk-4 well discovered gas in the Antelope block but outside the main reef. The Antelope-1 well, drilled in 2008, was the first drilled on the main reef complex. The reef complex was further delineated by Antelope-2, in the south of the main reef, and Antelope-3, in the central part of the main reef in 2010-11. Antelope-2 confirmed that the reef extends to the south with good reservoir quality. Antelope-3 confirms that good reef quality is also present in the central part of reef. The field has been further appraised by three further Antelope wells, some with side-tracks. Antelope-4 and Antelope-4ST tested the southern extent of the reef. Antelope-5 was drilled to the west of the main axis where previous Antelope wells had been drilled and confirmed that good quality reservoir extends to the west. Antelope-6 was drilled to the east of the main axis and showed that reservoir quality deteriorates to the east but that the main reservoir zones seen elsewhere are still present. The Elk-Antelope structure has been penetrated by 10 wells and is covered by several generations of 2D seismic data. Antelope 7 was drilled in 2017 and is discussed below.

The Elk-Antelope accumulations (**Figure 4.23**) are referred to as separate fields due to differences in fluid contacts and gas composition. The Elk Field refers to the accumulation to the north, which has low matrix porosity but considerable fracture porosity resulting in high production rates. The Antelope Field is the main accumulation in the south which comprises the very good quality Antelope reef complex which has good reservoir properties and is also fractured. The vast majority of the gas volumes are contained in the Antelope structure. A thrust fault is interpreted as the boundary between Elk and Antelope.

The Elk and Antelope gas fields are hosted in Tertiary reefal, platform and associated deepwater carbonates in the present day foothills region of the Fold and Thrust Belt in the Gulf Province of Papua New Guinea. The fields lie at the leading edge of the New Guinea Orogen, which is the collision zone between more stable Australian craton to the southwest and the islands and ranges constructed by Cenozoic volcanic activity in the northeast. The Elk/Antelope Fields lie at the junction of two dominant fold bend trends, the Papuan Fold Belt to the west and the Aure Tectonic Belt to the east. The combined Elk/Antelope structure has dimensions of approximately 15 km by 5 km, with the main Antelope reef being around 7 km by 4 km.

The Elk Field consists of deep-water platform slope and bathyal deposits, although fracturing allows them to produce at high rates. Elk-4, although located in the Antelope block, is off the main reef and penetrated similar facies to those in Elk. The Antelope wells penetrate shallow platform to reef build-up deposits. The slope deposits encountered in the Elk wells originally flanked the shallow water Antelope carbonates but have subsequently been thrust up-section by the Elk Thrust. Antelope carbonates are Eocene to Early/Middle Miocene in age, with a thickness of up to ~960 m of shallow water carbonates. Elk carbonates may extend into Late Miocene in age.

There is extensive dolomitisation in all Antelope reef wells, which appears to be present within a well-defined dolomite zone, which GaffneyCline has used as the basis for its correlation scheme.

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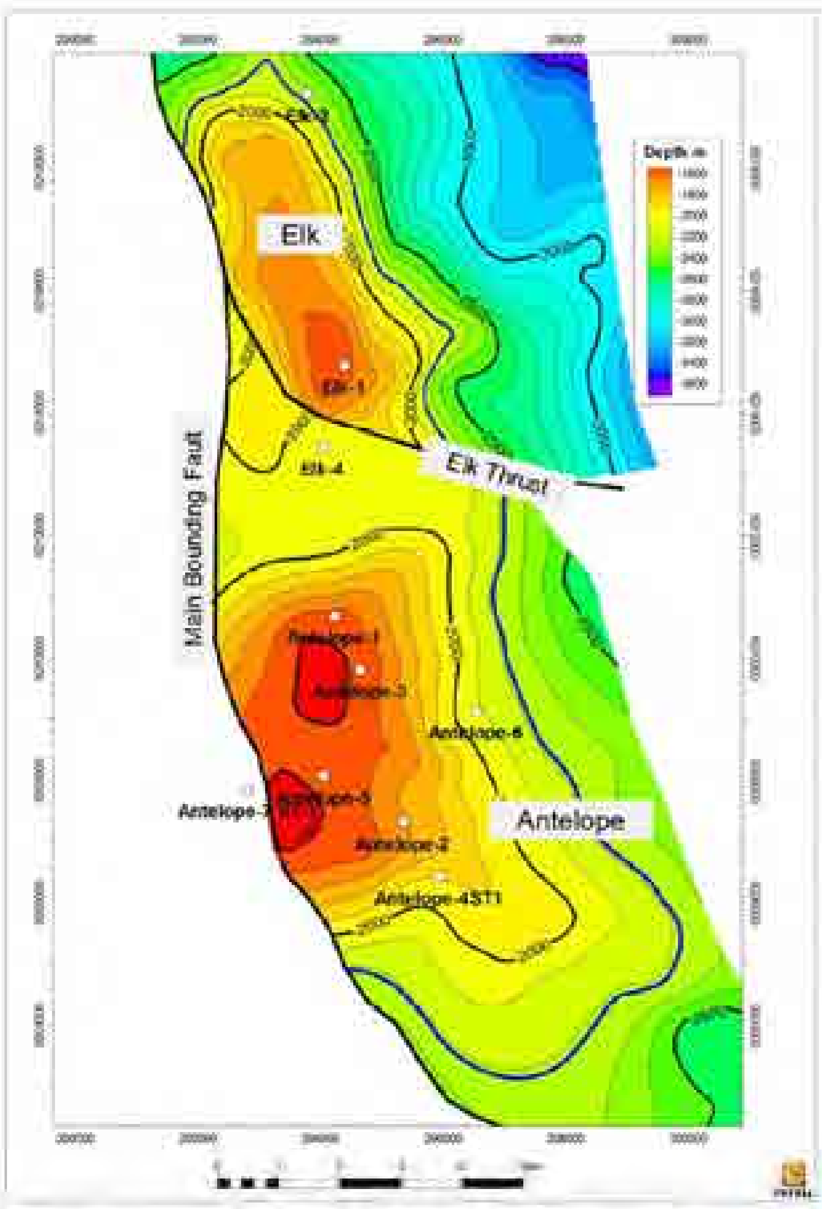
Figure 4.23: Elk-Antelope Top Structure Map



4.4.1.1 GaffneyCline Technical Review of Elk-Antelope Gas Field

The current technical review is based on GaffneyCline's resource assessment of 2017, which was carried out after the drilling of Antelope-7. GaffneyCline's assessment was based on a suite of data available at the time which included: 32 2D seismic lines of various vintages and nine wells with VSP, FMI, wireline log, core data and well test data.

GaffneyCline performed its own seismic interpretations to derive Low, Best and High Case interpretations for both the top reservoir structure and the internal architecture of the main Antelope reef. Seismic lines are generally orientated in dip (ENE-WSW) and strike (SSE-NNW) directions. Over the main Antelope reef, dip line spacing is approximately 1-1.5 km. Image quality of the seismic data varies from poor to good, although recent re-processing has generally enhanced seismic data quality. Check shot and VSP data was available and enabled well to seismic ties. Seismic interpretation was carried out for three main horizons; Top Reservoir, Top Dolomite and Base Dolomite. Due to the number of wells available, horizon interpretation is more constrained, especially within the main reef area. The main structural uncertainty lies in the location of the western bounding fault however, this uncertainty has somewhat been reduced by the recent Antelope-7 well.

GaffneyCline also performed its own petrophysical analysis based on available log, core and FMI data to derive a range of petrophysical properties. The assessment was based on the three major zones observed within the Antelope reef, an upper limestone unit, a dolomite unit and a lower limestone unit. The best reservoir properties are within the dolomite zone. The upper limestone unit also has good reservoir properties, with the lower limestone unit having the poorest properties.

Structural modelling was performed using the seismic interpretation of horizons and faults as main inputs. Three structural models were built to represent the range of GRV uncertainty. All structural models were built using the same three zone scheme; Upper Limestone, Dolomite and Lower Limestone. This zonation scheme is observed throughout the Antelope wells (although the Upper limestone is absent in some wells) and can be correlated with confidence throughout the Antelope reef.

Property modelling was performed in each of the structural models. The facies modelling workflow involved the definition of four facies type; good and poor for each of the limestone and dolomite lithologies. These facies were propagated throughout the field using stochastic techniques. Other reservoir properties were then propagated on a facies by facies, zone by zone basis. In all cases proportions of facies from wells and property statistics from wells were used to guide modelling. The well data is assumed to be representative of the reef as a whole. A velocity derived porosity relationship was used to guide porosity distribution.

Full 3D probabilistic modelling was only performed within the Antelope Block which contains the majority of the GIIP. The Elk Block was evaluated using a 1D Monte Carlo probabilistic methodology. GaffneyCline's estimates of GIIP for the Antelope structure ranges from 6.46 – 8.63 Tcf with a Best Case of 7.62 Tcf. GaffneyCline's estimates of GIIP for the Elk structure ranges from 0.41 – 0.93 Tcf with a Best Case of 0.65 Tcf.

GaffneyCline also reviewed all the well test data as well as other reservoir simulation studies performed by other parties as a basis for fluid properties and production profiles. The very good quality reservoir, high test rates and good connectivity of the reservoir suggest high recovery factors of around 80% can be achieved from relatively few wells (~5-11) concentrated in the Antelope reef. The numbers and types of wells are largely a function of offtake rates.

Key uncertainties in the assessment included: the location of the main bounding fault to the west of the field and the extent of the field and the reef to the flanks of the field especially to the south and east. To some degree, these uncertainties have been reduced through the current appraisal programme.

GaffneyCline's volumetric assessment was a combination of these interpreted data, the results of which were combined within a probabilistic Monte Carlo assessment to derive in place volumes and recoverable resources.

Table 4.22: Elk-Antelope Contingent Resources Summary

Contingent Resources	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Raw Gas (Tcf)	5.38	6.35	7.37

Notes:
1. Contingent Resources reported are 100% of the volumes estimated to be recoverable from Elk-Antelope in the event that it is developed.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that Elk-Antelope may not be developed in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
3. Raw Gas is defined as the volume of gas prior to separation and recovery of condensate.

The GaffneyCline 2017 independent volumes were used to support the volumes utilised by Oil Search in the valuation profiles. Since the GaffneyCline 2017 review the Operator has acquired new seismic across the Antelope and Mule Deer pinnacle reef to the northwest, with a high confidence in connectivity between Antelope and Mule Deer (**Figure 4.24**). GaffneyCline has reviewed the seismic and model and has accepted the updated work for valuation purposes as reasonable.

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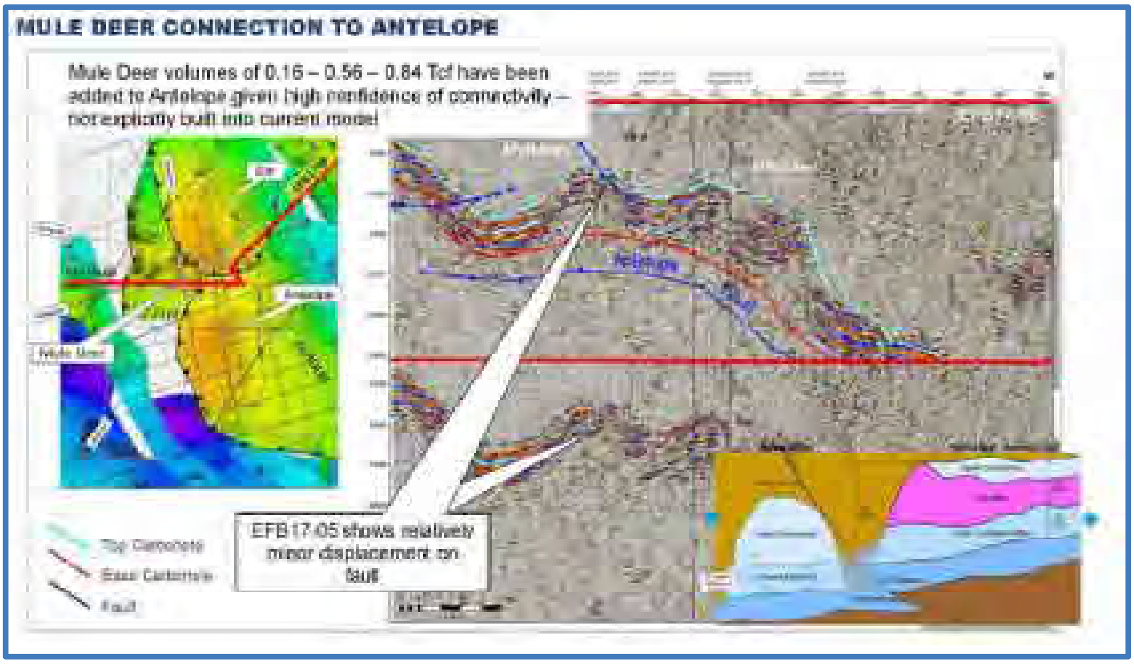
Figure 4.24: Updated Oil Search Elk-Antelope Top Structure Map and Mule Deer Seismic



4.4.1.2 Elk-Antelope Development

The Elk-Antelope development assumed to include production from two well pads and a 2-phase flowline to a new Central Production Facility (CPF) 30 km to the west. Current plans are for the gas and condensate pipelines to be constructed with 60 km onshore and 260 km offshore. Initially there will be free flow to the LNG facility at Caution Bay with the provision for low pressure and medium pressure compression in later life Export pipeline design has capacity for expansion from future prospects / discoveries.

The PNG Government endorsed the Papua Gas Agreement in September 2019. The agreement resulted in changes to the structure of returns to the landowners and the Government with a 5% Domestic Market Obligation (DMO) and a 2% production levy and a deferred mechanism for the state's payments of past costs. It also included Comprehensive National Content plan to support local workforce development which will be finalised prior to FID.

Key Assumptions, Risks, Uncertainties and Opportunities

The 2C GaffneyCline estimates for Elk/Antelope are a reasonable basis for the Papua LNG development and provide appropriate volumes for valuation purposes based on the technical work. GaffneyCline has reviewed the seismic and model and has accepted the updated work by Oil Search as a Stretch Case where Antelope and Mule Deer are connected for valuation.

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Chance of Development

This project is Development Pending and is scheduled for production start-up in 2027. Production and cost profiles are in **Figure 4.25** and **Figure 4.26** for both Base and Stretch Cases. Only GaffneyCline estimated condensates are displayed.

Figure 4.25: Base Case Production Profiles

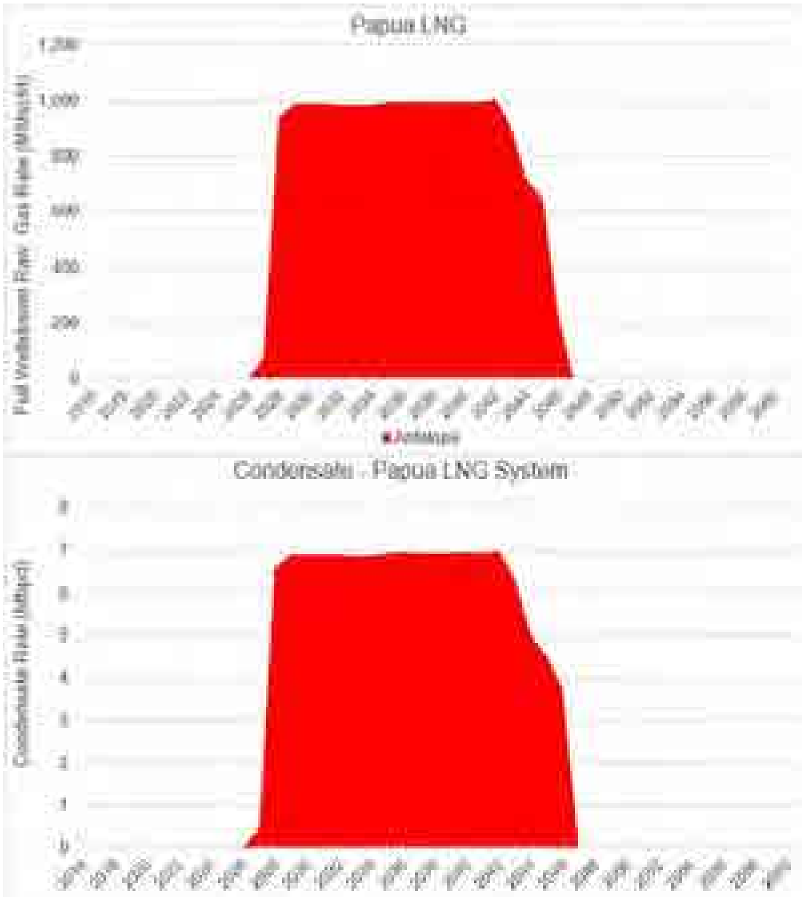
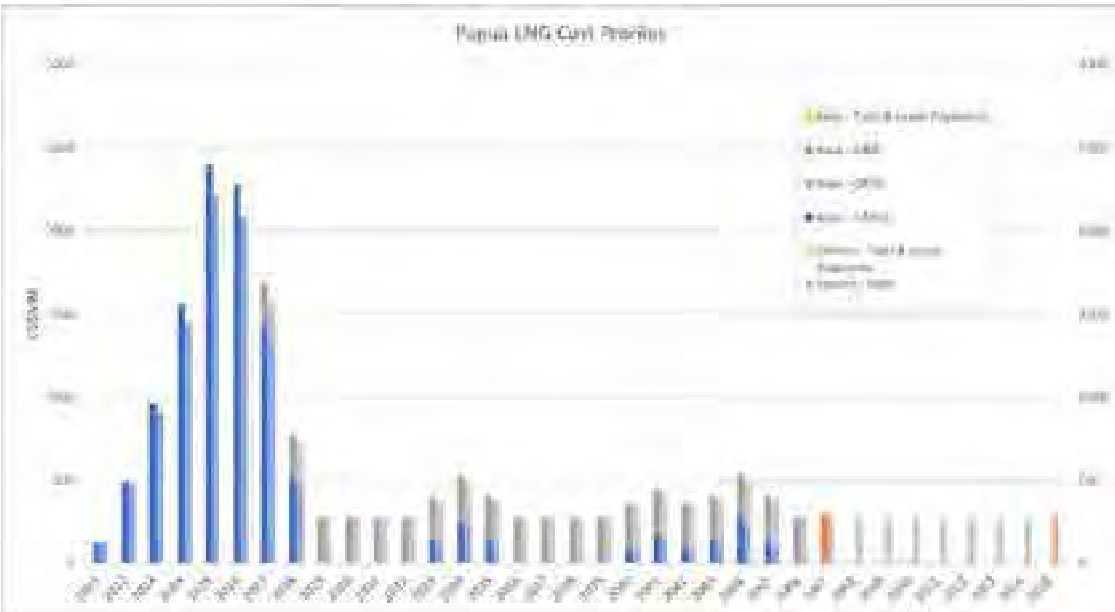


Figure 4.26: GaffneyCline's Base and Stretch Case Cost Profiles for Papua LNG (US$ MM, 100%, RT2021)



Note: 2% p.a. escalation for costs represented above is recommended for application in the financial model.

4.5 Other Discoveries

4.5.1 Cobra, Iehi, Bilip

Table 4.23: Cobra, Iehi, Bilip Summary

Field Data	
Permits	PRL 14, expiry 1 March 2023
Location	Southern Highlands Province, PNG Foldbelt, approximately 95 km southeast of Kutubu Complex.
Oil Search Permit Interests	62.556%
JV Partners	NPCP Oil Company Pty Ltd (Kumul Petroleum) (37.444%)
Operator	Oil Search Limited
Work Commitment	Years 1&2 acquire 15km seismic (completed), Years 3-5 market and pre-feasibility studies and Contingent concept and FEED studies
2C Resources net to Oil Search	Cobra- 32.66 Bscf, Iehi-48.22 Bscf, Bilip volumes not provided
Volumes as of 1 July 2021	
GaffneyCline Profile Basis	Stranded Assets Not Included in Valuation

The Cobra (**Figure 4.27**) gas field is located approximately 15 km east of the SE Gobe oil field and approximately 25 km north east of the Iehi gas field. The Iehi gas field is located approximately 15 km south southeast of the SE Gobe oil field and 20 km north of the Barikewa gas discovery. The Bilip Field straddles the western boundary of PPL 190 with PDL 4 and is located 10 km east southeast of the SE Gobe oil field.

No development concepts have been considered for the Cobra, Iehi or Bilip discoveries to date because there is no commercial market, either domestic (power/electricity generation) or export (pipeline sales gas), for the gas. Due to the limited resource size any development of the Cobra, Iehi and Bilip resources will only be possible as an add on to a larger scale existing PNG LNG development, or by combination with other stranded gas resources to achieve a critical base for a separate development.

At the top Upper Hedinia level in the Cobra Field, the field forms an elongated west northwest to east southeast trending footwall anticline with dip closure to the south and closure to the north provided by cross fault seal. A series of lineaments relating to the Mount Murray transfer zone are mapped in the area, and these are interpreted to constrain the extent of the gas column to the east and west.

At the top Toro level the Iehi gas field forms a simple hanging wall anticline with closure provided by cross fault seal along the strike of the Iehi thrust fault and dip closure to the southwest.

At the top Iagifu level the Bilip Field geometry is one of a hanging wall anticline with dip closure to the north and closure to the south provided by cross fault seal along the strike of the Bilip thrust fault.

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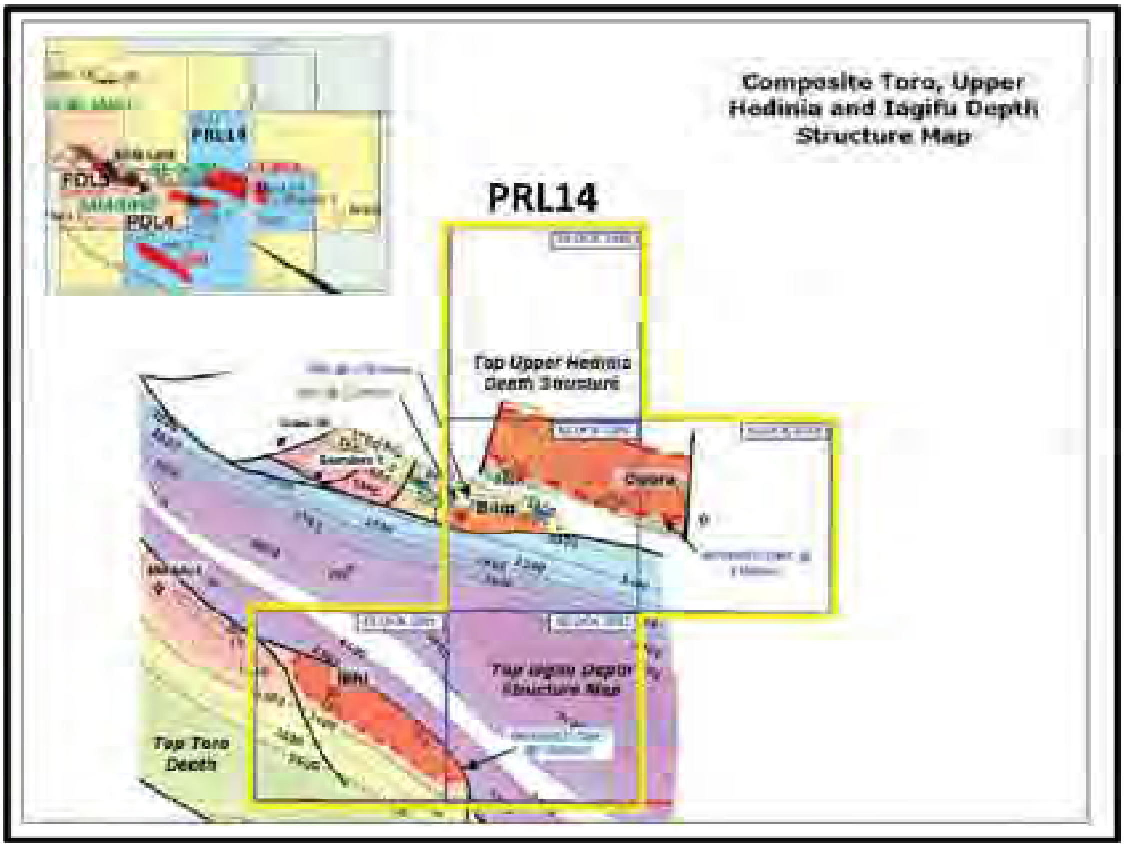
Figure 4.27: Cobra, Iehi and Bilip



Source: Oil Search

GaffneyCline considers these volumes as stranded and are not recommended for inclusion in Grant Samuel's valuation assessment. They are summarised for completeness.

4.5.2 PNG Offshore Discoveries

Oil Search has also been successful with their offshore exploration program with the Flinders and Hagana discoveries, where they have proven the viability of Turbidite reservoirs.

The offshore section of the Papuan Basin is sparsely explored. The area lies within the foreland basin and stable platform segments of the main basin and is structurally simpler with less deformation than seen in the onshore highlands. Several discoveries, largely made in the 1960's to 1980's indicate that the Miocene Dari limestone is the primary reservoir. Structures are formed of pinnacle reefs which have been subject to aerial exposure and meteoric waters, both of which can enhance reservoir quality, before being buried and sealed by marine shales. Secondary reservoirs may exist in shallower clastic sediments which were deposited during periods of rapid sedimentation in the late Cenozoic from delta systems to the North.

The Mesozoic play which is targeted in the onshore highlands has not been fully explored in the offshore section and seismic data indicates the presence of northeast - southwest trending compressional structures lying beneath the Miocene limestones which may offer additional potential.

Differential gas compositions in discoveries to date indicate the presence of both thermogenic and biogenic sources. There is thermogenic source rock potential in the Jurassic and Cenozoic with basin modelling studies showing that significant sediment thickness currently lies within the oil window and discoveries containing both methane and heavier hydrocarbons have been made. Additionally, 100% methane discoveries suggest the presence of a biogenic source and it is likely this originated from the late Cenozoic sediment influx which was rich in terrestrial organic carbon. Regional seismic data indicates gas flowing through the system with gas chimneys and flat spots both present. Flinders and Hagana are both biogenic gas discoveries (**Figure 4.28**), while Pasca and Uramu are gas-condensate discoveries.

Oil Search farmed into to Gulf of Papua offshore deepwater exploration acreage PPL374 and PPL375 in 2016 (**Figure 4.28**). Following 3D seismic acquisition and technical evaluations, the acreage was deemed too high risk and hence the Operator (ExxonMobil) will soon be surrendering the licences.

Oil Search relinquished its licenses related to Uramu, Moa, Omega and Pasca and plans to exit the remaining offshore acreage with the exception of PRL 41 (Flinders and Hagana).

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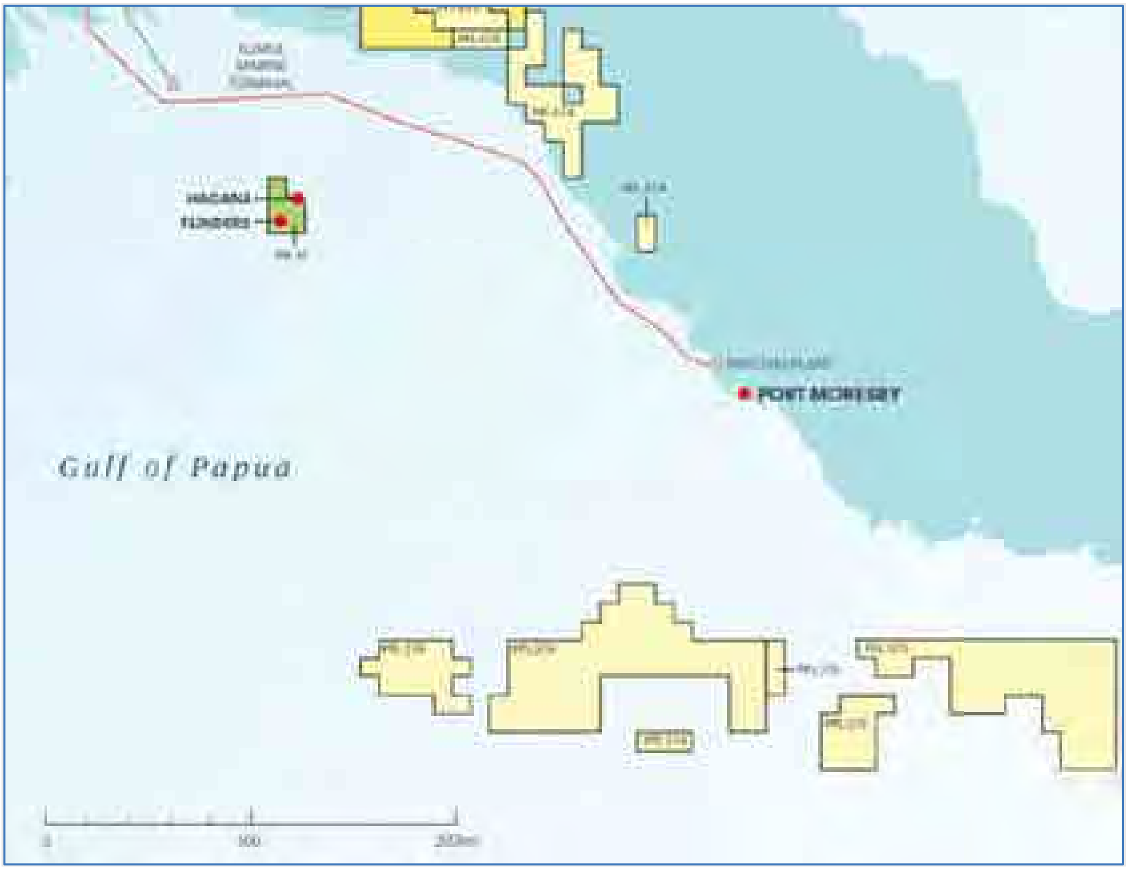
Figure 4.28: Flinders and Hagana Offshore discoveries with additional Oil Search Prospects



4.5.2.1 Flinders & Hagana

Oil Search discovered both Flinders and Hagana in 2013. They have a combined gas resource of ~210 Bscf based on provided descriptions. Recent Oil Search work shows Flinders-Hagana only have access to biogenic gas. The well costs are considered low due to the benign environment and any Pasca development (if it proceeds by a 3rd party) creates an option for monetisation of Flinders and Hagana gas. Recent PSDM re-processing of the 3D seismic data provides AVO amplitude direct hydrocarbon confirmation.

Chance of Development

These discovered volumes are not considered for valuation due to their immature nature, geological/area setting and volume sizes.

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4.6 Oil Search PNG Exploration Valuation

Oil Search has a large inventory of exploration leads and prospects. GaffneyCline has evaluated exploration prospects as prioritised by the Oil Search five-year drilling program. For each exploration target in the drilling plan, Oil Search provided information which included: prospect location, geological summary, resource volumes, schedule, exploration well costs, Chance of Success, conceptual development plan and Oil Search's NPV at a 10% discount rate for a success case to be used for EMV calculations. GaffneyCline reviewed the information provided and made some adjustments to the Geological Chance of Success based on the technical review by considering the geology and recent exploration history. The Chance of Development and the timing of development along with current proposed projects such as Papua LNG were also considered. **Table 4.24** summarises the GaffneyCline adjusted Base Case EMV10 for Oil Search's PNG assets. GaffneyCline's overall Chance of Success is the Geological Chance of Success multiplied by the Chance of Development.

Table 4.24: GaffneyCline's Base Case PNG Exploration EMV10

Prospect	Drilling Plan	Net Unrisked Prospective Resources (MMboe)	Net NPV Unrisked 10% (US$MM)	Net NPV Failure 10% (US$MM)	Chance of Success (%)	Net EMV 10% (US$MM)	Suggested Development Concept
Agogo South	2023	30	200	-5	24%	44	Tie-back to APF
Hides FW	2024	42	237	-12	45%	100	Tieback to HGCP
Wilde Beest	2024	472	711	-13	14%	88	US + DS 2 x 2.7Mtpa expansion
White Tail	2024	118	195	-13	39%	67	Backfill to Papua LNG
Karoma	2025	102	70	-25	34%	7	Tieback to Muruk, backfill LNG
Mosa Deep	2026	74	520	-18	23%	105	Infield processing, export to Kutubu
Antelope South	2026	50	71	-14	44%	24	Backfill to Papua LNG
Total	-	-	-	-	-	**436**	-

Note: 'Chance of Success' calculated as 'Geological Chance of Success' x 'Chance of Development'

Oil Search's proposed EMV10 case for these exploration targets is US$622 MM. GaffneyCline has accepted this as its Stretch Case which is shown in **Table 4.25**. Additional midstream value was proposed by Oil Search for potential tolling revenue from the PNG LNG and Papua LNG midstream assets by processing additional discovered gas including gas from other companies. GaffneyCline has not proposed any value for midstream assets through these exploration programs because the volume of gas to establish an operating model for tolling is too uncertain for consideration in a valuation case.

Table 4.25: GaffneyCline's proposed Stretch Case (Oil Search) PNG Exploration EMV10

Prospect	Drilling Plan	Net Unrisked Prospective Resources (MMboe)	Net NPV Unrisked 10% (US$MM)	Net NPV Failure 10% (US$MM)	Chance of Success (%)	Net EMV 10% (US$MM)
Agogo South	2023	30	242	-5	50	118
Hides FW	2024	42	237	-12	45	100
Wilde Beest	2024	472	711	-13	27	182
White Tail	2024	118	195	-13	47	85
Karoma	2025	102	74	-27	34	8
Mosa Deep	2026	74	520	-18	23	105
Antelope South	2026	50	71	-14	44	24
Total	-	-	-	--	-	**622**

Note: 'Chance of Success' calculated as 'Geological Chance of Success' x 'Chance of Development'

Based on the information provided to GaffneyCline, investments to date in PPL and PDL licenses associated with these exploration targets (namely PDL1, PDL2, PPL402, PPL474, PPL475 and PPL476) is US$303 MM. The Antelope South prospect is in PRL15 and its cost could not be established separately. GaffneyCline could not identify suitable market comparable transactions from public data sources for valuation of these exploration targets. PNG presents a unique set of asset technical and commercial characteristics, not least of which is the logistics of exploration and development which are not reflected in other transactions in the region to make a comparison. Thus, comparable transactions are those that happen within PNG. Such transactions are few, often between existing JV partners and under changing fiscal terms, which make it difficult to normalise for value. Further, GaffneyCline considers the sunk cost approach for PNG exploration does not reflect the binary nature and potential magnitude of successful outcomes and presents an unreasonably wide spectrum of outcomes from a small statistical population and hence does not provide an optimal valuation approach.

GaffneyCline propose a range of **US$436 MM** to **US$622 MM** based on GaffneyCline's adjusted EMV10 and Oil Search's provided EMV10 values respectively.

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4.7 Oil Search Alaska Assets

4.7.1 Alaska Overview

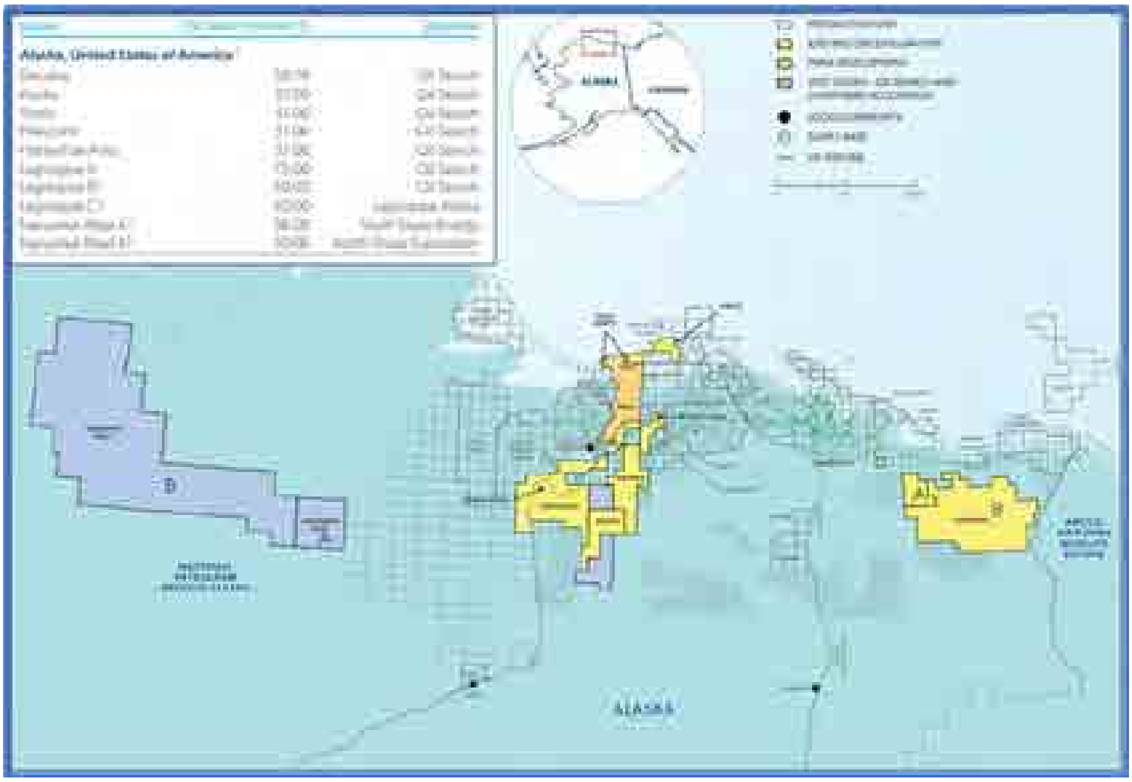
Table 4.26: Alaska Summary

Field Data	
Permits	Pika Unit, Quokka, Kooka, Thetis, Horseshoe Area, Lagniappe and Nanushuk West
Location	North Slope Alaska
Oil Search Permit Interests	As Per Appendix 1 (Pikka Unit 51%)
JV Partners Pikka Unit	Repsol 49%
First Production Schedule	Scheduled for H2 2025
Valuation Scenario Volumes as of 1 July 2021	
Gross Valuation Scenario Volume	392 MMBbl Pikka Phase 1 development, 464 Other Development Pending, 112 MMBbl Development Unclarified
Status/Chance of Development	Development Pending for Phase 1 (Primary Case for Grant Samuel Consideration)

Oil Search is the Operator of the Pikka Unit, a joint venture with Repsol, located on the North Slope of Alaska. Oil Search holds a 51% working interest with Repsol holding the remaining 49%. The Pikka Unit is located in the coastal area of the Alaska North West Slope (**Figure 4.29**). The Pikka Unit is situated to the east of the National Petroleum Reserve in Alaska (NPRA). To the east lies the Kuparuk River Unit and to the west, the Colville River Unit, both operated by ConocoPhillips. ConocoPhillips is currently producing from the equivalent Pikka Unit reservoirs on their leases.

The Pikka Unit consists of 89 different subsurface leases. The Pikka Unit was formed in 2015 with an initial five year term and was expanded to its current area in 2016. The Pikka Unit will remain in effect as long as Oil Search is operating under an annual Plan of Development approved by the subsurface landowners pursuant to the Unit Agreement and is working towards bringing the Pikka Unit area into production. Oil Search is required to apply for a Pikka Unit renewal prior to the Unit expiration.

Figure 4.29: Pikka Unit Location



The initial development project targets oil deposits in the major Nanushuk and Alpine reservoirs within the Pikka Unit initially using waterflood with extension into a Miscible Water-Alternating-Gas (MWAG) injection project. Wells will be drilled into the laminated formations with multi-stage fracture stimulation in producer/injector pairs from three locations across the reservoir structure.

Subject to final approvals the Pikka project has been:

- Re-planned as a phased development. Phase 1 is only one of the original 3 drill sites (NDB) (**Figure 4.30**) with downsized facilities. The CAPEX estimate has been significantly reduced from \$4.8 – 6.1 billion to \$2.7 to \$3.1 billion.
- Gravel already laid for NPF and NDB reducing forward costs.
- Oil Search have high-graded the project to a better reservoir at NDB. Breakeven cost of supply is now below \$40/bbl according to Oil Search
- Oil Search have fully aligned with JV partner Repsol
- FEED entry occurred in February 2021 with FID planned by H1 2022 for Phase 1
- Joint partial divestment process planned with Repsol to improve funding

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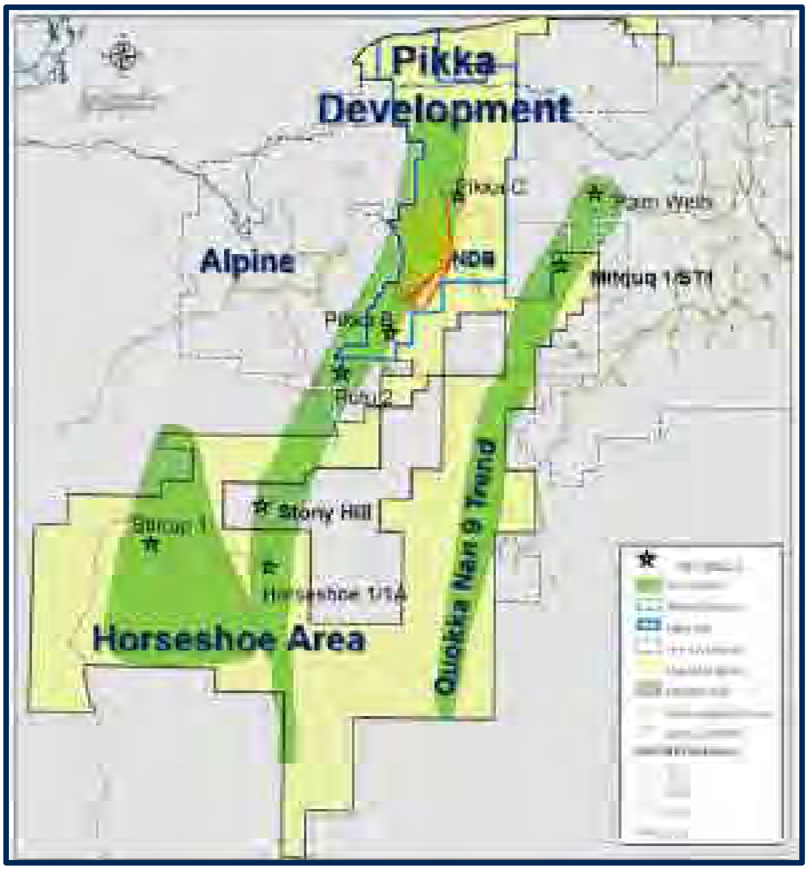
- Acquired new acreage in January 2021 in State of Alaska lease sale as a conveyor belt for future opportunities
- Plan to spud development wells July 2022. First oil targeted at 2025

Oil will be exported to the Kuparuk Transportation Company's common carrier oil pipeline and then on to the Trans-Alaska Pipeline System. Produced water and gas will be recycled for pressure maintenance and enhanced oil recovery. The project will involve construction and installation of all required infrastructure including operations camps, roads and pads with facilities being a combination of truckable and sealift modules.

During 2020, the exploration wells Mitquq and Stirrup (**Figure 4.30**) were drilled with the data and test results fully analysed including core analyses. The new Mitquq and Stirrup data was incorporated into the static models for subsequent resources estimates. Oil Search identified two major new trends (Quokka & Horseshoe/Stirrup) with similar scope and scale to Pikka.

Figure 4.30: Pikka Unit Location



Source: Oil Search

4.7.2 Regional Exploration and Development

The Alaska North Slope was established as a world class basin with the discovery of the USA's largest field, Prudhoe Bay in the 1960's. Exploration focused largely on structural and sub-crop traps with further major discoveries made throughout the 1990's.

In 2011, Repsol acquired acreage in and around the Colville High, a large structure covering both onshore and offshore areas adjacent to the Beaufort Sea on the central North Slope of Alaska. The leases were adjacent to several producing fields; Fjord, Oooguruk, Nikaitchuq, Kuparuk River and Alpine.

Repsol, together with partners Armstrong Oil and Gas (AOG), drilled seven exploration wells and five appraisal wells between 2011 and 2015 and identified the Nanushuk topset play with a total of four main reservoirs, Nanushuk, Kuparuk C, Alpine C and Nuiqsut. Feasibility studies for the exploitation of the Nanushuk reservoir were undertaken and Environmental Impact Statement (EIS) work was commenced with the U.S. Army Corps of Engineers at the same time that the pre-Front-End Engineering design (FEED) work was initiated in 2015. Since 2013, approximately 70% of exploration wells drilled on the Alaska North Slope have targeted the Nanushuk play-fairway.

In 2015, AOG assumed operatorship of the Pikka Unit and continued to progress the pre-FEED studies while exploring the south of the Pikka Unit.

In early 2018, Oil Search acquired a working interest in and the operatorship of the Pikka Unit. In May 2019, the U.S. Army Corps of Engineers issued a final EIS for the Pikka project and Oil Search has advanced development of the project in line with the EIS. Oil Search has also completed additional appraisal drilling and entered in FEED in February 2021 with the project being near completion.

4.7.2.1 Regional Infrastructure

The Alaska North Slope has an extensive existing infrastructure network of pipelines, roads, airports, docks and camps. The North Slope is accessible to the rest of North America by road and marine access is available via an existing dock at Oliktok Point where barge access for sea-lifted modules is available. There are also a number of airstrips.

Export pipeline options include the Kuparuk Transport System (KTS), which terminates at the beginning of the Trans-Alaska Pipeline System (TAPS). The TAPS is an 800-mile-long pipeline that transports North Slope sales crude to the Valdez Marine Terminal, in the northeast of Prince William Sound in the Gulf of Alaska. Existing processing facilities include a ConocoPhillips owned Seawater Treatment plant at Oliktok Point which provides treated seawater for injection at the Kuparuk, Alpine, and Oooguruk oil fields.

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4.7.2.2 Environmental Considerations

The North Slope is a unique and sensitive environment comprised in areas of tundra and wetlands that give rise to limitations for construction activities including shortened construction seasons. The environment creates limitations for construction activities including shortened construction seasons. Construction seasons typically occur during winter months when temperature and snowfall thresholds are met (**Figure 4.31**). The Alaska Department of Natural Resources (ADNR) opens tundra travel for construction activities after ground temperatures reach -5°C and snowfall accumulation reaches 5 inches on the coast and 9 inches in the Brooks Range foothills. Arctic weather characterised by high winds and cold temperatures creates challenges for equipment and personnel.

Figure 4.31: Winter-Only Remote Exploration: Ice Roads, Ice Pads

Source: Oil Search, Conoco Phillips, US Army Corps of Engineers (Alaska Department of Natural Resources)

4.7.3 Data Summary

The data coverage of the Pikka development includes a 'Mega-Merge' seismic database which incorporates nine 3D seismic datasets which have been reprocessed and merged across the Pikka-Horseshoe area. The data spans various vintages acquired over 20 years which have been merged to produce a single 3D seismic volume 800 square miles in area. The full Mega-Merge PSTM cube was delivered in November 2019 with the PSDM cube due in February 2020.

Oil Search is also in the process of reprocessing an additional six 3D surveys which will be merged and integrated into the Mega-Merge survey to form a Giga-Merge survey to give a continuous 1,200 square miles survey.

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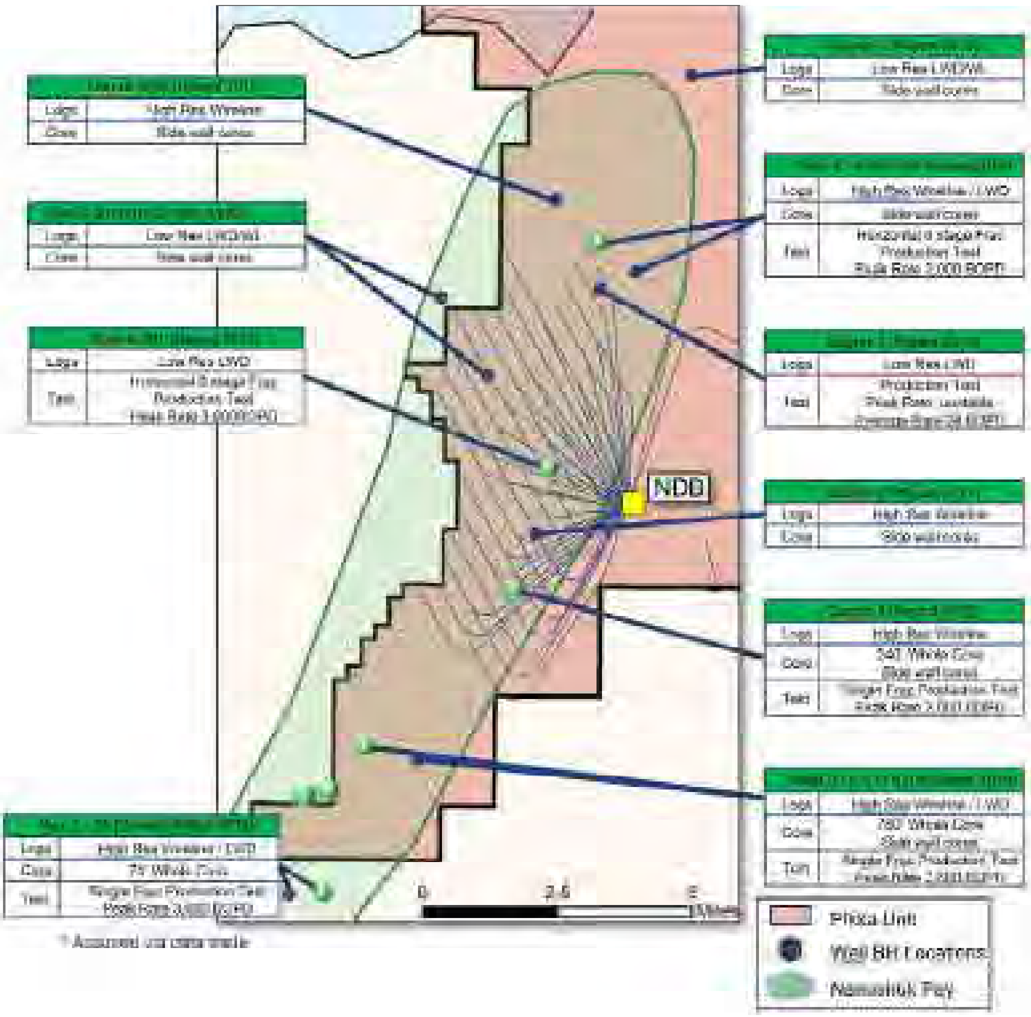
Several delineation wells have been drilled as part of the Pikka Unit appraisal. Wells have also been drilled by ConocoPhillips outside of the lease boundary to the South and West and data for these wells has been acquired by Oil Search. Well distribution is shown in **Figure 4.32** with the outline of the potential Nanushuk oil bearing reservoir sands. The new seismic surveys exhibit a better well/core to seismic correlation to aid the reservoir characterisation and 3D reservoir property distribution.

Figure 4.32: Pikka Unit Well Database



Source: Oil Search

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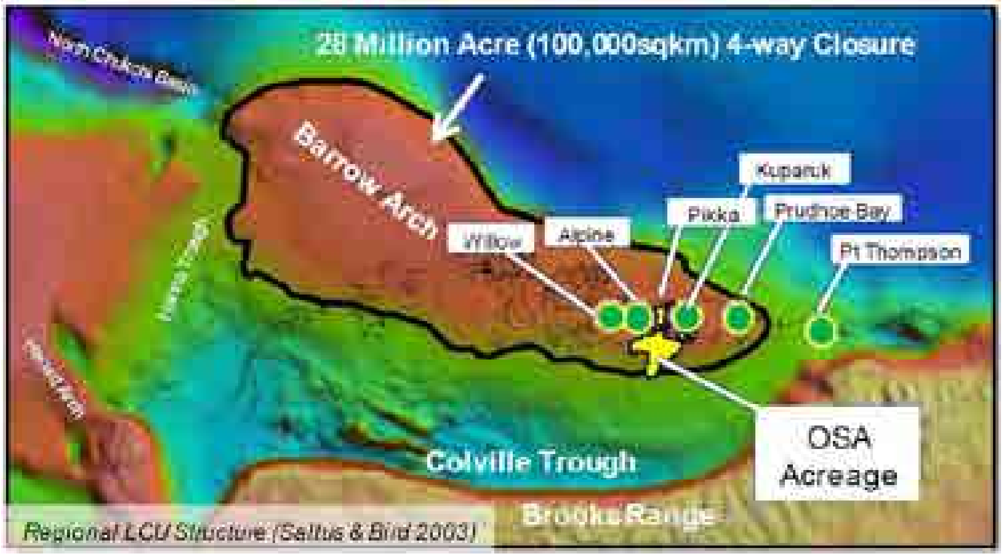
4.7.4 Geology and Petroleum Systems

Four world class source rocks are present across the Alaska North Slope. Hydrocarbon generation began during the burial of a foreland basin (Colville Trough) with migration occurring northwards into the regional Barrow Arch Structure. The Pikka Unit Nanushuk Reservoir is predominantly sourced from the Upper Triassic - Lower Triassic Shublik Shale Formation. **Figure 4.33** shows the major structural components and fields.

Figure 4.33: Major Structural Components and Fields of the North Alaska Slope



Source: Oil Search

The Pikka Unit region contains four main reservoirs: the Nanushuk, Kuparuk C, Alpine C and Nuiqsut. The Nanushuk and the Alpine C represent the primary development targets while the Kuparuk C and Nuiqsut may require further resource maturation.

The Nanushuk Formation consists of a large-scale clinoform system. Within the Pikka Unit, the primary objective is the Nanushuk 3 clinothem (the clinoform bounded sediment body) which was deposited in a wave dominated, distal deltaic setting. The reservoir is divided into an Upper Reservoir related to higher energy shoreface sands and a Lower Reservoir associated with lower energy, offshore transitional facies. The Nanushuk 3 accumulation is a stratigraphic trap sealed by juxtaposition of degrading reservoir quality units.

Alpine C sandstones are transgressive, near-shore deposits which in-filled paleo lows during the Kimmeridgian of the Beaufortian sequence. Oil Search reports that the Alpine C has a strong seismic contrast, and it is possible to map its presence where reservoir thickness is in excess of 50 ft. Thinner pods can be identified by seismic attributes. The Alpine C accumulation is also formed of a stratigraphic trap with transgressive sands being surrounded by shale rich deposits. **Figure 4.34** shows the stratigraphic column for the Alaska North Slope.

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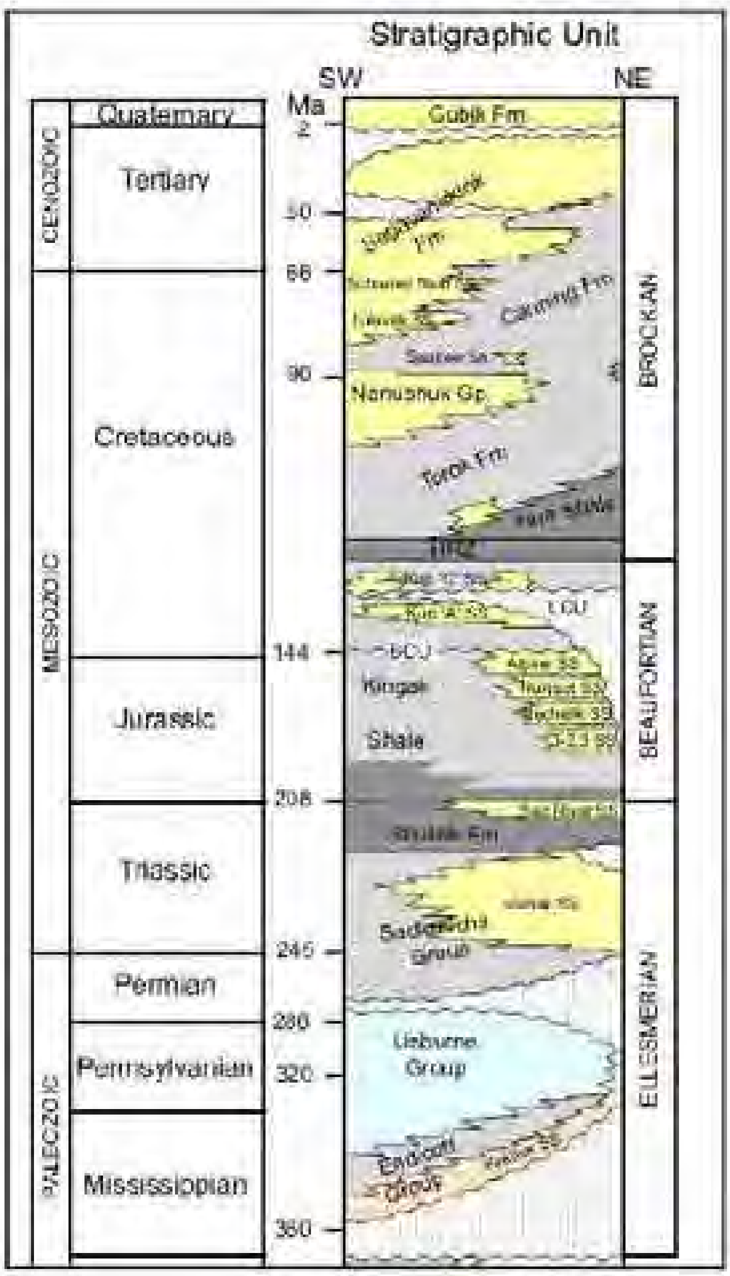
Figure 4.34: The Stratigraphy of the Alaska North Slope



Source: Oil Search

Grant Samuel & Associates Pty. Limited
October 2021

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4.7.4.1 Reservoir Description

The Nanushuk Reservoirs are characterised by thin, laminated sands with high shale content. Given the clinoform depositional environment the play is a typical generation-migration-stratigraphic trapping cycle. The laminated oil sandstones have average porosities of 17% (an Upper Nanushuk range of 15-30%) and average permeability of 10 mD. The reservoir is hydrodynamically trapped with a transition zone apparent and an estimated oil water content at ~ 4,950 ft TVDss. The thin sand intervals are generally quite good quality as indicated by the porosity ranges. Horizontal wells and hydraulic fracture stimulation is utilised to maximise the flow due to the laminations and to produce economic rates with waterflooding used as a pressure maintenance and sweep efficiency strategy for the reservoirs. There are wells in other operator blocks that are on production without fracture stimulation such as the Qannik accumulation which is produced via 6 non-fracture stimulated wells with 4 injectors, and this is discussed in more detail in later sections.

The main characteristics of the Nanushuk Reservoir are given in **Table 4.27**.

Table 4.27: Characteristics of the Nanushuk Reservoir

Reservoir Parameter	Description
Porosity	Upper Nanushuk: 15% - 30% Lower Nanushuk: 15% - 25% Mean: 17%
Permeability (Oil Search FDP plan)	P90: 0.01 mD
Oil Water Contacts	No FWL encountered. Estimated at -4,950 ft TVDss, which best represents a match between High Resolution Total Water saturation and the Capillary Pressure Curve.
Reservoir Pressure	1,900 psi at a datum of 4,150 ft TVDss Oil gradient follows a 0.365 psi/ft gradient
Fluid Properties	Bubble Point: 1,420 – 1,670 psi Oil gravity: gradual API reduction with depth Fluid segregation has been observed

The main characteristics of the Alpine C reservoir are given in **Table 4.28**.

Table 4.28: Characteristics of the Alpine C Reservoir

Reservoir Parameter	Description
Porosity	10% – 25% Mean: 17%
Permeability	0.01 mD - >1D Mean: 8 mD
Oil Water Contacts	No FWL encountered.
Reservoir Pressure	3,176 psi at a datum of 6,360 ft TVDss Oil gradient follows a 0.36 psi/ft gradient
Fluid Properties	Bubble Point: 2,280 psi API Oil gravity: 31

4.7.5 Volume Estimate

Ryder Scott performed an independent audit of Oil Search's estimates in 2019 and 2020 for the appraised areas. A summary of Ryder Scott's in-place volume estimates for the Nanushuk and Alpine C reservoirs from their report is given in **Table 4.29** and recoverable volumes in **Table 4.30**. GaffneyCline considers the in place volumes reasonable based on checks of the static model with specific focus on the main Pikka Development. The Contingent Resources are also considered reasonable based on GaffneyCline's technical check performed on the Pikka development as a whole and specifically on the Phase 1 development. This is discussed further in subsequent sections.

Table 4.29: Ryder Scott Estimates of in-place Volumes for the Pikka Unit (100%)

Reservoir	STOIIP (MMBbl)			GIIP (Bscf)		
	P90	P50	P10	P90	P50	P10
Nanushuk	1,635	1,949	2,323	677	780	912
Alpine C	145	150	155	116	120	124

Table 4.30: Ryder Scott Estimates of Recoverable Volumes for the Pikka Unit (100%) as of 31 December, 2019

Reservoir	(MMBbl)			(Bscf)		
	1C	2C	3C	1C	2C	3C
Nanushuk 3 main	459.0	664.6	838.3	190.0	275.1	347.0
Alpine C -Q5	14.8	17.4	18.9	11.8	13.9	15.1
Alpine C -Q9	38.8	45.6	49.4	31.1	36.5	39.6
Total	**512.7**	**727.6**	**906.6**	**232.9**	**325.6**	**401.7**

4.7.6 Pikka Unit Development Plan

4.7.6.1 Overview

Oil Search's planned Pikka Unit development will develop the oil accumulations in the Nanushuk 3 and Alpine C reservoirs, and partially develop the Mitquq area reservoirs. The reservoirs will be developed using waterflooding as the primary pressure maintenance and sweep efficiency strategy and will be supplemented by smaller-scale Miscible Water Alternating Gas (MWAG) injection to enhance recovery.

Oil Search plans to drill wells in rows of alternating horizontal injector and producer pairs at 550 m spacing with both producers and injectors drilled with multi-stage hydraulically fracture stimulated completions.

The development will occur in 2 phases:

1. Phase 1 will comprise of 22 producer wells, 21 water injection wells, one cuttings injection well and one produced water disposal well, all drilled from the ND-B wellsite (**Figure 4.35**).

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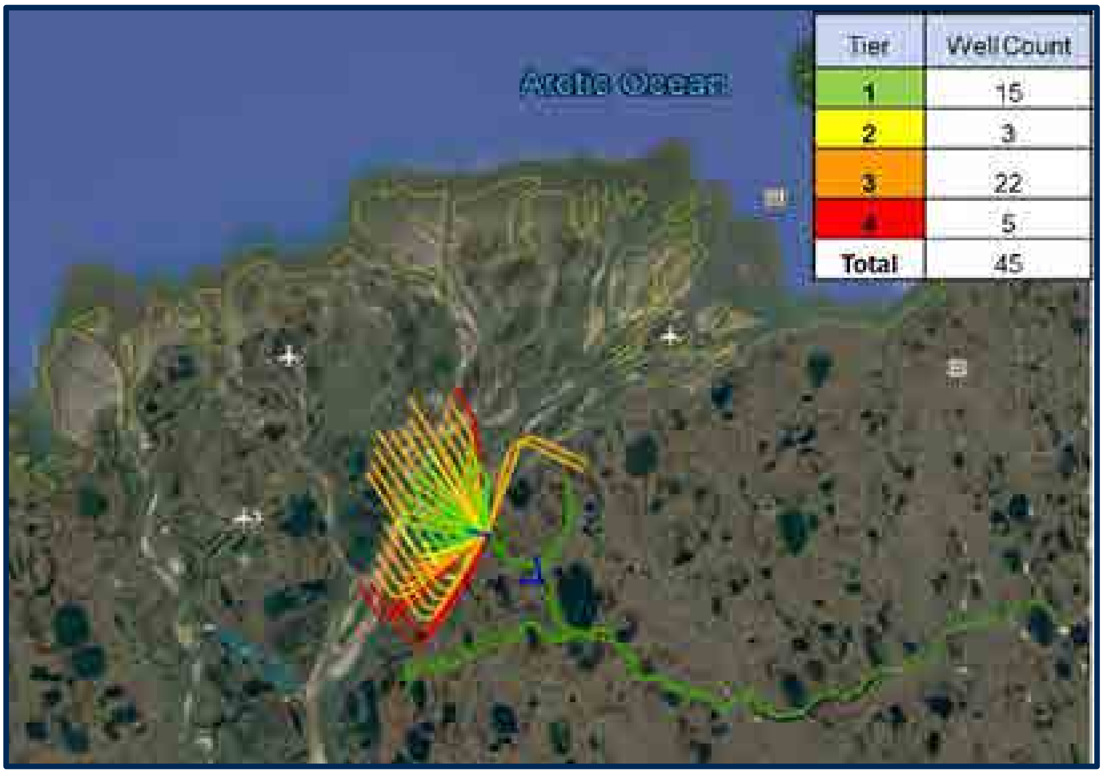
Produced fluids will flow to a new facility with a capacity of 80,000 bopd. Phase 1 will also include a new-build sea-water treatment plant and pipeline to treat and deliver water for flooding. Supporting infrastructure will include the Nanushuk Operations Pad (NOP), infield pipelines, import and export pipelines, infield and access roads, and a tie-in pad. The Phase 1 surface development configuration is given in **Figure 4.36**.

2. Initial Phase 2 plans comprise of the drilling of additional development wells from the ND-A, ND-C and QD-1 wellsites to increase the development well count from 45 wells to 81 wells. The production facility capacity will be increased from 80,000 bopd to 120,000 bopd. The sea-water treatment plant from Phase 1 will have sufficient capacity to also treat and deliver water for flooding for Phase 2.

Detailed data and profiles were available only for Phase 1, and so a detailed production profile was prepared only for Phase 1. The value for Phase 2 was scaled from the value calculated for Phase 1.

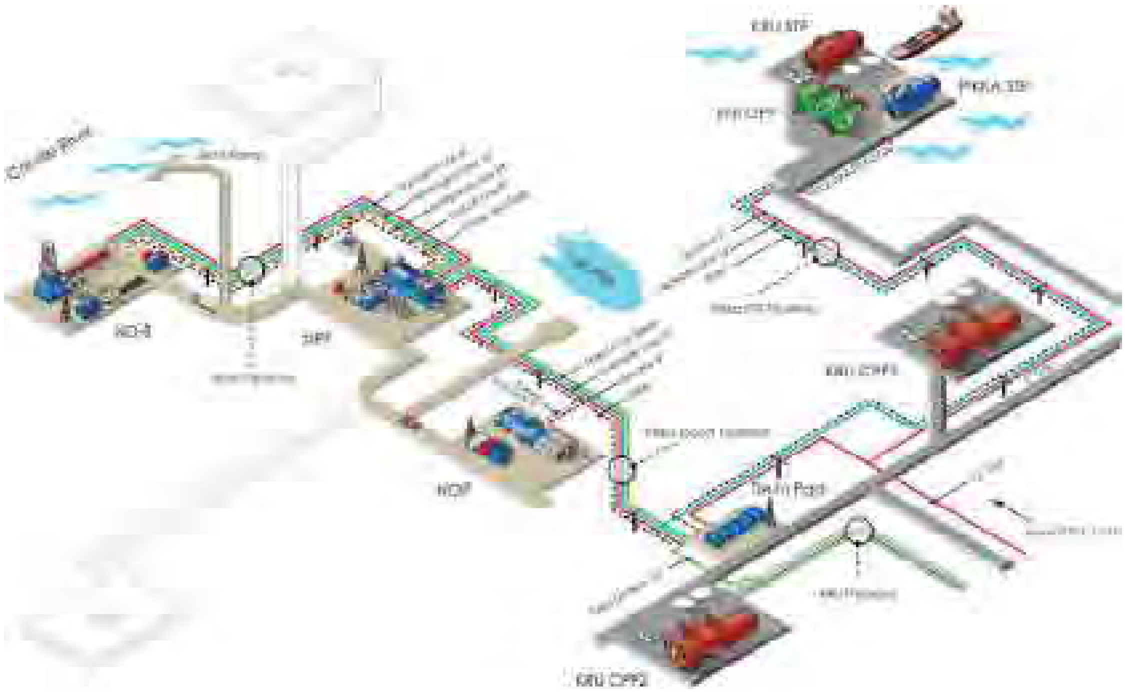
Figure 4.35: Full-Field Surface Facilities



Source: Oil Search

Note: cuttings injection well and produced water disposal well locations not provided by Oil Search

Figure 4.36: Phase 1 Surface Facilities



Source: Oil Search

4.7.6.2 Depletion Strategy

4.7.6.2.1 Waterflood

Water flooding will be key to maintain the reservoir pressure close to the original pressure. This is important to avoid gas evolution as the bubble point is only a few hundred psi below the original reservoir pressure. Pressure maintenance will be provided by a line drive waterflood with alternating horizontal producers and injectors with oil being displaced from each injector to the offset producers. The water required for 100% voidage replacement will come from seawater that is planned to be sourced from a new-build plant located near the existing Kuparuk Seawater Treatment Plant. Oil Search anticipates the waterflood to double the recovery factor when compared to primary depletion only. GaffneyCline agrees with this estimate, as water-flooding has been proven to increase oil recovery in all the large North Slope fields and is the default initial development scheme in the area.

4.7.6.2.2 *Miscible Water Alternating Gas (MWAG)*

Oil Search is currently undertaking to include MWAG injection as a form of Enhanced Oil Recovery (EOR). Injected gas will be miscible with the reservoir oil, provided the reservoir pressure is maintained near the original pressure. Additional gas volumes above the produced solution gas will be required to implement a significant MWAG project. This additional gas will come from Mitquq (gas cap and solution gas) and additional reservoirs (solution gas) or imported as a last resort.

MWAG has been proven over several decades to increase oil recovery in Alaskan Fields by 11% of STOIIP in the P50 case. However, these fields typically have permeability an order of magnitude higher than the permeability in the Nanushuk, and so this level of increase in oil recovery is not certain to be repeated in the Nanushuk. GaffneyCline supports a lower increase in oil recovery of 5% of STOIIP as proposed by Oil Search.

4.7.6.3 Development Wells

Wells in the Pikka Development will be designed as extended reach horizontal wells. The wells will be hydraulically fracture stimulated in around 12 stages. The orientation of the wells means that the fracs will be longitudinal not transverse, and so will allow flow between the laminated layers along the well path but will not short circuit the flow path between injectors and producers. The wells will be categorised into four tiers based on step-out requirements.

In addition to the producer and injector wells, two disposal wells are planned which subject to permit approval will inject cuttings into the Torok formation and produced water into the Ivishak formation.

4.7.7 Pikka Unit Production Profiles

4.7.7.1 Background

GaffneyCline estimated recoverable oil volumes for the Pikka Unit Phase 1 development scenario of a waterflood development with an additional oil recovery of around 5% of STOIIP from a MWAG flood.

4.7.7.2 Analogue Fields and Wells

The performance of the Nanushuk Formation has not yet been proven under a large-scale development under primary production or waterflood or MWAG. However, there are semi-analogous fields where well performance can be used to constrain initial oil rates and oil recoveries at the well-level for the Pikka Development.

The Qannik Field, located 14 km northwest from the planned Pikka Development, is the only geologic analogue with a significant production history. A comparison of the Qannik and Nanushuk 3 is shown in **Table 4.31**. At Qannik, current cumulative oil production is around 10% of STOIIP and a large extrapolation is required to the estimated end-of-field-life oil recovery of 25% of STOIIP.

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In addition to Qannik, some 40 miles west of the Pikka Development lies the Willow oil field, operated by ConocoPhillips, that also targets Nanushuk clinoforms. In late 2020, the Willow field entered FEED with Willow undergoing a legal challenge to its EIS in 2021. Subsequently COP is believed to be working on a revised EIS submission. The fact that another operator is pursuing a large-scale development of the Nanushuk adds confidence in the potential of the Nanushuk.

Table 4.31: Comparison of the Qannik Field and the Nanushuk 3

	Qannik	Nanushuk 3
Net Thickness	12 ft	10's ft
Permeability	??	10 mD
Gas Cap	✓	×
Active Aquifer	×	×
Horizontal well spacing	3,000 ft	1,800 ft
Fracture Stimulated	×	✓
Waterflood	✓	✓
Well count (Injector + Producer)	10	108 (all phases)
RF – current (WI)	10%	NA
RF – end of life – estimated (WI)	25%	NA

In addition to searching for analogues from producing fields and wells, Oil Search also tested the initial oil rates predicted by the dynamic model by upscaling well test results from all wells within the Nanushuk-3, as seen in **Table 4.32**.

The results provide comfort. Initial oil rates predicted by the dynamic model are mostly lower than the upscaled oil rates, and so the dynamic model is not systematically biased to the high side. In addition, the dynamic model covers the full range of outcomes, as the poorest well has an initial rate similar to Pikka C ST1, which was deliberately placed in lower quality reservoir.

Table 4.32: Scale-up of Well Test Results to Development Wells

Well	Reservoir	Tested Date	Tested Rate (bopd)	Scaled-up rate (bopd)	Appraisal Well Completion
Q3	N3	2013	-	-	Slanted well (24 degree) No frac
Q-7	N3	Apr-14	24	N/A	Experienced downhole mechanical issues during test
Q-8	N3	Apr-15	1,920	7,800	Vertical 1 stage frac
Q-301	N3	Apr-15	3,875	8,700	2000' horizontal in NS orientation 6 stage frac Gas-lift during cleanout
Putu 2A	N3	Apr-18	2,460	6,650	Vertical 1 stage frac, via two 20' perforation simultaneously Gas-lifted during cleanout
Pikka B ST	N3	Mar-19	1,790	7,000	Slanted well (71 degree) 1 stage frac Natural flow
Pikka C ST1	N3	Mar-19	865	2,000	3000' horizontal parallel to development well orientation 6 stage frac Post-frac clean out problems (downhole sand plugs) Natural Flow
Mitquq 1 ST1	NI9	Mar-20	910	2,900	Slanted well (40 degree) 1 small frac on 3/1/20 & 1 large frac on 3/12/20, from same perfs. Gas-lifted
Stirrup-1	N0	Mar-20	2,920	8,300	Vertical 1 stage frac, via 20' perforation GL during cleanout

4.7.7.3 Choice of Uncertainties to Model

GaffneyCline considered various project scenarios to test the commercial risk. GaffneyCline considers this approach consistent with the VALMIN Code (2015) where "Risks may arise with respect to the availability, uncertainty and quality of data and other information".

GaffneyCline considered a wide range of recoverable oil volumes due to:

1. A lack of geologic analogue fields with a comparable development scheme and a long production history.
2. Low oil rates from the Pikka C ST1 appraisal well drilled in the winter of 2018-2019.
3. Promising oil producer and water injector rates from a proprietary data trade from a similar reservoir located in adjacent acreage.

Keeping in mind the lack of analogue field developments and especially the lack of "Pikka producer-well" oil rates from the existing wells in the Nanushuk 3, to test the Commercial Risk of the project, GaffneyCline generated a range of production profiles around uncertainties in the Development Scenario and the Well Type Curve.

4.7.7.4 Development Scenario

GaffneyCline started with the development scenario from Oil Search as shown in **Figure 4.37**. GaffneyCline considered the development schedule to see if there were any natural stop-points in the development program, where further investment could be stopped.

After running economics, it became clear that on a look-forward basis, the breakeven oil recovery of later oil wells was low. Therefore, the only element that could be stopped would be the drilling of the later, longer Tier 4 wells, in the case where well construction for the Tier 3 wells proves difficult. Stopping at this point might be feasible, because the Tier 4 wells will require a more powerful drilling rig than the Tier 1/2/3 wells.

Given this background, GaffneyCline defined the Low, Best and High case drilling scenarios as shown in **Table 4.33**.

1. Low Case - GaffneyCline accepted well counts for Tier 1/2/3 wells and removed the Tier 4 wells. Note that these modifications will have little effect on overall oil recovery because the Tier 4 wells are only 2 producer wells and 2 injector wells.
2. Best Case – GaffneyCline accepted well counts for Tier 1/2/3/4 wells but decreased oil recovery per Tier 4 wells by 25%.
3. High Case - GaffneyCline accepted the High case as proposed by Oil Search.

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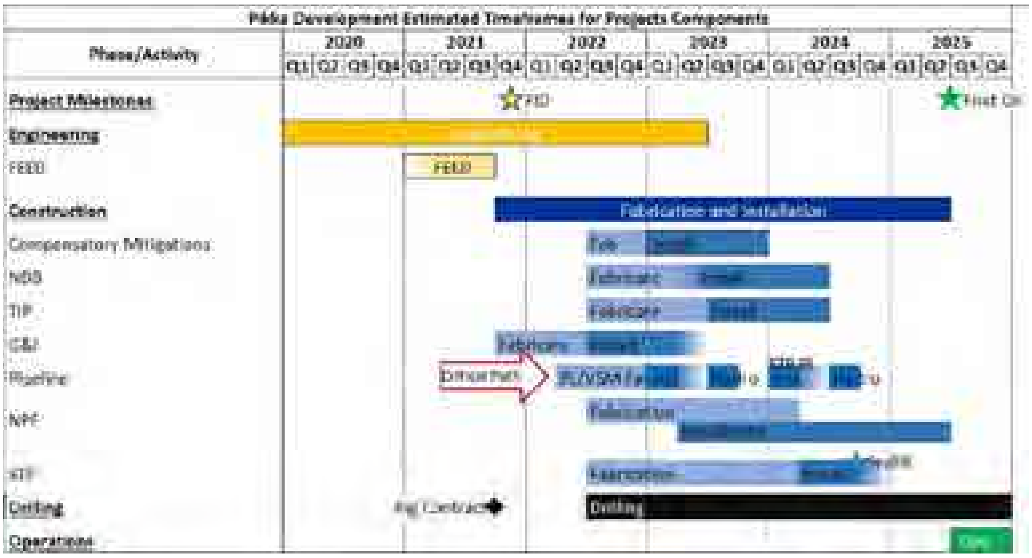
Figure 4.37: Development Schedule for Phase 1



Source: Oil Search

Table 4.33: Development Well Scenarios Used by GaffneyCline

Pad	Target	Tier	Low			Best			High			Notes
			Prod	Inj	**Total**	Prod	Inj	**Total**	Prod	Inj	**Total**	
ND-B	Nan-3	1	8	6	14	8	6	14	8	6	14	As per Oil Search
		2	-	2	2	-	2	2	-	2	2	As per Oil Search
		3	11	10	21	11	10	21	11	10	21	As per Oil Search
		4	-	-	-	2	2	4	2	2	4	The Low Case has no wells. The Best Case has a 25% discount on oil recovery
		Total	**19**	**18**	**37**	**21**	**20**	**41**	**21**	**20**	**41**	
	Alpine-C	1	1	1	2	1	1	2	1	1	2	As per Oil Search
		2			-			-			-	As per Oil Search
		3			-			-			-	As per Oil Search
		4			-			-			-	As per Oil Search
		Total	**1**	**1**	**2**	**1**	**1**	**2**	**1**	**1**	**2**	
	Water and Cuttings Disposal	1		2	2		2	2		2	2	As per Oil Search
		2	-	-	-	-	-	-	-	-	-	As per Oil Search
		3	-	-	-	-	-	-	-	-	-	As per Oil Search
		4	-	-	-	-	-	-	-	-	-	As per Oil Search
		Total	**-**	**2**	**2**	**-**	**2**	**2**	**-**	**2**	**2**	
	Grand Total		**20**	**21**	**41**	**22**	**23**	**45**	**22**	**23**	**45**	

4.7.7.5 Well Type Curves - Nanushuk-3

GaffneyCline generated Low/Best/High well types curves based on production forecasts from the Oil Search simulation model for all of the ND-B pad wells. The forecasts include the benefit of waterflood and MWAG.

The oil recovery per well adopted by GaffneyCline is listed in **Table 4.34**.

Table 4.34: Oil Recovery per Well adopted by GaffneyCline - Nanushuk-3 wells

	Low	Best	High
Cum Oil	(MMstb)	(MMstb)	(MMstb)
ND-B	10.9	17.4	22.6

4.7.7.6 Well Type Curves – Alpine C

GaffneyCline generated Low/Best/High well types curves based on historical production data from the Alpine Field, which match the forecasts from the Oil Search simulation model as seen **Figure 4.38**. The forecasts include the benefit of waterflood but not MWAG, and so an additional 5% of oil recovery was added.

The oil recovery per well adopted by GaffneyCline is listed in **Table 4.35.**

Figure 4.38: Type Curves adopted by GaffneyCline for Wells in the Alpine-C

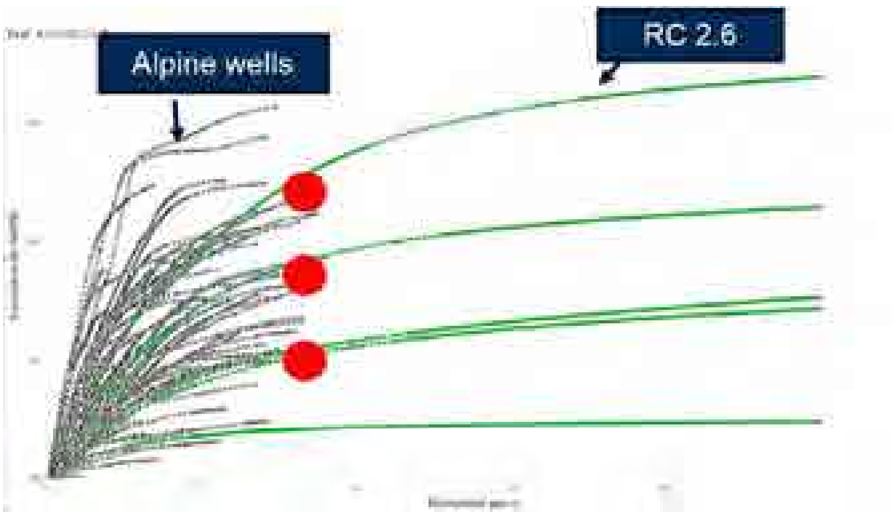


Table 4.35: Oil Recovery per Well adopted by GaffneyCline - Alpine-C wells

	Low	Best	High
Cum Oil	(MMstb)	(MMstb)	(MMstb)
ALPINE-C	4.2	8	12

4.7.7.7 Field Production Profiles

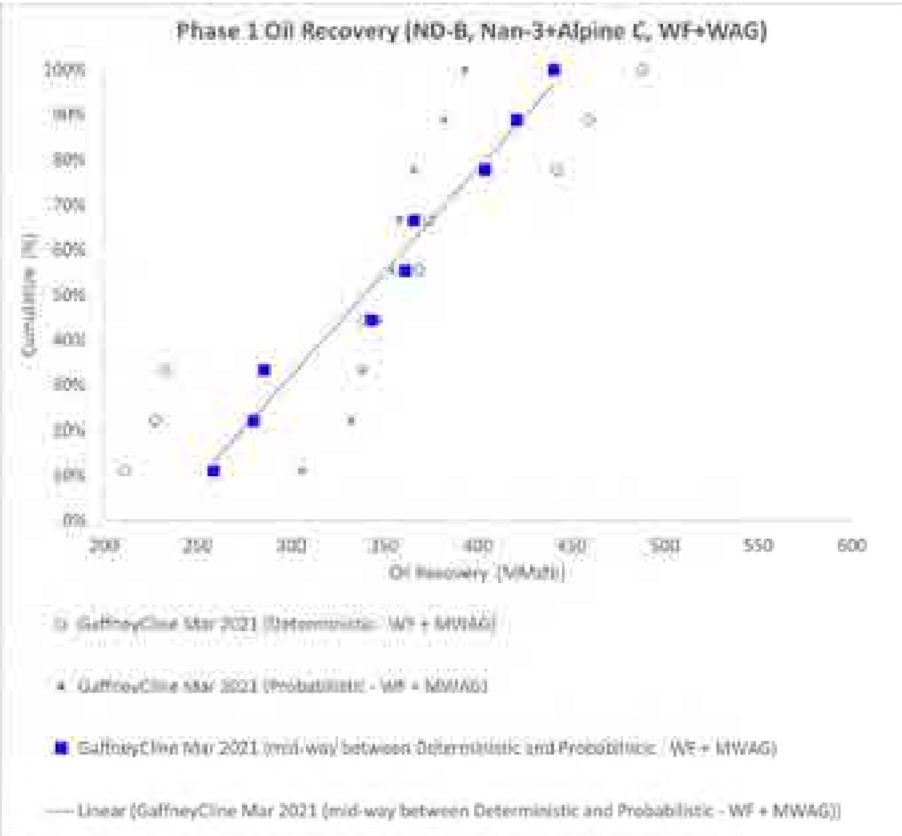
The field-level profiles were generated in a two-step process.

The first step was to estimate the field-level oil recovery using the type wells and the number of wells in the development.

Field level estimates of oil recovery were generated for the Nanushuk-3 and Alpine-C wells, and include the benefit of Waterflood and MWAG. **Figure 4.39** shows estimates were generated both deterministically (assumes the wells are fully dependent) and probabilistically (assumes the wells are fully independent) and the adopted estimates were midway between the deterministic and probabilistic estimates to capture partial dependence.

Figure 4.39: Oil Recovery Distributions from GaffneyCline and Oil Search

The nine mid-point cases retain a realistic range, wider than a pure probabilistic approach but not as wide as a pure deterministic approach.



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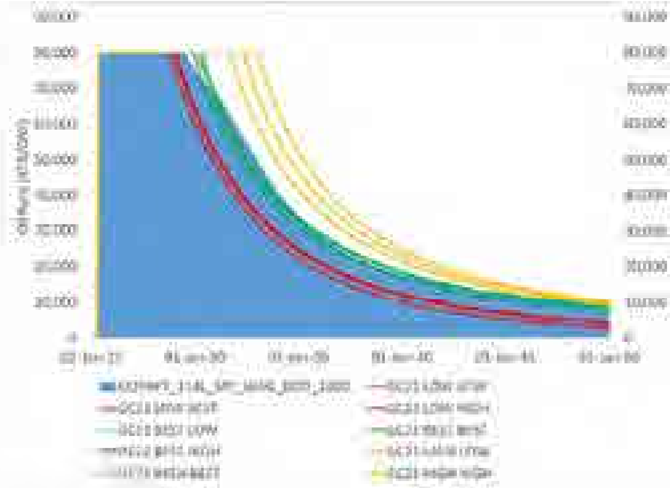
The second step was to create nine production profiles as shown in **Figure 4.40**. The range of profiles is similar to that from Oil Search. Of note, there is more upside than downside.

Figure 4.40: GaffneyCline's Nine Profiles for Phase 1

Profiles are generated by scaling of the plateau length from the Oil Search dynamic model to honour the oil recovery from the nine cases

Dev Scheme	Well Type Curve	Oil Recovery* (MMstb)
Low	Low	259
	Best	280
	High	288
Best	Low	343
	Best	361
	High	366
High	Low	404
	Best	421
	High	440

* Oil Recoveries are mid-point between the deterministic and probabilistic estimates



4.7.8 CAPEX and OPEX Profiles Summary

In developing the CAPEX, OPEX, and ABEX valuation scenario profiles, GaffneyCline has relied upon the Oil Search cost estimations and modelling. GaffneyCline accepted the Oil Search Production profiles and checked the cost profiles and found these reasonable as presented in the Oil Search Model for Phase 1.

4.7.9 Key Project Risks

4.7.9.1 Oil Recovery per Well

The nature of the Nanushuk Reservoir, which is formed of thin, laminated sand intervals with uncertain vertical connectivity between the sands means that poor reservoir drainage is a key risk in the Pikka Development. The current seismic data does not provide significant resolution to understand reservoir continuity and the current appraisal well density is not sufficient to properly evaluate reservoir connectivity. It is anticipated that the seismic mega merge which is currently underway may go some way to helping understand the reservoir connectivity. Oil Search has identified this risk and has planned development wells accordingly to try to maximise oil recovery with fracture stimulated horizontal wells that will be drilled to cut across the Nanushuk clinoforms in a perpendicular direction to optimise recovery in the various clinoforms. In addition, the pattern of alternating producer and injection wells is designed to push oil to the producers and to maintain reservoir pressure close to the initial reservoir pressure.

GaffneyCline supports the development concept and notes that similar schemes have been successfully operating on the North Slope for decades, including incremental oil recovery schemes such as Water-Alternating-Gas injection. However, to date, the Nanushuk play has undergone very limited development and not on a large scale, and so production history, although promising, is limited.

Of particular note, the Pikka-C well was the most recent well drilled into the Nanushuk-3 in the winter of 2018-2019. When tested, the well flowed far below the expected rate, which was attributed to a bottom-hole restriction to flow such as clogging by fracture stimulation proppant sand, as the well logs and fracture stimulation operations all looked positive. Whilst such downhole restrictions are easily remedied in development wells with a thorough wellbore cleanout, the actual Pikka-C flow rate leaves a wide range of uncertainty in both deliverability and oil recovery of the Pikka development wells.

4.7.9.2 Well Construction

The ability to construct effective development wells in the Nanushuk has not yet been proven on a large scale.

Despite this, GaffneyCline sees well construction overall as a low risk, as the planned well lengths, completions and fracture stimulations fall within the window of experience within the wider North Slope, and the Oil Search team includes individuals with many years of experience in drilling such wells.

4.7.9.3 Development Schedule and Chance of Development

The current status of the Pikka Phase 1 project is pre-FID. Phase 1 is currently progressing to development and has been recommended for valuation to Grant Samuel on a cashflow basis. Subsequent contingent resources projects are recommended for consideration by Grant Samuel on a timing and risk basis. Phase 1 is estimated to start producing in 2025 with subsequent volumes considered in 2030 and 2035 respectively.

The Development Pending volumes (464 MMbbl) beyond the Pikka Phase 1 development are assumed to be commence production five years (2030) after the Pikka development with funding supported by Phase 1 production.

The remaining Development Unclarified volumes of (112 MMbbl) are considered for production after an additional five years (2035).

GaffneyCline applied a sensitivity of a one year acceleration and a two-year delay, relative to the assumed five-year timing, for subsequent contingent resources volumes. This is to account for uncertainties in the operator's priorities and project technical definition. Based on these project execution timing sensitivities, the recommended value range for the 2030 tranche of Contingent Resources Volumes is 1.8 to 2.3 US$/Bbl and for the 2035 tranche is 0.6 to 1.1 US$/Bbl. This was provided for Grant Samuel's consideration.

4.7.10 Alaska Exploration

In addition to the core project scope, the Pikka Development represents an aggregation point for future exploration, both in-field and regional. This includes satellite reservoirs in the Pikka Unit including the Nechelik, Nuiqsut, Kuparuk C, Torok, Tuluvak as well as other Alpine and Nanushuk leads.

Additional reservoirs are drillable from drill sites NDA, NDB or NDC within ERD constraints. It is anticipated these volumes would be developed during production operations of the Pikka Unit. Given the low incremental cost of development, these would be prioritised over new pad developments.

In addition to the reservoirs drillable from NDA, NDB and NDC, there are potential targets both inside and outside the Pika Unit which would require new pads to be developed. These include Pikka East and Pikka North areas. There are also several discovered and prospective exploration targets at Horseshoe which lie outside of the current Pikka Unit (**Figure 4.30**). These included three clinoform sands units, Diamond, Red Tail and Sulphur which Oil Search plans to target with a single exploration well.

4.8 Alaska Exploration Valuation

Oil Search plans to drill the Diamond, Red Tail and Sulphur clinoforms in 2026. GaffneyCline has adjusted Oil Search's EMV assumptions and has calculated an EMV10 value of US$32 MM as shown in **Table 4.36**.

Table 4.36: GaffneyCline's Base Case Alaska Exploration ENV10

Prospect	Net Unrisked Prospective Resources (MMboe)	Net NPV Unrisked 10% (US$MM)	Net NPV Failure 10% (US$MM)	Chance of Success (%)	Net EMV 10% (US$MM)
Diamond, Red Tail, Sulphur	72	119	-19	37%	32

Note: 'Chance of Success' calculated as 'Geological Chance of Success' x 'Chance of Development'

Oil Search made various exploration acquisitions between 2018 to 2021 with total book value of US$67.5 MM as shown in **Table 4.37**. This value is a good representation of the sunk cost approach to value Oil Search's Alaska exploration assets.

Table 4.37: Oil Search's Alaska Exploration Acquisition Costs

Description	Capitalised On	Acquisition Value (US$ MM)
East Hue Acquisition	12/31/2019	11.6
Exploration KAA Acquisition	12/31/2019	7.4
Grizzly Acquisition	12/31/2018	0.0
Hue shale Acquisition	12/31/2019	35.9
Alignment Acquisition	02/28/2021	3.7
Million Acres Acquisition	02/28/2021	6.8
Castle West Acquisition	02/28/2021	2.1
Total		**67.5**

Outside of the Oil Search transactions themselves, GaffneyCline could not identify suitable market comparable transactions from public data sources for valuation of these exploration targets.

GaffneyCline also considers that the exploration assets were acquired in the recent past under similar market conditions and consequently, their acquisition value is a reasonable representation of a sunk cost approach to the valuation of the Alaska Exploration assets.

GaffneyCline proposes a valuation range where the EMV10 approach for valuing Oil Search's prospects in the drilling plan represents the **Base Case which is US$ 32 MM**. The sunk costs of **US$ 68 MM** are an appropriate estimate for the Stretch Case for Grant Samuel's Consideration.

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5 Santos' Assets

5.1 Executive Portfolio Overview

Santos is Australia's largest domestic gas supplier with additional activity in the International LNG market. Santos' portfolio of producing natural gas and oil assets are summarised for valuation input based on their areas of operations which include Western Australia, Cooper Basin, South East Queensland, New South Wales, Northern Australia, Timor-Leste and Papua New Guinea. Additional Santos exploration focus exists in the McArthur and South Nicholson basins onshore Australia. Detailed asset descriptions are provided in subsequent sections.

Western Australia

In Western Australia, Santos is a producer of natural gas, natural gas liquids and oil. Santos' share of Western Australia's domestic gas supply was reportedly 46% of the approximately 1,015 TJ/d in Q1 2021. Santos' Western Australia gas assets, located in the Carnarvon Basin, include 100% ownership and operatorship of the Varanus Island and Devil Creek domestic gas processing hubs, and a 28.57% working interest in the BHP operated Macedon gas plant. In its Western Australia long term domestic gas supply plan, Santos intends to add production from several discovered fields and several exploration opportunities. Development of near field discoveries planned as backfill production to the Varanus Island facility will begin with the Spartan project in 2023, followed by several others from 2026 onwards.

Santos' net share of crude oil production in 2020 was 2.4 MMstb. Its Carnarvon Basin oil projects consist of a 52.5% working interest and operatorship in the Ningaloo Vision FPSO, 28.6% of the BHP operated Pyrenees Venture FPSO, and a 28.57% working interest in the Barrow Island oil facility.

The Dorado discovery in the neighboring Bedout Sub-basin, in which Santos has an 80% working interest, will be developed in two phases, starting with oil production from 2026. This is planned to be followed by gas and LPG production as part of its long-term plan for Western Australia domestic gas supply. Also included in the plan are volumes from the success case of several exploration assets near Dorado.

GaffneyCline largely concurs with Santos on its oil and gas production valuation scenario profiles, although in GaffneyCline's scenario profiles, the Ginger and Spar Deep discoveries have only been included in the Stretch Case. In Dorado, GaffneyCline's Base Case valuation scenario profile is lower than the Santos' profile because of the exclusion of Prospective Resources. Prospective Resources for Baxter Oil, along with the volumes of four other Prospects (Yoorn, Dancer, Pavo and Apus) are accepted, but valued using an alternate methodology in the exploration section.

GaffneyCline reviewed the Santos provided CAPEX, OPEX, and D&R costs and scenario profiles. In general, Santos' cost profiles were accepted with minor phasing adjustments related to the GaffneyCline production valuation scenario profile. GaffneyCline reviewed independent third-party consultant's estimates that formed the basis of D&R estimates, adjusting these to account for documented exclusions and rephased D&R expenditures from the end of production.

Cooper Basin

Santos' Cooper Basin assets incorporate 190 gas fields and 115 oil fields. Most discoveries are found within tight fluvial-lacustrine sequences which are interbedded with coal measures and shales within gentle four-way, dip closed structures. Reservoirs are highly heterogeneous and unique development plans are required for each field and reservoir. In addition to producing fields there are future development opportunities in near field exploration around the current developments as well as in the Deep Coal and Granite Wash Plays.

GaffneyCline audited aggregated field (pseudo basin level), field and well level production profiles together with third party audit reports to reconcile volumes which Santos has used in its production profiles to present to Grant Samuel for valuation. GaffneyCline confirmed the reasonableness of Santos' valuation scenario profiles for projects classified as 2P Developed based on decline curve analysis (DCA). For projects classified as 2P Undeveloped and Contingent Resources, GaffneyCline reviewed Santos' profiles based on an analysis of the forecast EUR per well against recent historical EURs per well. GaffneyCline's focus was primarily on gas as the dominant value product and oil as a secondary value given the smaller quantities. GaffneyCline's estimated EURs per well for the four largest project areas and compared these to Santos' EUR per well for the same areas. Based on this comparison, GaffneyCline produced scaling factors for each project area to account for differences between the GaffneyCline and Santos valuation scenario profiles. GaffneyCline then created a basin level scaling factor which is a weighted average of the project level scaling factors, with project area reserves and resources volumes as weights. The basin level profile scaling factors for the Cooper Gas Undeveloped Reserves and Contingent Resources tranches are 95% and 80% respectively. GaffneyCline has utilised these scaling factors to build its Base Case production profiles. For its Stretch Case, GaffneyCline has accepted the Santos profiles but has removed any projects classified as exploration.

GaffneyCline cost valuation scenario profiles do not include exploration. An explanation of the assumptions made by GaffneyCline are included in **Section 5.3.2.2**.

The 1.7 million tonne per annum Moomba CCS project is located in the Cooper Basin. Currently CO_2 is extracted from the produced well stream in the Moomba facility prior to export and is vented. The Moomba gas processing facility has a highly developed infrastructure and as the extraction/production of relatively pure CO_2 occurs on site, it offers an attractive opportunity to initiate a CCS project with minimal cost and limited risk. FID was announced on this project on 1 November 2021. The project is considered investment-ready given the recent announcement regarding CCS project eligibility for Australian Carbon Credit Units. GaffneyCline has incorporated this project in the valuation scenario profiles.

Queensland and NSW

The Santos operated GLNG project utilises a defined sub-project sanctioning process to provide feedstock to the GLNG plant. Given the robust nature of the Santos sub-project assessment process, GaffneyCline focused on this project-based methodology for final valuation scenario profiles provided to Grant Samuel. This is reflected in GaffneyCline's analysis and in the volumes presented and explained in subsequent sections. The Fairview, Scotia and Arcadia sub-projects and associated volumes are accepted as presented by Santos after reconciliation against current production performance by GaffneyCline. Commitment for sanctioning of all the provided sub-projects by Santos management based on their JV process has been received by GaffneyCline and with that undertaking all currently unsanctioned sub-projects have been included. Possible substitutions for later life sub-projects are possible based on production performance. This is considered a reasonable approach for valuation purposes by GaffneyCline.

For the Roma CSG developments, GaffneyCline conducted performance analysis in the developed areas of the field with reconciliation of the production type curves proposed by Santos in the undeveloped areas. Checks were conducted for different geodomains and project areas, comparing Santos' expected peak rates and EURs versus performance from existing wells. This process led to a scaling factor being applied to Roma sub-projects reducing volumes by approximately 10% for valuation purposes.

The Base Case valuation scenario profile provided to Grant Samuel includes 325 MMboe Net to Santos as of 1 January 2021. The volumes as of 1 July 2021 Net to Santos reduce to ~315 MMboe due to production and ELT effects. The valuation scenario profiles provided to Grant Samuel have H1 2021 production factored into the asset for their financial modelling as per all the assets presented in this report.

For the Base Case, GaffneyCline applied a 2% p.a. escalation only on the operating cost profiles presented by Santos; no CAPEX escalation was applied to account for Santos' demonstrated savings in this CSG operating environment. GaffneyCline also adjusted the CiO for GLNG using analogues from other midstream projects. Midstream capital and operating costs were adjusted for gas throughput changes by GaffneyCline in the valuation cases. GaffneyCline included midstream D&R in both cases to the valuation scenario profiles.

The GaffneyCline Stretch Case volumes accepts the 338 MMboe profiles presented after adjustment for the effective date to 1 July 2021. No CAPEX or OPEX escalation was applied with the other midstream adjustments kept consistent with the Base Case.

The Eastern Queensland (OBO) GaffneyCline Base Case of 86 MMboe focused mainly Reserves and Resources from the highest confidence projects. The Santos cost profiles for these projects included were accepted based on GaffneyCline's review. In the Stretch case the 136 MMboe Santos production and cost valuation scenario profiles were accepted.

GaffneyCline's Narrabri CSG project Base Case included higher confidence development areas with a total volume of 103 MMboe with the sub-project costs appropriately included. In the Stretch Case, the Santos 170 MMboe project volume was accepted with the associated costs.

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Northern Australia and Timor-Leste

Gas is supplied to DLNG from the Santos operated Bayu-Undan Field located approximately 500 km north-west of Darwin in Timor-Leste offshore waters. The Bayu-Undan Field has been producing since 2004. Based on production from the declining developed wells, end of field life was expected as early as December 2021. In order to address this and to extend production to the end of the PSC (end 2022), Santos has begun a three well, infill drilling campaign. In July 2021, Santos announced that production from the first of the infill wells had begun. The first well was brought online at 178 MMscfd of gas and 11,350 bbld of liquids. Drilling has now commenced on the third of the three wells with the program expected to be completed by early 2022.

The undeveloped Barossa gas field is located 300 km north of Darwin and will be developed to backfill DLNG when the Bayu-Undan Field ceases production. FID on Barossa was made in March 2021. The Barossa development wells and facilities are designed to deliver annual average LNG production of approximately 3.5 MMtpa depending on downtime and seasonal impacts. Santos plans to commence production from Barossa in December 2024. The undeveloped Caldita gas field is located 35 km from Barossa and any future development of Caldita could also supply DLNG.

Based on its review of the Bayu-Undan, Barossa and Caldita Fields, GaffneyCline has built Base Case and Stretch Case production and cost profiles. The valuation scenario profiles have been built based on the following scenarios:

Base Case: Bayu-Undan + Barossa. This assumes production from the development of Barossa will backfill DLNG when the Bayu-Undan Field ceases production.

Stretch Case: Bayu-Undan + Barossa + Caldita. This assumes production from the development of Barossa will backfill DLNG when the Bayu-Undan Field ceases production. In turn, production from the development of Caldita will backfill DLNG when Barossa production begins to decline.

For the Bayu-Undan Field, GaffneyCline has accepted Santos' production valuation scenario profiles for both its Base and Stretch Cases. For the producing wells, Santos' DCA forecasts were found to be within the range of gas and water rate history match plots from the Eclipse simulation model. For the infill wells GaffneyCline's review showed forecast well recoveries are in line with historical well performance. The production valuation scenario profiles extend the field life from December 2021 to April 2023 beyond the PSC expiry.

For the Barossa Field, GaffneyCline has scaled its production profiles to account for differences in GIIP and EUR estimates. This has been used in both the Base and Stretch Case scenarios. The profile assumes Barossa gas will be available to backfill DLNG in Q4 2024 and GaffneyCline's modelling shows the economic limit of the Barossa development is 2047.

For the Caldita Field, GaffneyCline's audit checks of GIIP using a 1D Monte Carlo model showed Santos' estimate is reasonable. GaffneyCline has therefore accepted the Santos GIIP estimate. GaffneyCline believes the low gas recovery factor used by Santos is consistent with Lower Flamingo reservoir quality which has low permeability with poorly connected GIIP. Consequently, GaffneyCline believes Santos' production valuation scenario profiles are reasonable and has accepted them. The Caldita Field has reasonably small volumes and has only been included in

GaffneyCline's Stretch Case valuation scenario profile. Assuming a 2024 start-up for Barossa, the Caldita Field is expected to be online for backfill in 2037 and will extend the plateau rate for approximately 20 months. Caldita production would extend the ELT of the Barossa and Caldita development to 2048.

The undeveloped Petrel and Tern gas fields are located 250 km west of Darwin and could either feed into domestic or export markets. GaffneyCline has built production and cost profiles for the fields based on a joint development which sees the Petrel Field being developed first before the Tern field is developed to backfill declining Petrel production. The timing of any potential Petrel/Tern development appropriately risks the valuation scenario profiles.

GaffneyCline applied minor phasing adjustments on cost profiles for Northern Australia and Timor-Leste. The Santos costs have generally been accepted except for D&R which has been updated based on third party costing reports provided by Santos and reviewed and accepted by GaffneyCline.

Section 5.5.11 includes a GaffneyCline evaluation of additional Northern Australia assets such as the Greater Poseidon, Crown and Lasseter discoveries. Cashflows were not utilised to value these assets due to their less mature project status.

PNG

GaffneyCline has provided one set of valuation scenario profiles to Grant Samuel based on updated volumes for the foundation PNG LNG project which includes both Base and Stretch Cases. Santos provided geological and dynamic digital models to opine on the volumes and compare with other operator and partner models received. Additional reconciliation was also carried out with other 3rd party auditors. This process has been discussed in detail in the Oil Search section of this report.

GaffneyCline volumes are utilised for the Base Case profiles which rely on GaffneyCline's reconciled estimates of the 2P and/or 2C volumes. The Stretch Case scenario provided to Grant Samuel includes a Hides FW success case and Juha North development given the success seen in the adjacent Muruk discovery. Some 3C volumes are considered to bracket this project's value range given the excellent production to date. Volume tables are provided in **Section 4.2.2**.

Exploration value is discussed in Section 5.8 with the methodology and value range indicated.

The total volumes summarised in the **Santos Summary Table** (**Table 5.1**) are based on incorporating the outcomes of the audits of Santos' major assets including those from the other auditors and Santos' own estimates for unaudited properties, and GaffneyCline's understanding of the estimation processes employed by Santos. GaffneyCline is of the opinion that the volumes for the fields included, and in the aggregate, represent a reasonable estimate of Santos' Reserves and Contingent Resources position in those assets as of 31 December 2020 based on the work performed in this report. All scenario profiles for valuation have an effective date of 1 July 2021 and have been adjusted for production.

Table 5.1: Santos Summary Table
Statement of Remaining Recoverable Hydrocarbon Volumes
for all Fields in which Santos has an Interest
as of 31 December 2020

Net to Santos' Interest							
Developed Reserves	**Sales Gas (PJ)**	**Ethane (PJ)**	**Total Sales Gas (PJ)**	**LPG (kTonne)**	**Condensate (MMstb)**	**Oil (MMstb)**	**Oil Equivalent (MMboe)**
1P	1,832	23	1,855	379	12	15	349
2P	2,475	47	2,523	797	21	29	490
Un-Developed Reserves	**Sales Gas (PJ)**	**Ethane (PJ)**	**Total Sales Gas (PJ)**	**LPG (kTonne)**	**Condensate (MMstb)**	**Oil (MMstb)**	**Oil Equivalent (MMboe)**
1P	789	6	795	88	4	6	147
2P	2,415	23	2,437	472	11	10	443
Total Reserves	**Sales Gas (PJ)**	**Ethane (PJ)**	**Total Sales Gas (PJ)**	**LPG (kTonne)**	**Condensate (MMstb)**	**Oil (MMstb)**	**Oil Equivalent (MMboe)**
1P	2,622	29	2,650	466	16	22	496
2P	4,890	70	4,960	1,269	33	39	933
Contingent Resources	**Sales Gas (PJ)**	**Ethane (PJ)**	**Total Sales Gas (PJ)**	**LPG (kTonne)**	**Condensate (MMstb)**	**Oil (MMstb)**	**Oil Equivalent (MMboe)**
1C	5,737	40	5,777	1,060	63	80	1,141
2C	11,240	121	11,361	3,014	148	165	2,282

Notes:
1. Totals may not exactly equal the sum of the individual entries because of rounding.
2. Total Sales Gas is the sum of Sales Gas and Ethane.
3. Conversion factors to MMboe are provided in Appendix 1.
4. Audited in compliance with SPE-PRMS Definitions and Guidelines dated June 2018 (Version 1.01)

Santos provided descriptions of each of their producing assets and proposed developments for GaffneyCline's consideration. Where GaffneyCline considered the descriptions consistent with their technical review they were accepted with consistent documentation. GaffneyCline's focus, at all times, was to document the analysis performed to verify and/or modify production and cost valuation scenario profiles presented for submission to Grant Samuel.

All production and cost profiles were provided on a Santos Net basis and GaffneyCline maintained the Santos nomenclature of sales gas produced. GaffneyCline adjusted profiles as necessary depending on the asset and the explanations are included in the body of this report. Commercial and cost information is considered sensitive and not included in detail even though reviewed by GaffneyCline.

Appendix IV includes a list of Santos' provided Licence holdings utilised for valuation input in this report. GaffneyCline has not undertaken an independent verification of these Licence interests.

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5.2 Santos' Western Australia Assets

5.2.1 Western Australia Overview

Santos has been operating in Western Australia (WA) since its first offshore discovery in the Carnarvon Basin in the early 1980's. Santos' WA assets are shown in **Figure 5.1**, and can be grouped into WA Gas projects, WA oil projects, and the Bedout assets.

Figure 5.1: Location Map of Western Australia Assets

Source: Santos

The fields in each asset group are listed in **Table 5.2**. Not listed in the table are several Prospective Resources assets. The exploration asset volumes have been accepted by GaffneyCline and the valuation methodology is explained in **Section 5.8**. Two of the exploration assets are located in the Carnarvon basin, i.e. Yoorn, intended as infill for the Varanus Island facilities and Dancer, intended as infill for the Devil Creek facilities. The Dancer well is slated for 2021 and the Yoorn well for 2022. The rest of the Prospective Resources assets are located in the Bedout Sub-basin and are intended as part of integrated Dorado development. These are Dorado's Baxter oil leg, Pavo and Apus. The Apus and Pavo wells are slated to be drilled in 2022.

Also not listed in the table is the Reindeer CCS project, which is still at an immature stage of assessment.

Table 5.2: Western Australia Assets Summary

Group	Facility	Field / Hydrocarbon Type	Field Status
Gas Projects (Northern Carnarvon Basin)	Varanus Island	John Brookes (Gas – Condensate)	Producing + Infill
		Spar-Halyard (Gas – Condensate)	Producing
		Harriet JV (Bambra: Oil, Lee: Gas – Condensate)	Producing
		Spartan (Gas – Condensate)	Discovered
		Corvus (Gas – Condensate)	Discovered
		Kultarr (Gas – Condensate)	Discovered
		Spar Deep (Gas – Condensate)	Discovered
		Ginger (Gas – Condensate)	Discovered
	Devil Creek	Reindeer (Gas – Condensate)	Producing
	Macedon	Macedon (Gas – Condensate)	Producing
Oil Projects (Northern Carnarvon Basin)	Ningaloo Vision	Van Gogh (Oil)	Producing + Infill
		Coniston-Novara (Oil)	Producing
	Pyrenees Venture	Pyrenees (Oil)	Producing + Infill
	Barrow Island	Barrow Island (Oil)	Producing
Bedout Sub-basin	Dorado	Dorado (Oil – Gas)	Discovered

5.2.1.1 Geology of the Northern Carnarvon and the Roebuck Basins

The WA assets are located in several sub-basins of the Northern Carnarvon Basin and the Roebuck Basin **Table 5.3**.

Table 5.3: Geological Location of the Fields

Location		Field / Hydrocarbon Type
Basin	Sub-basin	
Northern Carnarvon Basin	Dampier	Reindeer (Gas – Condensate) Corvus (Gas – Condensate)
	Barrow	John Brookes (Gas – Condensate) Spar-Halyard & Spar Deep (Gas – Condensate) Harriet JV (Bambra: Oil, Lee: Gas – Condensate) Spartan (Gas – Condensate) Kultarr (Gas – Condensate) Ginger (Gas – Condensate) Barrow Island (Oil)
	Exmouth	Van Gogh (Oil) Coniston-Novara (Oil) Pyrenees (Oil) Macedon (Gas – Condensate)
Roebuck	Bedout	Dorado (Oil, Gas)

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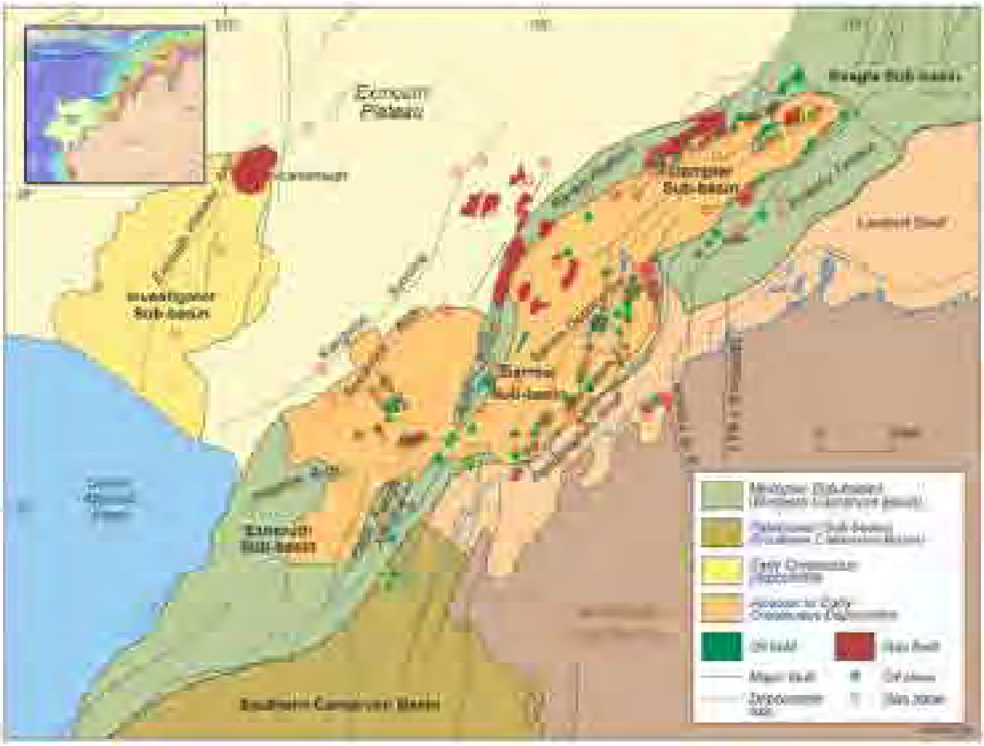
5.2.1.1.1 Northern Carnarvon Basin

The Palaeozoic-Recent Northern Carnarvon Basin, is a large, mainly offshore basin on the northwest shelf of Australia. It encompasses several sub-basins, including the Exmouth Sub-basin, Barrow Sub-basin and Dampier Sub-basin (**Figure 5.2**).

Figure 5.2: Tectonic Elements of the Northern Carnarvon Basin

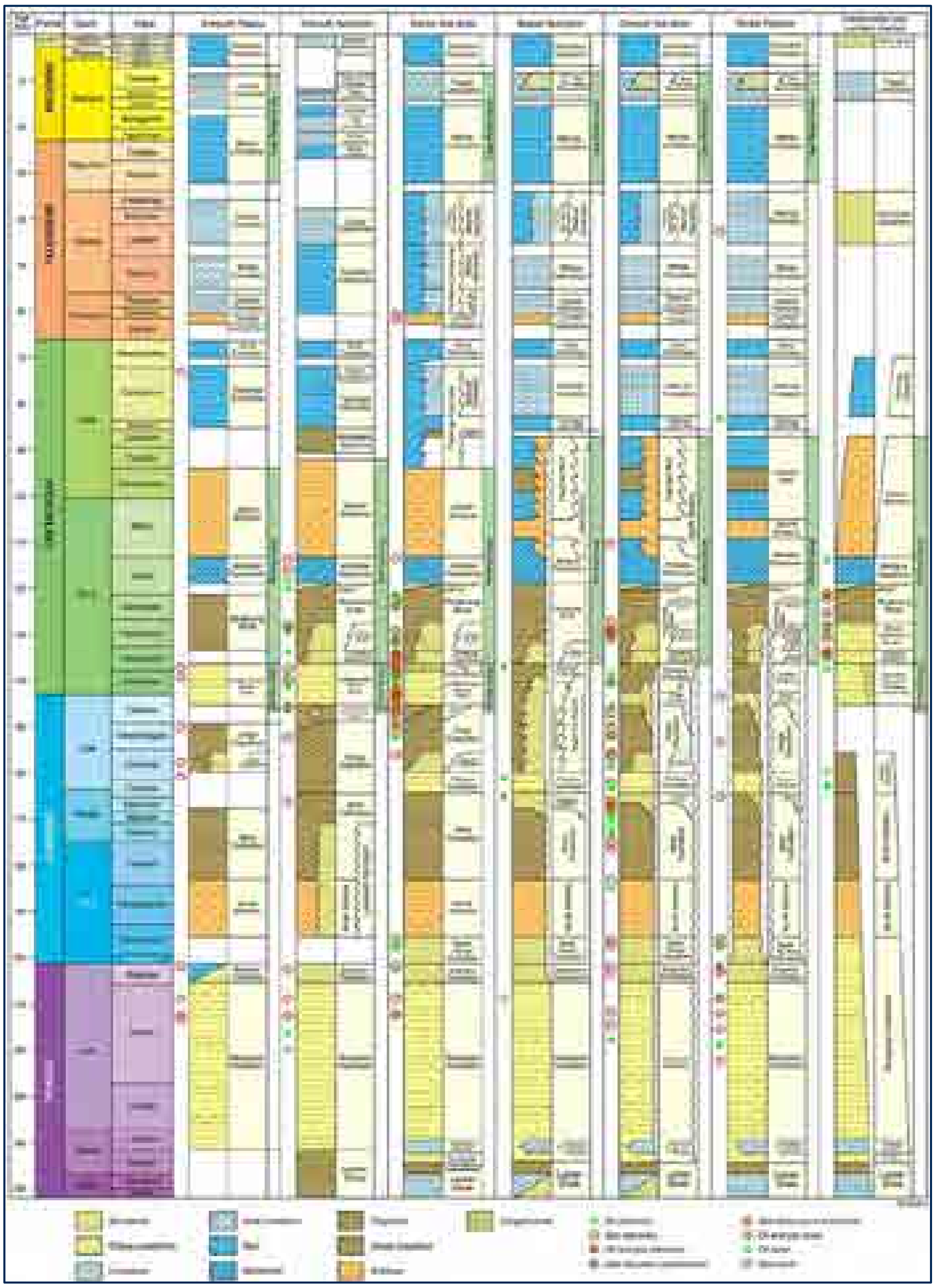


Source: Geoscience Australia

The main depocentres contain up to 15 km of sedimentary infill. Triassic to Early Cretaceous deposition is dominantly siliciclastic deltaic to marine, whereas slope and shelfal marls and carbonates dominate the Mid-Cretaceous to Cainozoic section. The stratigraphy of the Northern Carnarvon Basin is shown in **Figure 5.3**.

The main reservoirs of the fields within the Barrow and Exmouth Sub-basins are the Early Cretaceous Barrow Group and the overlying Birdrong Formation. For the fields in the Dampier Sub-basin, the reservoirs are either the Early Cretaceous Angel Formation or the Late Jurassic Legendre Formation.

Figure 5.3: Stratigraphy of the Northern Carnarvon Basin

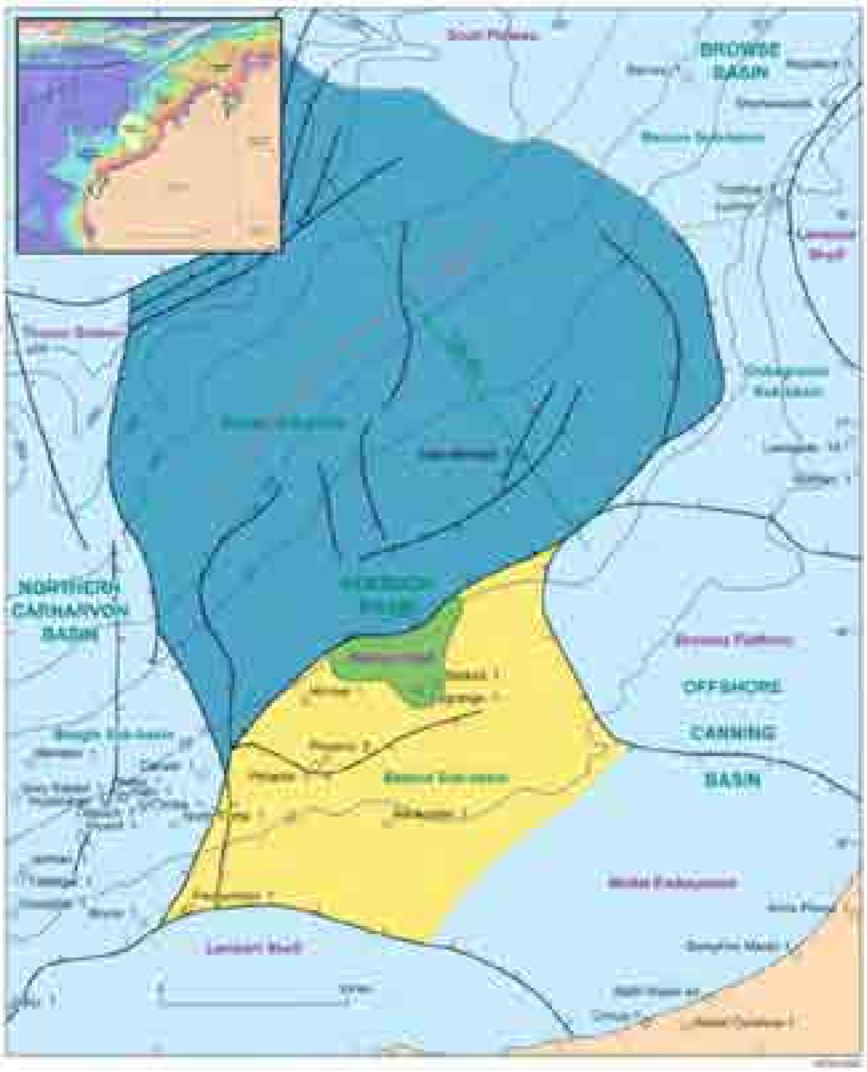


Source: Geoscience Australia

5.2.1.1.2 Roebuck Basin

Previously known as part of the Offshore Canning Basin (prior to 1994), the Roebuck Basin is located on the central North West Shelf between the Northern Carnarvon and Browse Basins. The Roebuck Basin consists of the Bedout and Rowley Sub-basins (**Figure 5.4**).

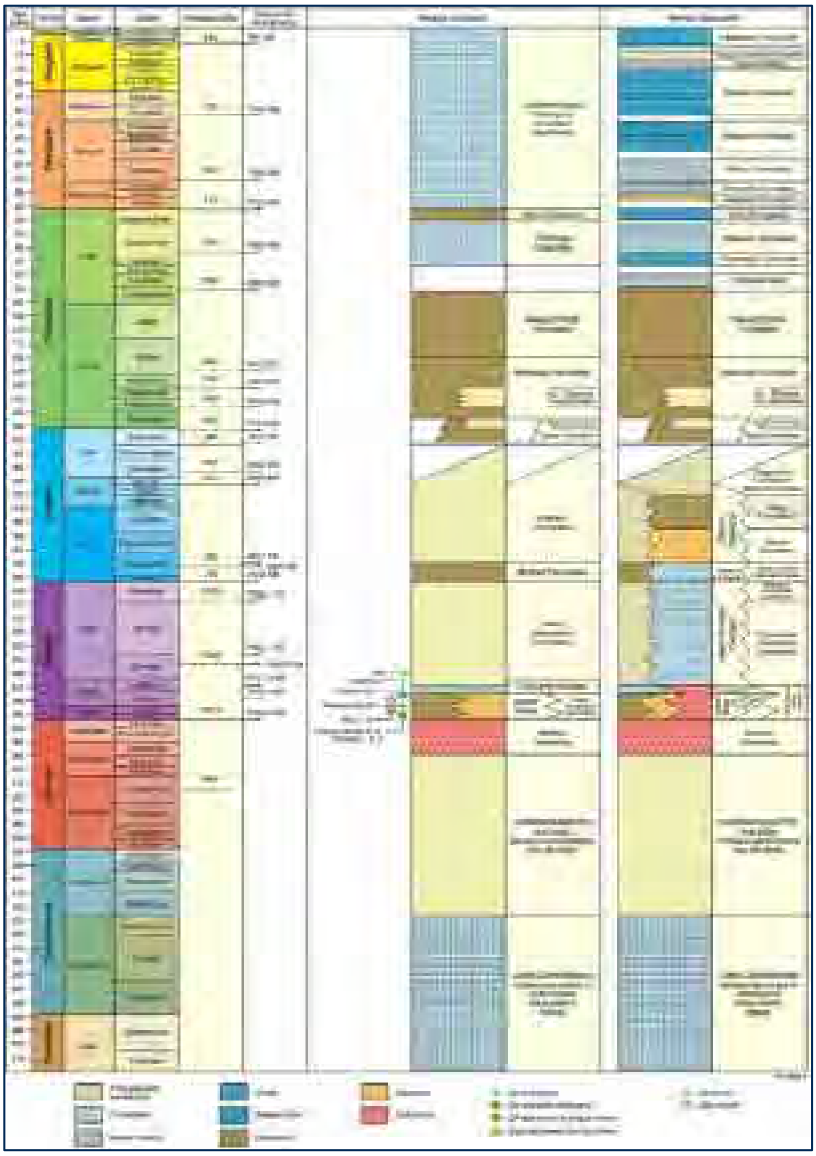
Figure 5.4: Tectonic Elements of the Roebuck Basin



Source: Geoscience Australia

It contains Permian to Cretaceous siliciclastic sediments and Tertiary carbonates. The stratigraphy of the basin is shown in **Figure 5.5**. The Roebuck Basin developed on the North West Shelf as a result of multi-phase rifting on the western flank of the Palaeozoic Canning Basin. The Mesozoic geology of the Roebuck Basin is similar to that of the adjoining Northern Carnarvon and Browse basins. The reservoir in the Dorado Field is the early Triassic sandstones.

Figure 5.5: Stratigraphy of the Roebuck Basin



Source: Geoscience Australia

5.2.1.2 Dataset

For the technical review of the Western Australia assets GaffneyCline was provided with the following data:

- Santos management presentations
- Year End 2020 Reserves and Resources Audit report by a third party[1] (referred to as "YE2020 Audit Report"),
- One realisation of the static model in Petrel projects for the following fields: John Brookes, Spar-Halyard, Spartan, Kultarr, Reindeer, Van Gogh, Pyrenees, Dorado.
- Dynamic models for the following fields: J.Brookes, Reindeer, Spar-Halyard, Corvus, Dorado, Kultarr, Macedon (plus GAP model), Pyrenees (plus GAP model) and Van Gogh.
- MS Excel files with Aucerna Reserves and Resources volume summary for the following fields: J.Brookes, Reindeer, Spar-Halyard, Corvus, Dorado, Van Gogh, Spartan and Harriet JV
- MS Excel files with production profiles for the following fields: J.Brookes, Reindeer, Spar-Halyard, Corvus, Van Gogh, Spartan and Harriet JV
- Field Development Plan (FDP) documents for the following fields: John Brookes, Spar-Halyard, Spartan, Reindeer, Macedon, Dorado

Additionally some presentation files and/or word documents from Santos to their third-party auditor (RISC) related to the Year End 2020 Reserves and Resources Audit ("Santos YE2020 Audit presentations"), for the following fields: John Brookes, Spar-Halyard, Harriet JV, Spartan, Corvus, Reindeer, Van Gogh, Dorado were also received and reviewed.

5.2.2 Western Australia Gas

5.2.2.1 Western Australia Gas Overview

In the Carnarvon Basin Santos has multiple gas assets. It holds interests in three of the state's major gas plants at Varanus Island, Devil Creek and Macedon, supplying around 45 percent of the State's domestic gas demand.

The Santos operated Varanus Island facility receives gas, condensate and oil produced and piped from the offshore fields. The development of the Varanus Island projects involves two main fields, John Brookes and Spar Halyard and some production from the Harriet Joint Venture (HJV). Production from John Brookes is tied back to an unmanned platform tied back to Varanus Island while production from Spar Halyard is tied back sub-sea. All production is piped to Varanus Island where condensate is removed, and raw gas is processed using the East Spar or Harriet JV facilities. The sales gas is exported from Varanus Island to the mainland via two 100 km sales

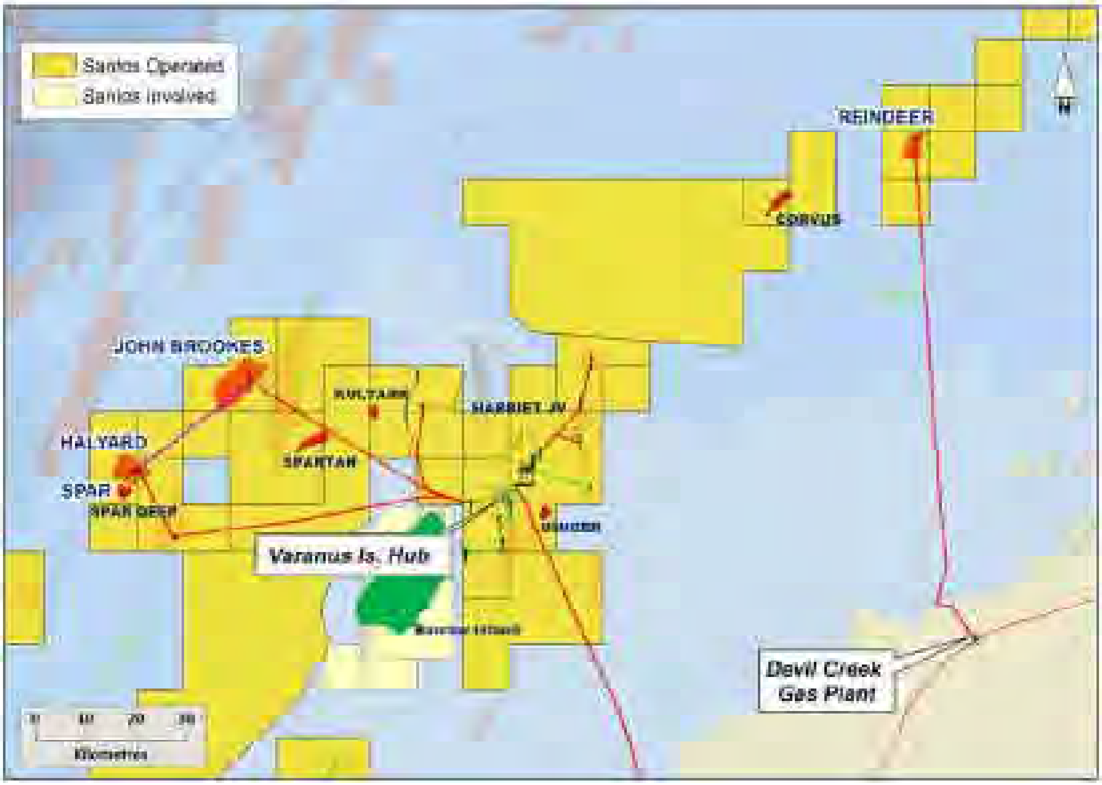
[1] RISC, January 2021, Independent Reserves and Resources Audit of selected Western and Northern Australian properties of Santos Limited as of 31 December 2020

gas pipelines which connect into the Dampier to Bunbury Pipeline and the Goldfields Gas Pipeline. Oil and condensate are stored on the island and transferred to tankers for direct export.

The Santos operated Devil Creek processing plant near Karratha has been operating since December 2011. It receives gas from the Reindeer Field unmanned wellhead platform via a 16-inch, 91 km subsea pipeline. From Devil Creek, sales gas is exported via a short spur line into the Dampier to Bunbury natural Gas Pipeline and condensate is trucked to BP Kwinana. The Devil Creek plant is a two-train facility with each processing train having capacity of approximately 130 MMscfd.

Figure 5.6 shows the location of the Varanus Island and Devil Creek facilities along with the associated fields.

Figure 5.6: Location Map of the Varanus Island and Devil Creek Facilities and the Associated Fields



Source: modified from Santos

Gas from the offshore BHP Operated Macedon field is piped to the Macedon Domestic Gas Plant near Onslow, also operated by BHP. Sales gas is compressed and sent to the WA domestic gas market. The Macedon Field and gas plant is located further south in the Exmouth Sub-basin (see map in **Section 5.2.3.1**).

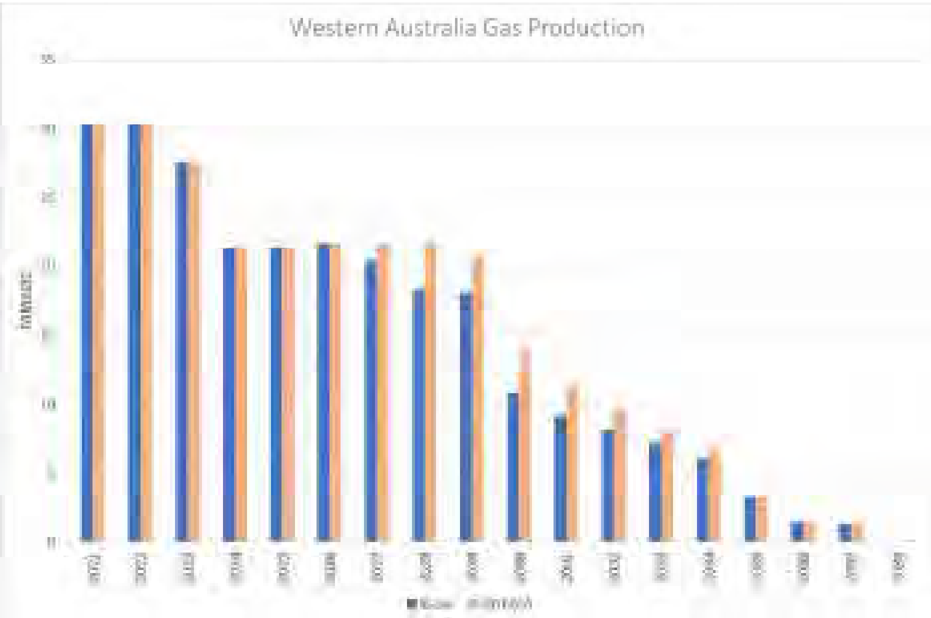
GaffneyCline's Base Case valuation scenario profile summary for Western Australia Gas is shown in **Table 5.4**. GaffneyCline considered a Varanus Island Stretch Case scenario for input to Grant Samuel based on the maturity of projects provided by Santos. Note all volumes are as of 1 January 2021 with Fuel and process shrinkages (Consumed in Operations (CiO) removed and represent sales profiles.

Table 5.4: Western Australia Gas Valuation Scenario Profile Summary as of 1 July 2021

Western Australia Gas	
GaffneyCline Net STO Profile Volume	242 MMboe Base, 257 MMboe Stretch

The gas production profiles for the Base Case include gas production from five currently producing fields and three undeveloped fields. The gas production profiles for the Stretch Case include production from the above fields plus the currently undeveloped Ginger and Spar Deep fields. The valuation scenario profiles are GaffneyCline's assessment based on Santos' production profiles with GaffneyCline's adjustments where indicated, which were accepted after a technical review was conducted for each field as described in the next sections. The profiles are given in **Figure 5.7** in aggregate due to commercial sensitivities declared by Santos.

Figure 5.7: Western Australia Gas Production Valuation Scenarios



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5.2.2.2 John Brookes

5.2.2.2.1 John Brookes Overview

Table 5.5: John Brookes Summary

Field Data	
Permit	WA-29-L
Location	60 km NW of Varanus island
Water Depth	75 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	November 1998 (John Brookes-1/ST1)
First Production	September 2005

John Brookes is a developed and producing offshore gas field located 60 km NW of Varanus Island in the Barrow Sub-basin (see location map in **Figure 5.6**).

The first well in the structure, Tryal Rocks-1 (1970) encountered poor reservoir and gas shows. Hydrocarbons were discovered in 1998 by the drilling of the John Brookes-1 well at the crest of the structure. Three further wells were drilled. Moon-1, drilled in 1999 on the north-eastern edge of the structure was unsuccessful. The following two wells, Thomas Bright-1 and Thomas Bright-2, drilled to the southwest and west of the John Brookes-1, respectively, successfully encountered the reservoir and hydrocarbons.

The field has been developed with four wells: John Brookes-2, -3, -5 and -6 via an unmanned wellhead platform. The platform was installed in 2005 and came onstream in September 2005. Raw gas is piped to the Varanus Island Processing Facility via a 55 km, 18-inch, multiphase pipeline. Condensate is removed on Varanus Island where it is stored, and the raw gas is processed into sales quality gas. Minimum turn down rates for the pipeline are in the order of 30-60 MMscfd.

5.2.2.2.2 Technical Review

<u>Geology and Geophysics Discussion</u>

The John Brookes Field is a NE-SW trending, large (18 km x 5 km) anticline with >100 m closure (**Figure 5.8**) in the Barrow Sub-basin of the northern part of Carnarvon Basin. The hydrocarbons were trapped in the Upper Barrow group sandstones, with top seal provided by the Lower Cretaceous Muderong Shale Formation. The structure was interpreted based on a set of multi-client 3D seismic data acquired by WesternGeco in 1997. The main interpreted horizon was the Base Muderong Shale, which is the base of the regional seal and generally represents the top reservoir in the field.

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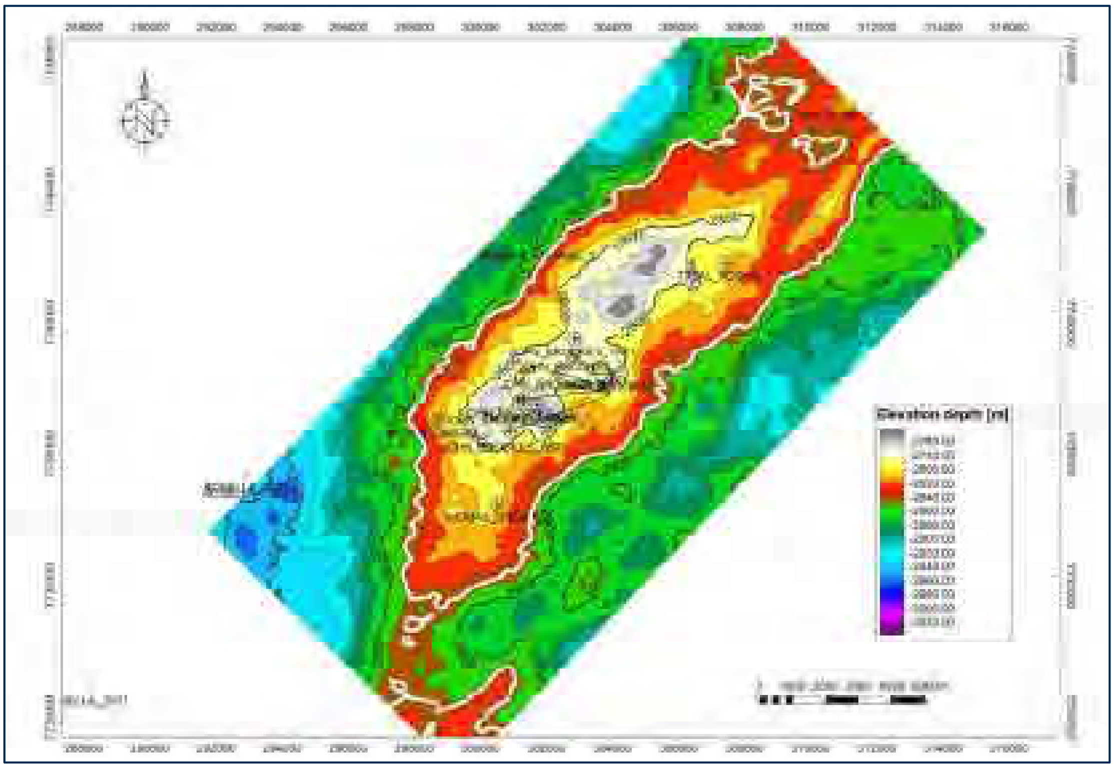
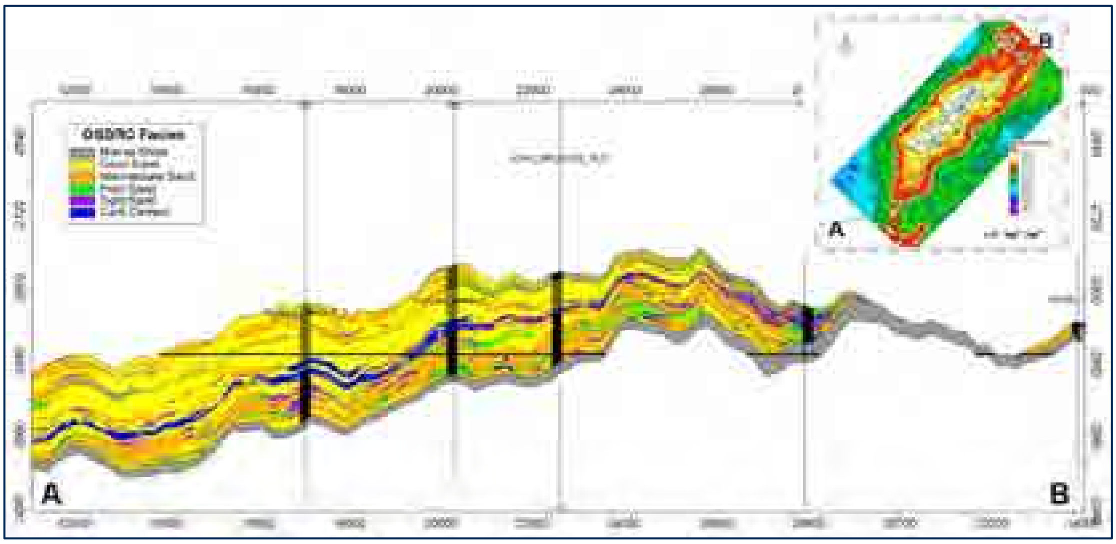
Figure 5.8: John Brookes Field Structure Depth Map at Top of Reservoir



The main reservoir of the field is the Barrow 'A' Sandstone, encountered at a depth of around 2,770 m TVDss. Reservoir quality is moderate in the upper part of the 'A' sandstone with porosities of 14% and permeabilities between 17 and 400 mD. Some gas is also present in the lower 'B' and 'C' reservoirs. The Barrow sandstones were deposited as lowstand debris flow turbidites and pinchout towards the northeast. A cross section through the strike of the field with the reservoir facies is shown in **Figure 5.9**.

Figure 5.9: John Brookes Field Cross Section



A Petrel project with one mid case static model realisation was provided along with YE2020 Audit Report. The report outlines a review of the static model and the GIIP of the field, which stated that uncertainty around the GIIP remains in the field despite over 15 years of production data. It is reported that in 2017 a full review of the static and dynamic uncertainties was conducted, with 12 static models in total constructed which were then brought to the dynamic simulation process. In 2019, new data was incorporated in the dynamic modelling and currently a static and dynamic modelling update is being conducted. In the YE2020 Audit, the auditor conducted material balance analysis to evaluate the range of GIIP. Based on this, Santos' estimates of GIIP is accepted. GaffneyCline reviewed the report and agrees with its methodology. The range of GIIP is shown in **Table 5.6**.

Table 5.6: John Brookes Field GIIP

Field	GIIP (Bscf)		
	Low	Best	High
John Brookes	1,523	1,761	2,155

Reservoir Engineering Discussion

GaffneyCline has reviewed the YE2020 Audit presentations on John Brookes Field.

The gas has a low CGR of 10.3 bbl/MMscf with 5.8 mol % CO_2. Santos has assumed a shrinkage factor for combined fuel, flare and gas composition change to be 6% pre-compression or 8% post-compression. Post compression involves higher requirement for fuel from September 2021 onwards. The sales gas HHV heating value is 1.11 PJ/Bscf. Initial reservoir pressure is 4,135 psia at 2,820 m TVDss.

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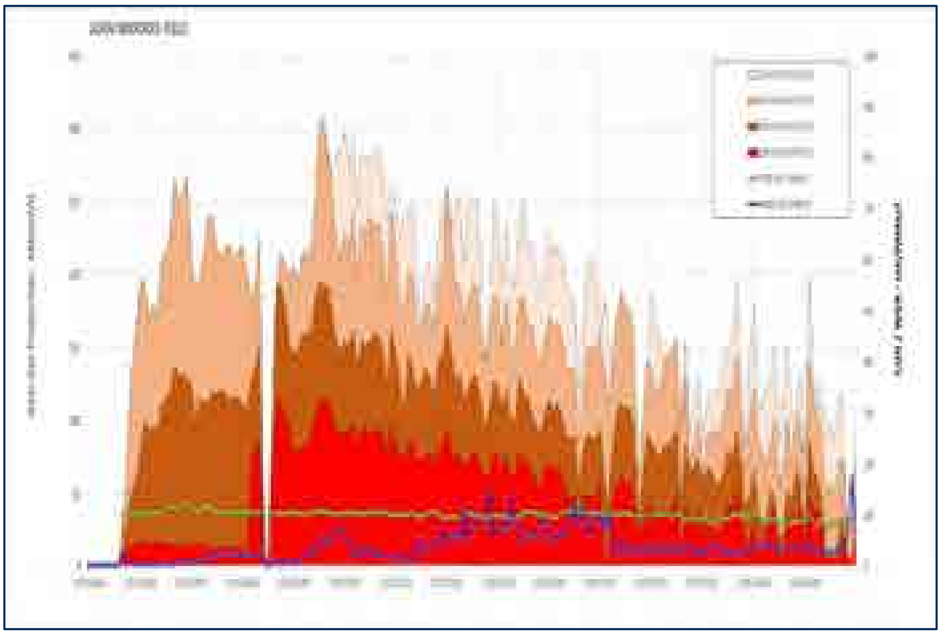
The production history of the field is shown in **Figure 5.10**. Cumulative production as of 30 September 2020 was 1,002 Bscf and 10.3 MMstb condensate or average produced CGR of 10.3 bbl/MMscf. There has been no formation water production to date.

Figure 5.10: John Brookes Field Production History



Source: Santos

Future production will continue from the existing 4 wells. In addition, Santos is planning one infill well in 2025. The infill (slant) well planned will target bypassed gas trapped by a dolomite streaks that exist at several existing wells.

Production Profile for Evaluation

GaffneyCline accepts Santos best estimate 2P sales gas production profile. It will be sourced from the 4 existing producers. The 2021 annual gas sales of 61.3 PJ (100% WI) or 164 MMscfd raw gas is slightly higher than historical 4Q2020 raw gas rate due to addition of compression in September 2021. Increased gas rate is expected in 2022 after compression is installed. The gas rate drop in 2023 is likely due to the Spartan well coming online and treated as a priority for production. Subsequently, the production profile shows an average decline of 14% p.a. for most of the profile period with a rate of 23 MMscfd in 2035. The decline is steeper than the historical decline from 2005 to 2020 and this could be attributable to dynamic model predicting water breakthrough in several wells.

The condensate recovery by Santos is based on a constant CGR of 10 stb/MMscf raw gas and it is accepted.

GaffneyCline accepts Santos best estimate 2C sales gas production profile related to the planned infill well. The recoverable volume for the proposed infill well is 14.2 Bscf raw gas, a relatively small volume and reasonable for bypass gas where the dolomite streaks act as baffles to flow. It will be a short production life with peak gas rate of 24 MMscfd. Incremental costs should be relatively low if the well can be drilled from the same wellhead platform and tied into the existing facilities. The condensate profile by Santos is based on a constant CGR of 10.0 stb/MMscf raw gas, and it is accepted.

The implied ultimate gas recovery factor ranges from 79 to 91% depending on the GIIP. P/Z analysis suggests a connected GIIP of 2,030 Bscf whilst the static model suggests a GIIP of 1,761 Bscf for the Best Case. After 15 years of relatively high-rate production, the reservoir pressure has dropped only 43% from an initial 4,000 psi to current 2,300 psi. It is more likely that there is a larger GIIP than that estimated by the static model.

The reference point for sales volumes is the East Spar gas plant, onshore Varanus Island. In the WA Gas Long Term Plan provided by Santos, John Brookes Field is sequenced to continue production in 2021 until 2035. The key uncertainty to the long-term field deliverability of John Brookes Field is the degree of aquifer support and GIIP.

The reasonable implied recovery factor, with compression to be available in late 2021, and a field with relatively high current reservoir pressure despite 15 years of relatively high production rate, all support the production profile generated by Santos for the existing and proposed infill well. John Brookes Field acts as a swing producer and provides back fill when required to ensure the Operator meets its contractual obligations.

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5.2.2.3 Spar-Halyard

5.2.2.3.1 Spar Halyard Overview

Table 5.7: Spar-Halyard Summary

Field Data	
Permit	WA-13-L / WA-45-L
Location	70 km W of Varanus Island
Water Depth	130 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	March 2008 (Halyard-1), September 1976 (Spar-1)
First Production	June 2011 (Halyard), October 2017 (Spar)

Spar-Halyard is a developed and producing offshore gas field located 20 km to the southwest of the John Brookes Field and 70 km west of Varanus Island in the Barrow Sub-basin (see location map in **Figure 5.6**).

The Spar-Halyard Field was discovered with the drilling of the Spar-1 well in 1976, which tested gas (11 MMscfd) in a poorly developed reservoir. In 2008 Halyard-1, drilled 3.5 km away in a NE direction, tested gas (68 MMscfd) in the Halyard reservoir. Spar-2 well drilled in 2010 between the two wells tested gas from the Spar reservoir at 58 MMscfd.

Production from Spar-Halyard is tied back sub-sea. Spar-Halyard gas is piped to the existing 16km, 10" East Spar pipeline, then onto Varanus Island via a 62 km, 13" pipeline where condensate is removed, and raw gas is processed using the East Spar and Harriet Joint Venture facilities. Minimum turndown rates for this pipeline are in the order of 20-40 MMscfd.

5.2.2.3.2 Technical Review

Geology and Geophysics Discussion

The Spar-Halyard structure is formed of a NE-SW trending, elongated four-way dip closure of about 10 km by 4 km size (**Figure 5.11**), and located in the Barrow Sub-basin of the northern part of Carnarvon Basin. Like its neighbouring larger field John Brookes, the Spar-Halyard Field is sealed by the regional Muderong Shale. The structure was mapped on a set of speculative 3D seismic data acquired by WesternGeco in 1997. The original processed data was of poor quality and was mainly used to map the top of the structure. More recent reprocessing was able to show the internal architecture of the reservoir, showing that the youngest unit of the Barrow Group (Halyard Sand) was only penetrated by the Halyard-1 well, while the older reservoir unit (Spar Sand) was penetrated by all three wells.

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The reservoir of the field is part of the Early Cretaceous Barrow Group, formed by the Barrow Delta. It was found at a depth of around 2,550 m TVDss. It comprises a series of delta front foresets with good to excellent quality sands of around 16% porosity and poor to moderate shaley sands of around 12% porosity. **Figure 5.12** shows the cross section of the field through the three wells with the facies distribution throughout the field.

Figure 5.11: Spar-Halyard Field Structure Depth Map at Top of Reservoir

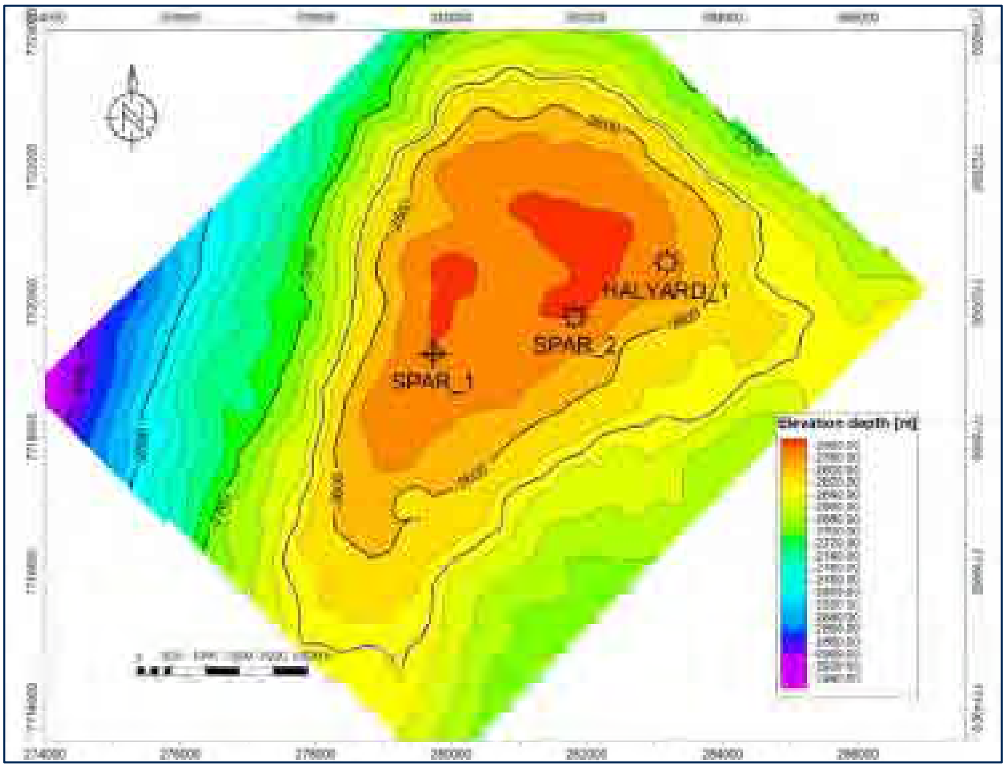

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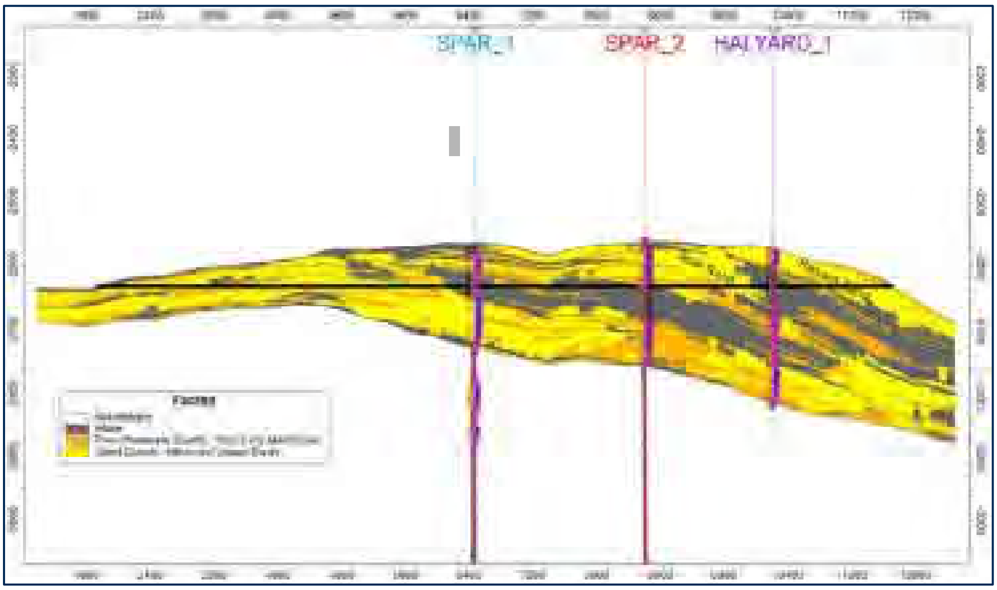
Figure 5.12: Spar-Halyard Field Cross Section Showing the Facies Distribution



A Petrel project with one mid case static model was provided along with the YE2020 Audit Report. The report outlines a review of the static model and the GIIP of the field. It is reported that in 2017 a full review of the static and dynamic uncertainties was conducted, with 9 static model in total constructed, which were then brought to the dynamic simulation process. An additional 3 static models were created in 2018. The static models were reviewed by RISC in 2018 and yielded a range of GIIP from 472 Bscf in the Low Case to 823 in the High Case. The static model provided to GaffneyCline is one of the High Case realisations. Subsequent history matching narrowed the range. This range has been reviewed and accepted by RISC. The GIIP range as reported in the YE2020 Audit Report is shown in **Table 5.8**.

Table 5.8: Spar-Halyard Field GIIP

Field	GIIP (Bscf)		
	Low	Best	High
Spar-Halyard	705	727	831

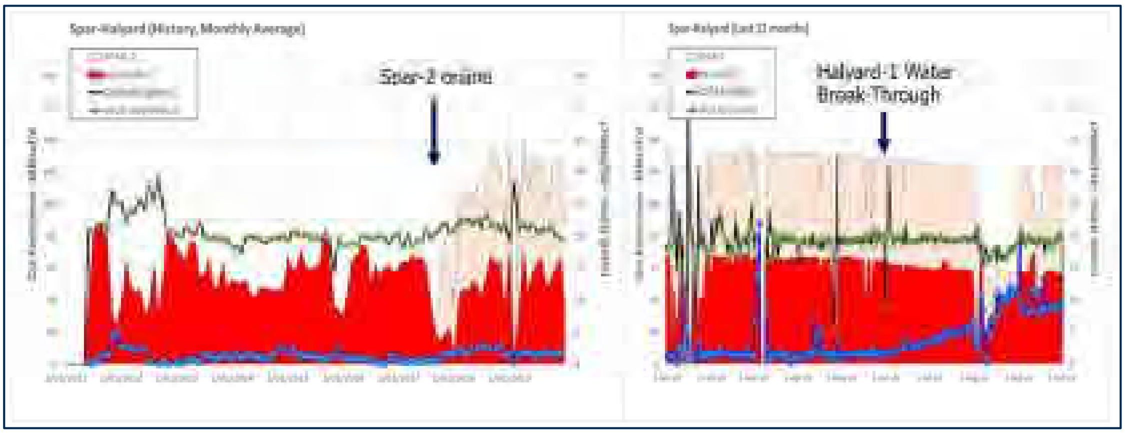
Reservoir Engineering Discussion

GaffneyCline has reviewed Santos presentation slides, Eclipse stand-alone simulation models and the YE2020 Audit Report.

Compositional analysis of Halyard and Spar bottomhole gas indicated wet gas with methane content of 85%, CO_2 3% and N_2 1%. The dew point pressure is 3,600 psi. Spar and Halyard production history is shown in **Figure 5.13**. Halyard has produced 187 Bscf of raw gas and 3.8 MMstb of condensate as of 1 November 2020. Spar has produced approximately 62 Bscf of raw gas and 1.4 MMstb of condensate as of 30 September 2020. Monthly gas production from Halyard-1 and Spar-2 in total has increased to average of 135 MMscfd since 2019. Water breakthrough occurred in Halyard-1 in June 2020.

In 2020 Santos updated its YE2019 dynamic model due to Halyard-1 water breakthrough in June 2020 (**Figure 5.13**). No significant updates to static modelling have been performed in 2020. As Halyard-1 water breakthrough happening later than expected, half of the YE2019 dynamic sensitivity models became invalid and therefore Santos updated the dynamic modelling work. The updated history matched model has increased the Best Case estimate GIIP from 689 to 727 Bscf (an increase of 38 Bscf).

Figure 5.13: Spar-Halyard Production History and Halyard-1 Water Breakthrough



Source: Santos

RISC has conducted an independent audit of Santos 2020 updated model and has supported Santos YE2020 remaining recoverable gas, which was generated using RESOLVE by connecting the GAP network model to a subsurface Eclipse model.

GaffneyCline reviewed the simulation model by checking the GIIP, EUR, input of critical gas saturation (largest uncertainty), permeability modifications, history matching and forecast of the two producers. GaffneyCline opines that model is acceptable for forecasting purposes and the final EUR in the model matches what was reported by Santos. GaffneyCline observed the difference in EUR between integrated network IPM/Eclipse model and stand-alone model is negligible as shown in Santos presentation slides. GaffneyCline supports Santos production profiles for the valuation inputs.

<u>Production Profile for Evaluation</u>

GaffneyCline accepted the Santos valuation gas and condensate production profiles.

5.2.2.1 Harriet JV (Bambra/Lee)

5.2.2.1.1 Harriet JV Overview

Table 5.9: Harriet JV (Bambra/Lee) Summary

Field Data	
Permit	TL/1 (Bambra & Lee), TL/10 (Bambra)
Location	10 km NE of Varanus Island
Santos Working Interest	100%
JV partners	N/A

The Harriet JV comprise of several fields in multiple production and exploration licenses, most of which have been suspended or P&A'd. The remaining producing fields are the Bambra oil field and the Lee gas and condensate field. The group of fields is located in the Barrow Sub-basin, about 10 km NE of the Varanus Island (see location map in **Figure 5.6**).

Bambra has been producing oil since 2005, with gas lift injection. In Bambra, only two wells are active, Bambra-7 and Bambra-8. All other wells to the platform are inactive or suspended. Lee has been producing gas (with a high condensate gas ratio) since 2013, and only two wells are active- Lee-3 and Lee-4. All other wells to the platform are inactive or suspended, except for Linda-3 which provides instrument gas.

5.2.2.1.2 Technical Review

The remaining operational fields in Harriet JV are Bambra oil field and Lee gas condensate field. The Harriet JV volume is very small (0.5 MMboe). The YE2020 Audit supports Santos remaining volume. GaffneyCline did not conduct any analysis and has accepted Santos volume.

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5.2.2.2 Spartan

5.2.2.2.1 Spartan Overview

Table 5.10: Spartan Summary

Field Data	
Permit	WA-63-L
Location	37 km NW of Varanus Island
Water Depth	60 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	September 2016
First Production	1Q 2023

Spartan is a small undeveloped gas field, one of the infrastructure-led tie-back opportunities to maintain production for the Varanus Island facilities. It is located 37 km NW of the Varanus Island, in the Barrow Sub-basin (see location map in **Figure 5.6**).

The field was discovered in 2016 by the drilling of Spartan-1A well, which encountered 30.5 m of gas pay in the *S.Tabulata* sand of the Birdrong Formation, which overlies the Barrow Group. A well drilled previously in 2003, Montgomery-1, encountered a thin gas bearing sand in the *P. burgeri* sandstone, above the *S.tabulata* sandstone.

The Spartan proposed development will be a subsea tie-back to the existing John Brookes wellhead platform. The field will be produced using single deviated well, which will be drilled around Q3 2022. The project was sanctioned in February 2021 with RFSU expected in Q1 2023.

5.2.2.2.2 Technical Review

<u>Geology and Geophysics Discussion</u>

The Spartan structure is a NE-SW trending, elongated, narrow four-way dip closure about 8 km in length (**Figure 5.14**). The field was interpreted based on several sets of 3D seismic data of several vintages. The structure is coincident with a high amplitude seismic event at the top of reservoir. One of the key uncertainties in the structure is the gross rock volumes, which were captured in three different structural cases: Low, Reference and High cases. The *S.tabulata* reservoir is encountered at a depth of around 2,500 m TVDss. Gas water contact was interpreted at a depth of 2,547 m TVDss based on the extrapolation from the water gradient found at the Montgomery-1 well.

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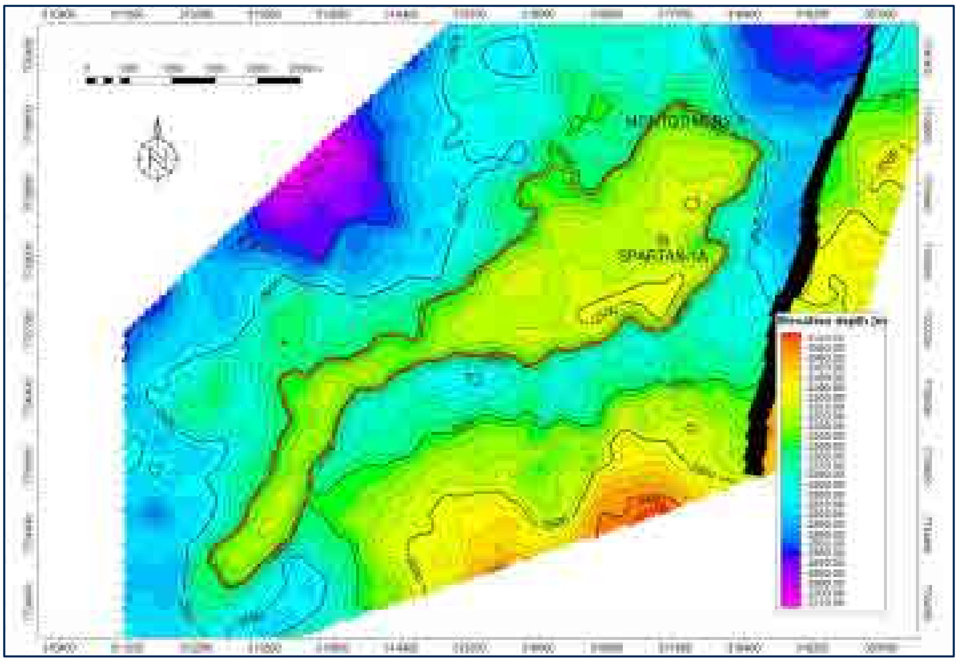
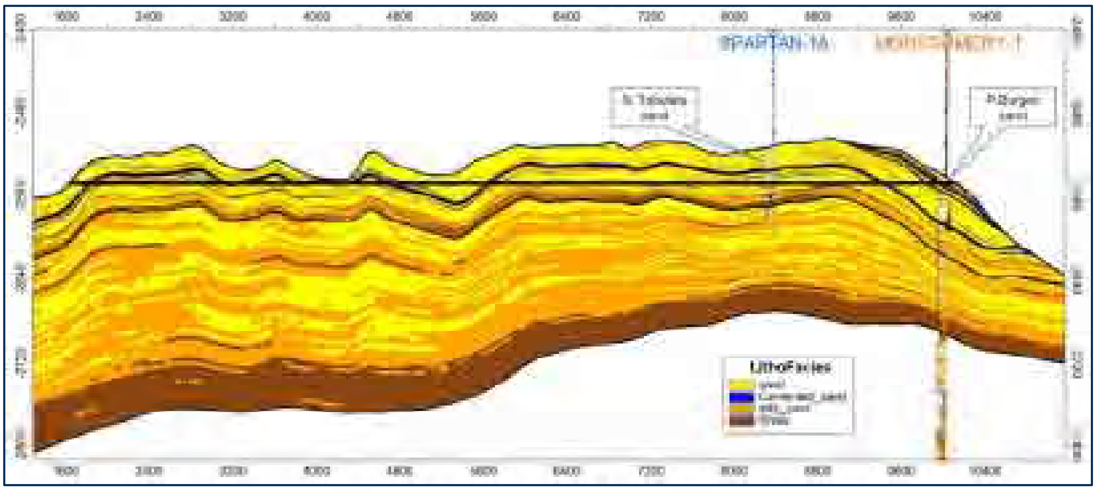
Figure 5.14: Spartan Structure Depth Map at the Top of the Reservoir



The reservoirs of the Spartan fields are interpreted to be deposited in a deltaic environment, representing deposition by gravity mass in a pro-delta setting. The facies are dominated by sandstones (**Figure 5.15**), thought to be deposited by turbidity currents and debris flows. The sandstone has an average porosity of 16%.

Figure 5.15: Spartan Structure Cross Section Showing Facies Distribution



Santos incorporated the gross rock volumes uncertainty in its modelling. Reservoir facies and quality were also considered as key uncertainties. GaffneyCline was provided with one realisation of the static model but has reviewed the YE2020 Audit Report and is satisfied with the review and checks conducted by the third party auditor. The GIIP volumes of the Spartan Field are shown in **Table 5.11**.

Table 5.11: Spartan Field GIIP

Field	GIIP (Bscf)		
	Low	Best	High
Spartan	87	136	184

Reservoir Engineering Discussion

GaffneyCline has reviewed Santos' presentation slides, Eclipse stand-alone simulation models, Spartan preliminary Field Development Plan Rev-0 and the YE2020 Audit Report.

Spartan is an undeveloped gas field scheduled to be developed as a single deviated subsea well tie-back to the John Brookes gas pipeline. Well Spartan-1A indicates the reservoir is normally pressured with a reservoir pressure of 3,600 psia. PVT samples taken from 2,561 m-MD indicate a lean gas with 5% CO_2 and 1.6% N_2 with average CGR of 16.2 stb/MMscf (C5+/raw gas). The dew point pressure is close to the reservoir pressure and maximum condensate drop out is only 1.2%, which indicates liquid drop out is not a concern. MDT sampling only taken in the gas leg and as such no GWC has been identified from pressure analysis.

The development of Spartan is a tie-back to John Brookes WHP and the development will defer some of John Brookes' production. The profiles assume Spartan produces at an offtake rate of 50 TJ/d, Varanus Island targets a plateau rate of 240 TJ/d and John Brookes production reduced (deferring) to meet the Varanus Island plateau target of 240 TJ/d. Spartan resources have been categorised as Contingent Resources - Justified for Development and the first gas is expected in 2023.

Santos' Eclipse stand-alone dynamic simulation result indicates a gas recovery factor of 59% with minimum THP of 1,000 psia, the same recovery factor as reported in the preliminary Field Development Plan.

The latest update for YE2020 is to tie-back Spartan production to the John Brookes WHP using a smaller flowline and the recovery factor has increased to 61%, modelling with surface network model. Santos investigated other various production scenarios (John Brookes Hot-Tap tie-back, East Spar pipeline tie-back, Wonnich pipeline tie-back) resulting in similar recovery. The YE2020 Audit has endorsed Santos YE2020 remaining recoverable gas. GaffneyCline supports the recovery estimated by Santos, therefore accepting Santos' volume for the gross remaining recoverable raw gas.

Production Profile for Evaluation

GaffneyCline accepted Santos' gas and condensate production profiles. The net sales gas (net of fuel and flare of 4%) and condensate (based on constant CGR of 14.2 stb/MMscf).

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5.2.2.3 Corvus

5.2.2.3.1 Corvus Overview

Table 5.12: Corvus Summary

Field Data	
Permit	WA-45-R
Location	70 km NE of the Varanus Island Hub
Water Depth	63 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	2000
First Production	2026

Corvus is a small undeveloped gas field, located in the Dampier Sub-basin 25 km SW of the Reindeer Field (see location map in **Figure 5.6**). The field was considered to be tied back to either the Varanus Island or the Devil Creek facilities. The current plan is for a tie-back to the Varanus Island facilities (70 km away to the SW).

The field was discovered in 2000 with the drilling of the Corvus-1 ST1 well, which intersected 401 m of Mungaroo Formation sandstones with poor reservoir quality. Corvus-2 appraisal well drilled in 2019 about 2.5 km SW of the Corvus-1 ST1 well intersected a gas column of over 400 m, but in similar poor reservoir intersected by the first well. The sidetrack of the first well was tested in an open hole DST, flowing 14.6 MMscfd.

Santos has classified the recoverable volumes as Contingent Resource Development on Hold due to pending subsurface development studies. Santos has included Corvus volume in the valuation model run as an integrated case with midstream assuming start up production in 2026 supplying gas to Varanus Island.

5.2.2.3.2 Technical Review

Geology and Geophysics Discussion

The Corvus structure is an elongated, NE-SW trending anticline, of about 4 km long by less than 1 km wide (**Figure 5.16**). The crest of the structure is encountered at approximately 3,363 m TVDss.

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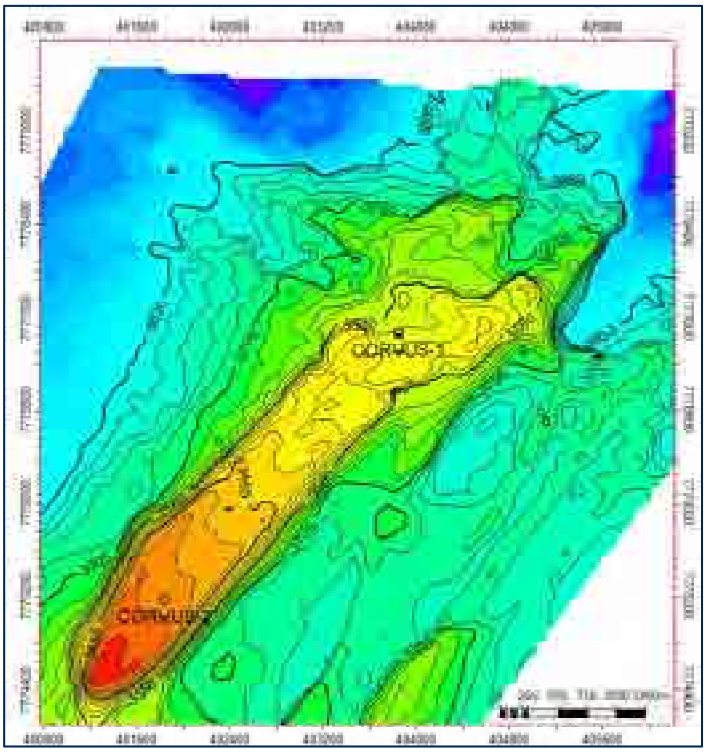
Figure 5.16: Corvus Field Structure Depth Map at Top Mungaroo Sandstone



Source: Santos

The field is bounded by large extensional faults to the east and west along with smaller counter-regional northward dipping faults towards the northern end of the field. Some faulted out, missing sections were encountered in Corvus-2.

The reservoir of the field, the Triassic age Mungaroo Formation, is interpreted to be deposited in a fluvial environment, in a dominantly braided fluvial system. It is also interpreted from the well data that the reservoir property degradation was due to diagenesis, with quartz overgrowth reducing the overall pore volume. The average porosity of the net hydrocarbon column is 9.5%.

GaffneyCline was not provided with a static model for the field, hence relies on the YE2020 Audit Report for the GIIP volumes. The report described the static model and the review performed, and GaffneyCline concurs with its findings. The GIIP volumes of the Corvus Field are shown in **Table 5.13**.

Table 5.13: Corvus Field GIIP

Field	GIIP (Bscf)		
	Low	Best	High
Corvus	314	382	467

Reservoir Engineering Discussion

GaffneyCline has reviewed Santos presentations on Corvus.

DST was performed on one well, Corvus-1. Formation pressures and PVT fluid sample was acquired in Corvus-2. MDT data indicate both wells to be in pressure communication in the gas column. There is uncertainty in the FWL as there were no pressure points acquired in the water leg.

The Corvus-1/ST1 well in the Mungaroo sand was tested over the open hole interval from 3,551 to 3,709 m MDRT at 14.6 MMscfd through a 28/64 inch choke with 1,000 psi drawdown and CO_2 content of 8%. Initial reservoir pressure was 5,474 psia and interpreted flow capacity is 100 mD-m or reservoir permeability of 1.6 mD.

Santos planned to develop Corvus gas field by drilling two subsea deviated (45 degrees) wells and tie-back via a 62 km rigid flowline to the junction in the Linda pipeline at Varanus Island, where inlet compression will be provided. Power and controls would be provided from the nearby Reindeer platform. A vertical flow turndown limit of 10 MMscfd through 5.5 inch tubing has been used to cut-off the production forecast. Experimental design by Santos generated a maximum potential raw gas rate from two deviated wells with a range of 52 (P90), 70 (P50) and 137 (P10) MMscfd.

GaffneyCline agrees with Santos' implied Gas Recovery factor of 29% (Best Case EUR of 109 Bscf and GIIP of 382 Bscf). It is reasonable for a low permeability (0.01 to 5 mD) gas reservoir. The GIIP is based on no NTG and porosity cut-offs. The EUR was determined from detailed dynamic modelling by Santos.

Production Profile for Evaluation

GaffneyCline accepts Santos' best estimate sales gas production profile. The peak sales gas rate is 52 MMscfd (or 55 MMscfd raw gas) in Year 2 and then declining.

The condensate recovery is based on initial CGR of 5 stb/MMscf raw gas with no decline over the 10 years of production. It is a relatively dry gas, so a low dew point pressure is expected; and there will be significant gas in place left behind after this period.

In Santos' WA Long Term gas plan, the Corvus field is sequenced to produce from mid-2026 onwards. The key uncertainty in the long term field deliverability of Corvus field is associated with the facies distribution.

The implied recovery factor and the turndown gas rate well limit are reasonable and support the production profile generated by Santos. Corvus Field will serve as infill Contingent Resource in the WA Long Term gas plan with first gas production in mid-2026.

5.2.2.1 Kultarr

5.2.2.1.1 Overview

Table 5.14: Kultarr Summary

Field Data	
Permit	WA-55-R
Location	30 km NW of the Varanus Island
Water Depth	45 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	2005
First Production	2028

Kultarr is a small undeveloped gas field in the Barrow Sub-basin, one of the infrastructure-led tie-back opportunities to maintain production for the Varanus Island facilities. It is located approximately 30 km NW of the Varanus Island (see location map in **Figure 5.6**).

The field was discovered in 2005 by the drilling of Kultarr-1. Santos has advised of pending subsurface development studies. Santos has included Kultarr volumes in the valuation model run as an integrated case with midstream.

5.2.2.1.2 Technical Review

The Kultarr Field is a small (1 km by 1.5 km) three-way dip closure against a fault at its eastern side (**Figure 5.17**). The reservoir is the *S. Tabulata* sand of the Birdrong Formation, which overlies the Barrow Group, encountered at a depth of approximately 2,500 m TVDss.

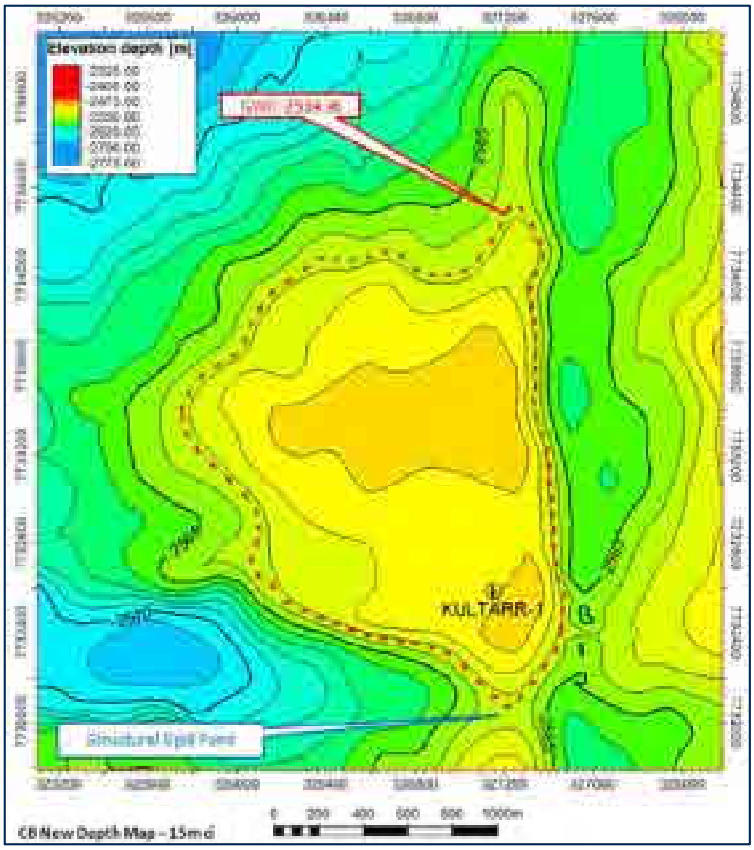
GaffneyCline has reviewed Santos simulation (Eclipse) files and sales production profile (Excel) for Kultarr Field. There was minimal technical information in the documents provided. It is unknown if the reservoir was tested.

The simulation model was based on one horizontal well of 500 m horizontal length. The average porosity is 9% and the permeability is 25 mD. Raw gas production rate in the model was 50 MMscfd for a one-year plateau and then declined as water encroachment occurred.

Kultarr gas field is planned to be developed with one subsea well tie-back to the slightly bigger Spartan gas field, located 11 km SW. A vertical flow turndown limit of 7 MMscfd is expected.

GaffneyCline agrees with Santos' simulation model implied gas recovery factor of 65% which is reasonable for a gas reservoir with average permeability around the well of 25 mD and porosity of 9%. The simulation model EUR is very close to the production forecast recoverable volume used by Santos for its valuation.

Figure 5.17: Kultarr Field Depth Structure Map at the Top Reservoir Section



Source: Santos

GaffneyCline accepts the Santos best estimate sales gas production profile with a peak sales gas rate of 52 MMscfd (or 55 MMscfd raw gas) in Year 2 and then declining. GaffneyCline assumed a shrinkage of 2% and a heating value of 1.02 PJ/Bscf.

The condensate recovery is based on initial CGR of 13 stb/MMscf raw gas (simulation model) and with no decline over the 3 years of production. It is a relatively dry gas and there is some pressure support with the model showing a WGR of 360 bbl/MMscf at end of production, and therefore the reservoir pressure could have remained above the dew point pressure (due to aquifer support).

The implied recovery factor, checks on the simulation model and the turndown gas rate well limit are all reasonable and support the production profile generated by Santos.

5.2.2.2 Ginger

5.2.2.2.1 Ginger Overview

Table 5.15: Ginger Summary

Field Data	
Permit	TL/1
Location	8 km SW of the Varanus Island
Water Depth	27 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	2003 (Ginger-1)
First Production	2027

Ginger is a small gas discovery in the Barrow Sub-basin, one of the infrastructure-led tie-back opportunities to maintain production for the Varanus Island facilities. It is located approximately 8 km SW of the Varanus Island (see location map in **Figure 5.6**).

The Ginger field was discovered by the drilling of Ginger-1 well in 2003. Santos has classified the recoverable volumes as Contingent Resource Development Unclarified due to pending subsurface development studies. Santos has included Ginger volumes in the valuation model run as an integrated case with midstream assuming start up production in 2027 supplying gas to Varanus Island. The current plan is to have one deviated or horizontal well tie-back to an existing platform.

5.2.2.2.2 Technical Review

The Ginger gas accumulation is trapped stratigraphically in a sandstone body deposited by gravity mass flow. The reservoir is the Late Jurassic *W. clathrata* zone of the Biggada Sandstone, within the Dingo Claystone. The reservoir was encountered at a depth of 2,394 m TVDss and has a net pay of 13.5 m. The GDT of the gas accumulation is at 2,401 m TVDss. The reservoir has an average porosity of 18.3% with core permeability averaging 9 mD. The field's structure depth map and cross sections, also the well logs are shown in **Figure 5.18**.

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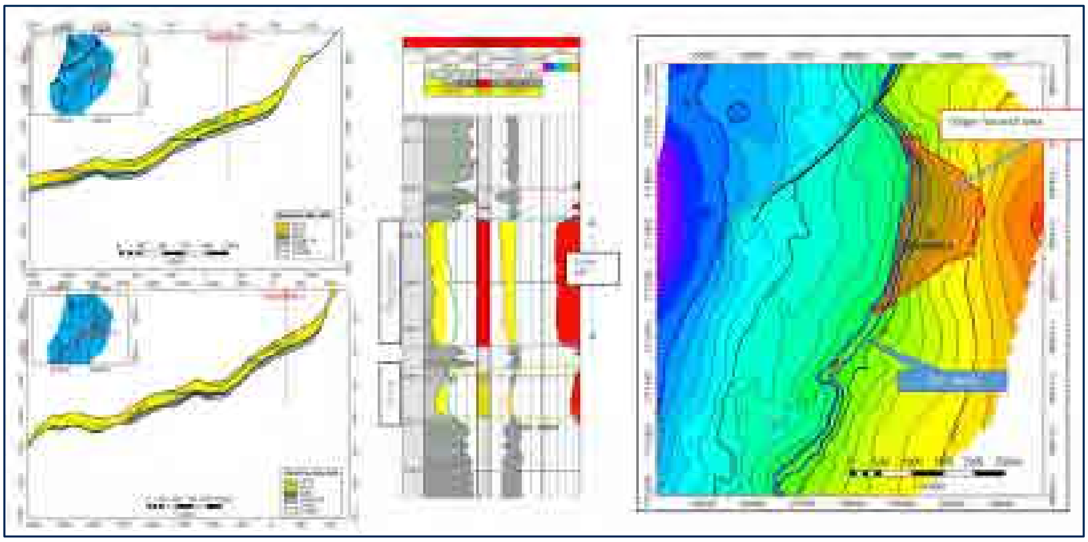
Figure 5.18: Ginger Field Structure Depth Map, Cross Section and Well Log



Source: Santos

Ginger's development plan is currently at an early stage and needs to be further defined.

Since no further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development and the justification as a commercial development is unknown based on available information, GaffneyCline has considered Ginger volume only in the Stretch Case based on Santos' profile provided.

Gaffney Cline

5.2.2.3 Spar Deep

5.2.2.3.1 Spar Deep Overview

Table 5.16: Spar Deep Summary

Field Data	
Permit	WA-13-L / WA-45-L
Location	70 km W of Varanus Island
Water Depth	130 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	2010 (Spar-2)
First Production	2029

Spar Deep, also known as Orlop, is undeveloped gas-condensate field, located below the developed Spar-Halyard Field in the Barrow Sub-basin which is producing from shallower interval. It is located 20 km to the southwest of the John Brookes Field and 70 km west of Varanus Island (see location map in **Figure 5.6**). Spar Deep was first encountered in the Spar-1 well drilled in 1976 but was only tested in 2010 by the Spar-2 well.

Santos has classified the recoverable volumes as Contingent Resource Development Unclarified due to pending subsurface development studies. Spar Deep volumes are included in the valuation model run as an integrated case with midstream assuming start up production in 2029 supplying gas to Varanus Island.

5.2.2.3.2 Technical Review

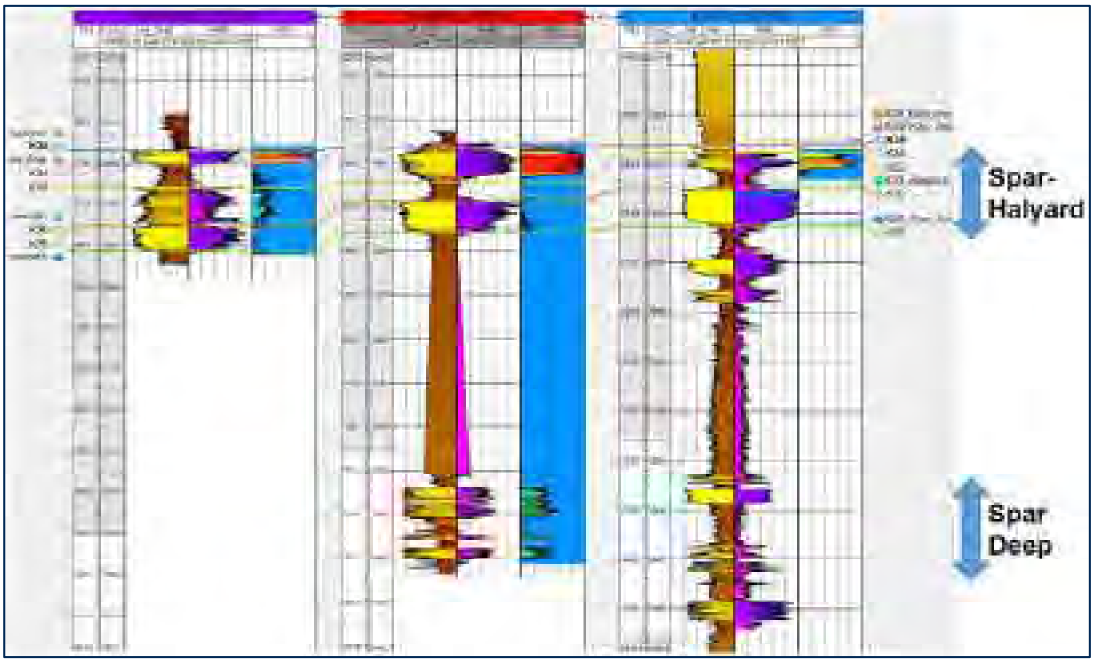
The Spar Deep reservoir is the *B reticulatum* (also known as K10) sands, a series of low permeability turbidite sands which underlies the main Spar reservoir (**Figure 5.19**). The reservoirs are divided into 3 group: Upper *B. reticulatum* sand, Middle *B. reticulatum* 1 sand and Middle *B. reticulatum* 2 sand. The Upper *B. reticulatum* sand was tested in Spar-2 well, flowing a maximum rate of 5.16 MMscfd.

The Spar Deep gas accumulation is stratigraphically trapped, with no clear seismically derived limit (**Figure 5.20**).

No GIIP or further data was provided, and the field was not included in YE2020 Audit Report, hence GaffneyCline could not comment upon the in-place volumes of the field.

The Spar Deep development plan needs to be further defined. Since no further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development and the justification as a commercial development is unknown based on available information, GaffneyCline has considered Spar Deep volume only in the Stretch Case.

Figure 5.19: Spar and Spar Deep Well logs



Source: Petrel project on Spar-Halyard, provided by Santos

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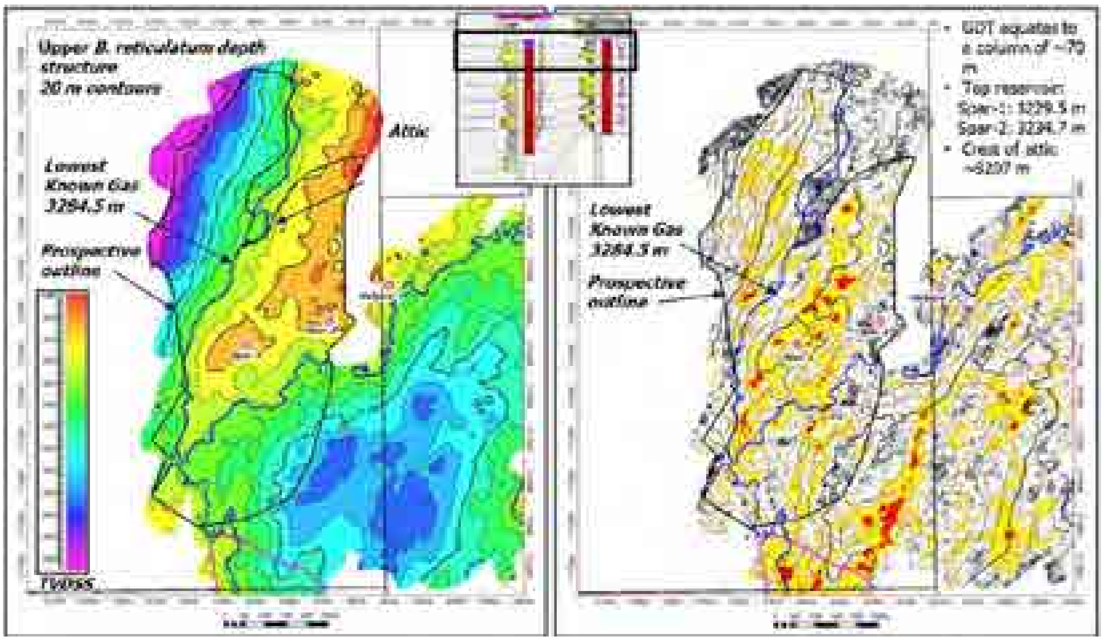
Figure 5.20: Spar Deep Structure Depth Map at Top *B. Reticulatum* Reservoir



Source: Santos

Gaffney Cline

5.2.2.4 Reindeer

5.2.2.4.1 Reindeer Overview

Table 5.17: Reindeer Summary

Field Data	
Permit	WA-41-L
Location	80 km NW of Dampier
Water Depth	65 m
Santos Working Interest	100%
JV partners	N/A
Discovery Date	October 1997 (Reindeer-1)
First Production	November 2011

Reindeer is a gas field located in the Dampier Sub-basin, 80 km NNW of Dampier in Western Australia. It supplies gas to the Devil Creek gas plant (see location map in **Figure 5.6**).

The Reindeer-1 discovery well was drilled in 1997 and encountered gas in the Middle Jurassic Legendre Formation. The discovery was appraised in 1998 with by the Caribou-1 well. The well was tested and flowed at 38 MMscfd. The field was further appraised by the Gnu-1 well, drilled in 2006.

The field has been developed with three wells from an unmanned wellhead platform. Production started in November 2011. Cumulative production as of 30 September 2020 was 306 Bscf gas and 1.2 MMstb of condensate.

5.2.2.4.2 Technical Review

Geology and Geophysics Discussion

The Reindeer gas field is formed of an SSW-NNE trending anticline located in the Dampier Sub-basin. The anticline is partially dip closed on its western flank and is faulted further by both along strike and E-W trending faults (**Figure 5.21**). Pressure data from the Reindeer-1, Caribou-1 and Gnu-1 wells does not suggest any fault compartmentalisation.

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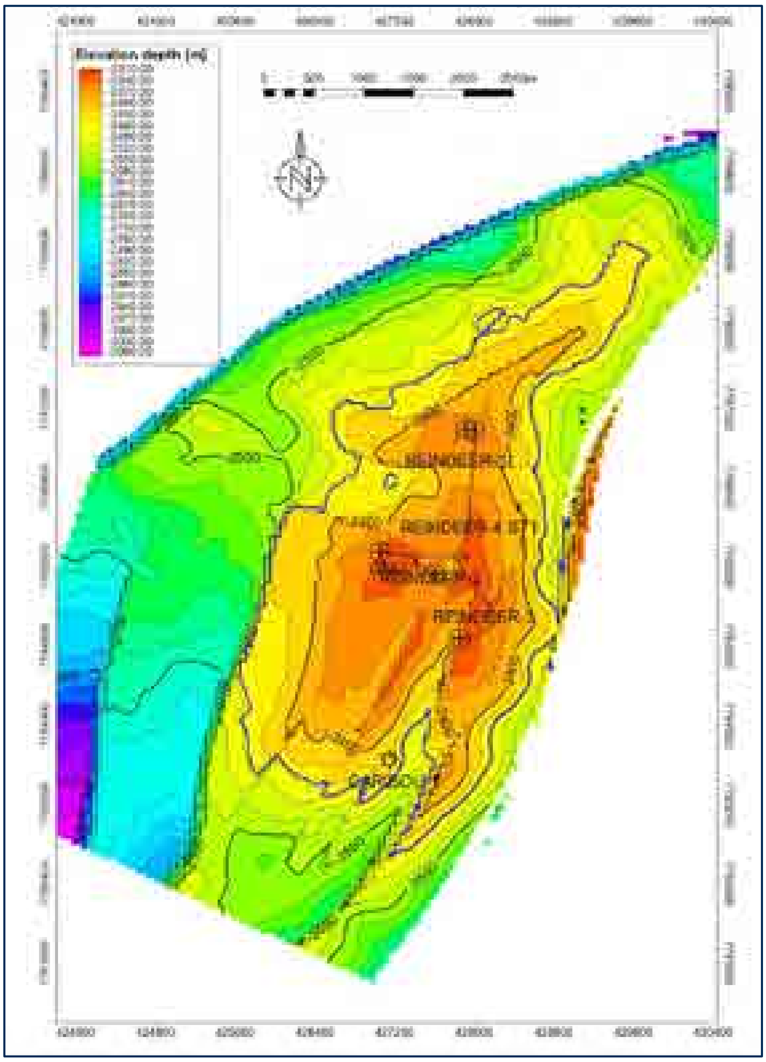
Figure 5.21: Reindeer Field Depth Structure Map at Top Legendre Formation



Source: Santos Petrel Project

The Legendre Formation reservoir is formed of stacked fluvio-deltaic sandstones with high net-to-gross. Reservoir quality is generally good with porosities of 18-20% and multi-Darcy permeability. The structural configuration and the facies distribution of the field can be seen in a cross section in **Figure 5.22**.

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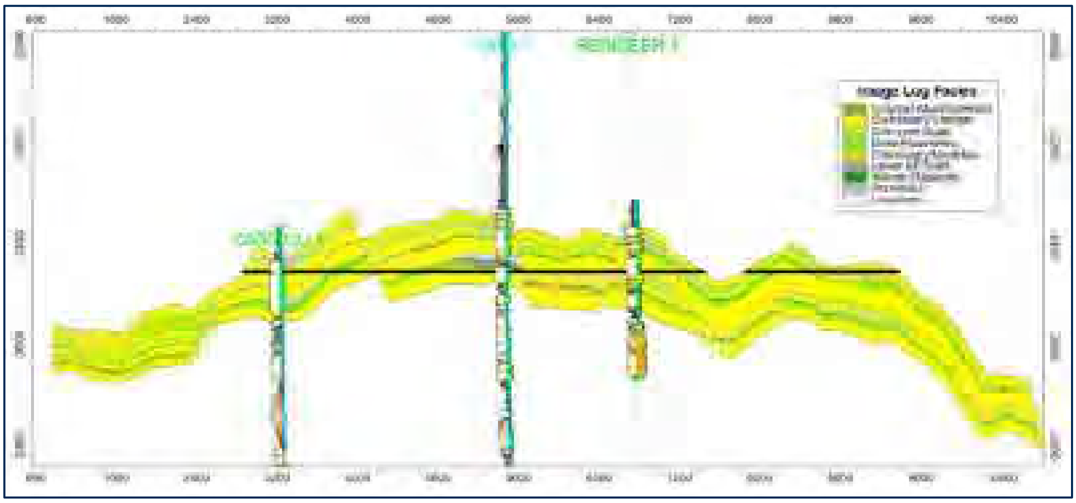
Figure 5.22: Reindeer Field SW-NE Cross Section



Static and dynamic modelling was updated in 2020, incorporating results of the reprocessed seismic data and the recently acquired production logging data. GaffneyCline was provided with one realisation of the static model, reflecting the Base Case interpretation, and used this to compare with the reported GIIP volumes. GaffneyCline also reviewed the YE2020 Audit Report and concurs with the checks that have been conducted by the third party auditor. The GIIP volume range of the Reindeer Field as reported in the YE2020 Audit Report is shown in **Table 5.18**.

Table 5.18: Reindeer Field GIIP

Field	GIIP (Bscf)		
	Low	Best	High
Reindeer	492	641	698

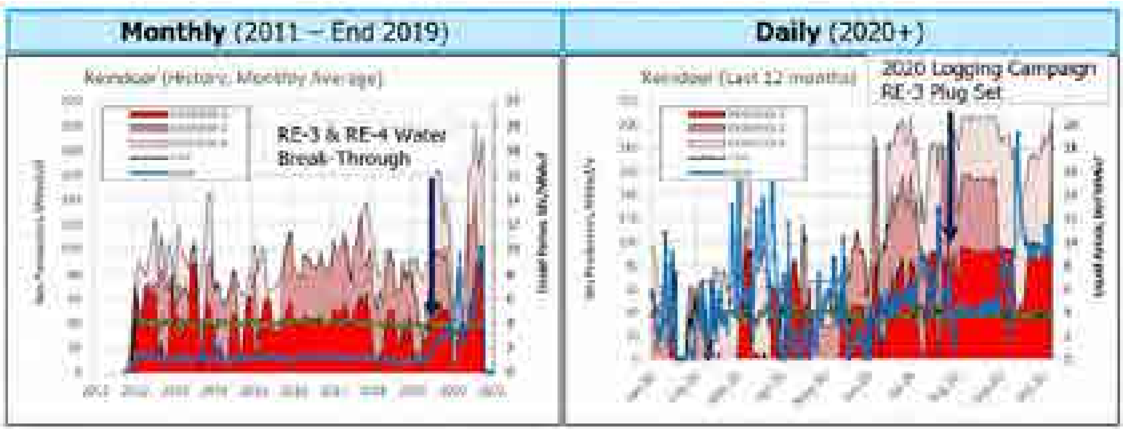
Reservoir Engineering Discussion

GaffneyCline has reviewed Santos presentation slides, production profiles in MS Excel sheet and simulation models, the YE2020 Audit Report, and Tyke Petroleum Consultants Pty Ltd (Tyke) simulation model and its presentation slides.

The Reindeer Field contains dry gas with a producing CGR of about 3.5 stb/MMscf and low CO_2 content of 3.6%. Initial reservoir pressure was 3,568 psia at datum depth of 2,400 m TVDss and reservoir temperature of 222° F. The gas expansion factor is 201 scf/rcf. Condensate gravity is 61.8°API. Production started in November 2011 and since June 2020 gas rate averages at 180 MMscfd. The cumulative production at 30 September 2020 was 306 Bscf raw gas and 1.2 MMstb of condensate. The recent average producing CGR is 3.9 stb/MMscf.

In 2020 Santos updated its 2015 static/dynamic model due to an unpredicted water breakthrough event in 2019 (**Figure 5.23**) and data from a logging campaign conducted in July 2020 which confirmed water production in two of three producers which was used to tune the dynamic model. The update had resulted in significant reduction in GIIP (-17% in the best estimate) and reserves. RISC has conducted an audit of Santos 2020 updated model and has agreed with Santos YE2020 remaining recoverable gas which was generated using RESOLVE by connecting the GAP network model to a subsurface Eclipse model.

Figure 5.23: Reindeer Production History, Water Breakthrough and Logging Campaign



Source: Santos

Santos has hired Tyke to conduct a review of 2020 Santos modelling studies and provide engineering insights relevant to history matching and reserves estimations. Tyke agrees that Santos 2020 reservoir modelling methodology represents good industry practice and provides a suit of models that can be used confidently for production forecasting, reserves estimation and planning. Tyke's re-evaluation of model by capturing alternative uncertainties (sealing of Maximum Flood Surfaces and RE3 fault block connectivity) has indicated there is an additional 15 to 27 Bscf of gas can be recovered in the best estimate case compare to Santos YE2020 volume. Santos has considered Tyke's updated remaining recoverable gas and has used its production profiles for the valuation.

GaffneyCline has reviewed the simulation model by checking the history matching of the three producers and opines that model is acceptable for forecasting purposes and the final EUR in the model matches what was reported by Tyke.

Production Profile for Evaluation

GaffneyCline has accepted Santos' volumes and has therefore accepted the associated gas and condensate profiles for the valuation scenario input.

Gaffney Cline

5.2.2.1 Macedon

5.2.2.1.1 Macedon Overview

Table 5.19: Macedon Summary

Field Data	
Permit	WA-42-L
Location	100 km W Onslow
Water Depth	160 m
Santos Working Interest	28.570%
JV Partners	BHP Billiton (71.430% & Operator)
Discovery Date	1992 (West Muiron-3)
First Production	2013

Macedon is a dry gas field located in the Exmouth Sub-basin, about 40 km north of Exmouth in Western Australia (see location map**, Figure 5.27** in **Section 5.2.3.1**). The field's gas is processed in the Macedon gas plant.

The field was discovered in 1992 with the drilling of the West Muiron-3 well, which discovered gas in the Macedon Sandstone reservoir. The next two wells failed to encounter pay. The field was then appraised by seven wells (Macedon-1 to 5 and Pyrenees 1 and 2), with two wells successfully encountering gas in the Macedon Sandstone and the rest encountering water wet reservoir.

The field has been developed with four subsea wells (Macedon-7, 8, 9, and 10) tied back to the Macedon onshore Gas Production Facilities located near Onslow via a 90 km, 20" wet gas pipeline. A gas injector/producer, Macedon-6, provides fuel gas to Pyrenees. Gas is conditioned for sale at the Macedon plant and exported into the Dampier to Bunbury Natural Gas Pipeline. The Macedon plant is capable of processing up to 220 MMscfd raw gas. Santos plans to install additional compressors (expected start up in 2023) to extend plateau length and maximise field recovery.

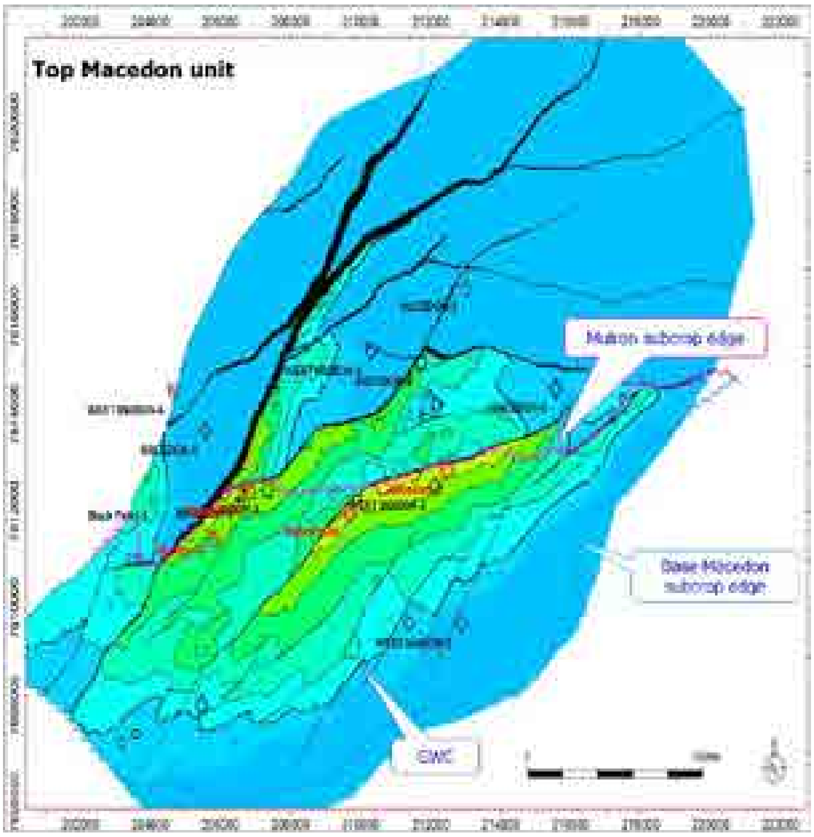
5.2.2.1.2 Technical Review

Geology and Geophysics Discussion

The Macedon field is a large structural-stratigraphic feature. The field consists of three NE-SW trending segments - three rotated fault blocks that form structural highs at the base of the regional Muderong Shale seal with the sandstone reservoirs sub-cropping the seal, creating a larger stratigraphic closure. The depth structure map of the field is shown in (**Figure 5.24**). The segments share a common GWC.

Gaffney Cline

Figure 5.24: Macedon Field Structure Depth Map at Top Macedon Unit

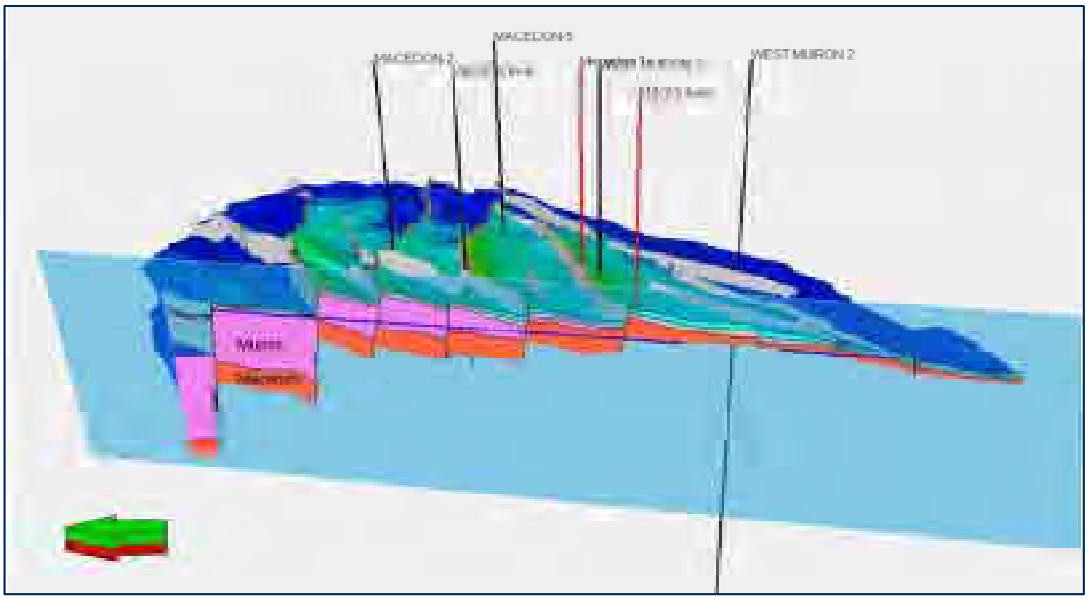


Source: Santos

The Barrow Group was deposited in a slope, turbidite fan complex, with the facies types consisting of channel sands, stacked fan lobes and sandy or muddy heterolithics. The reservoir consists of the better quality Macedon sandstone (average porosity 23.6% and permeability 800-1,200 mD) and the overlying Muiron sandstone which has lower quality (average porosity 19% and permeability 79 mD).

The configuration of the field is illustrated in the 3D view of the N-S cross section of the field in **Figure 5.25**.

Figure 5.25: Macedon Field Cross Section in 3D View



Source: Santos

GaffneyCline was not provided with any static model hence were unable to perform any review of the GIIP volumes of the field. The YE2020 Audit Report summarise the GIIP estimations of the fields. The auditor compares the estimation conducted by the operator and by Santos and reviewed the MBAL and simulation modelling studies to investigate the range. The total GIIP range of the Macedon field, combining both the pay in the Macedon and Muiron reservoirs, is shown in **Table 5.20**.

Table 5.20: Macedon Field GIIP

GIIP (Bscf)		
Low	Best	High
1,200	1,695	1,959

Reservoir Engineering Discussion

Macedon Formation

Reserves are attributed to the discovered Macedon formation within the Macedon Field. The gas is dry with 5 mole % N_2 and 0.1 mole % CO_2. CGR is 0.07 bbl/MMscf. Santos has assumed a shrinkage factor of 2% for combined fuel, flare and gas composition change and heating value of 1.008 PJ/Bscf. Initial reservoir pressure is 1,522 psia at 1,003 m TVDss (OGWC). The three fault block areas are in pressure communication.

Initial development of the field was via 4 subsea wells (Mac-7, 8, 9 and 10) and first production started in August 2013. In September 2020, production was at 197 MMscfd (Macedon plant capacity is 220 MMscfd). Cumulative production as of 30 September 2020 was 464 Bscf and 0.031 MMstb condensate or average produced CGR of 0.07 bbl/MMscf.

There is suspicion from P/Z and material balance studies reported in the YE2020 Audit Report, that the overlying Muiron formation is feeding gas into the Macedon formation over time and is in hydraulic (pressure) communication. The P/Z analysis suggests a connected GIIP of 1,960 Bscf. Dynamic model studies obtained good well bottomhole pressure history matches with a GIIP of 1,695 Bscf.

Muiron Formation

The Muiron formation was tested (DST) by Mac-2 well and produced at rate of 18.5 MMscfd from 15 m perforated interval through 60/64 inch choke and mostly from 5 m of higher permeability stringers

There is potential to drill 2 horizontal wells at rates of around 40 MMscfd per well to access remaining gas in the Muiron formation. GaffneyCline opines that a slight scale down of the initial gas rate commencing at 30 MMscfd with a corresponding lower EUR is more appropriate because a reduced aquifer support can be expected given the relatively low vertical permeability in most areas of the Muiron formation.

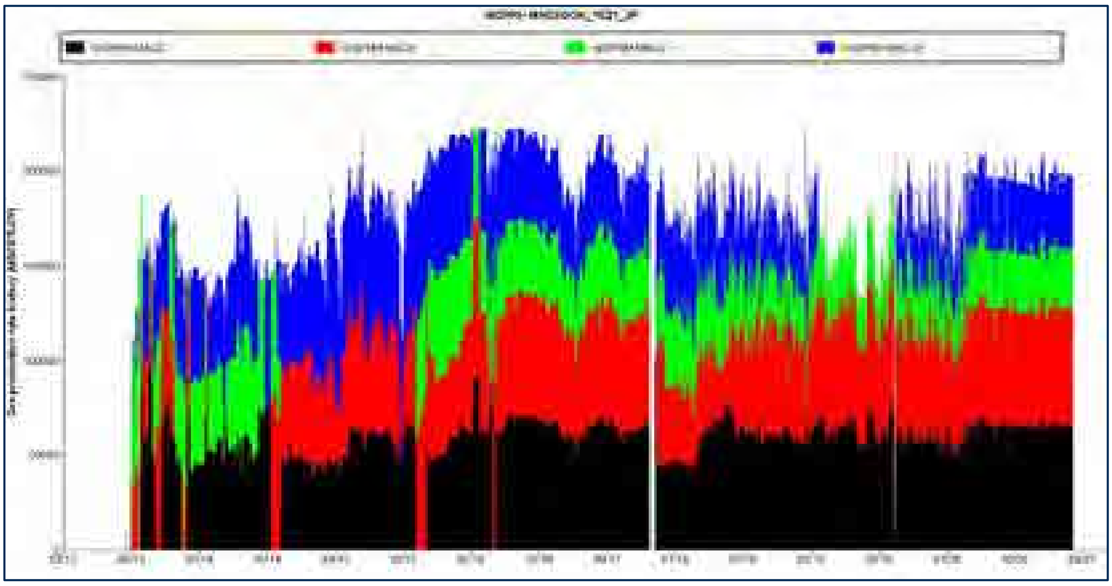
Santos did not provide a production profile from Muiron for the Valuation; hence, GaffneyCline assumed that the 2C (Development Unclarified) best fits the classification of a future Muiron development and has not included this resources in the valuation.

Production Profiles for Evaluation

Gas from Macedon field is transported via a 90 km x 20 inch wet gas pipeline to the onshore gas processing plant with capacity of 220 MMscfd. The inlet plant pressure is 278 psi, and the turndown gas rate is 100 MMscfd in the case of no compression. If there is wet gas compression (planned in the future), the plant inlet pressure will be reduced to 210 psi.

GaffneyCline accepts Santos best estimate sales gas production profile. The 2021 gas sales are 65.8 PJ (Gross 100%) or 182 MMscfd of raw gas. There are 4 current gas producers. Production decline is expected to be arrested in 2025 when compression is installed. Thereafter, the production decline is about 8% p.a., until the final cut-off rate of 73 MMscfd. In comparison to the historical decline of 7% p.a. during 2017-2018 (**Figure 5.26**), the forecast decline is reasonable. Mac-10 well was brought back online in 2019 after communication with the wells was restored back

Figure 5.26: Macedon Field Production History



The condensate recovery by Santos is based on initial CGR of 0.0001 stb/MMscf raw gas and with no decline over the remaining approximately 15 years of production. It is relatively dry gas with minimal condensate volume.

Reference point for sales volumes is Ashburton, onshore WA. In the WA Gas Long Term Plan, Macedon field is sequenced to continue production in 2021 until 2035. The key uncertainty in the long term field deliverability of Macedon Field is the timing of the wet gas compressor installation, expected around 2025 and the final turndown gas rate for gas supply cut-off.

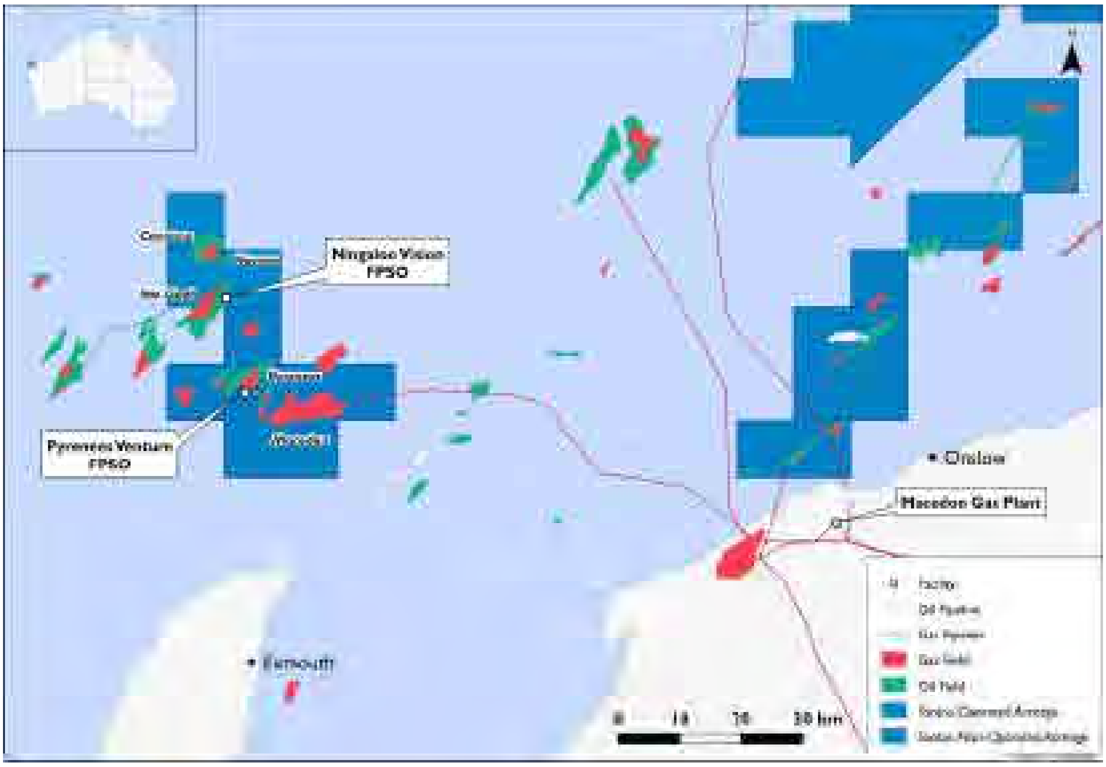
A reasonable implied recovery factor, a forecast decline rate that is consistent with historical decline behaviour, and compression to be available in 2025 all support the production profile generated by Santos. Macedon Field will continue to provide gas supply to domestic WA. GaffneyCline's production profile is based on 2P volumes.

5.2.3 Western Australia Oil

5.2.3.1 Western Australia Oil Overview

Santos' Western Australia oil assets comprise the Ningaloo Vision, Pyrenees, and Barrow Island projects. The Ningaloo Vision and the Pyrenees are located in the Exmouth Sub-basin in deeper water, whereas the Barrow Island is located in the Barrow Sub-basin onshore and in shallower water. The location of the Exmouth Sub-basin fields is shown in **Figure 5.27**, whereas the location of the Barrow Island Field is shown in **Figure 5.6** in **Section 5.2.2.1**. Total net Santos volume included in the valuation scenario is 28.1 MMboe.

Figure 5.27: Location map of the fields and facilities in Exmouth Sub-basin



Source: Santos

The Ningaloo Vision project comprises the following offshore oil fields: Van Gogh and Coniston-Novara, which produce to the Santos operated Ningaloo Vision FPSO located 40 km north of the North West cape. The subsea development consists of four subsea manifolds tied back to the Ningaloo Vision FPSO. Van Gogh and Coniston-Novara production is commingled subsea. Produced water is re-injected through two water injection wells in the Van Gogh aquifer and gas is handled through one dedicated gas cap well in the Van Gogh Field. Producing wells are long horizontal multilateral wells completed with sand screens and inflow control devices and are equipped with gas lift facilities to provide artificial lift.

The Pyrenees Field is serviced by the Pyrenees Venture FPSO vessel, stationed approximately 25 km north of the North West Cape. The Barrow Island oil field is a mature onshore field that has been producing since 1967. Oil is piped 10 km offshore through a 20" diameter pipeline to an eight-point tanker mooring facility.

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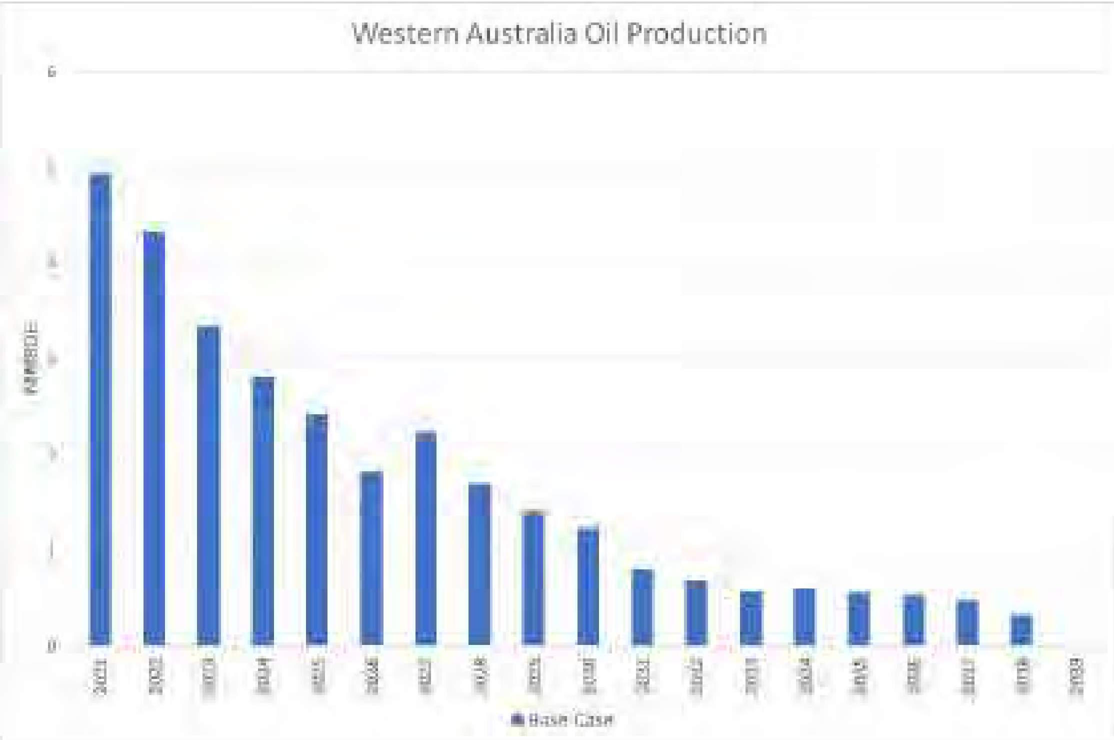
5.2.3.1 Western Australia Oil Production Profiles

The oil production profiles for the Base Case, which include production from the Van Gogh (including Coniston-Novara), Pyrenees and Barrow Island fields, is depicted in **Figure 5.28**. The profiles are based on Santos' production profiles, which were accepted after technical review was conducted for each field. The profiles are aggregates due to commercial sensitivities declared by Santos.

Figure 5.28: Western Australia Oil Production Valuation Scenario - Base Case



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5.2.3.2 Coniston-Novara

5.2.3.2.1 Coniston-Novara Overview

Table 5.21: Coniston-Novara Summary

Field Data	
Permit	WA-35-L / WA-55-L
Location	50 km NW Exmouth
Water Depth	380 m
Santos Working Interest	52.501% (Operator)
JV Partners	INPEX Alpha (47.499%)
Discovery Date	1982
First Production	May 2015 (Coniston), July 2016 (Novara)

Coniston-Novara is an oil field located in 380 m of water in the Exmouth Sub-basin, 50 km NW of Exmouth in Western Australia. The oil from the field, along with oil from the neighbouring Van Gogh field, is processed in the Ningaloo Vision FPSO (see location map in **Figure 5.27**).

The field was discovered in 1982 with the drilling of Novara-1 well. The Coniston-Novara Field has been developed with seven wells consisting of three tri-laterals and three dual laterals at Coniston and one dual lateral at Novara.

5.2.3.2.2 Technical Review

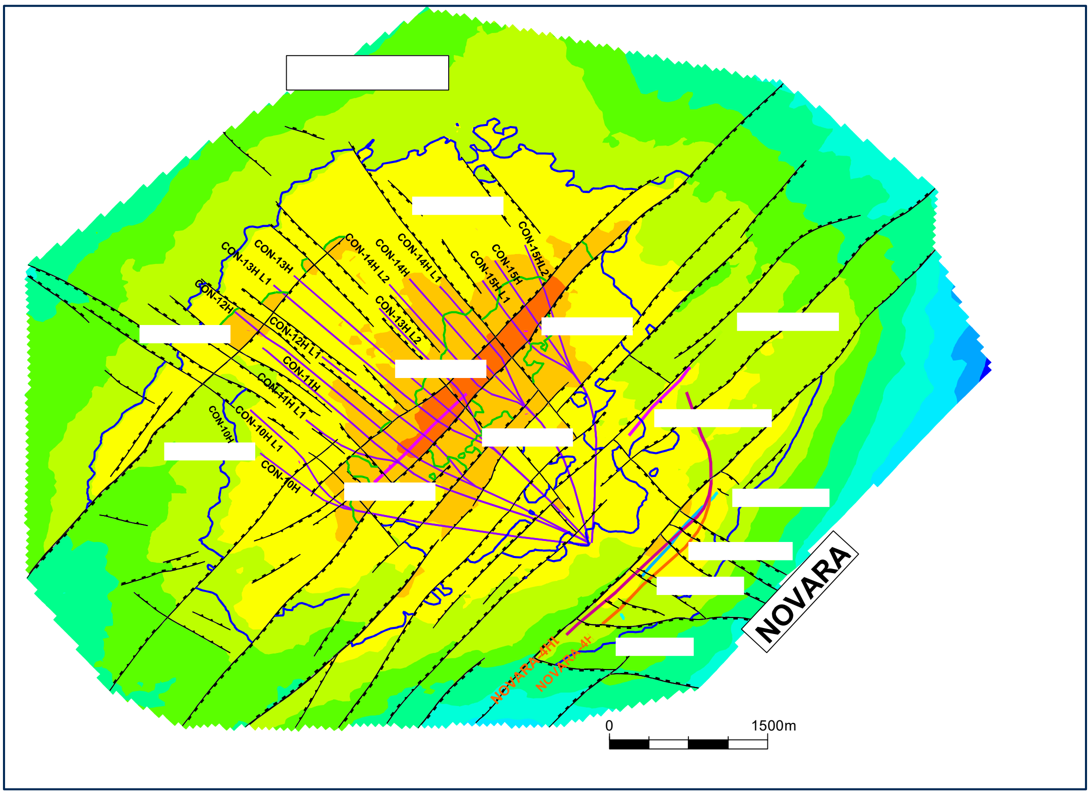
Geology and Geophysics Discussion

The Coniston accumulation is formed of a four-way dip closed structure (**Figure 5.29**). It is a 16.2 km^2 low relief anticline closure cut by a series of prominent northeast-southwest trending faults and minor northwest southeast lineaments. These faults dissect the field into areas with different oil-water contacts but a common gas-oil contact. Novara structure is a separate structure located 2 km SE of Coniston. It is a NE-SW trending footwall closure, with 3-way dip closure to the north, east and south. It measures 1.5 km^2 in size. The two accumulations have different fluid contacts.

Both the Coniston and Novara reservoirs are formed of Upper Barrow Group sands. The sandstones were deposited in deltaic to shallow marine settings, upper shoreface to lower foreshore environment, resulting in homogenous, good quality sandstones with porosities of 22-25% and permeabilities of 2-7 Darcy.

No static model was provided and the YE2020 Audit report does not include STOIIP estimation.

Figure 5.29: Coniston-Novara Depth Structure Map at Top Reservoir



Source: Santos

<u>Reservoir Engineering Discussion</u>

The oil in the field is viscous (17-24 cp) with an initial GOR of 120-150 scf/stb. Initial reservoir pressure was 1,868.5 psia at the OGOC depth.

The field has been producing since May 2015 with 7 subsea multi-lateral wells. The development is tied back to the Van Gogh subsea infrastructure and the Ningaloo Vision FPSO where production is commingled. There is a strong water drive at the field. Wells cut water easily and water cut steadily rises. Gas lift is provided to lift high water cut wells. Cumulative production to date is 9.9 MMstb and recent average rate was 1,179 bopd. End of field/facility life is estimated by Santos to be January 2025.

<u>Production Profile for Evaluation</u>

Santos combined the production profile for Coniston-Novara and Van Gogh as both are produced through the Ningaloo Vision FPSO. Therefore, the discussion on the production profile for Coniston-Novara can be found in **Section 5.2.3.3.2**, under Van Gogh Field section.

5.2.3.3 Van Gogh

5.2.3.3.1 Van Gogh Overview

Table 5.22: Van Gogh Summary

Field Data	
Permit	WA-35-L
Location	50 km NW Exmouth
Water Depth	400 m
Santos Working Interest	52.501% (Operator)
JV Partners	INPEX Alpha (47.499%)
Discovery Date	1998 (Vincent-1), 1999 (Van Gogh-1)
First Production	February 2010

Van Gogh is an oil field located in 400 m water depth in the Exmouth Sub-basin, 50 km NW of Exmouth in Western Australia. The oil from Van Gogh is processed in the Ningaloo Vision FPSO (see location map in **Figure 5.27**).

The field was discovered by the Vincent-1 well in the adjacent WA-28-L permit (where Santos has no working interest) in 1998. The Van Gogh-1ST1 well was drilled in 1999 in the WA-35-L and showed that the two wells had separate OWC. Consequently, the field was divided into the Vincent field in WA-28-L and the Van Gogh field in WA-35-L.

Van Gogh is produced via nine dual laterals and one single lateral, horizontal producers together with one gas injector and two water disposal wells. The field started producing in February 2010. The adjacent Vincent field was developed separately, via 10 dual/multi-lateral horizontal producers, 1 gas injector and 2 water disposal wells. Production began in August 2008. Santos does not have a working interest in the Vincent field and therefore has limited knowledge of the field.

5.2.3.3.2 Technical Review

<u>Geology and Geophysics Discussion</u>

The Van Gogh field is a gas capped, viscous oil field. The structure is formed of a three-way dip closed structure which requires fault closure to the northwest. It is cut by a series of SW-NE trending normal faults and (**Figure 5.30**). The top seal is provided by the Muderong shale.

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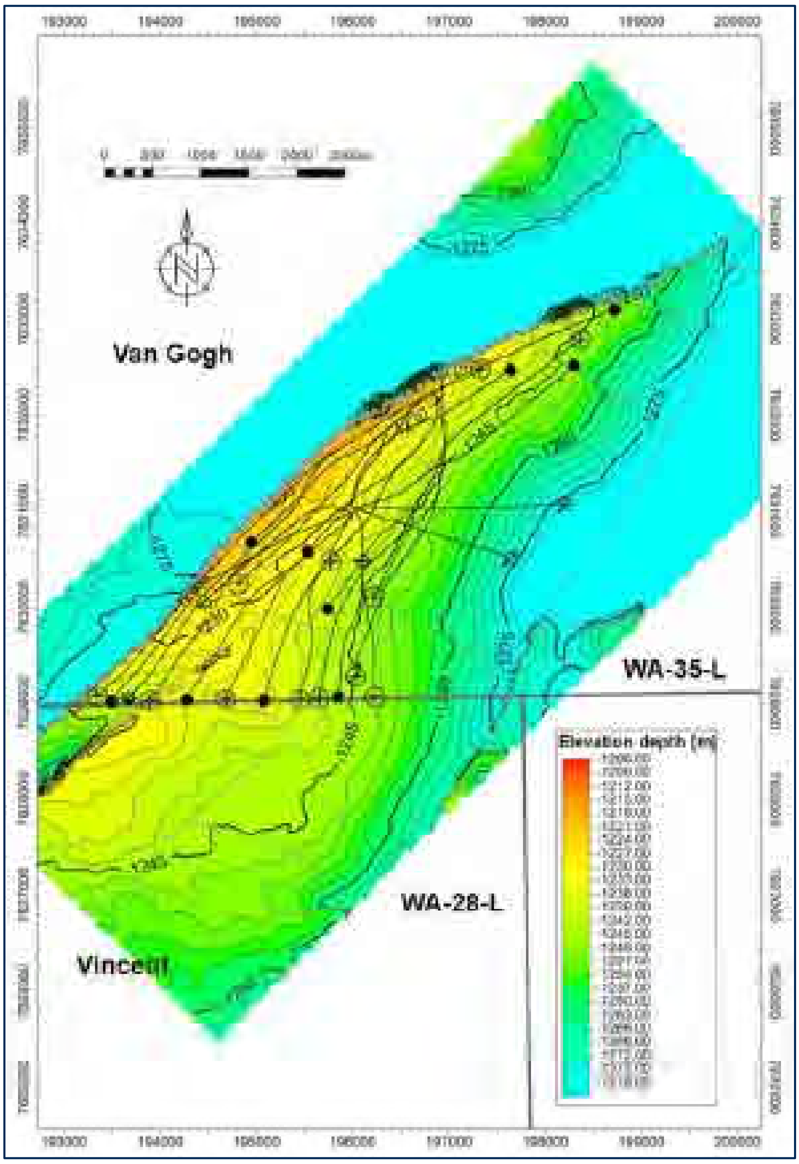
Figure 5.30: Van Gogh and Vincent Fields Structural Map



Source: Santos Petrel project

The field is covered by 3D seismic data, acquired in 1999 (conventional and 2013 (high resolution). The field has relatively flat GOC at 1,295.5, with ~11 m oil column in Van Gogh (OWC 1,306 m TVDss) and ~30m oil column in Vincent (OWC 1,325 m TVDss).

The reservoir is formed of fluvio-deltaic sands of the Top Barrow Group deposited as a sandy braided delta complex. Reservoir quality is good with porosities of 29% and permeabilities of 1-6 Darcy.

The YE2020 Audit report does not include STOIIP estimation.

Reservoir Engineering Discussion

The oil in the field is viscous of 15-27 cp (17 degree API) with an initial GOR of 80-160 scf/stb. Initial reservoir pressure is 1,950 psia at mid-oil column.

Initial development of the field was from 9 dual laterals, 1 single lateral, 1 gas injector and 2 water disposal wells. Production started in February 2010. Then in January 2019, two dual lateral horizontal infill wells (Phase 1) were drilled and brought on production.

Production was shut-in to allow FPSO dry dock maintenance in 2014-2015. Then in 2015-2016 the field was choked back to allow the adjacent field Coniston to produce into the water rate limited facility on the shared FPSO. In 2019, when 2 infill wells were drilled in Van Gogh there was minimal facility constraint because other fields (Coniston-Novara) then choked back their high water cut production. The field was not producing for most of 2020 because the FPSO was on dry dock service and resumed production in March 2021.

Cumulative production to March 2020 is 37.2 MMstb and recent average rate was 8,120 bopd with 87% water cut. Gas lift is used to lift the wells. The combined oil rate history for both fields is shown in **Figure 5.31.**

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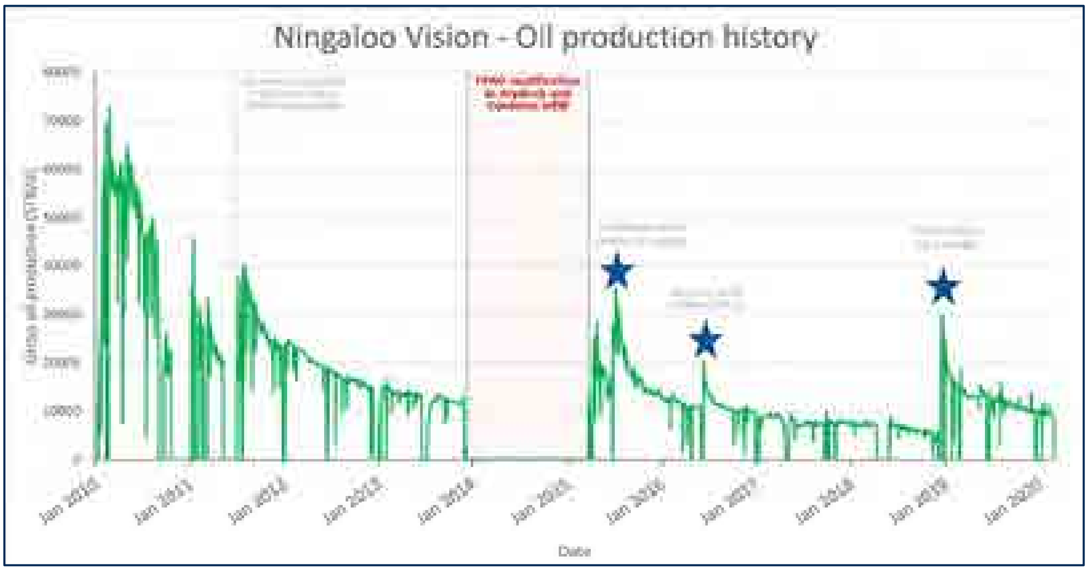
Figure 5.31: Van Gogh and Coniston-Novara Fields Production History



Source: Santos

Production Profile for Evaluation

Santos has used DCA and a GAP network model to generate type curves for future wells and model the back pressure between Van Gogh and Coniston-Novara wells, oil rate vs cumulative oil and water cut versus cumulative oil are appropriate to analyse the historical production which has been affected periodically by long shut-in or rate cut back due to facility water handing limit. Measurement challenges lead to uncertainty in well back allocation, so DCA analysis should also be done on a reservoir/field basis.

The Operator's production forecast methodology has indicated that downtime has been incorporated. A planned 1.5 months production station shutdown in 2022 and an annual 2 weeks shutdown in future years; an unplanned facility and weather downtime of 14% in the cyclone period (Nov-April) and 4% for the remainder of the year are included.

<u>Coniston-Novara & Van Gogh Developed Production Profile</u>

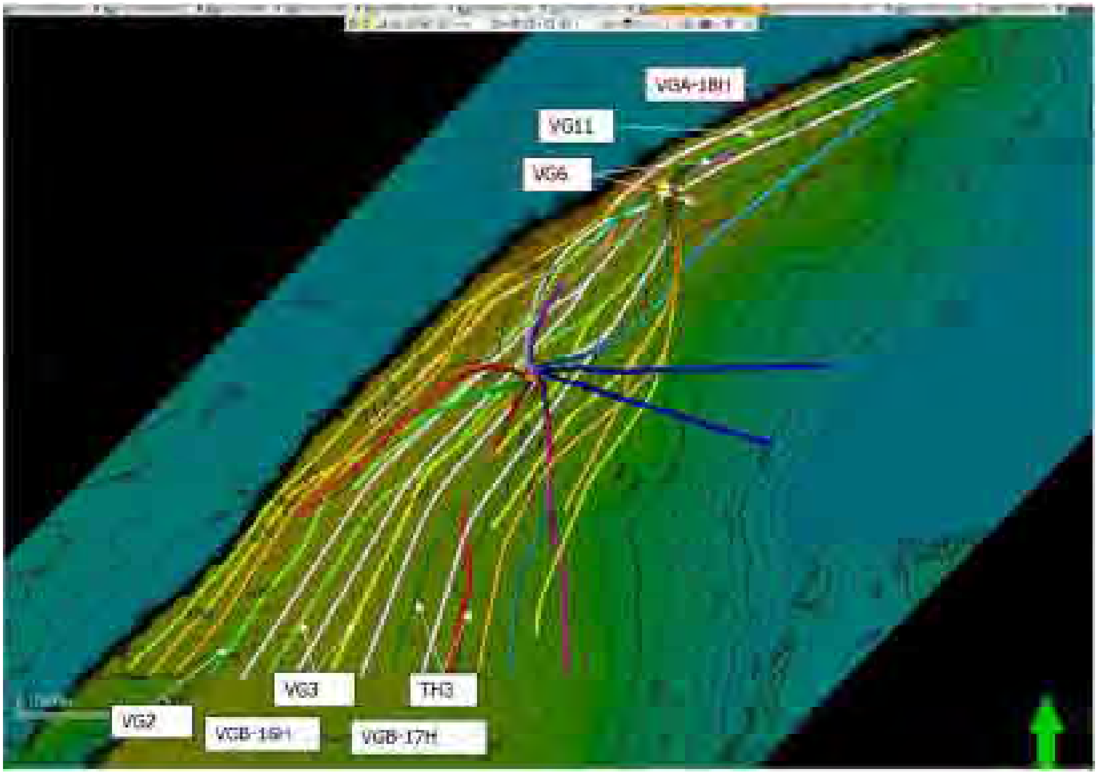
GaffneyCline accepts Santos' best estimate 2P (Developed) sales oil production profile combined for both Coniston-Novara and Van Gogh Fields. The last combined shut-in production in 2020 was 9,299 bopd (8,120 bopd from Van Gogh and 1,179 bopd from_Coniston-Novara). The forecast oil rate in 2021 is 6,057 bopd, reflecting a 35% p.a. decrease. The steep decline can be explained by water breakthrough in the larger but newer producers from Van Gogh and cutback on rates to meet the water handling limit.

In later years, the average decline from all existing wells is more gradual due to pressure support from a strong water drive. The decline behaviour agrees with historical behaviour. The remaining well life is short duration with the FPSO scheduled for a dry dock service in 2025. There is no sales gas production because of the limited associated gas produced which will be used for field operations.

Van Gogh Infill Phase 2 Production Profile

The undeveloped Profile will be from a Phase 2 project involving 3 infill wells (proposed locations, VG-16H, VG-17H and VG-18H) shown in **Figure 5.32.**

Figure 5.32: Van Gogh Field Phase 2 Planned Well Locations



Source: Santos

GaffneyCline accepts Santos best estimate 2P (undeveloped) sales oil production profile. Production commences in 2021 and peaks in 2022. This is followed by a more gradual decline due to pressure support from a strong water drive. The short well life duration is partly due to a significant part of the produced gas has to be used for gas lift and as fuel. There is minimal available gas given that there are no gas cap or gas reservoirs within the field or in nearby fields.

There is no sales gas production because the limited associated gas produced will be used for field operations or reinjected back.

Coniston-Novara & Van Gogh Contingent Resources

Santos has estimated recoverable oil volumes for Van Gogh and for the Coniston-Novara Fields for potential development after 2025.No production profile was included for this.

The drilling of these wells is dependent on the performance of the existing and the planned 3 infill wells. Further, there are 3 constraints to any economic development of more oil beyond the approved (3 infill wells in 2021) at Van Gogh and Coniston-Novara. There are fuel shortages (which would require a part of the produced oil to be used as fuel), the requirement for the FPSO to perform a dry dock service in 2025, and the water handling facility limit on these high water cut wells. Hence, GaffneyCline did not consider the Contingent Resources from these two fields in the Valuation as the exploitation of these resources is not matured yet and the economic viability is unknown.

Implied Recovery Factor

For the Coniston-Novara and Van Gogh fields the recovery factor is acceptable to GaffneyCline for a field that has been producing with a strong water drive pressure support but fair areal sweep due to viscous oil in a high permeability oil reservoir.

The reasonable implied oil recovery factor, a forecast decline rate that is consistent with historical decline behaviour, and an appropriate curtailment of forward production to consider water handling capacity limit and facility downtime; these support the production profile generated by Santos.

5.2.3.4 Pyrenees

5.2.3.4.1 Pyrenees Overview

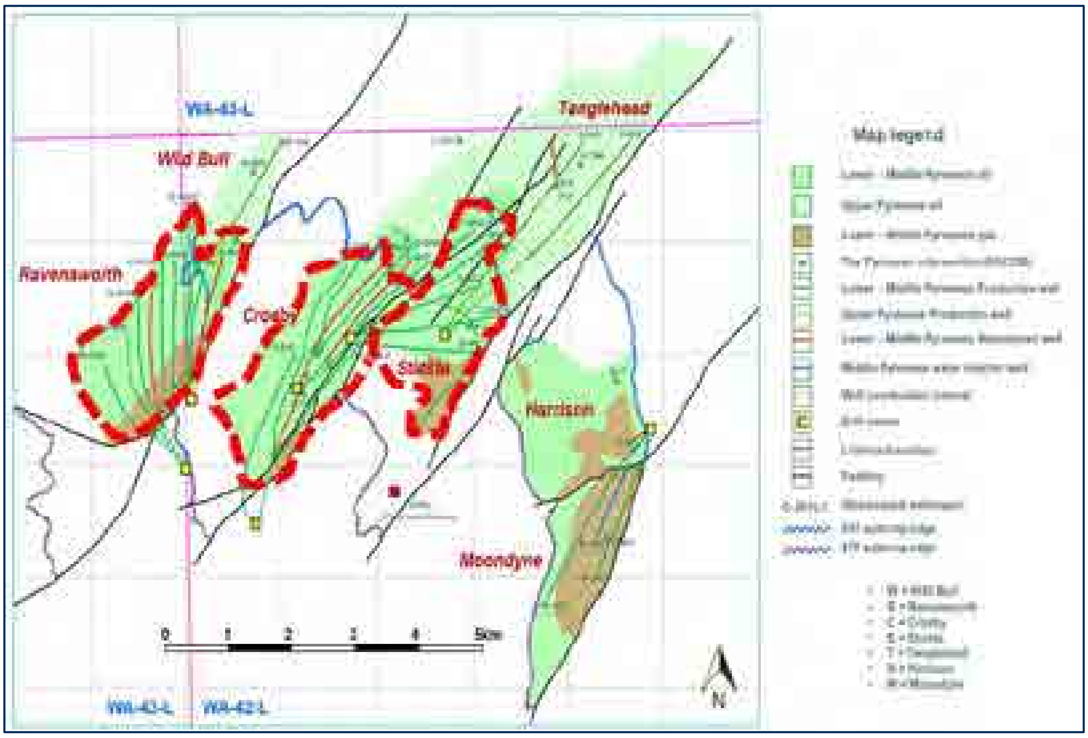
Table 5.23: Pyrenees Summary

Field Data	
Permit	WA-42-L / WA-43-L
Location	40 km NW Exmouth
Water Depth	400 m
Santos Working Interest	WA-42-L: 28.570% WA-43-L: 31.501%
JV Partners	WA-42-L: BHP Billiton (71.430% & Operator) WA-43-L: BHP Billiton (39.999% & Operator), INPEX Alpha (28.500%)
Discovery Date	2003
First Production	2010

The Pyrenees Field is an oil field located in 400 m water depth in the Exmouth Sub-basin, 40 km NW of Exmouth in Western Australia. The oil from the field is processed in the Pyrenees Venture FPSO (see location map in **Figure 5.27**).

Oil was discovered in the Pyrenees Field in 2003 and production started in 2010. The Pyrenees development comprises of the development of seven separate oil pools tied back to the Pyrenees Venture FPSO. The oil pools are Ravensworth, Wild Bull, Crosby, Tanglehead, Stickle, Harrison, and Moondyne. The fields straddle between two permits with different Santos working interests, as shown in **Figure 5.33**. The southern half of the Ravensworth oil pool is located in the WA-43-L, while the rest of the oil pools are located in the WA-42-L.

Figure 5.33: Pyrenees Field Oil Pools



Source: Santos

The field has been developed with a total of 18 subsea horizontal wells. Any surplus gas is injected into the adjacent Macedon gas field or back produced to supply fuel. Oil is produced via the FPSO, which has total processing capacity of 96,000 bopd. The fields were developed in three phases:

- Phase-1: 2010 development of Ravensworth, Crosby and Stickle via single lateral horizontal wells
- Phase-2: 2014 development of Wild Bull, Tanglehead and Moondyne via single lateral horizontal wells
- Phase-3: 2015/16 infill drilling with three wells in Crosby, two in Ravensworth and one in Stickle, some as dual lateral sidetracks of Phase-1 wells.

Phase 4 infill drilling program is currently in the Select phase and if the project is approved, first oil is planned for early 2023.

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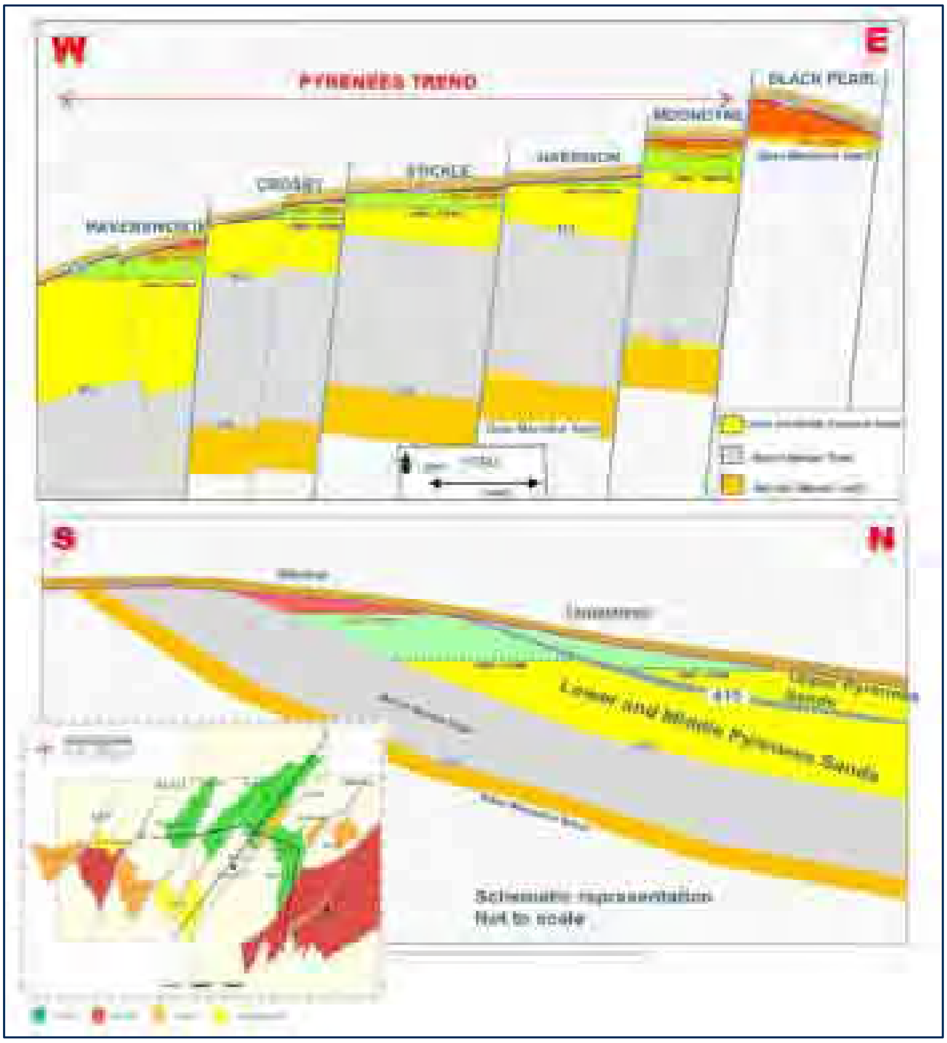
5.2.3.4.2 Technical Review

Geology and Geophysics Discussion

The Pyrenees field consists of a series of structural compartments formed by SW-NE trending fault terraces, some of which are further sub-divided stratigraphically by intra-formational shale (as shown in the field cross sections in **Figure 5.34**), resulting in seven separate pools (as shown in **Figure 5.33**).

Figure 5.34: Pyrenees Field Schematic Cross Section



Source: Santos

The primary reservoir is formed of good quality fluvio-deltaic sands of the Early Cretaceous Upper Barrow Group, which has an average porosity of 29% and permeability of 3-5 Darcy. The third party auditor had not audited the in-place volumes from this field but quoted the operator's Best Estimate STOIIP of 445 MMstb.

Reservoir Engineering Discussion

The various hydrocarbon pools have oil columns of 37-53 m. The oil is viscous (5 to 11 cp) and heavy (19 - 21 degree API) with an initial GOR of 150-190 scf/stb. The initial reservoir pressure is 1,793 psi.

Development of the field has been in 3 phases using subsea wells (**Figure 5.33**) that currently comprise 19 horizontal laterals or drainage points wells with 6 laterals/drainage points currently not producing. The wells are connected to an FPSO. There are four water disposal/injection wells. The field has been producing for 11 years and the minor gas caps in Ravensworth, Crosby and Stickle have been blown down. Produced gas is injected into the Macedon gas field nearby or used as fuel. Gas lift is used to facilitate production. There is a strong water drive.

Production was shut-in to allow FPSO dry dock maintenance in 2013 and 2018 (71 days). Next scheduled service is in 2023. The field is producing at the water handing limit of 150,000 bwpd and several wells are choked in to stay within the limit and optimise oil production. Back pressure in the subsea network affects well productivity. Cumulative production as of October 2020 is 144 MMstb and the average oil rate in 2020 was 15,260 bopd, with 90% water cut and constant historical GOR.

Production Profiles for Evaluation

DCA analysis was performed by Santos and that is reasonable for a field with fairly long (11 years) production history. An integrated production (GAP) model was used by Santos to aggregate the decline curves and create production profiles. Downtime and facility constraint limits were incorporated into the model. Oil rate vs cumulative oil and water cut versus cumulative oil are appropriate to analyse the historical production which has been affected periodically by long shut-in or rate cut back due to the facility water handing limit. Downtime is incorporated which includes an unplanned facility and weather downtime of 11.5% in the cyclone period (Nov-April) and 4.5% for the remainder of the year. The FPSO is scheduled for dry dock service, resulting in 2 months field shutdown, every 5 years. The auditor's review in the YE2020 Audit observed that the best estimate GAP profile does not exceed the DCA forecast from oil rate against cumulative oil production and hence found the methodology for production forecasting reasonable.

Pyrenees Base Case Production Profiles

The developed profiles will be from the 19 existing drainage points (laterals, etc.). GaffneyCline accepts Santos best estimate developed sales oil production profile. The oil forecast shows a harmonic behaviour (consistent with historical decline) due to pressure support from a strong water drive. The oil rate in 2021 of 13,551 bopd is a continuation of the decline from the 15,260 bopd recorded in late 2020. The oil rate dips in 2023 due to downtime associated with FPSO maintenance/inspection at dry dock. There is no sales gas production. The associated gas produced will be used for field operations or injected into Macedon Field.

Pyrenees Phase 4 Infill Production Profiles

The undeveloped profile (Phase 4) will be from one dual lateral well and a water shut-off intervention in one 1 existing lateral. GaffneyCline accepts Santos' best estimate undeveloped sales oil production profile. An initial steep decline due to water breakthrough is followed by a more gradual decline due to pressure support from a strong water drive. There is no sales gas production because the limited associated gas produced will be used for field operations or injected into the Macedon Field.

Pyrenees Phase 5 Infills Production Profiles

The Contingent Resources (Development On-hold) profile for Phase 5 will likely be from 6 remaining infill opportunities not addressed in Phase 4. One reason for not being included in Phase 4 is because of the water handling limit of 150,000 bwpd at the Pyreenes facilities. The exact number and location of the wells to be drilled in Phase 5 is uncertain at this moment. It would be dependant partly on the performance of Phase 4 wells and the existing wells. It is also planned in 2027.

Implied Recovery Factor

The implied ultimate best estimate oil recovery factor considering historical production and remaining recoverable from existing wells and Phase 4 wells is 43%. The recovery factor is acceptable for a field that has been producing with a strong water drive pressure support with moderate areal sweep due to a slightly viscous oil (7cp) in a high permeability oil reservoir.

For the Phase 5 wells the remaining recoverable resource is included then the implied ultimate best estimate oil recovery factor will be on a slightly high side of expectations considering empirical data for similar type of fields. Hence, this is another consideration in Phase 5 being classified as Contingent Resources by GaffneyCline.

The reasonable oil recovery factor, a forecast decline rate that is consistent with historical decline behaviour, and an appropriate curtailment of forward production to consider water handling capacity limit and facility downtime; all support the production profile generated by Santos.

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5.2.3.5 Barrow Island

5.2.3.5.1 Barrow Island Overview

Table 5.24: Barrow Island Summary

Field Data	
Permit	L 1H
Location	Barrow Island, 50 km off the coast of North Western Australia
Water Depth	onshore
Santos Working Interest	28.57%
JV Partners	Chevron (57.14% & Operator), ExxonMobil (14.29%)
Discovery Date	1964
First Production	April 1967

Barrow Island is a mature oil field that has been producing for over 50 years. It is located in the Barrow Island, 88 km north of Onslow, Western Australia, in the Barrow Sub-basin (see location map in **Figure 5.6**).

The first well, Barrow-1 was drilled in 1964 at the crestal portion of the anticline as it was mapped then based on refraction seismic data, and found a small oil accumulation was found at the Late Jurassic Dupuy Formation. Barrow-2 and 3 also encountered the accumulation about 1 km away from the first well. Barrow-4, drilled after reflection seismic data was acquired, discovered oil in the Early Cretaceous Windalia Sand Member of the Muderong Shale, which is the main reservoir of the field. Production commenced in December 1966, with first shipment of oil in April 1967.

Since then the field has been developed with hundreds of wells, the majority of which are electric driven beam pumps. Currently there are 628 active wells, consisting of 420 producers and 208 water injectors, and 152 shut-in wells. The produced oil is sent to eight gathering stations, which take out the gas and send the oil and water to a central processing facility.

5.2.3.5.2 Technical Review

Geology and Geophysics Discussion

The Barrow Island Field at the top of the main reservoir is a NNE trending, four way dipping anticline, cut at the southern end by the WSW trending, downthrown to the south Barrow Fault (**Figure 5.35**). Minor gas cap is trapped at the crest of the structure.

The main reservoir for the Barrow Island oil accumulation is the Windalia Sand Member of the Muderong Shale, however small oil and gas accumulations are found in various younger and older formations as well, including in the underlying deltaic sand of the Barrow Group. The Windalia sandstone was deposited at a very slow rate in the middle to outer marine shelf environment. The sandstone has excellent porosity averaging 28% but low average of 5.7 mD.

No STOIIP estimation was provided for the field.

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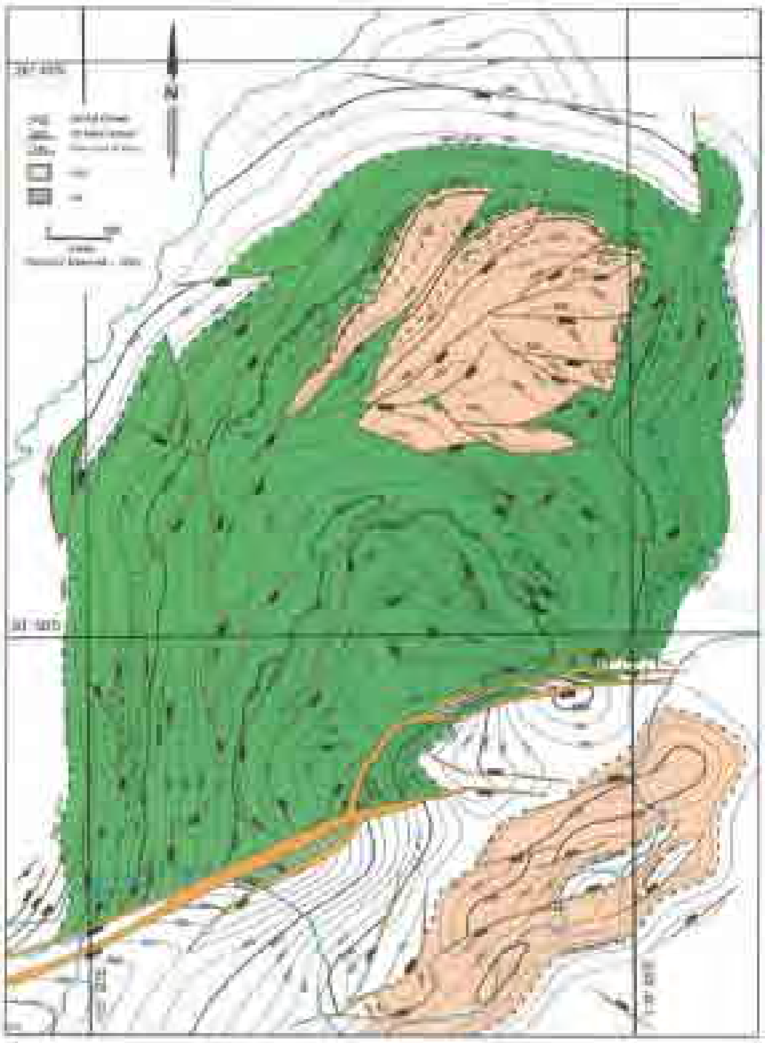
Figure 5.35: Barrow Island Field Structure Depth Map at Top of Windalia



Source: Ellis et.al, 1999[2]

[2] Ellis, G.K., Pitchford, A., and Bruce, R.H., 1999, Barrow Island Oil Field, APPEA Journal

Reservoir Engineering Discussion

The volume from Barrow Island only accounts for approximately 1% of total Santos WA valuation volume. Based on DCA plot shown in the YE2020 Audit Report, GaffneyCline opines that the Santos' forecast is reasonable. GaffneyCline accepts Santos technical recoverable volumes until end of 2030 production as per Long Term Plan outlook with end of field life at end 2030.

Production Profile for Evaluation

GaffneyCline accepted Santos' valuation modelled profile until 2030 and the related volume (**Table 5.25**).

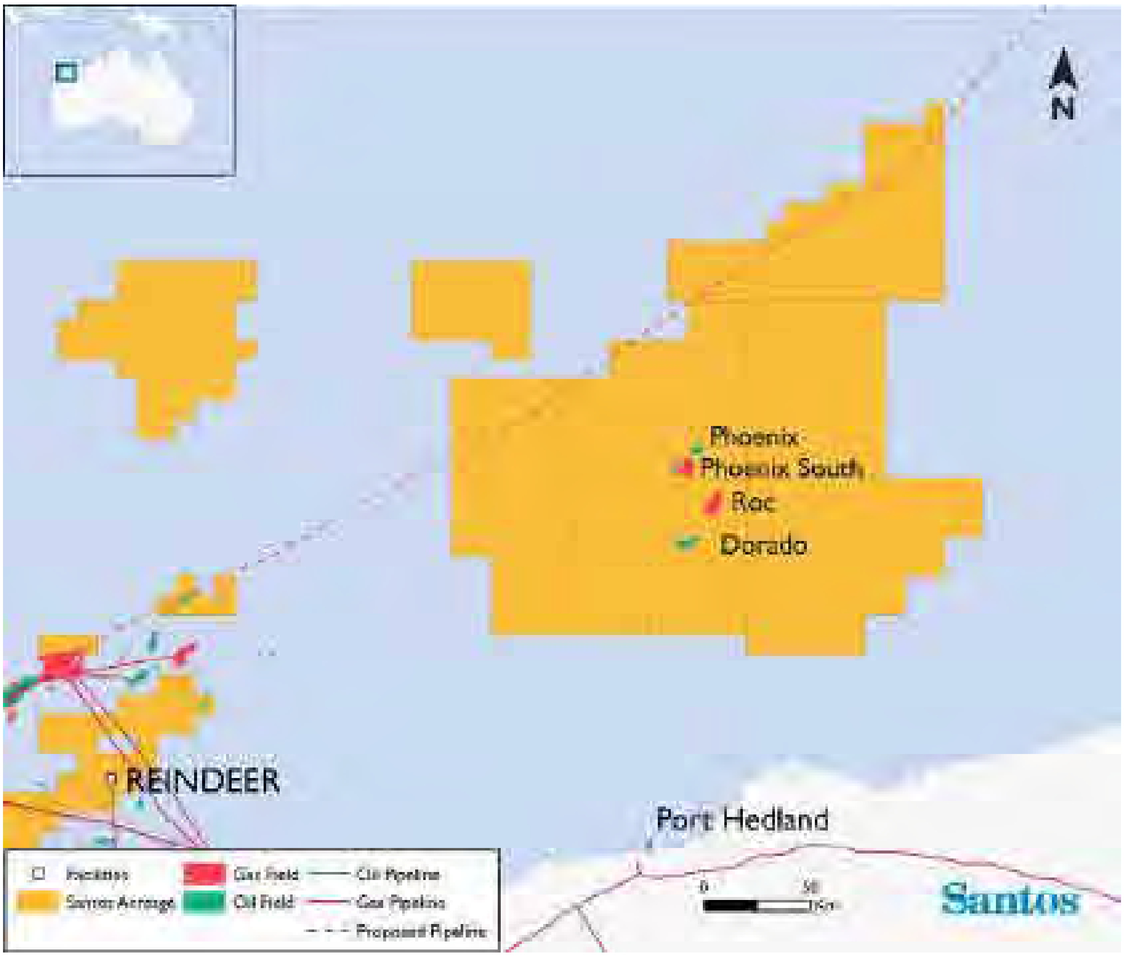
Table 5.25: Barrow Island Net Sales Volume as of 1 January 2021

Field	Best Estimate MMboe
Barrow Island	3.5

5.2.4 Bedout Sub-basin

Santos' portfolio in the Bedout Sub-basin includes the Dorado and Roc discoveries. In 2019, it conducted a successful appraisal programme de-risking the development options for Dorado, which is slated for oil development in Phase 1 producing from 2026, followed by gas blowdown in Phase 2 producing from 2036. The location of the Bedout Sub-basin assets is shown in **Figure 5.36**.

Figure 5.36: Location Map of the Bedout Sub-basin Asset



Source: Santos

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5.2.4.1 Dorado

5.2.4.1.1 Dorado Overview

Table 5.26: Dorado Summary

Field Data	
Permit	WA-437-P
Location	145 km north of Port Hedland
Water Depth	90 m
Santos Working Interest	80%
JV Partners	Carnarvon (20%)
Discovery Date	July 2018
First Production	May 2026
Valuation Scenario Volumes as of 1 July 2021	
GaffneyCline Net STO Profile Volume	196.8 MMboe Base Case

Dorado is a light oil and rich gas, currently undeveloped field, located in the Bedout Sub-basin, approximately 145 km north of Port Hedland (see location map in **Figure 5.36**).

The Dorado Field was discovered in July 2018 by the Dorado-1 well, which found five separate light oil and gas-condensate accumulations in several reservoirs in the Early Triassic Archer Formation. The discovery was appraised by Dorado-2 and 3 wells in 2019.

The field is planned to be developed in two phases. In Phase 1 LPG rich gas will be reinjected to enhance oil recovery in the Caley reservoir. It will consist of a 16 slot wellhead platform with an FPSO. Up to 10 initial development wells (6 oil producers, 2 gas producers and 2 gas injectors) are considered for the Base Case development concept. In Phase 2 gas is planned to be exported to either domestic and/or LNG facilities.

5.2.4.1.2 Technical Review

Geology and Geophysics Discussion

The Dorado accumulation is a stratigraphic trap formed by a large incised canyon filled with shale, cutting a series of gently northerly dipping formations, forming a side seal to the south of the field. The same shale also provided top seal over the reservoir. The field size is approximately 21 km^2 (**Figure 5.37**). It is mapped mainly using a multi-client 3D seismic dataset, although several other 2D and 3D dataset were also used.

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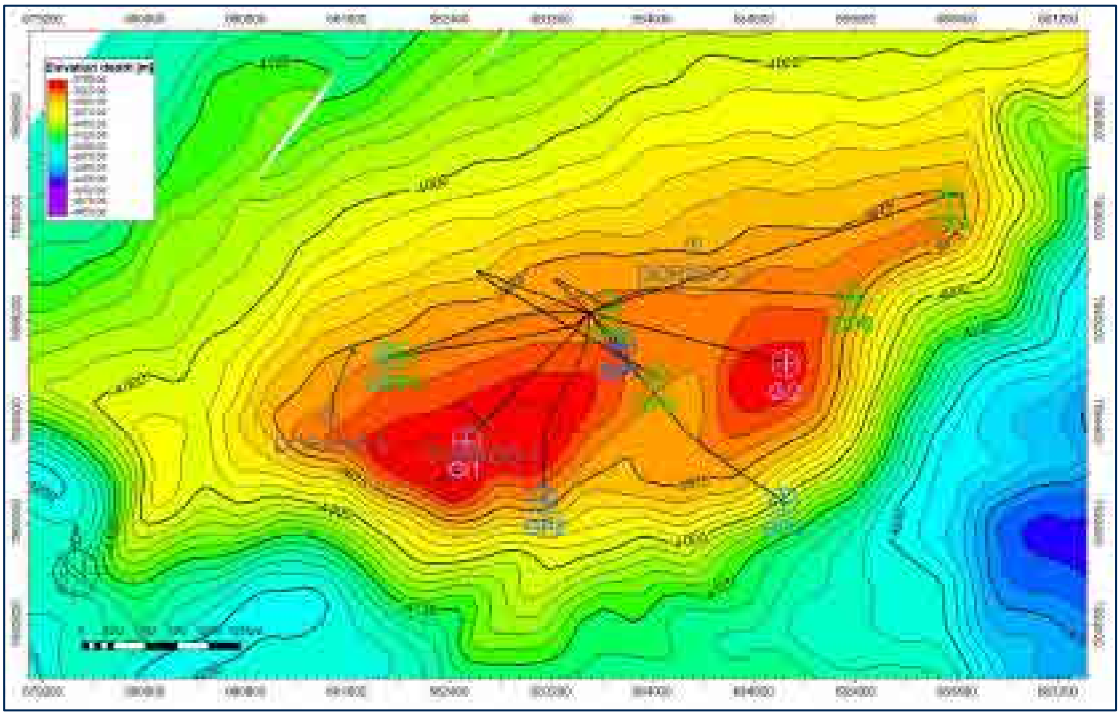
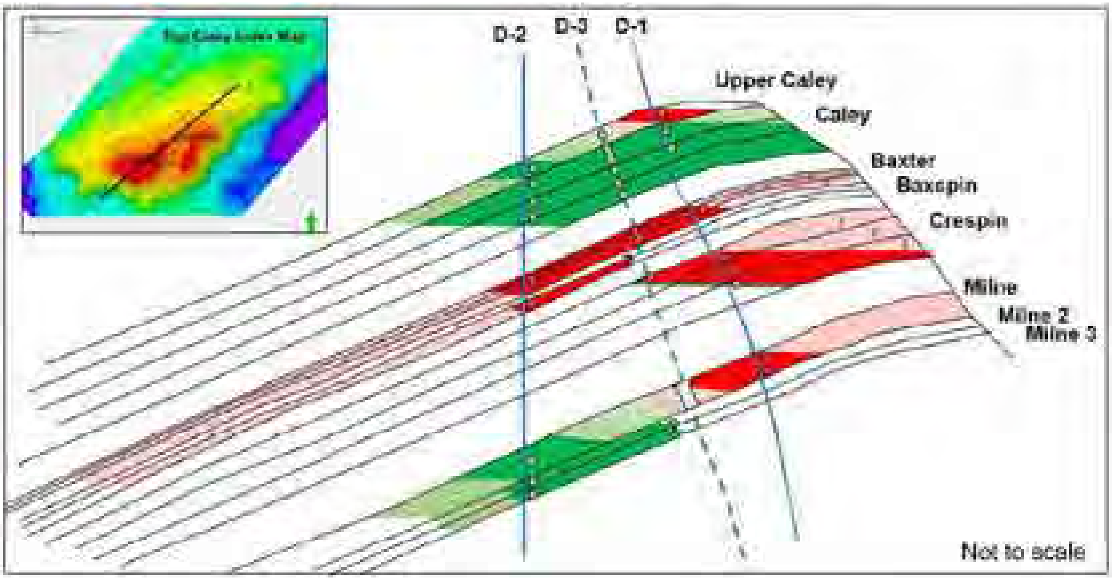
Figure 5.37: Dorado Field Depth Structure Map at Caley Unconformity with Existing & Proposed Well Location



Source: Santos Petrel project

The reservoirs are formed by the members of the Archer Formation, which is a series of stacked delta complexes with incised valleys. It was deposited rapidly in rift related depocentres, in a fluvio-deltaic systems. There are several reservoirs: Caley group (Upper Calley and Calley E, D, and C&B), Baxter, Baxspin, Crespin and Milne, with different hydrocarbon types. The distribution of the reservoir and hydrocarbon types are shown schematically in **Figure 5.38**.

Figure 5.38: Dorado Field Schematic Cross Section
Showing Hydrocarbon Distribution



Source: Santos (redrawn)

GaffneyCline reviewed the YE2020 Audit Report where the third party auditor evaluated the Dorado Field in-place volumes and was able to replicate Santos' in-place volumes for key static model cases. GaffneyCline was also provided with a single static model realisation, which was used as a comparison. GaffneyCline concurred with the auditor's view and was able to reproduce the in-place volumes from Santos' Experimental Design process.

Reservoir Engineering Discussion

The proposed development phases are summarised below:

Phase 1A: Oil development of the Caley reservoir in 2026 and liquids stripping from Upper Caley, Baxter, Baxspin and Crespin gas reservoirs. It involves 6 oil producers, 2 gas producers and 2 gas injectors (**Figure 5.37**). FID is expected in 1H2022. Gas reinjection (miscible LPG) will be to a capacity of 215 MMscfd.

In the Caley reservoir, Dorado-3 tested 11,100 bopd, GOR of 1,900 scf/stb, drawdown of 220 psi (68/64 inch choke) and with flow capacity of 8,000 mD-m over the depth interval (3,999-4,015 m-MD). The oil is light at 49°API with low CO_2 (1.5%) and found in high quality (74 m net pay, porosity of 20%, NTG of 94%) sand.

Development wells will be slant producers (with gravel pack and dual zone completion) or horizontal well (single zoned gravel pack completion). Oil recovery is expected to be very high for this gas reinjection (miscible flood) into oil reservoirs. A peak oil plus condensate rate of 92,000 bopd is expected.

<u>Phase 1B</u>: Oil development into Milne in Year 4. This will involve gas injection into Milne and Crespin to enhance liquids recovery and requires 1 infill well and the recompletion of 1 existing well.

<u>Phase 2</u>: Gas and LPG sales. Gas blowdown of Caley and Milne oil reservoirs and gas production from Upper Caley, Baxter, Baxspin and Crespin gas condensate reservoirs.

The development drilling program for Phase 2 is not definitive at this stage as it is dependent on the gas demand at that time. For about 82 MMscfd maximum field gas rate (from associated gas and non-associated gas), several (2 gas producers and 2 gas injectors) of the Phase 1 wells should be able to meet the gas deliverability. It is possible that after Santos (as Operator) has completed further technical studies that the Phase 2 project may require recompleting at least 1 existing well and potentially drilling at least 1 new well into the Baxter gas reservoir.

In the Baxter gas reservoir (4,136-4,157 m MD), Dorado-3 tested 48 MMscfd gas (DST#1) at CGR of 94 bbl/MMscf with drawdown of 150 psi (60/64 inch choke) and flow capacity of 8,600 mD-m. Reservoir quality is fair to good with permeability of 267 mD (porosity of 11%).

The volumes of the field currently assigned as Contingent Resources (Development Pending) refers to the oil from Phase 1 development. Those assigned as Contingent Resources (Unclarified) represent all gas and LPG volumes in Phase 2 blow-down. It also includes the tail oil and condensate. The volumes are sub-classified as Unclarified as the development concept is not yet finalised and there is another cycle of work in progress that will continue to be refined.

Part of the Dorado hydrocarbon accumulation which has been excluded is the Baxter Oil, a potential oil column underlying the Baxter gas, which Santos has postulated from extrapolation of the compositional fluid gradient analysis based on pressure and fluid data in the updip gas column. There are no well penetrations in this potential oil leg and neither has a GOC or FWL been intersected so far. The predicted GOC and FWL from compositional gradient analysis are highly sensitive to the assumed oil density and aquifer pressure line. The CGR of 94 bbl/MMscf (in Dorado-3 gas column) is significant but does not provide a firm indication of the existence oil column downdip in commercial quantity.

GaffneyCline has excluded Baxter oil in its valuation input and considers it a Prospective Resource. This is in line with Santos' statement that it requires a well to be drilled. If successful (the prospect effectively has a high chance of success on an exploration well, with GaffneyCline estimated Geological Chance of Success of 64%), it would be tied back to Dorado. The potential Baxter oil column can be considered as an upside. An opportunity exists in 2024 to appraise the downdip part of the Baxter formation when several of the Phase 1 development wells will be drilled in the shallower Caley and deeper Milne oil reservoirs. .

<u>Production Profile for Evaluation</u>

Dorado Field will initially produce oil in 2026 and in later years will produce gas as part of the WA Long Term gas plan.

GaffneyCline generated a Base Case production profile scenario for valuation of Dorado by including all Contingent Resources (Development Pending and Development Unclarified) for the Phase 1A, 1B and 2 development.

GaffneyCline used the Santos Best estimate oil production profile scenario for Phase 1A (from Dorado Phase 1A Standalone Cashflow Summary) for the period 2026 to 2035. After 2036, the Santos net (80%) converted to gross (100%) production profile for oil, gas, condensate and LPG was used.

The standalone Phase 1A oil profile (2026 to 2035) is higher than the Santos combined profile of Caley plus Baxter Oil less the incremental due to Baxter Oil because the Caley oil alone development will not be constrained by the gas reinjection capacity (2 gas reinjection wells) and therefore could produce more oil on a standalone basis.

GaffneyCline then examined the other aspects of the Santos production profile. RISC commented that they determined slightly less sweep efficiency and therefore liquids recovery for the Phase 1 project. In the absence of its own detailed work, GaffneyCline considered Santos' interpretation to be within the overall range of uncertainty in the oil and hydrocarbon liquids recovery factor, and therefore has not made any adjustment to Santos' production profile with regards to this aspect.

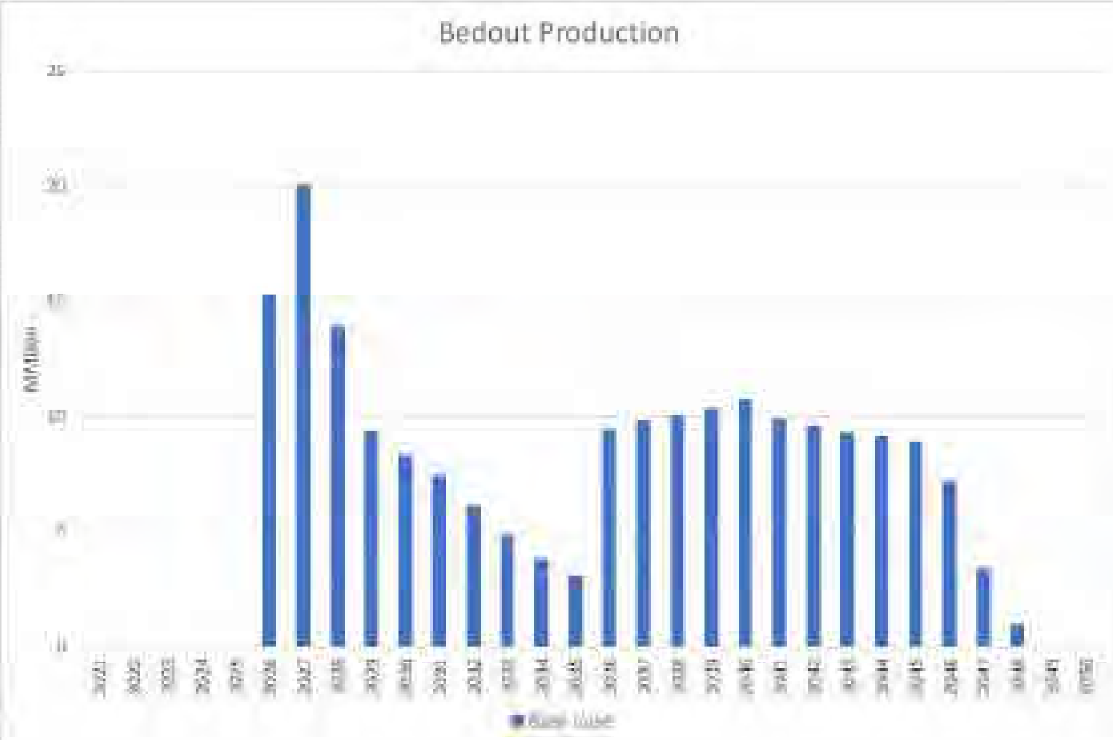
GaffneyCline conducted other high level checks such as peak well rate and the implied recovery factor. The peak average well rate for the oil or gas completion is reasonable, being less than the DST rate.

The implied gas recovery factor is reasonable and the Phase 1A oil recovery factor is reasonable for a miscible flood oil recovery with pressure maintenance.

5.2.4.2 Bedout Production Profile

The GaffneyCline production profile for the Base Case is depicted in **Figure 5.39** and is based on Santos' production profile with GaffneyCline adjustments based on the technical review performed. The profile is aggregated due to commercial sensitivities declared by Santos.

Figure 5.39: Bedout Production Valuation Scenario Profile - Base Case



5.2.5 Carnarvon CCS

In Western Australia, Santos assessed a number of reservoirs related to the Devil Creek and Varanus Island facilities and infrastructure for the CCS opportunities. Of these, the Devil Creek facility was considered the most feasible for the large amount of space available to accommodate CCS facilities. It envisages the reuse if the existing Devil Creek to Reindeer Field pipeline.

The Reindeer project is the most immature of the three CCS projects envisaged by Santos. Nominally the plan is to covert the depleting offshore Reindeer gas field to CCS. Santos envisages utilising the pore volume within the Reindeer structure originally occupied by gas that has been produced, as well as potential surrounding aquifer storage.

Santos has identified this project as an opportunity, to make use of available voidage in a mature gas field and to utilize existing infrastructure. The project is too immature to comment on suitability of the site for storage, injectivity and containment and to consider for valuation at this stage.

5.2.6 Western Australia Facilities and Cost Estimation

5.2.6.1 Assumptions

GaffneyCline has reviewed the cost profiles and a range of supporting documentation provided by Santos and adjusted the costs and/or the phasing in line with GaffneyCline's view of the development plan, production profile, and costs.

Costs can by divided into:

i. Capital costs (CAPEX) including the costs for drilling, new facilities, and ongoing improvements to existing operating assets

ii. Operating costs (OPEX) which include the costs for field and processing plant operations, lease costs for leased facilities, and tariffs paid for production services

iii. Decommissioning and Restoration (D&R) costs (often termed "ABEX") being the costs to plug and abandon (P&A) all wells; and to decommission, remove, and carry out site restoration for all installed production facilities in accordance with the currently prevailing regulations and good industry practise.

iv. Carbon Emissions costs are estimated applying the Santos carbon cost profile to those emissions forecast to above the permitted baseline. GaffneyCline has accepted the Santos provided "baseline" emissions profile without review.

Each of the sections below will provide additional field-specific facilities information and the cost profiles used. Costs are provided in millions of U.S. dollars (US$ MM), Santos Working Interest share, and in Nominal (i.e. escalated) terms. An escalation rate of 2% p.a. has been applied throughout.

The total costs for Santos' WA oil and gas assets are shown in **Figure 5.40**. The profiles are aggregated due to commercial sensitivities declared by Santos.

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Figure 5.40: GaffneyCline's Base and Stretch Case Cost Profile for Western Australia (US$ MM, Santos Share, Nominal)

5.2.6.2 Facilities

5.2.6.2.1 Varanus Island

Many of the fields previously producing to Varanus Island have ceased production. An extensive system of offshore platforms, pipelines and wells produce to the processing facilities on the island (**Figure 5.41**).

Figure 5.41: Varanus Island Infrastructure

Source: Santos

The costs provided here relate to the ongoing operation of the onshore Varanus Island facilities and the Harriet Joint Venture (HJV), John Brookes, Spar Halyard, and East Spar Fields as well as the future development of the Spartan, Corvus, and Kultarr Fields. All fields and facilities are 100% Santos Working Interest.

Santos CAPEX costs related to the above fields have been accepted without modification.

Santos OPEX profiles have been generally accepted; however Intra-asset Tolls have been adjusted based on the GaffneyCline production profiles.

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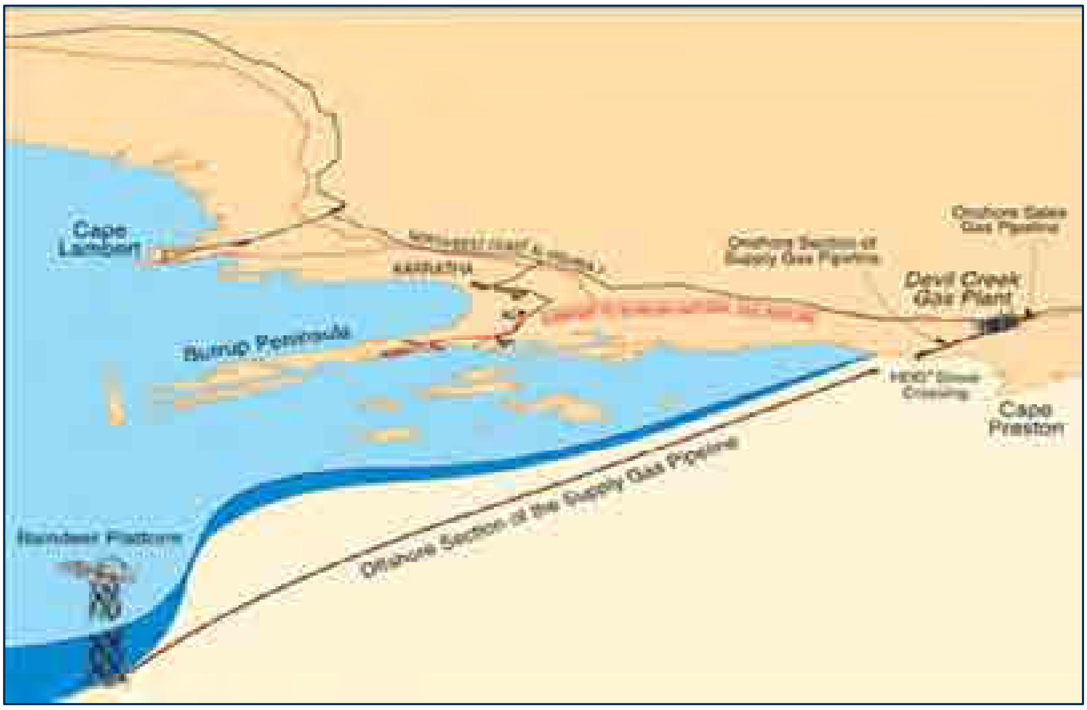
D&R costs have been extensively reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants. GaffneyCline has accepted the "Linchpin" estimates, made adjustments for escalation, any additional infill wells and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

No emissions above baseline and therefore no emissions costs are forecast.

5.2.6.2.2 Devil Creek

The Reindeer Field development comprises an unmanned offshore wellhead platform producing to the onshore Devil Creek gas plant (**Figure 5.42**).

Figure 5.42: Reindeer- Devil Creek Development Layout



Source: Santos

The costs provided here relate to the ongoing operation of the Reindeer field and the onshore Devil Island gas plant. Costs for the exploration and possible development of the Dancer prospect have been excluded. Reindeer and Devil Creek are 100% Santos Working Interest.

Santos CAPEX costs related to the above fields have been accepted without modification.

Santos OPEX profiles have been generally accepted and adjusted to match the GaffneyCline profile duration.

D&R costs have been reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants. GaffneyCline has accepted the "Linchpin" estimates, made adjustments for escalation and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

No emissions above baseline and therefore no emissions costs are forecast.

5.2.6.2.3 Macedon

The Macedon Field development comprises an unmanned offshore wellhead platform producing to the onshore Macedon gas plant.

The costs provided here relate to the ongoing operation of the Macedon Field and the onshore gas plant. The Macedon development is operated by BHP with Santos holding a 28.6% Working Interest.

Santos CAPEX costs related to the above fields have been accepted without modification.

Santos OPEX profiles have been generally accepted and adjusted to match the GaffneyCline profile duration.

D&R costs have been reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants. GaffneyCline has accepted the "Linchpin" estimates, made adjustments for escalation and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

No emissions above baseline and therefore no emissions costs are forecast.

5.2.6.2.4 Ningaloo Vision

The Van Gogh and Coniston Novara Fields are developed with subsea wells tied back to the Ningaloo Vision FPSO (**Figure 5.43**). Oil is exported to the buyer's vessel from the FPSO. Gas is used as fuel or reinjected.

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Figure 5.43: Ningaloo Vision Development Layout

Source: Santos

The costs provided here relate to the ongoing development and operation of the Van Gogh and Coniston-Novara Fields and the FPSO. Santos is the Operator and holds a 52.5% Working Interest.

Santos CAPEX costs related to the above fields have been accepted without modification.

Santos OPEX profiles have been generally accepted and adjusted where necessary to match the GaffneyCline profile duration.

D&R costs have been reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants. GaffneyCline has accepted the "Linchpin" estimates, made adjustments for escalation and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

GaffneyCline has accepted the Santos emissions costs forecast without review of operational emissions.

5.2.6.2.5 Pyrenees Venture

The Ravensworth, Wild Bull, Crosby, Tanglehead, Stickle, Harrison, and Moondyne Fields are developed with subsea wells tied back to the Pyrenees Venture FPSO (**Figure 5.44**). Oil is exported to the buyer's vessel from the FPSO. Gas is used as fuel or reinjected into the Macedon field.

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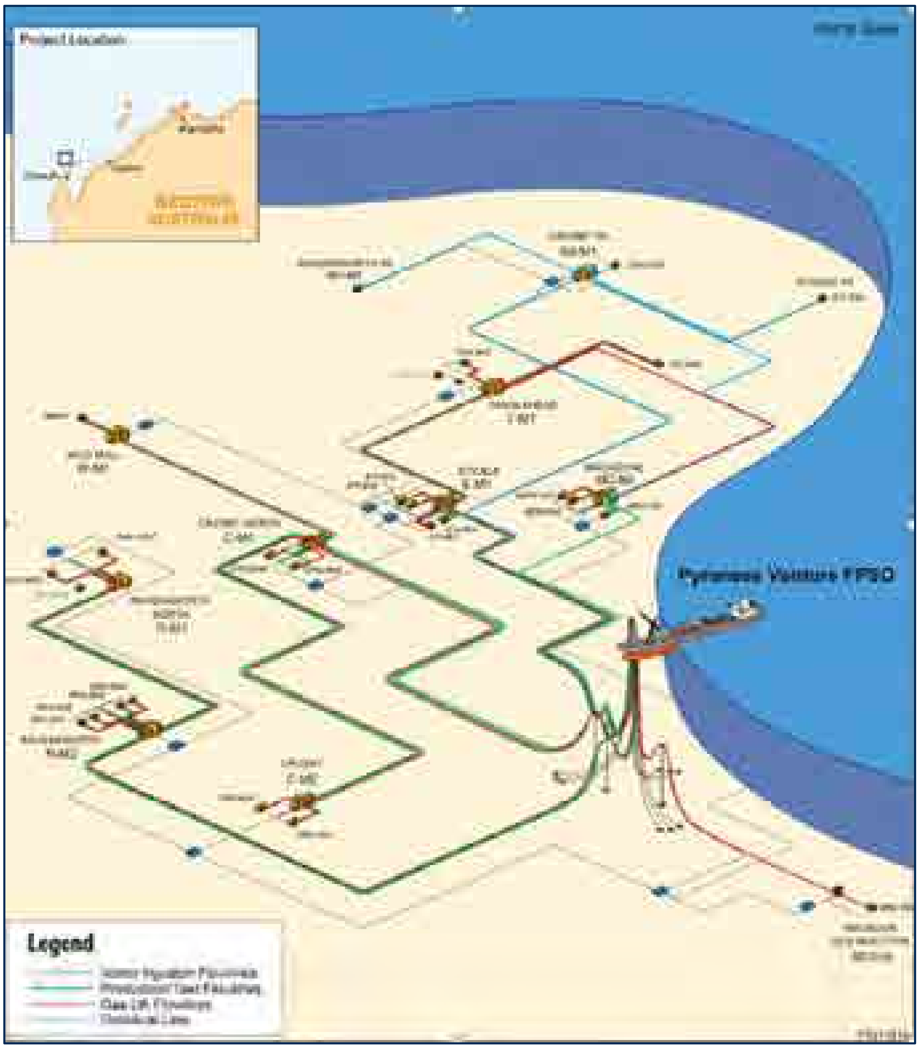
Figure 5.44: Pyrenees Venture Development Layout



Source: Santos

The costs provided here relate to the ongoing development and operation of all the developed fields and the FPSO. BHP is the Operator, with Santos holding a 28.57% Working Interest.

Santos CAPEX costs related to the above fields have been accepted with minor modifications.

Santos OPEX profiles have been generally accepted and adjusted where necessary to account for additional infill wells and to match the GaffneyCline profile duration.

D&R costs have been reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants. GaffneyCline has accepted the "Linchpin" estimates, made adjustments for escalation, additional infill wells, and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

There are no carbon emissions forecast above baseline, so no carbon emissions costs.

5.2.6.2.6 Barrow Island (and Legacy Oil Assets)

The costs and production for the Barrow Island joint venture have been consolidated together with a number of other "Legacy Oil" non-producing assets. This section, therefore covers and Barrow Island and Thevenard Island onshore assets and the Mutineer, Exeter, Fletcher, Finucane, Airlie Legendre, and other offshore fields. Of these, only Barrow Island is in production. The remaining fields have ceased production and will require only D&R activities.

The Barrow Island onshore facilities are extensive with development commencing in 1967. Barrow Island is classified as an A Class nature reserve. This poses an elevated requirement for restoration and rehabilitation that must be adopted as part of the scope of D&R activities

The Barrow Island development includes some 940 wells (excluding those already P&A'd), over 130 km of pipelines, 27 gathering and production stations and almost 900 well sites (**Figure 5.45**). D&R work is underway and expected to continue for the next 15 to 20 years.

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Figure 5.45: Barrow Island Development Layout

Source: Santos

The Mutineer, Exeter, Fletcher, and Finucane Fields were developed in the Mutineer-Exeter development with subsea wells tied back to the MODEC-owned MODEC Venture 11 FPSO. The FPSO was demobilized in 2018, with the 12 subsea development wells, 3 E&A wells, flowlines, umbilicals, structures and mooring remaining.

The costs provided here relate to the ongoing operation and D&R of the Barrow Island development and the D&R of all the suspended fields noted above. The Santos working interest and Operator of each is shown in **Table 5.27** below.

Table 5.27: Legacy Oil Assets: Santos Working Interest and Operator

Asset	Santos WI	Operator
Barrow Island	28.6%	Chevron
Thevenard Island	35.7%	Chevron
Airlie Legendre	66.8%	Santos
Mutineer	37.5%	Santos
Exeter	37.5%	Santos
Finucane	37.5%	Santos
Fletcher	50%	Santos
WA Other	Assumed 100%	Santos

Santos' CAPEX costs related to the above fields have been accepted with minor modifications.

Santos' OPEX profiles have been generally accepted and adjusted where necessary to match the GaffneyCline profile duration.

D&R costs have been reviewed and recalculated based on Santos-provided independent assessment reports provided by "Linchpin" consultants, and (for Barrow and Thevenard Island) the Operator's latest D&R assessment. GaffneyCline has accepted the "Linchpin" and Chevron estimates, made adjustments for escalation and any exclusions noted in the reports and phased the D&R expenditure in the five years following the end of production.

There are no carbon emissions forecast above baseline, so no carbon emissions costs.

5.2.6.2.7 Bedout Sub-basin Facilities and Cost Estimation

The Dorado Phase 1 development includes a 16-slot wellhead platform producing to an FPSO where full reservoir flow is processed and gas is compressed for injection into the reservoir. Oil will be loaded to the buyer's vessel from the FPSO (**Figure 5.46**).

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Figure 5.46: Dorado Field Phase 1A Oil Development

Source: Santos

In the Phase 2 gas blowdown phase, a pipeline will be laid from the field to a new or redeveloped onshore gas plant- for which four potential sites are under evaluation. During this phase, gas will no longer be reinjected but processed to produce sales gas and LPG's.

The costs provided here relate to the ongoing development and operation of the Dorado Field, the FPSO, and the Phase 2 onshore gas plant. Santos is the Operator and hold an 80% Working Interest.

Santos CAPEX costs for the Dorado Field Phase 1 and 2 developments have been crosschecked against an independent estimate and accepted.

The Santos Phase 1 OPEX profiles have been crosschecked with an independent estimate and accepted. The Phase 2 OPEX profiles include an assumed processing tariff to the onshore gas plant. GaffneyCline have accepted the initial Santos proposed processing toll and applied the same toll (escalated at 2% p.a.) going forward.

The Santos D&R costs have been reviewed, accepted, and adjusted to reflect the reduced development scope assumed by GaffneyCline (excluding the Baxter oil development) and phased following the end of production.

The carbon emissions forecast above baseline has been adjusted to reflect the GaffneyCline production profiles, and a revised Carbon emissions cost calculated assuming the Santos baseline emissions profile and carbon price.

5.3 Santos' Cooper Basin Assets

5.3.1 Cooper Basin Overview

The Cooper Basin spans the borders of northeast South Australia and southwest Queensland. It is a formed of a northeast – southwest trending structural depression covering an area of approximately 130,000 km^2. Together with the Eromanga Basin, it houses Australia's largest onshore oil and gas development. Santos produces sales gas, ethane, crude oil and gas liquids from the basins having made the first commercial gas discovery in 1963 and the first oil discovery in 1970.

Santos' Cooper Basin assets incorporate 190 gas fields and 115 oil fields which in 2020 produced 16.8 MMboe. The majority of discoveries are found within tight fluvial-lacustrine sequences which are interbedded with coal measures and shales within four-way, dip closed structures. Reservoirs are highly heterogeneous and unique development plans are required for each field and reservoir. In addition to the producing fields there are future development opportunities in near field exploration around the current developments as well as in the Deep Coal and Granite Wash Plays.

Santos' JV partners include Beach Energy who holds between 34-40% WI over the various blocks together with 6 other listed mid-cap companies. To date, Santos has drilled over 3,000 wells and plans a further 1,150 by 2040. Infrastructure includes 125 compressors across 28 satellites and over 7,000 km of pipeline (the majority of which is 4" and 6").

The Cooper Basin also houses the Moomba processing plant which is operated by Santos and is integral to the processing and transportation of natural gas and ethane to the east coast of Australia. Natural gas liquids recovered at the Moomba plant are sent together with stabilised crude oil and condensate via a 659 km pipeline to Port Bonython in South Australia for processing. Products including naphtha, crude oil, propane and butane are sold to domestic customers via road tanker loading facilities and export customers via ship loading facilities.

Santos plans an increase in production from its Coper Basin asset and targets 17-19 MMboe of annual production by 2025. It plans unit production cost reduction through lower cost drilling with associated higher production and reserves additions. Santos also plans to utilise horizontal drilling to unlock additional resources from the Deep Coal and Granite Wash Plays. Cooper basin asset. Four drilling rigs will drill a total of 100 wells per year. Santos' states its sustaining CAPEX profile is reasonably stable out to 2030 and states its vertical well cost has been reduced by 56% since 2016. Further well cost and operating efficiency initiatives and projects are underway over the next five years.

The Cooper Basin also contains the Moomba CCS project which is mature and is currently assessed as Development Pending with a Final Investment Decision announced on 1 November 2021.

A location map of Santos' Cooper basin assets is given in **Figure 5.47**.

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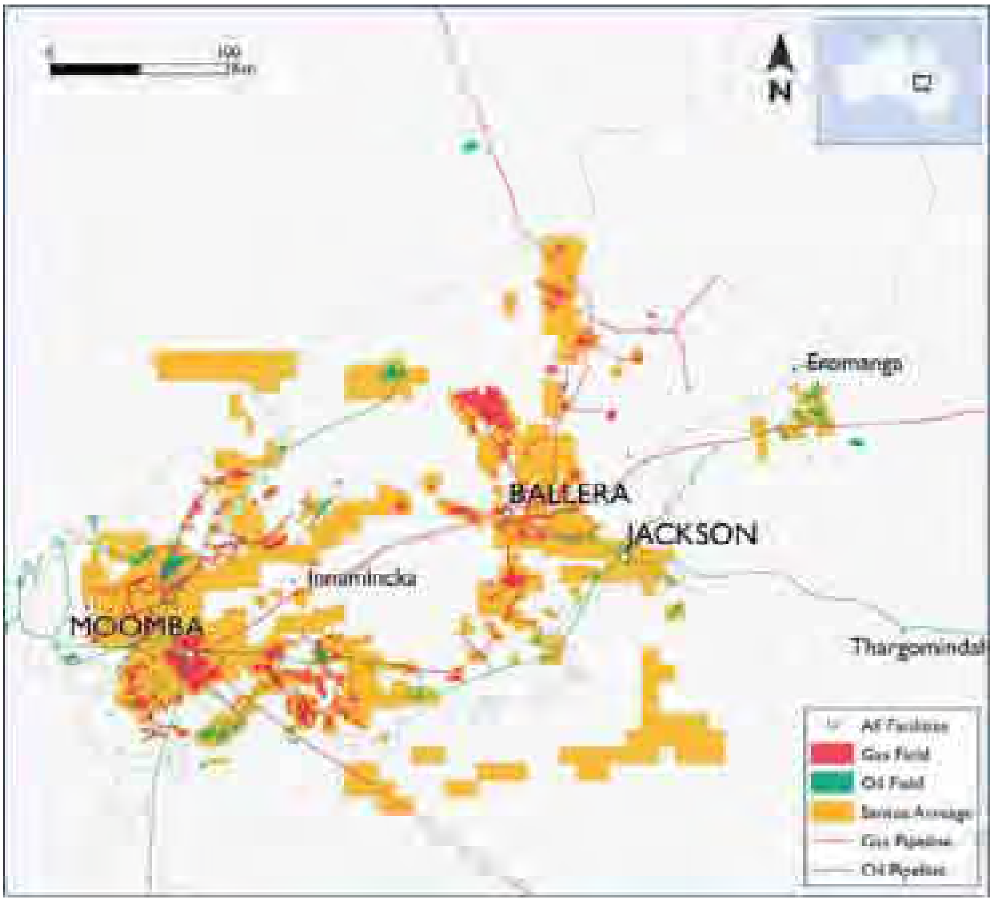
Figure 5.47: Location Map of Cooper Basin Fields



Source: Santos

5.3.1.1 Dataset

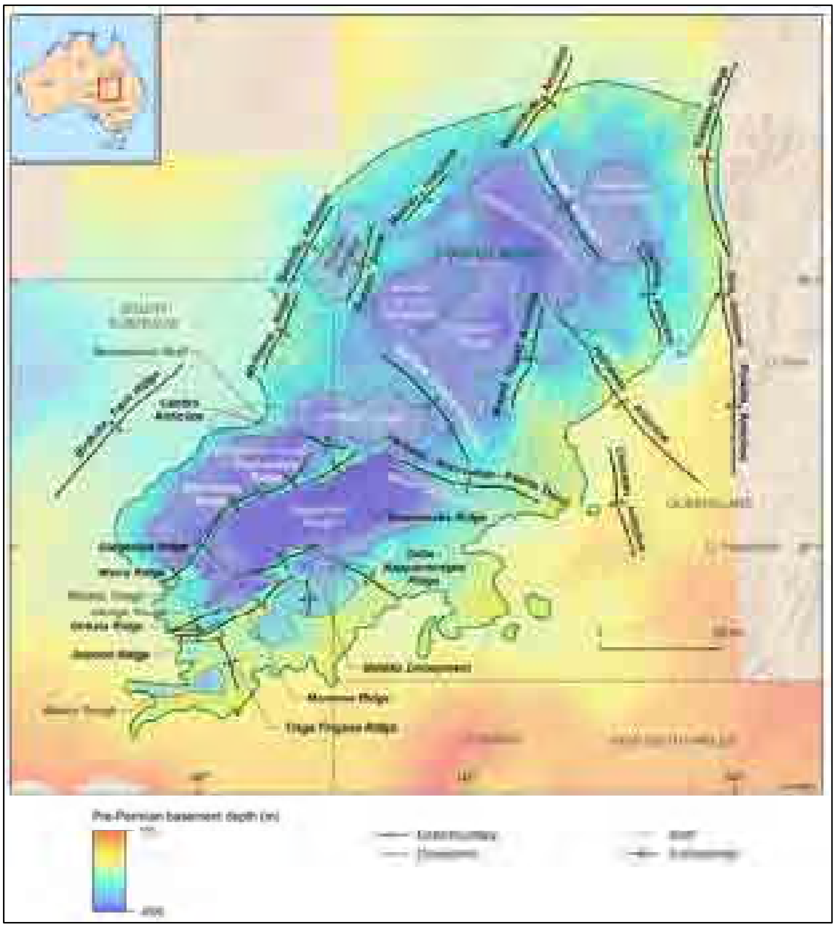
GaffneyCline was provided with a dataset which included historical production data, Santos' end 2020 Reserves, YE19 and YE20 Reserves Audit Reports caried out by NSAI and a summary spreadsheet of the YE20 NSAI Audit Evaluation. In addition, GaffneyCline was provided with various technical presentations covering twenty of the producing fields. GaffneyCline has supplemented these data with information from the public domain, most notably:

- Cooper Basin by the Department for Energy and Mining - Energy Resources, Government of South Australia
- Eromanga Basin by the Department for Energy and Mining - Energy Resources, Government of South Australia
- Cooper Basin Prospectively Study by Geoscience Australia.

5.3.1.2 Geology of the Cooper Basin

The Cooper Basin is a Late Carboniferous to Triassic intracratonic basin which lies unconformably above early Palaeozoic sediments of the Warburton Basin and which is overlain disconformably by the Eromanga Basin. The basin is formed of a series of troughs which are separated by structural ridges associated with the reactivation of thrust faults in the underlying Warburton Basin. The troughs contain up to 2,500 m of Carboniferous to Triassic sedimentary fill and are overlain by up to a further 1,300 m of Jurassic to Tertiary cover of the Eromanga Basin (**Figure 5.48**).

Figure 5.48: Structural Elements of the Cooper Basin



Source: Geoscience Australia

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The earliest deposits in the Cooper Basin are the Late Carboniferous to Early Permian Merrimelia Formation and Tirrawarra Sandstone. These comprise terminoglacial and glaciofluvial systems deposited unconformably on a glacially scoured landscape. The Tirrawarra Sandstone is formed of braided fluvial and deltaic deposits and is overlain by peat swamp and floodplain facies of the Patchawarra Formation. The Patchawarra Formation is overlain by the Murteree and Roseneath lacustrine shales with intervening fluvio-deltaic sediments of the Epsilon and Daralingie Formations. In the southwest of the basin, the age equivalent sediments of the Patchawarra to Epsilon sequence is a thick interbedded sequence of fluvial sands, coals and shales.

Early Permian uplift led to the erosion of the Daralingie and other underlying formations from basement highs. The Late Permian Toolachee Formation was deposited on the Daralingie unconformity surface and is overlain conformably by the Nappamerri Group consisting of late Permian to Middle Triassic Arrabury Formation and the Middle to early Late Triassic Tinchoo Formation. The Nappamerri Group provides a regional seal for the Cooper basin and separates the Cooper basin from the overlying Eromanga Basin.

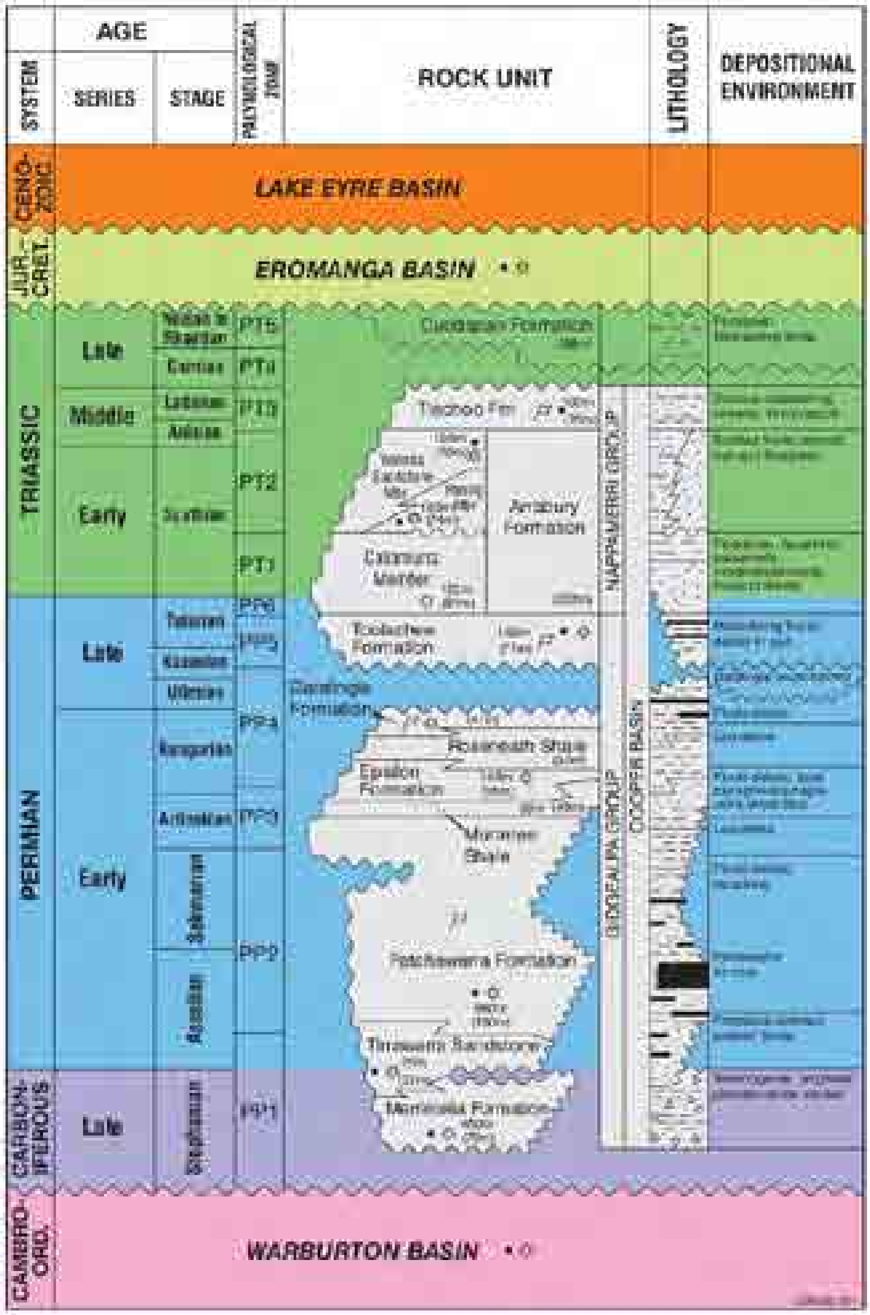
A stratigraphic column for the Cooper Basin is given in **Figure 5.49**.

The base Eromanga unconformity has been mapped across the whole basin. The overlying Eromanga Basin stratigraphy can be divided into three sequences: lower non-marine, marine and upper non-marine. In the Cooper region, the lower non-marine interval is formed of braided fluvial deposits of the Hutton and Namur formations, lacustrine deposits of the McKinlay Member and the fluvial, overbank and lacustrine sediments of the Poolowanna, Birkhead and Murta Formations, deposited as sandstones, shales and minor coal measures.

The non-marine section is conformably succeeded by a sequence reflecting transition from non-marine to marginal marine to open marine shales and sandstones which include a basal unit of the Cadna-owie Formation which is seismically mappable across the basin. Further marine deposition included the deposition of the Wallumbilla Formation and the overlying Toolebuc Formation and Allaru Mudstone.

Marine conditions ceased during the deposition of the Mackunda Formation, with the overlying Winton Formation deposited entirely under fluvial and lacustrine conditions. Major folding followed deposition of the mid-Cretaceous Winton Formation resulting in termination of sedimentation in the Eromanga Basin.

Figure 5.49: Stratigraphy of the Cooper Basin Assets



Source: Department for Energy and Mining – Energy Resources SA

5.3.1.3 Petroleum Systems of the Cooper Basin

5.3.1.3.1 Source Rocks

The Cooper Basin is dominated by coal rich source rocks. Oils and condensates are typically medium to light (30-60° API) and paraffinic. Most Permian oils contain significant dissolved gas. Gas composition is closely related to maturity and depth of burial with drier gas occurring towards basin depocentres. The Patchawarra Trough contains the bulk of oil and wet gas volumes consistent with local source rocks being in the oil window. The Nappamerri Trough however, which is underlain by granite and has high geothermal gradient (40-50 °C) is over mature and contains mainly dry gas.

The Toolachee and Patchawarra Formations are the thickest and richest source units with secondary contributions from the Epsilon and Daralingie Formations. The coal measures of these units are the principal hydrocarbon source rocks in the region and are dominated by Type II/III to Type III kerogens. The more coal rich facies have TOC>10% and other non-shale source rocks have oil generation potential. Shales however have lower potential with TOC<10% reflecting a more gas prone Type III-IV kerogen.

Early Permian lacustrine deposits of the Murteree and Roseneath shales have lower source rock potential for conventional hydrocarbons with gas prone kerogen and low TOC values. The Nappamerri Group has more limited source potential with TOC of 1.3% and Type III-IV gas prone kerogen.

Hydrocarbon generation primarily occurred from kitchen areas within the Patchawarra and Nappamerri Troughs where most of the drilling in the Cooper Basin has focussed. Basin modelling studies suggest there were multiple episodes of expulsion. Minor volumes of hydrocarbons were generated in the late Permian, particularly in the Nappamerri Trough. The main generation event occurred in the mid-Cretaceous and was related to a high heat flow event approximately 90 – 85 Ma. Modelling also suggests that minor generation occurred within the last 5 million years.

In the overlying Eromanga Basin, the presence of thick Poolowanna, Birkhead and Murta Formations is critical to the evaluation of oil source potential. The overlying marine and upper non-marine sequences are immature for hydrocarbon generation across much of the basin.

5.3.1.3.2 Reservoir Rocks

The primary gas reservoirs occur within the Patchawarra and Toolachee Formations. Reservoirs are formed of stacked, highly sinuous, fluvial sandstones. Porosity and permeability are highly variable due to a combination of facies changes, burial depth and diagenesis. Most porosity is not primary and is either reduced by authigenic minerals or enhanced by dissolution of lithic and feldspar grains. The shoreface and delta distributary sands of the Epsilon and Daralingie Formations form important secondary reservoirs.

Oil is principally produced from low sinuosity fluvial sands within the Tirrawarra Sandstone. Towards the margins of the basin, oil is also produced from the Patchawarra Formation and from fluvial channel sands in the Merrimelia Formation.

Unconventional reservoir potential is found in the laterally extensive shales of the Roseneath and Murteree Formations. These shales were deposited in large, freshwater lakes and have low porosity and permeability but are brittle and frackable. The Murteree Shale is widespread and reaches a maximum thickness of 86 m in the Nappamerri Trough, it thins to the north reaching maximum thickness of 35 m in the Patchawarra Trough. The Roseneath Shale reaches a maximum thickness of 105 m in the Tenappera Trough and is absent over much of the Patchawarra Trough.

Thick, laterally extensive, deep coal seams in both the Patchawarra Formation and the Toolachee Formation are also potential unconventional CSG reservoirs. Core samples show that the coals, which are thick and laterally continuous in parts of the basin, contain significant mesoporosity which is accompanied by permeabilities of 15-500 mD.

Within the Eromanga Basin sediments, the principal reservoirs are the braided fluvial Hutton and Namur sandstones. Oil is also reservoired in meandering fluvial units of the Poolowanna and Birkenhead Formations, lacustrine shoreface sands of the McKinlay Member and lacustrine turbidite sands of the Murta Formation.

5.3.1.3.3 Traps

The structural framework of traps in the Cooper and Eromanga Basins inherited from mild but widespread compression and regional tilt and erosion in the late Triassic. Regional downwarping commenced in the Early Jurassic. In the Tertiary, regional W-E compression reactivated Palaeozoic structures.

5.3.1.3.4 Seals

Intraformational shales and coals form local seals within the major reservoir units. Underlying the Daralingie unconformity are two important early Permian regional seals, the Roseneath and Murteree shales. The Roseneath Shale acts as the top seal for the Epsilon Formation and the Murteree Shale seals the Patchawarra Formation. A younger regional seal is provided by the Triassic Arrabury Formation.

Seals in the Eromanga section consist of intraformational diagenetic sandstones, siltstones and shales of the Poolowanna, Birkhead and Murta formations.

5.3.1.3.5 Proven and Potential Plays

Most fields in the Cooper Basin comprise multiple stacked reservoirs in anticlinal traps. Reservoirs may occur anywhere from the Late Carboniferous – early Permian Tirrawarra Formation to the early Cretaceous Coorikiana Sandstone depending on the extent of regional seals. Accumulations in the Patchawarra, Epsilon and Toolachee may be partially stratigraphic and successful wells are dependent on intersecting high sinuosity channel facies.

In addition to conventional hydrocarbon plays, unconventional plays are also present. Tight gas sands are found in the Early Permian Patchawarra Formation in the Moomba and Big Lakes Fields in the southern end of the Nappamerri Trough. Tight gas sands have also been intersected in the centre of the Patchawarra Trough.

The Cooper Basin contains thick Permian coal measures which are at potentially exploitable depths for CSG. The Early Permian Patchawarra Formation contains a major coal seam up to 30 m thick. The Weena Trough in the southern Cooper Basin contains the shallowest occurrences of thick Patchawarra Formation sub-bituminous coal seams (~1,500 m deep). Higher rank, thick Permian coal seems in the deeper parts of the Cooper Basin lie between depths of 2,000 and 3,500 m. Generally, 2,000 m is considered the floor for CSG production due to cleat closure and permeability reduction at greater depths. The Cooper Basin coals however are characterised by a high inertinite content. Inertinite is essentially non-reactive during the carbonisation process and the cellular structure of the component plant material is preserved. As a result, these coals contain significant macro-porosity and therefore free-gas storage potential in addition to gas storage by adsorption.

5.3.2 Cooper Basin Fields and Associated Production Summary

Table 5.28: Cooper Basin Summary

Field Data	
Permit	Multiple permits
Location	NE South Australia/SW Queensland
Santos Working Interest	Various
JV Partners	Various
Discovery Date	Gas - 1963 (Gidealpa-2) Oil - 1970 (Tirrawarra-1)
First Production	Gas - 1969 Oil - 1982
Valuation Scenario Volumes as of 1 July 2021	
GaffneyCline Net STO Valuation Scenario Volumes	222 MMboe Base Case, 243 MMboe Stretch Case
Chance of Development	Producing Asset with Contingent Resource opportunities

In its review, GaffneyCline audited basin and well level production profiles together with third party audit reports to reconcile volumes which Santos has provided in its production profiles.

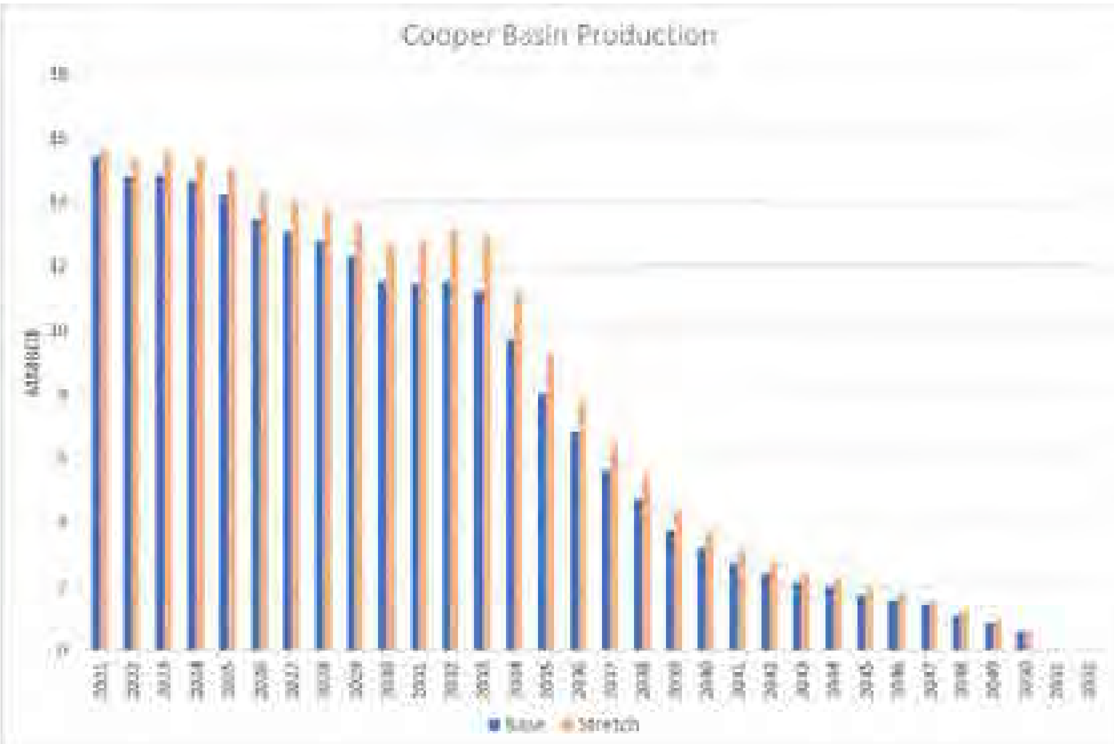
GaffneyCline has reviewed the reasonableness of Santos' profiles for 2P Developed projects based on checks of DCA forecasts. For projects classified as 2P Undeveloped and Contingent Resources, GaffneyCline has reviewed Santos' profiles based on a review of the EUR per well against recent historical EURs per well. GaffneyCline's focus was on gas as the dominant product, with lesser checks on oil. GaffneyCline volumes for both Base and Stretch Cases focus on 2P and 2C volumes based on performance reconciliation and the maturity of the basin.

Based on this methodology, GaffneyCline estimated EURs per well for the four largest project areas and compared these to Santos' EUR per well for the same areas. Based on this comparison, GaffneyCline produced scaling factors for each project area to account for differences between the GaffneyCline and Santos profiles. GaffneyCline then created a basin level scaling factor which is essentially a weighted average of the project level scaling factors, with project area reserve and resource volumes as weights. The basin level profile scaling factors for the Cooper Gas Undeveloped Reserves and Contingent Resources tranches are respectively 95% and 80%.

5.3.2.1 Production Profiles for Evaluation

GaffneyCline has prepared two profiles for this work, Base and Stretch Cases, by applying the estimated scaling factors to the Undeveloped Reserves and Contingent Resources tranches in its Base Case estimate. GaffneyCline utilised the Santos EUR estimates for Reserve and Contingent Resources and excluded exploration and Deep Coal in the Stretch Case. GaffneyCline's production profile for the Base and Stretch Cases is given in **Figure 5.50**. The profiles are aggregated due to commercial sensitivities declared by Santos.

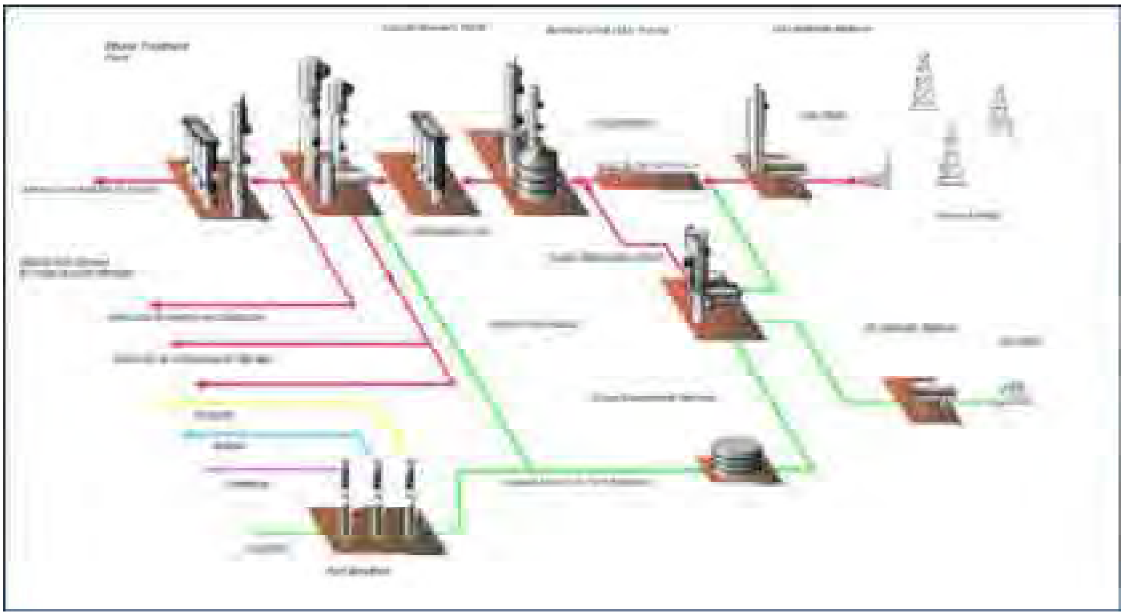
Figure 5.50: GaffneyCline's Base and Stretch Case Production Profile



5.3.2.2 Facilities and Cost Estimates for Evaluation

The Moomba development facilities are extensive and integrated into the gas and oil distribution networks in Eastern Australia. The Moomba midstream processing hub provides gas conditioning to sales specification, CO2 removal, liquids processing, ethane production, crude stabilization, and compression/pumping for transport of the produced gas and liquids to market. Hydrocarbon liquids are transported to Port Bonython where further processing produces propane, butane, naphtha, and crude oil for sale. The production facilities are illustrated in **Figure 5.51**.

Figure 5.51: Cooper Midstream Facilities



Source: Santos

In a facility of this complexity and age, there is a risk of operating cost escalation- if costs and processing requirements are not continuously evaluated and challenged. The Santos development and operations team have such a process embedded and generate an inventory of efficiency improvement opportunities.

As an example, a program is underway to simplify field compression by reducing the number of units and electrifying compressor drivers. This provides higher reliability, lower operating costs, and lower emissions.

In the long term, there are opportunities identified to further simplify, scale down, and automate the processing steps in response to declining throughput by taking trains or processes out of service.

5.3.2.2.1 Costs

GaffneyCline has reviewed the cost profiles and a range of supporting documentation provided by Santos and adjusted the costs and/or the phasing in line with GaffneyCline's view of the development plan, production profile, and costs. The costs to develop, operate and decommission the Cooper facilities are estimated based on the Base and Stretch profiles provided in Figure 4. Cost profiles were reviewed in the following categories:

i. Capital costs (CAPEX) including the costs for drilling, new facilities, and ongoing improvements to existing operating assets

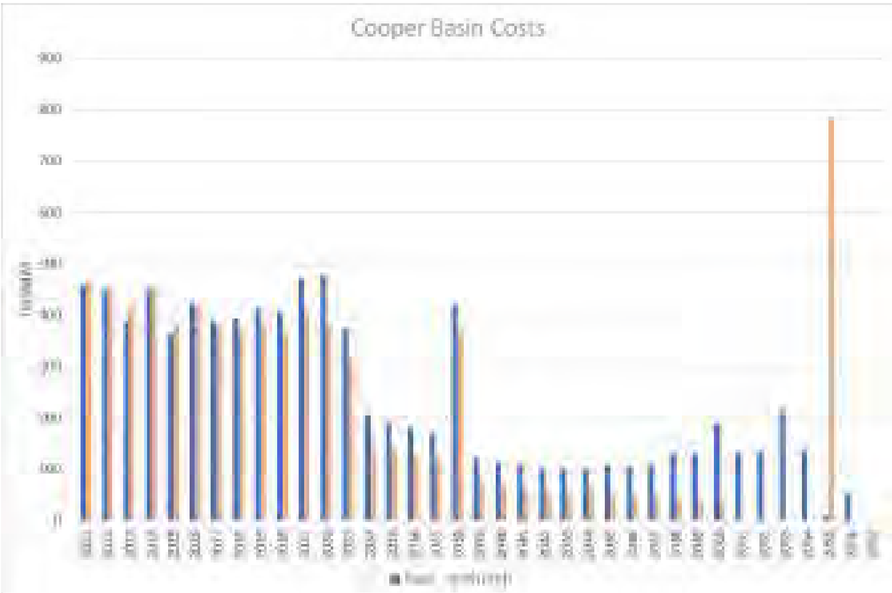
ii. Operating costs (OPEX) which include the costs for field and processing plant operations, lease costs for leased facilities, and tariffs paid for production services

iii. Decommissioning and Restoration (D&R) costs (often termed "ABEX") being the costs to plug and abandon (P&A) all wells; and to decommission, remove, and carry out site restoration for all installed production facilities in accordance with the currently prevailing regulations and good industry practise.

iv. Carbon Emissions costs are estimated applying the Santos carbon cost profile to those emissions forecast to above the permitted baseline. GaffneyCline has accepted the Santos provided "baseline" emissions profile without review.

GaffneyCline's cost profile for the Base and Stretch Cases is given in **Figure 5.52**. Costs are shown in US$ MM, Santos Working Interest, Nominal terms. The profiles are aggregated due to commercial sensitivities declared by Santos.

Figure 5.52: GaffneyCline's Base Case Cost Valuation Scenario Profiles for the Cooper Basin (US$ MM, Santos Share, Nominal)



The Santos cost profiles have been adjusted overall to exclude costs related to exploration.

Santos' CAPEX profile is primarily drilling costs. GaffneyCline has reviewed drilling costs per well on historical (from 2016) and projected basis. Santos forecast continuous savings in cost/well over the 20-year development period, keeping pace with inflation. GaffneyCline have accepted the projected savings in the first five years (2021-26) CAPEX profile and applied 2% p.a. escalation thereafter.

GaffneyCline have reviewed OPEX in terms of Midstream, Downhole, and Surface categories. "Midstream" OPEX is related to the operation of the midstream facilities and is essentially fixed until structural changes are made to the operation. Santos has included a number of such step changes in the profile, which GaffneyCline has accepted.

"Downhole" costs are primarily related to the costs to operate wells. GaffneyCline has reviewed and accepted the Santos cost/well/year over the 2021-26 period and applied 2% p.a. escalation, thereafter, applying this to the projected active producing well count.

"Surface" costs are projected forward on a unit of production basis i.e. a cost/boe.

GaffneyCline has generally accepted, but rephrased, the Santos D&R estimate, assuming that wells will be P&A'd as they are removed from the active well count- producing a continuous, longterm phasing of D&R expenditure.

5.3.2.3 Key Assumptions, Risks, Uncertainties and Opportunities

GaffneyCline's Base Case profiles have been scaled for projects classified as Undeveloped Reserves and Contingent Resources based on GaffneyCline's review of recent EURs per well for the four largest areas. GaffneyCline has accepted Santos' profiles for Developed projects. GaffneyCline has excluded volumes classified as Development not viable and exploration from its Production profiles. Exploration has been valued separately.

5.3.3 Cooper Basin Fields and Associated Production Technical Review

5.3.3.1 Gas Fields

The first commercial gas discovery in the Cooper Basin was made at Gidgealpa in 1963. Gas production commenced in 1969 and 8.6 Tcf has been produced from 1,800 gas wells. Gas liquids content and CO_2 content are the two overlays which have determined Cooper gas field development. Currently, Cooper gas is averaging 20% CO_2 while the Cooper gas liquid content varies from dry gas (<1 bbl/MMscf) around Moomba and Big Lake to very liquid rich (40+ bbl/mmscf) in other areas. The two largest fields are Moomba and Big Lake which lie to the southwest of the Nappamerri trough. Gas from these fields has low liquid content but high CO_2.

Santos' Cooper gas fields are divided into four separate asset areas, Northern and Central in South Australia, SWQ in Queensland, and Cross Border which straddles the boundary between the two states (**Figure 5.53**). The assets areas are further divided into satellite areas which the fields feed into (**Table 5.29**). All satellites flow into the Moomba Plant.

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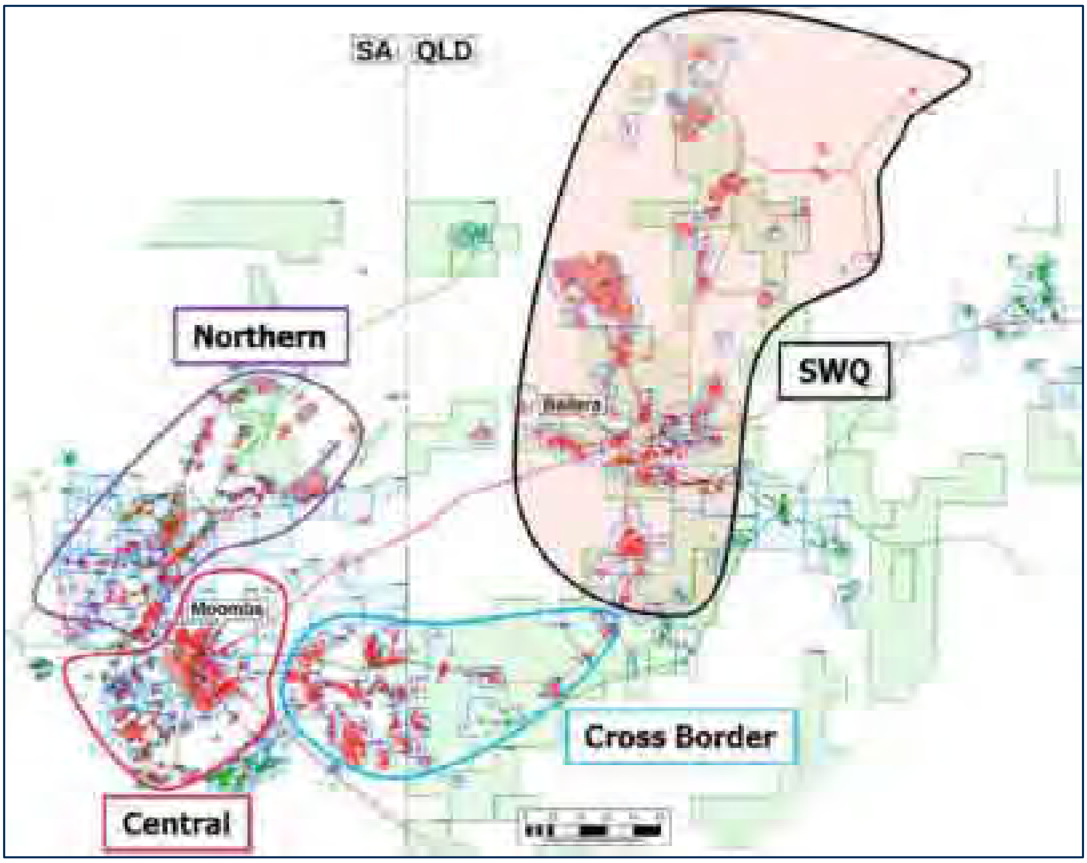
Figure 5.53: Santos' Cooper Gas Field Asset Areas.



Source: Santos

Table 5.29: GIIP Estimates for the Bayu-Undan Phase 3C Infill Wells

Asset Area	Satellites	Field Count
Northern	Tirrawarra	90+
	Bookabourdie	
	Merrimelia	
	Gidgealpa	
Central	Moomba North	40+
	Big Lake	
	Daralingie	
	Moomba South Central	
Cross Border	Toolachee	150+
	Kidman/Strzelecki	
	Dullingari	
	Della	
SWQ	Ballera	30+

The field development plans in the mature Cooper basin gas fields are typically phased in order to test reservoir extent, pressures and deliverability. This phased approach allows for appraisal drilling to be followed by development drilling and confirmation of well type. The primary development well type has historically been vertical, fracture stimulated wells; however, in depleted areas there has been success with underbalanced drilling and horizontal wells are being tested in tighter and more permeable areas. In addition to subsurface considerations, the field development plan includes surface constraints to ensure deliverability from the wells and fields is maximised.

5.3.3.2 Oil Fields

Oil production in the Cooper Basin commenced in 1982. Oil is produced from many stratigraphic intervals; however, the key horizons are all in the Jurassic comprising both good quality reservoirs of the Hutton and Basal Birkhead Formations and tighter formations of the Murta, McKinlay and Namur Formations. Cooper oil discoveries are primarily located on the flanks of the basin or adjacent to faults which have enabled migration from deeper source rocks. Traps are typically low relief structures.

The key oil satellites are Charo, Limestone Creek, Watson, Caroo, Jackson Tarbat and Cook. The main pipelines are Charo to Tirrawarra (CTOP), Cook to Merrimelia (CMOP), Tarbat to Jackson (TJOP) and Jackson to Moomba (JMOP). All crude flows to Moomba for stabilisation and then to Port Bonython for fractionation and sale. There are between 150 and 200 active oil fields within the basin.

In addition to the currently producing fields, there are a number of exploration, development and appraisal opportunities. Appraisal activity is primarily concerned with testing the extent of the reservoir prior to development to de-risk step outs. Additional uncertainties include reservoir compartmentalisation and understanding reservoir heterogeneity. Development activities include modelling and studies to plan infill drilling, reduced spacing drill activities and secondary recovery projects. Well design includes vertical and horizontal wells with waterflood planning part of the FDP in some of the fields. Well design appraisal includes both stimulated and unstimulated horizontal well producibility.

5.3.3.3 Geoscience Discussion

GaffneyCline's review of the developed Cooper Basin Fields has focused primarily on production data provided by Santos in order to forecast future production. As such, no detailed review of any geological models has been carried out.

5.3.3.4 Reservoir Engineering Discussion

GaffneyCline received production profiles for the Cooper Basin in the form of the following data sources:

- Basin level forecasts (volumes and drill counts) broken down by tranches and products provided by Santos' long term planning team
- Well level forecasts in a ValNav database provided by Santos' reserves team
- Third-party reserves reports and audit letters from NSAI

The basin level forecasts are the inputs to Santos' economic model, while the well level forecasts form the building blocks of the basin level forecasts. Santos' production profiles for the Cooper Basin asset include projects which have been classified as 2P Developed, 2P Undeveloped Approved for Development, 2P Undeveloped Justified for Development, 2C Development Pending, 2C Development on Hold, 2C Development Unclarified and Prospective Resources.

The well level forecasts do not account for the phasing of different projects, as they all start on the same day. The basin level forecasts do account for project scheduling however, the breakdown of the basin level forecasts by field or the scheduling for specific projects was not available. GaffneyCline compared totals from these two forecasts and noted a small disconnect as the totals were not the same but were within 10%. As such, GaffneyCline considers the data sources to be consistent with each other. Based on the reconciliation, GaffneyCline also confirmed the statement from Santos that not all the 2C Development Unclarified projects at the well level data have been included in the basin level forecasts.

GaffneyCline adopted the following top-down workflow:

1. Perform QC on Santos' profile at the project area level
    a. Focus on gas as the dominant product, with quick checks on oil
    b. 2P Developed projects recovery - check DCA forecast at project area level

c. 2P Undeveloped and Contingent Resources recovery

i. EUR per well - check 2P Undeveloped and Contingent Resources projects (excluding Development Not Viable projects) against recent historical EUR per well.

ii. Project schedule – check reasonableness of drilling schedule by comparison with recent drilling history.

2. Modify recoveries as necessary

3. Propagate modifications from project area level to basin level by the application of scaling factors to be applied to Santos' basin level profiles to create Base Case and Stretch Case valuation scenario profiles. The number of future activities is the same in both cases.

For the Cooper Gas business area (includes Cooper gas and Permian oil fields), GaffneyCline has estimated the hydrocarbon recoveries in the four largest project areas (as defined in the third-party reserves report provided), which are Moomba (3 fields), Big Lake (1 field), Tirrawarra (3 fields) and Barrolka (8 fields). Checks were performed for 2P Developed, 2P Undeveloped and Contingent Resources projects.

For the Cooper Oil business area, GaffneyCline has estimated the hydrocarbon recoveries in the largest project area which is the NM Horst project area. The hydrocarbon volumes in the Cooper Oil business are much smaller than in the Cooper Gas business area. There are 32 fields in the NM Horst project area, and the remaining volumes come from 75 small fields. Due to the smaller volumes in NM Horst, only a quick check on 2P Developed projects was performed.

For both gas and oil, remaining recoverable volumes are dominated by Contingent Resources class projects, which are, by definition, more at risk than Reserves class projects. Therefore, GaffneyCline focused on the volumes associated with Contingent Resources class projects.

Additionally, GaffneyCline has also compared Santos' expected future activity levels against historical drill counts. Omitting exploration wells, the expected future well counts were found to be within the range of annual drill counts from year 2016 to 2020 (between 40 and 117 wells). As such, GaffneyCline accepts Santos' valuation scenario drill counts for the 2P Undeveloped and Contingent Resources projects.

5.3.3.5 Basin Level Scaling Factors

Based on its analyses GaffneyCline has estimated scaling factors to be applied to Santos' basin level profiles, in particular for the Cooper Gas Undeveloped Reserves and Contingent Resources tranches. The scaling factor for the Cooper Gas Undeveloped Reserves is given in **Table 5.30**. The basin level scaling factors are essentially weighted averages of the project level scaling factors, with project area volumes as weights. The basin level forecast scaling factor for Cooper Gas Undeveloped Reserves is 95%. For Contingent Resources, GaffneyCline has determined a basin level scaling factor of 80% based on a comparison of basin level profiles.

Table 5.30: Basin Level Cooper Gas Undeveloped Reserves Scaling Factor.

(MMboe)	Santos UD	GaffneyCline UD	Factor
Total	49	47	**95%**

Note: Volumes in the table were obtained from the Santos' well level database

5.3.3.6 Production Profiles for Evaluation

GaffneyCline has prepared two valuation scenario profiles for this work: Base and Stretch Cases. **Table 5.31** shows the scaling factors used to scale Santos' Basin level forecasts to arrive at GaffneyCline's forecasts. The scaling factors of 95% and 80% applied to the UNO/IntOps, Gas 2P Undeveloped and Gas Contingent tranches are those estimated in **Section 5.3.3.5**. The scaling factors represent GaffneyCline's view on future average well performance. GaffneyCline has not modified the number of future projects, omitting exploration wells, the expected future well counts are within the range of annual drill counts from year 2016 to 2020. As such, GaffneyCline accepts Santos' profile drill counts for the Undeveloped Reserves and Contingent Resources classes.

In the Base Case forecast, exploration has been excluded. Additionally, with the application of scaling factors, GaffneyCline's Base Case forecast is lower than Santos' forecasts. In the Stretch Case forecast, GaffneyCline has simply excluded exploration, and has not applied any performance cuts. The Stretch Case forecast matches Santos' forecast excluding exploration.

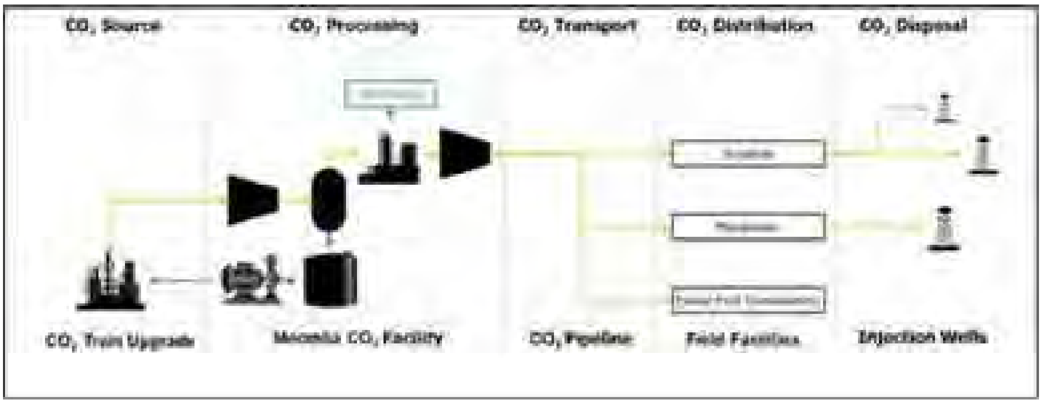
Table 5.31: Scaling Factors Applied to Santos' Basin Level Forecasts

Tranche	GaffneyCline Base	GaffneyCline Stretch
Gas 2P Developed	100%	100%
Oil 2P Developed	100%	100%
UNO/IntOps	95%	100%
Gas 2P Undeveloped	95%	100%
Gas Contingent	80%	100%
Oil 2P Undeveloped	100%	100%
Oil Contingent	100%	100%
Gas Exploration	0%	0%
Oil Exploration	0%	0%

5.3.4 Moomba CCS

The Moomba CCS project is located in the Cooper Basin in the central eastern part of Australia. Currently CO_2 is extracted from the produced well stream prior to export, and vented. The Moomba area has a highly developed infrastructure and as the extraction of CO_2 in a relatively pure form occurs on site, it offers an attractive opportunity to initiate a CCS project with minimal cost and limited risk. The project is illustrated conceptually in **Figure 5.54**.

Figure 5.54: Moomba CCS Project Facilities



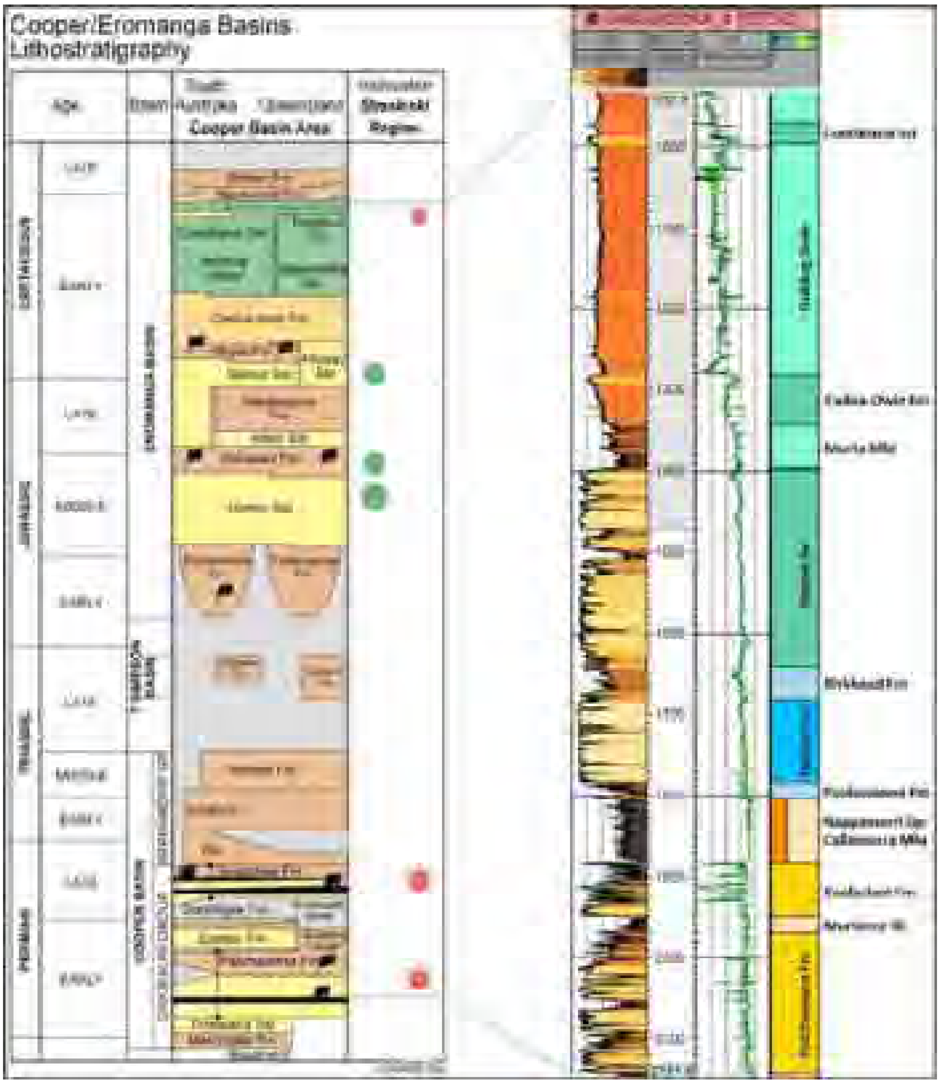
Source: Santos

Santos has carried out an extensive screening study of potential storage site, including a range of depleted and depleting gas fields and various aquifers. Geological formations in the region are relatively well understood due to significant historical exploration, appraisal and development drilling, seismic acquisition and dynamic data from decades of production activity. Santos selected two relatively small, depleted gas reservoirs, Strzelecki and Marabooka, as targets for storage of CO2 in its first phase of CCS on the basis that gas production is at a suitable level of maturity, the reservoirs are relatively simple and well understood and the risk of CO2 leakage is relatively low. Strzelecki and Marabooka are located approximately 45 km east-southeast of the Moomba plant.

The Santos plan is to utilize the depleted gas reservoir in the Toolachee sandstone formation (**Figure 5.55**) of the Strzelecki and Marabooka anticlinal structures during Phase 1a. These structures have the combined capacity to store between 13 and 14 Mt of CO2 (gross), at an injection rate of approximately 1.7 Mtpa over eight years. Santos plans to drill three new storage wells on the Strzelecki structure and one well in Marabooka and has made provision for two contingency wells in Strzelecki and one in Marabooka.

Once the Toolachee reservoirs have been re-pressurized to their original, pre-development pressures with injected CO2, Santos plans to utilise additional reservoir sections in close proximity to the Strezlecki and Marabooka to continue the injection rate of 1.7 Mtpa for the remaining 17 years of the planned overall 25 year life of the project.

Figure 5.55: Cooper Basin Stratigraphic Column and Type Curve of the CCS Target Formations



Source: Santos

5.3.4.1 Marabooka and Strzelecki Gas Reservoirs

The Toolachee formation comprises multiple sandstone intervals interbedded with shale (**Figure 5.56**). The top structure is shown in **Figure 5.50**, together with the historical development wells, the four proposed CO_2 injection wells and three contingency wells, and the ten existing candidate observation wells.

The Strzelecki Field was discovered in 1970 and to date 34 wells have been drilled across the structure most recently in 2018, targeting multiple levels. Besides gas in the Toolachee formation, small oil accumulations have been encountered in the shallower Birkhead, Hutton and Namur formations and gas has been encountered in the Patchawarra and Coorikiana formations.

The Marabooka Field was discovered in 1981 and to date 18 wells have been drilled across the structure, most recently in 2015, targeting multiple levels. Besides gas in the Toolachee formation, small gas accumulations have been encountered in the shallower Namur and Coorikiana formations.

Estimates of gas initially in place are approximately 180 and 80 Bscf for Strzelecki and Marabooka respectively. These volumes are substantiated with material balance calculations. The gas is dry, comprising 80% methane, and 7% CO_2, with negligible condensate. By the beginning of 2021, cumulative produced gas volumes from Strzelecki, and Marabooka were approximately 142 Bscf through 11 wells and 58 Bscf through five wells respectively.

Pressure has declined in both fields and there is little remaining gas production capacity. The current reservoir pressures are approximately 700 psia (Strzelecki) and 500 psia (Marabooka). Minor water influx has occurred during depletion, more notably in Marabooka.

Material balance calculations show that injection of approximately 10 Mt and 4 Mt into Strzelecki and Marabooka would restore the pressure in each field to their original pre-development values of 2,800 psia and 2,840 psia.

Santos has carried out detailed subsurface analyses to evaluate the suitability of the two depleted gas field for CCS and to estimate potential storable volumes and make injection profiles.

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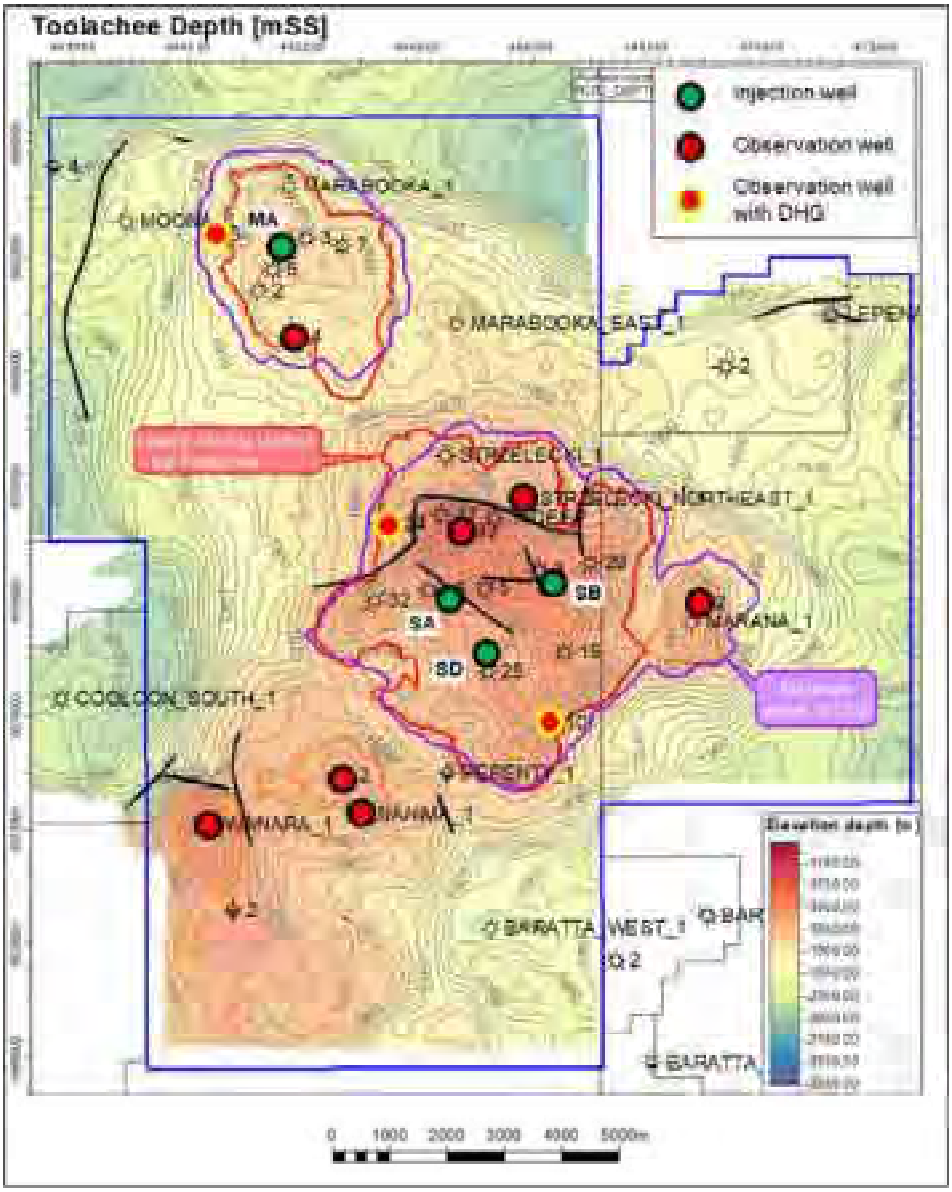
Figure 5.56: Top Structure Map of Toolachee Formation



Source: Santos

5.3.4.2 Project Extension

A number of options are being considered including the nearby Kidman, Aroona, Bagundi (KAB) and Della fields, and injection into other formations within the Strzlecki and Marbooka Field areas. Depleted gas reservoirs such as KAB are ideal for CO2 storage thanks to a mature level of reservoir characterisation and understanding key CCS subsurface uncertainties of capacity, containment and injectivity. These reservoirs are generally well understood from historical field appraisal, development and decades of production. 230 Bscf of hydrocarbon gas has been produced from the Toolachee, Epsilon and Patchawarra reservoirs in KAB, equating to 326 Bcf CO2 to 'refill' back to original reservoir pressure equivalent.

5.3.4.3 Moomba CCS Valuation

Based on the technical assessment of storage volumes GaffneyCline has provided injectivity valuation scenario profiles aligned with Santos however has included an additional contingent well in 2040 to de-risk the project for valuation purposes to Grant Samuel.

5.3.5 Cooper Basin Exploration

In addition to the producing fields, Santos has several potential development opportunities within the Cooper Basin. These include near field exploration opportunities and the Deep Coal and Moomba Granite Wash Plays. All Santos exploration value is discussed in **Section 5.8**. Below is a technical description of the potential.

5.3.5.1 Deep Coal Play

The Deep Coal Play refers to gas and associated liquids retained in the deep (>2,500 m) Permian coals of the Toolachee, Epsilon and Patchawarra Formations (**Figure 5.57**). The Permian coal seams of the Cooper Basin are recognised as the principal source rocks of the basin. The possibility that these coals could be targeted as a source rock reservoir has been recognised for over 15 years, with the first coal core acquired in the Dartmoor 1 well in 2002 (Epsilon Formation, Jackson trend) and the first successful coal fracture stimulation in the Moomba 77 well in 2007.

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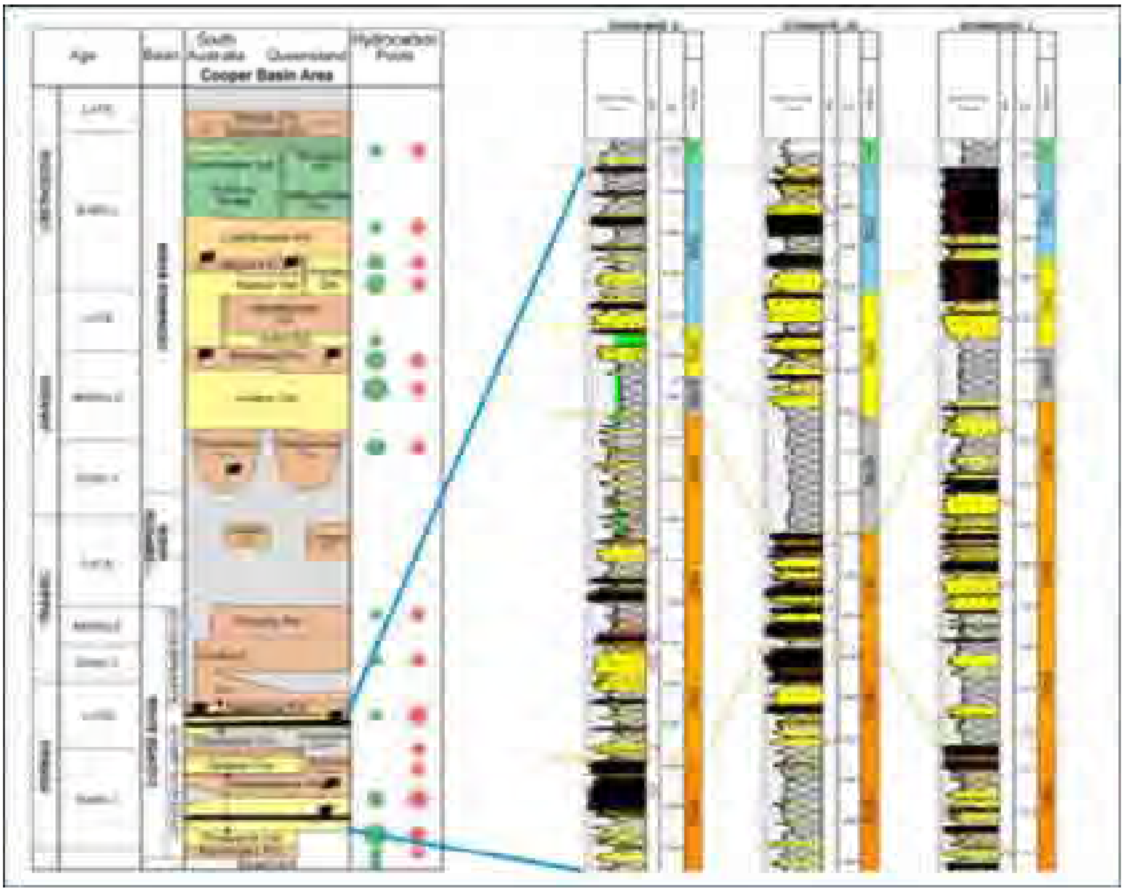
Figure 5.57: Deep Coal Stratigraphy



Source: Santos

The Cooper Deep Coal Play is more analogous to Shale Gas plays than to typical Coal Seam Gas. The coals reservoir a mixture of free and adsorbed gas, unlike typical CSG which is mostly adsorbed. Permeability is very low as cleating is only present within thin vitrinite bands and is typically closed due to depth of burial. Gas production relies on accessing free gas stored in the porous coal matrix, and a hierarchy of fractures including micro, capillary and tectonic.

In recent years, exploration and appraisal of the Deep Coal Play has progressed with over 100 coal frac stages in vertical wells to date. Encouraging production has been observed from these coal fracs with initial rates up to 0.8 mmscf/d (Gooranie-6) and in many cases, continued production at economic rates for over 3 years.

The next phase of exploitation targets the thicker coal seams with horizontal wells and multistage fracture stimulation.

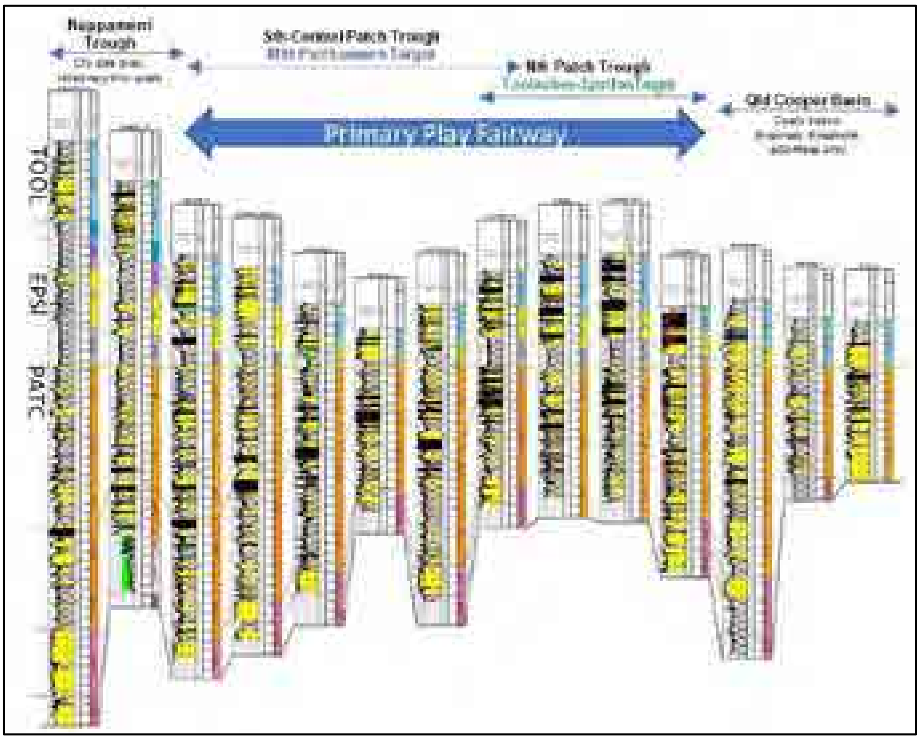
5.3.5.1.1 *Deep Coal Play Areal Extent*

The Permian coals of the Toolachee, Epsilon and Patchawarra Formations extend, and are therefore potential add-frac targets, across the entire Cooper Basin. However, seams in the South Australian part of the basin are typically thicker and more laterally extensive than those found in Queensland and can be targeted specifically for Deep Coal development as shown in the regional cross-section in **Figure 5.58**.

There are two sub-plays recognised to date; medium rank bituminous coals that retain wet gas/condensate and high rank anthracitic coals with retained dry gas. There are also two potential completion strategies; vertical completion of stacked coal seams; or horizontal completions of single thick seams (>10 m).

Although there are a significant number of data points collected from add-fracs in vertical wells, due to the low permeability and low relative rate of each stage, the current view is that the play requires a horizontal development strategy to be commercially viable. Play extent for horizontal development is defined as the area within which there is at least one coal seam measuring 10 m thick or greater. A play fairway map is given in **Figure 5.59**.

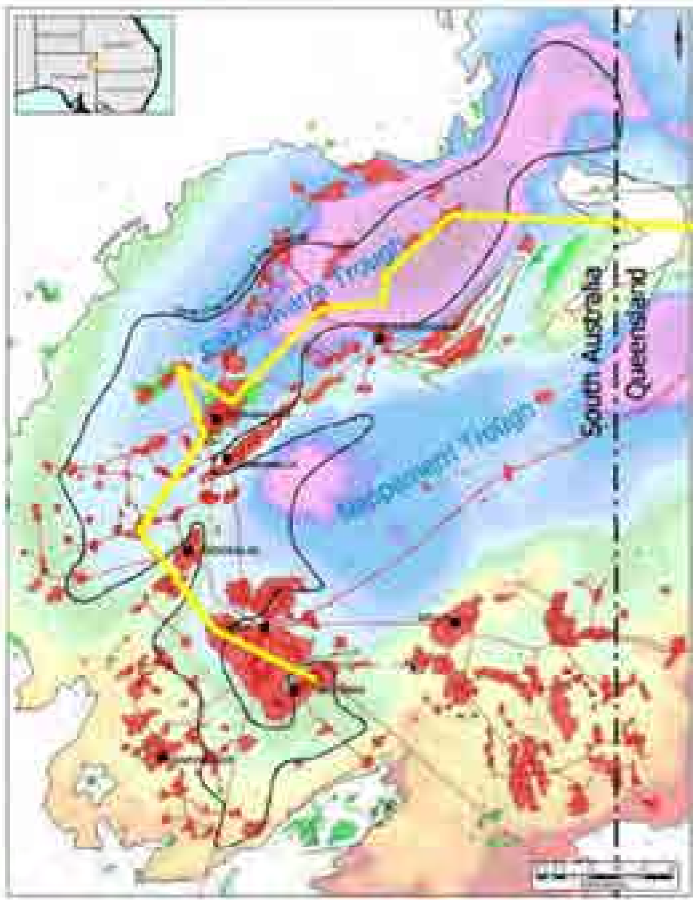
Figure 5.58: Regional Cross-section flattened on the Patchawarra Formation (See Figure 5.59 for Section Location)



Source: Santos

Gaffney Cline

Figure 5.59: Play Fairway Map of the Deep Coal Play



Source: Santos

5.3.5.1.1 Deep Coal Development

The Deep Coal play is technically proven (through the add-frac campaign). Santos plans to move into Exploration-Appraisal phase with a four-well horizontal drilling campaign. The objective of the Exploration-Appraisal phase is to demonstrate repeatable success (i.e. ≥50% of wells successfully meet objectives) with the objective being to drill, case, cement and frac a 1,000 m lateral, and achieve line of sight to commerciality.

The first of these appraisal wells is to be drilled in 2021 in the Beanbush Field, located in the northern Patchawarra Trough of the Cooper Basin. There are three coal 'reservoirs' suitable for horizontal development (i.e. greater than 10 m thick) in the prospect, the Late Permian Toolachee Formation coals, which are the primary targets, and the Early Permian mid-Patchawarra and the early Permian Epsilon coals. Permeability in the coal is very low and a 20-stage fracture stimulation scope is planned for the 1,000m lateral, scheduled for early 2022. Follow up locations will be contingent on the results at Beanbush, but a successful Deep Coal horizontal well will provide critical information to inform any decision for a larger field development plan to develop the Deep Coal play.

5.3.5.1.2 Deep Coal Resource Estimate

GaffneyCline has not carried out a detailed review of Santos' Deep Coal volumes as they have not been included in its Base or Stretch Case profiles as standalone opportunities. Deep Coal add-frac opportunities are considered in GaffneyCline's Cooper forecasts as part of the 2P Developed and Undeveloped Reserves and Contingent Resource volumes provided by Santos and incorporated in the valuation scenario profiles. Standalone Deep Coal production is yet to be proven commercial in the Cooper Basin.

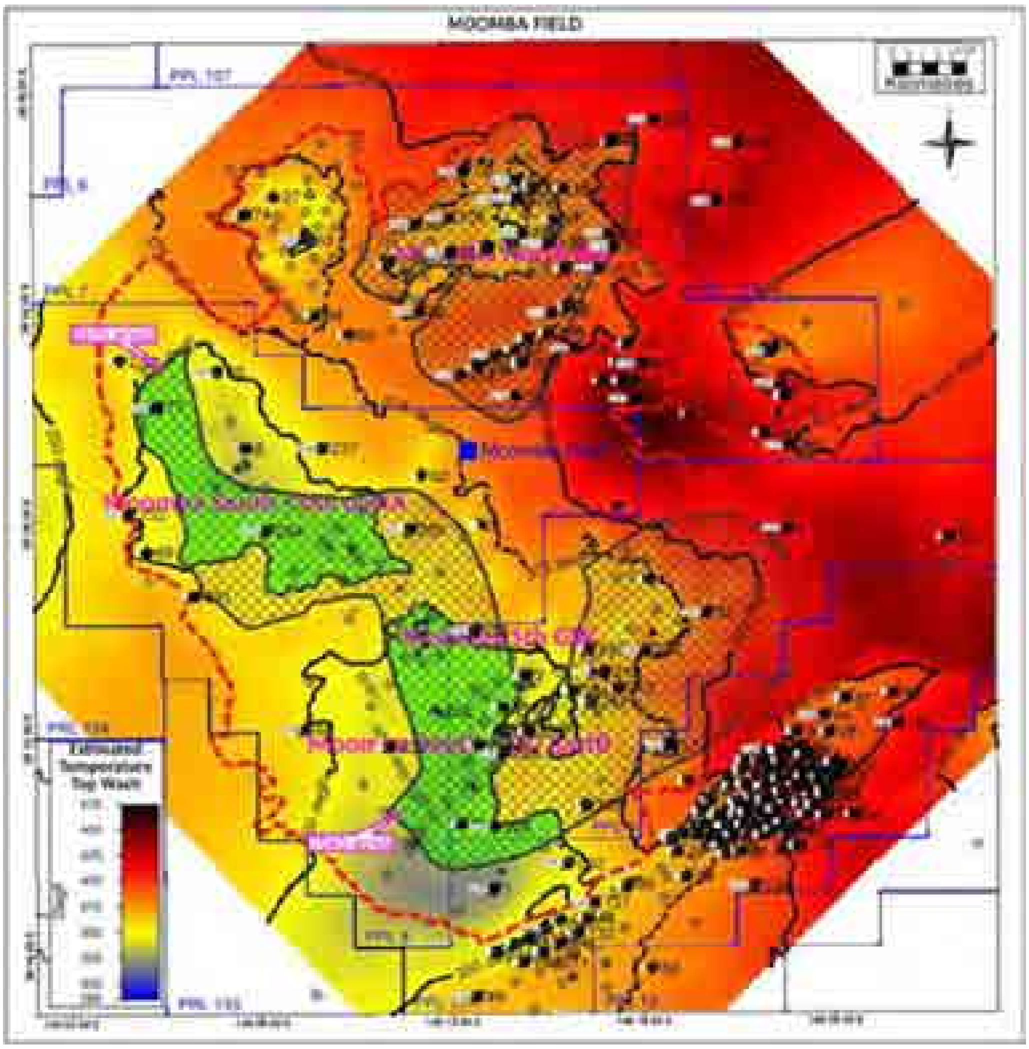
5.3.5.2 Granite Wash

The Granite Wash Play (**Figure 5.60**) in the Moomba Field constitutes a potential future development option that currently requires appraisal to characterise the reservoir, reduce geological uncertainty and provide deliverability information necessary for determining the most appropriate development strategy. The prospective area covers approximately 400 km^2 and Santos has estimated a GIIP of 2.7 Tcf to the lowest known gas. Flows have been obtained from 22 wells to date. The reservoirs for the Granite Wash Play consist of:

- Granite Wash – re-deposited reservoir involving erosion of Weathered Granite and local re-deposition as wash
- Weathered Granite – altered or weathered in situ granite with gas storage within primary matrix porosity and likely to be enhanced by microporosity

Standalone Granite Wash production is yet to be proven commercial in the Cooper Basin and has not been included in GaffneyCline's profiles.

Figure 5.60: Play Fairway Map of the Granite Wash Play



Source: Santos

5.4 Santos' Queensland and NSW Assets

5.4.1 GLNG Project

The GLNG facility produces liquefied natural gas (LNG) predominantly from coal seams from the Bowen and Surat basins for export to global markets from the LNG plant at Gladstone. The main areas of operation for GLNG by production to date are Fairview, Roma, Scotia and Arcadia (**Figure 5.61** and **Figure 5.62**). Santos has a 30% interest in GLNG. The LNG plant has two LNG trains with a combined capacity of 7.8 MTPA however with only~ 6.2 MTPA being utilised currently. Production from Train 1 commenced in September 2015 and Train 2 in May 2016. Feed gas is sourced from GLNG's upstream fields, contracted Santos equity gas, Santos portfolio gas, contracted third part gas and third-party uncontracted gas. GLNG have drilled ~2,304 wells to September 2021 with ~4,350 additional wells scheduled by Santos to be online by 2035.GaffneyCline has only reviewed the GLNG equity gas associated with planned developments that correspond to their GLNG declared Reserves and Contingent Resources.

The GLNG infrastructure includes 64 HP and LP compressors across 10 hubs with approximately 80 megawatts (MW) of power consumption, 4,800 km of gathering and pipelines and the processing of 47.5 megalitres (ML) per day of water. The GLNG plant name plant capacity is 3.9 MTPA per train (7.8) MTPA with an inlet capacity of ~725 TJ/d per train. LNG Storage includes 2 tanks at a capacity of 280,000 m^3. The shipping facilities include 4 loading arms which handle a rate of 25,000 m^3 per hour which equates to approximately 150 cargoes per annum.

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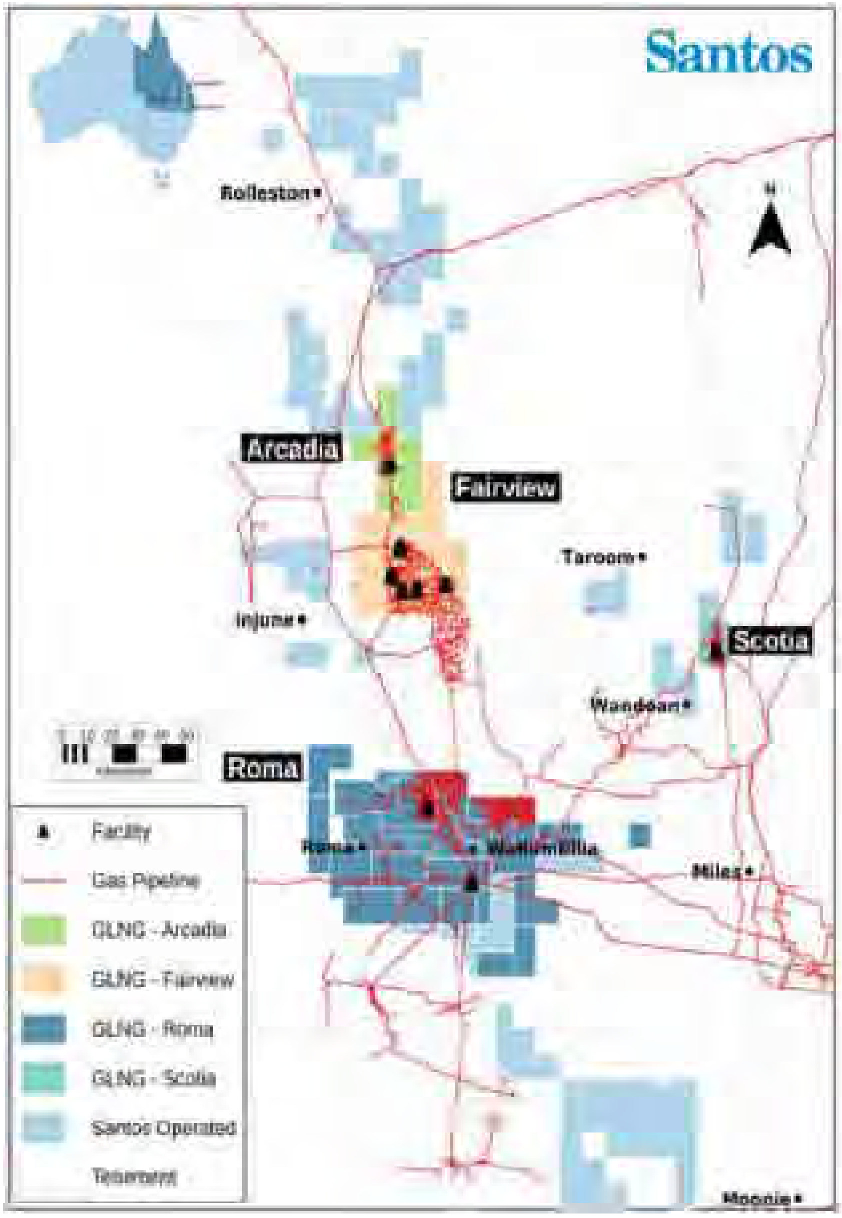
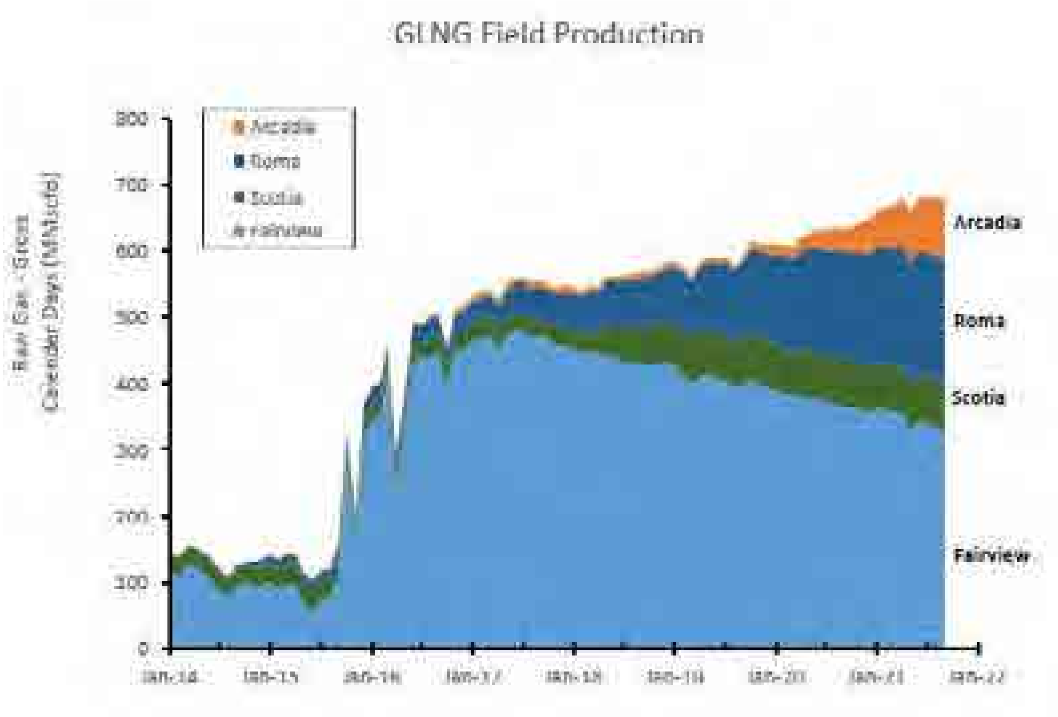
Figure 5.61: GLNG Tenements



Source: Santos

Figure 5.62: GLNG Project Historical Performance



Notes:
1. Production prior to Train startup existed with sales to domestic market
2. Calendar days is defined by raw gas volumes produced in a given month divided by the number of calendar days in that month

Source: Santos Production database, GaffneyCline review

Santos have embarked on a holistic, systematic approach to cost management delivering A$30 MM gross reduction for 2019-21. This includes:

- Infrastructure rationalisation and equipment strategy win A$4 MM per annum savings with the Fairview compression station 2 (CS2) rationalisation.
- Rig efficiency a pump run life savings resulting in flat OPEX despite a 25% well count increase.
- A frontline ideas portal with 40 - 50 "bottom up" savings ideas being realized delivering 2021 YTD A$0.3 MM per annum savings.

Additional initiatives for Midstream savings by Santos include ~A$18.5 MM of opportunities.

Through the 2022 to 2025 budget window and beyond the continued cost reduction focus by Santos has been estimated to drive year-on-year improvements in unit production cost by approximately -11% targeting a US$5/boe production cost for the project.

Geology of the Bowen Basin and Surat Basins

The Bowen Basin is a Permo-Triassic depocentre created by back-arc extension to the west of a subduction zone with passive thermal subsidence and foreland loading and fault reactivation. The basin is the birthplace of the CSG industry in Australia with the first commercial production from Dawson River in 1996 and Fairview in 1998. It is characterised by Late Permian coals (260-250 million years) that are Bituminous coals (medium to high rank) with low ash and high gas content. The coal seams are generally several meters thick, and highly regionally consistent. Individual seams can be correlated over 10's, possibly 100's of kms.

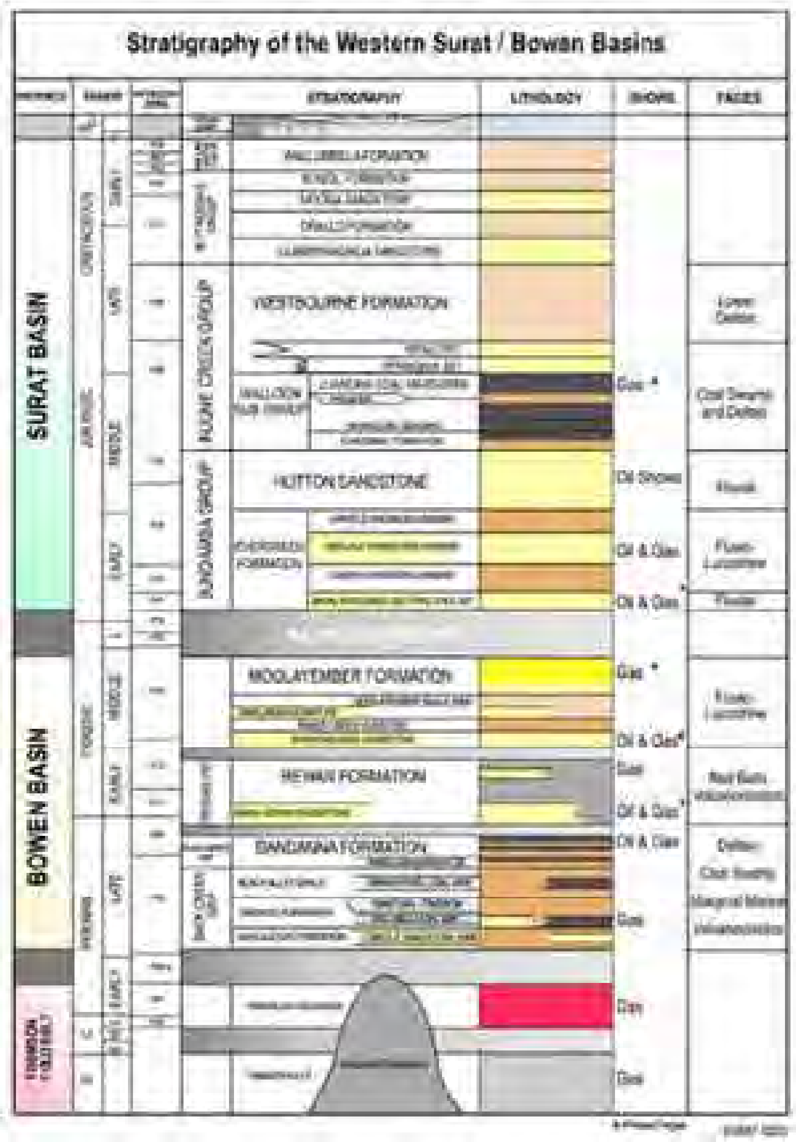
The Comet Ridge high separates the Denison Trough and the Taroom Trough. The basin consists primarily of fluvial and lacustrine sedimentary rocks with shallow marine sediments also deposited during four major transgressive cycles. The Bowen Basin is overlain by the Surat Basin in the south (**Figure 5.63**). In the Fairview area, the basin incurred a north-south dextral strike slip with Surat Basin sediments being removed by uplift and erosion over the last 25 million years.

The Jurassic to Cretaceous Surat Basin has undergone thermal subsidence with six major fining upward cycles. The Surat basin is an intra-cratonic system which is dominated by fluvio-lacustrine environments grading from high energy braided streams to lower energy meandering channels with inter-channel lakes and swamps. There was a late stage change in the Cretaceous to a coastal plain and shallow marine setting. The late compression and tilting has resulted in extensive erosion increasing to the north. First commercial production in the Surat started from Kogan North in 2006. The basin is characterised with high permeability (100+md) and thick widespread coal packages of Middle Jurassic age (176-161 million years). The coals have high ash content, with individual Walloon coal seams generally thinner (less than 1 m) and difficult to correlate regionally but stacked coal packages add up to 10's of metres and are regionally extensive.

The prolific Fairview CSG field currently produces from the Late Permian Bandanna formation coals, as well as the Early Permian Formation coals.

Gaffney Cline

Figure 5.63: Surat and Bowen Basins



Source: Santos

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Late Permian Bandanna Formation coals consist of two main packages of which net coal thickness range from 1 m to 16 m. The coals have a high gas content (10-15 m^3 per tonne), a low ash and moisture content, permeability ranging from 1 mD to > 100 mD, and a gas composition of 98-99% methane. The coals range in depth from ~ 200 mGL to ~1,500 mGL with the current productive interval between 450 m and 1,000 m. The interval is interpreted to have been deposited in a fluvial environment dominated by extensive swamps.

The various sub-basins located in the Fairview Early Permian Play were the result of extension during the Early Permian period. This caused the formation of a series of grabens and half-grabens which developed throughout the Early Permian at different rates. The Ridgelands play sub-crops to the west and dips to the northeast. The Springwater play dips to the northeast with a decreasing NTG trend to the northeast. A significant graben feature is present in the Waddy Brae geodomain (distinct geological regions utilised to analyse/forecast CSG well performance). Alluvial fans are common along major faults with little to no coal in these areas. Over 600 m to 800 m of structural variation is observed on the Cattle Creek Structure in the Springwater play and Ridgeland play respectively.

The Early Permian East area covers 339 km^2 and the coals lie between 1,100 mGL to 1,800 mGL. Net coal thickness is highly variable and ranges between 5 m to 58 m, distributed across 2 to 46 seams (16 on average). The permeability variation is considerable from 0.1 to 170 mD. The gas content varies between 10 and 15 m^3/t (daf) and the saturation ranges from 75 to 91% by geodomain. The gas contains between 88 – 99% methane and between 0.2 – 12% CO_2, >4% C_{2+}, and ≈ 2% nitrogen.

The Early Permian West area covers 131 km^2 and the coals lie between 200 – 900 mGL. Net coal thickness is between 3 m to 28 m. The permeability variation is considerable from 2 to 2,000 mD. The gas content varies between 2 and 8 m^3/t (daf) and the gas saturation (including inerts) varies between 56 – 89% (hydrocarbon saturation 38 – 77% (excluding inerts)). The gas contains 31 – 95 % methane and between 2.5 – 67% CO_2.

The Surat Basin Walloon coals represents the main target of the Roma development and consists of Upper and Lower Juandah coals measures, Tangalooma sandstone and Taroom coal measures.

The primary coal bearing sequence in the Roma area is the Middle Jurassic Walloon Subgroup of the Injune Creek Group. The Walloon Subgroup has been sub-divided into three coal measures, the Upper Juandah Coal Measures, the Lower Juandah Coal Measures, and the Taroom Coal Measures. The coal measures outcrop to the north of the Roma Project Area and deepen progressively to the south and east to depths in excess of 1,500 m. The Walloon Subgroup consists of interbedded fine to coarse grained volcano-lithic sandstones, siltstones, claystones, carbonaceous shales and coal seams distributed over a large interval (typically 150-250 m). Total net coal thickness range between 5-25 m, representing 5-10% of the total stratigraphic interval. Individual coal seams are generally thin (<0.5 m).

GLNG Reserves and Resources

Santos indicates over the past few years it has developed internal expertise and generated a comprehensive workflow that honours the subsurface fundamentals and includes:

- Geological static modelling
- Simulation type curve generation by Geodomain (known as the SLS and TUT tools)
- A systematic well development phasing known as Enersight
- Aggregation into long term supply plan (LTSP)

Santos document that this process is used by the asset team to mature sub-projects through to Board sanction. Santos considers their development plan best represents the future for GLNG development. Given the robust nature of the sub project process, GaffneyCline focused on this process for final valuation scenario profiles provided to Grant Samuel and this is reflected in GaffneyCline's work and volumes presented.

The Base Case valuation scenario profiles provided to Grant Samuel include a 325 MMboe Net Santos volume incorporated as of 1 January 2021. The volumes as of 1 July 2021 Net to Santos reduce to ~315 MMboe due to production and ELT effects. The valuation scenario profiles provided to Grant Samuel have H1 production factored into the asset for their financial modelling as per all the assets presented in this report.

For the Base Case GaffneyCline applied a 2% p.a. escalation on the operating cost valuation scenario profile only presented by Santos (no CAPEX escalation was applied to account for demonstrated Santos savings in this CSG operating environment). GaffneyCline also adjusted the CiO for GLNG using analogues from other midstream projects. Midstream capital and operating costs were adjusted for gas throughput by GaffneyCline in the valuation scenario profiles. GaffneyCline included midstream D&R in both cases to the forecasts.

The GaffneyCline Stretch Case volumes accepts the 338 MMboe valuation scenario production profile presented after adjustment for the effective date to 1 July 2021. No OPEX escalation was applied with the other Midstream adjustments also kept consistent with the Base Case.

GLNG Production and Cost Estimation for Evaluation

GaffneyCline's aggregated production forecasts for the Base and Stretch Case are included in **Figure 5.64.** The profiles are aggregated due to commercial sensitivities declared by Santos.

GaffneyCline has reviewed and accepted the Operator's upstream CAPEX costs (e.g. Drillex, water handling) and associated savings. GaffneyCline has applied a 2% p.a. escalation on the OPEX profiles for valuation purposes. The total GLNG cost profiles are represented below in US$ MM, Net to Santos, Nominal terms (**Figure 5.64**). The profiles are aggregated due to commercial sensitivities declared by Santos.

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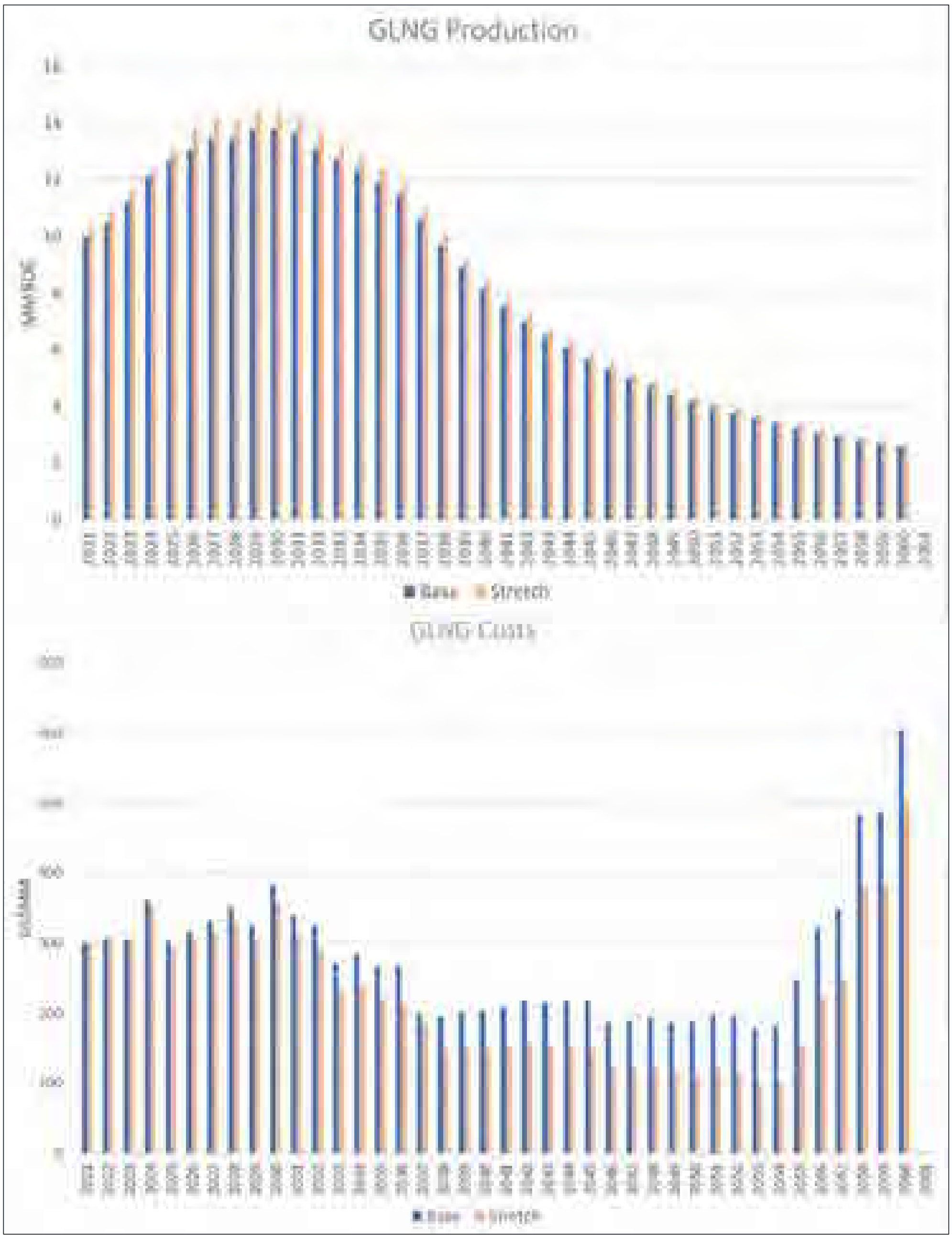
Figure 5.64: GaffneyCline's Base and Stretch Case Production and Cost Valuation Scenario Profiles for GLNG (US$ MM, Santos Share, Nominal)



5.4.1.1 Fairview

5.4.1.1.1 Fairview Overview

The Fairview Field is situated in south-central Queensland, approximately 400 km northwest of Brisbane. It is one of several Coal Seam Gas (CSG) projects Santos has an interest in. The field is covered by 7 petroleum leases, (PL 90, 91, 92, 99, 100, 232, 233 (**Figure 5.65**), all administered under the 1923 Petroleum Act. The area includes cleared agricultural land, state forest and, in the north, the Expedition National Park.

Table 5.32: Fairview Summary as of 1 July 2021

Field Data	
Permit(s)	PL 90, 91, 92, 99, 100, 232, 233
Location	100 km North of Roma
CSG Depths targeted	~450 m and 1000 m
Santos Working Interest	22.821%
JV Partners	APLNG
First Production	2014

The Fairview CSG Field is located on the western flank of the central Bowen Basin.

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Figure 5.65: Fairview PL's

Source: Santos

5.4.1.1.2 Fairview Development

The Fairview Field is relatively mature and highly developed in comparison to the other GLNG upstream fields. Santos has presented multiple options for the possible ways forward to develop the remainder of the field which includes a range of risk, capital intensity with associated consequences to value.

The Santos base plan is as per the Long Term Plan 2021 (LTP21) which is constrained by the Fairview development pace utilising a four rig forecast. The two light rigs are technically suitable for drilling most of the Roma and Arcadia well designs, and the two medium rigs mainly suitable for deeper and more complex drilling in the Fairview and Scotia areas.

The Santos objective of LTP21 for Fairview as provided and documented by Santos and accepted by GaffneyCline is to:

- Accelerate the Eastern optimisation development to offset production and value impairments to existing well forecasts;
- Improve Fairview short to mid-term production forecast to maintain minimum LNG contractual obligations.
- Balance rig utilisation for development drilling as well as reservoir management drilling (i.e. water influx shield well scope) to ensure base level of production while protecting reserves; and
- Optimise program order to improve asset economics within reservoir appraisal timeline and rig availability constraints.

The resulting Santos development is phased from 2022 onwards and the sub-project list is included in **Table 5.33**. Santos management has documented for GaffneyCline that they and all JV partners are committed to developing the GLNG sub projects with possible substitutions if appraisal results change. They have documented for GaffneyCline that "should any projects prove to be economically unviable we would expect these to be substituted by other sub projects that may not currently be in the plan". GaffneyCline has opined for Fairview that the production to date supports the proposed plan and approach for all sub projects.

5.4.1.1.3 GaffneyCline Technical Review

<u>Geology and Geophysics Discussion</u>

GaffneyCline has only focused on a production data review of the technical data with high level general geoscience reconciliation to understand production type curve distributions against mapped geological domains as presented by Santos. It is GaffneyCline's view that production performance in CSG Fields provide the greatest calibration and understanding of the technical uncertainty. Remapping in-place volumes based on GaffneyCline checks for CSG fields leads to audit range (10%) differences only hence the focus on production with operator provided geological maps.

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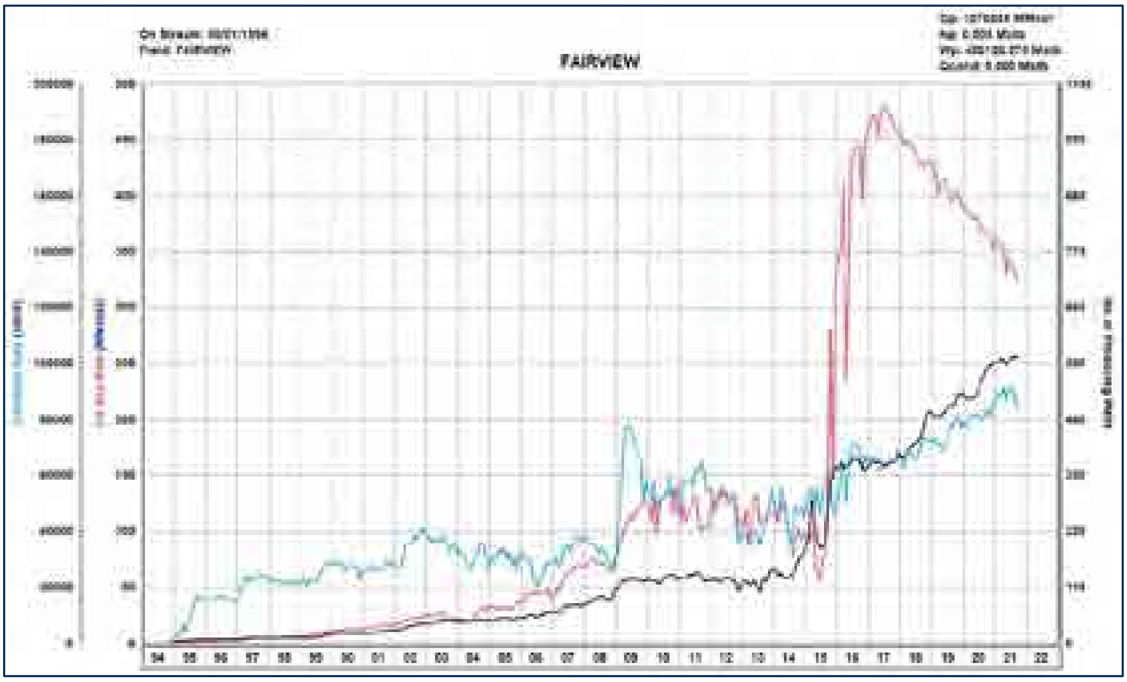
Reservoir Engineering Discussion

Figure 5.66 shows gas and water production history and well count for Fairview, from start of production in 1994 to September 2021, alongside producing well count. Fairview currently has over 560 production wells delivering some 366 MMscfd of raw gas and 90,000 Bbl/d of water.

Santos' LTSP21 estimated 2021 average production rate forecast of 332 MMscfd for Fairview has already been exceeded as of September 2021, with a year to date production rate of 340 MMscfd.

Fairview well count has been steadily increased over the years. The field started decline in 2017 at an approximate decline rate of 15 per annum.

Figure 5.66: Production History and Well Count for the Fairview Area



A total of 936 additional wells are proposed by Santos between 2021 and end of field life in LTSP21. Fairview production forecast has been divided into the sub-projects shown in **Table 5.33**.

Table 5.33: LTSP21 Sub-projects for the Fairview Area

Sub-project	Name	Status
SP2	Fairview Existing 1	Developed/Sanctioned
SP3	Fairview Existing 2	Developed/Sanctioned
SP4	Fairview SD21 Eastern Optimization	Developed/Sanctioned
SP5	Fairview SD21 Reservoir Mgmt	Undeveloped
SP6	Fairview SD22 ADPs	Undeveloped
SP7	Fairview SD23 Infield & Brownfield	Undeveloped
SP8	Fairview SD24 APDs	Undeveloped
SP9	Fairview SD24 Resource Ph2	Undeveloped
SP10	Fairview SD26 North, Dawson Bend	Undeveloped
SP11	Fairview Reminder	Undeveloped
SP12	Fairview Growth	Undeveloped

In order to validate Santos' LTSP21 production profile, GaffneyCline conducted performance analysis in the developed areas of the field and reconciled such performance with the type curves proposed by Santos in the undeveloped areas. Checks were conducted at geodomain and project area levels. Based on this analysis GaffneyCline has accepted the developed and undeveloped profiles in LTSP21. GaffneyCline has accepted Santos' LTSP21 profile for the purposes of valuation.

Chance of Development

Producing Sub Projects are performing above forecast in 2021. GaffneyCline has accepted the sub project plans as proposed by Santos based on the performance reconciliation and the review of the undeveloped sub projects for valuation. Santos updates forward undeveloped sub project type curves by production calibration and GaffneyCline has accepted these Fairview plans as an appropriate case for valuation.

5.4.1.2 Roma

5.4.1.2.1 Roma Overview

Table 5.34: Roma Summary as of 1 July 2021

Field Data	
Permit(s)	ATP 631P, 336P, 889P, 1187P
Location	Surrounding Areas around Roma and Wallumbilla
CSG Depths targeted	~300 m and 1,000 m
Santos Working Interest	30% except for ATP631P which is 22.1943 %
JV Partners	Petronas, Total, Kogas & APLNG (631P only)
First Production	2014

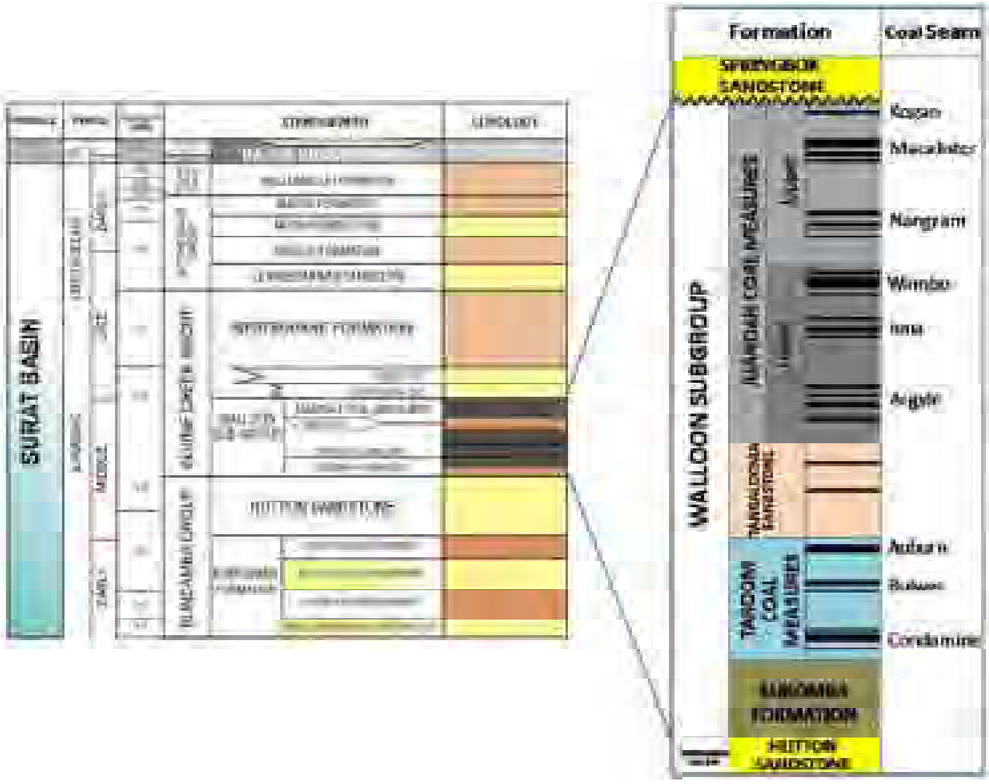
The Roma CSG Field is located in the North-Western part of the Surat Basin. The Walloon Subgroup represents the main target of the Roma development and consists of Upper and Lower Juandah coal measures, Tangalooma sandstone and Taroom coal measures. The Walloon coals can be further subdivided into 9 main coal seams; however, these are commonly split into further thin seams (**Figure 5.67**).

The Springbok Sandstone overlies the Walloon Subgroup. The lowest sandstone interval of the Springbok Sandstone is of variable quality and has the potential to act as a flow conduit for associated water.

A shale sequence stratigraphically overlays the Macalister coals (and Upper Walloons coal), however due to the erosion processes before the deposition of the sediments of the Springbok Sandstone, this shale formation has been eroded partially or totally. Consequently, there are locations where the Springbok Sandstone lays directly over the Macalister coals creating a natural hydraulic connectivity between the coals and the Springbok Sandstone.

Santos have created a workflow to determine the risk of aquifer flow. Coals with the potential to communicate with the Springbok are isolated and the expected gas volume from these coals removed from the project profiles.

Figure 5.67: Surat Basin Stratigraphy



Source: Santos

The coal seam gas initially in place (GIIP) and depth of the Walloons varies significantly across the Roma development area. This variability is utilised in the simulation process of the type curves for production forecasting with the main parameters being permeability and gas saturation.

5.4.1.2.2 Roma Development

Figure 5.68 shows which subprojects have been assigned to which geographical area. **Table 5.35** lists the status of the sub projects considered for this report and includes the full Roma LTSP21 inventory. Santos indicates that there are additional sub projects that are still too immature to put forward.

Figure 5.68: Roma Gas Production as of LTP21

Source: Santos

Table 5.35: LTSP21 Sub-projects for the Roma Area

Sub-project	Name	Status
SP15	Roma West Existing	Developed/Sanctioned
SP16	Roma East Existing	Developed/Sanctioned
SP17	Roma West SD20	Developed/Sanctioned
SP18	Roma West SD22	Sanctioned
SP19	Roma East SD22	Sanctioned
SP20	Roma West SD23	Undeveloped
SP21	Roma East SD23	Undeveloped
SP22	Roma West SD25	Undeveloped
SP23	Roma East SD25	Undeveloped
SP24	Roma West Reminder	Undeveloped
SP25	Roma East Reminder	Undeveloped

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5.4.1.2.3 GaffneyCline Technical Review

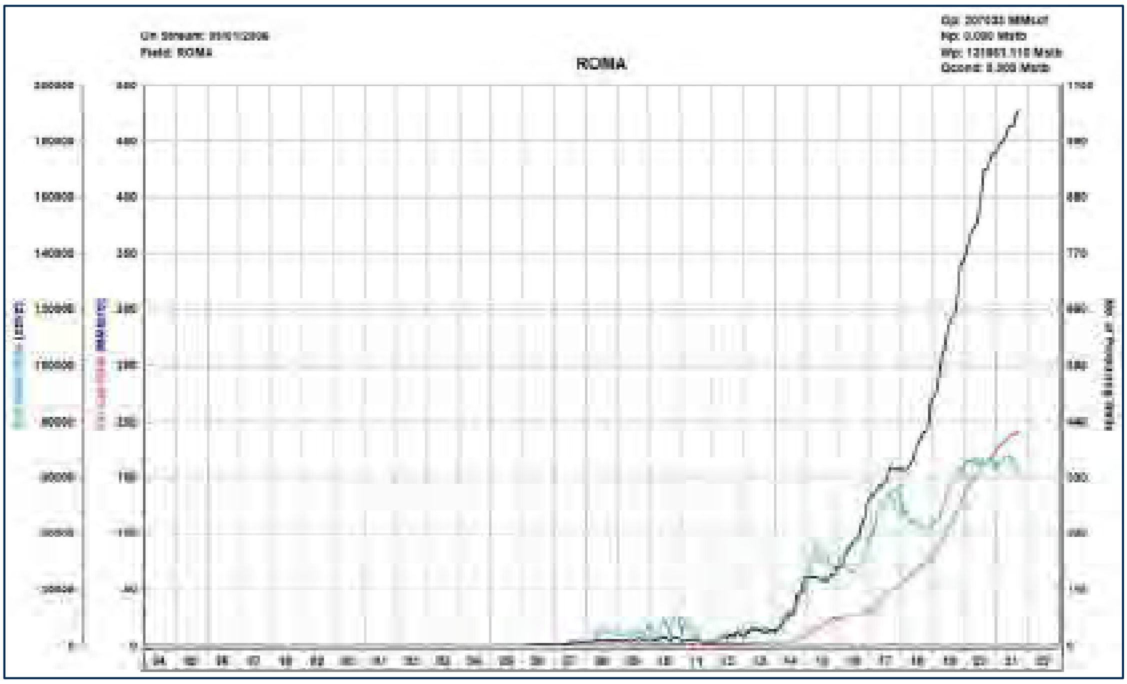
Geology and Geophysics Discussion

GaffneyCline has only focused on the decline curve review of the technical data with high level general geoscience reconciliation to understand production type curve distributions as presented by Santos.

Reservoir Engineering Discussion

Figure 5.69 shows gas and water production history and well count for Roma from start of production in 1997 to date. As of September 2021, Roma had over 1,000 production wells delivering some 190 MMscfd of raw gas.

Figure 5.69: Production History and Well Count for the Roma Area



The Roma area has historically faced challenges related to well performance. Original simulator-based type curves systematically overestimated production rates and predicted shorter time-to-peak periods in most areas.

Over time, Santos has optimized its well design and has adjusted its well performance expectations in line with its field performance analysis. However, Santos' LTSP21 estimated 2021 average production rate forecast of 219 MMscfd for Roma has not been met as of September 2021, with a year to date average production rate of 186 MMscfd. Projecting rate increments from recent wells to year-end is expected to result in a 10-15% production shortfall.

A total of 2,267 additional wells are proposed by Santos between 2021 and end of field life in LTSP21. Roma production forecast has been divided into the sub-projects shown in **Table 5.35**.

GaffneyCline conducted performance analysis in the developed areas of the field and reconciliation with the type curves proposed by Santos in the undeveloped areas. Checks were conducted for different geodomains and project areas, comparing Santos' expected peak rates and EURs versus performance from existing wells.

Performance checks of producing geodomains versus simulator-derived curves showed a significant gap, with the simulator curves consistently overestimating peak rates and underestimating time-to-peak periods. Further investigation revealed that Santos further calibrates simulator-based type curves to observed performance for undeveloped geodomains.

Some differences were also observed between LTSP21 project profiles and the project sanction curves applied to the proposed well schedule.

Based on the above, GaffneyCline introduced the following changes to Santos' production estimates:

- Production was scaled down by 10% in the producing areas to account for current shortfall, and assuming that some performance improvements will continue into the future.
- Forecast for the project immediately adjacent to producing areas (SP18 and SP19). LTSP21 project forecast was replaced by the well sanction curves –calibrated to neighbouring performance- applied to the proposed well schedule.
- Forecast for other areas further away from the core production area we scaled down by 10%, with the objective of capturing potential slower ramp-ups and performance shortfalls such as that observed in 2021.

In summary, GaffneyCline has edited Santos' LTSP21 profiles for the purposes of valuation.

Chance of Development

Santos management has documented for GaffneyCline that they and all JV partners are committed to developing the GLNG sub projects with possible substitutions if appraisal results change. They have documented for GaffneyCline that "should any projects prove to be economically unviable we would expect these to be substituted by other sub projects that may not currently be in the plan". GaffneyCline has opined for Roma that the GaffneyCline adjusted production profiles supports all sub projects being included after confirmation from Santos Management.

5.4.1.3 Scotia

5.4.1.3.1 Scotia Overview

The Scotia Field is located in PL 176 in the south eastern Bowen Basin, approximately 100 km to the east of Fairview and Roma Fields, and 340 km northwest of Brisbane. PL 176 is located on the Burunga structural anticline, directly north of the PL 101 Peat Field operated by Origin Energy (**Figure 5.61** GLNG Summary).

Table 5.36: Scotia Summary as of 1 July 2021

Field Data	
Permit(s)	PL 176
Location	100 km to the east of Fairview
CSG Depths targeted	~300 m and 1000 m
Santos Working Interest	30%
JV Partners	Petronas (27.5%), Total (27.5%), Kogas (15%)

The Burunga structure is a doubly plunging anticline with two main crests separated by a saddle, bounded on the East by the Burunga Fault System. The stratigraphy of the Scotia Field is outlined in **Figure 5.70**. The Baralaba Formation is the equivalent of Late Permian Bandanna Formation elsewhere in Bowen Basin. The Upper Baralaba is the main coal-bearing unit of at least three major coal seams (BR120, BR110 and BR100), whilst the Middle Baralaba coal consists of thinner seams and lesser overall net pay. Coal distribution is well understood after extensive appraisal and production programs across all seams and near full-field 3D seismic coverage.

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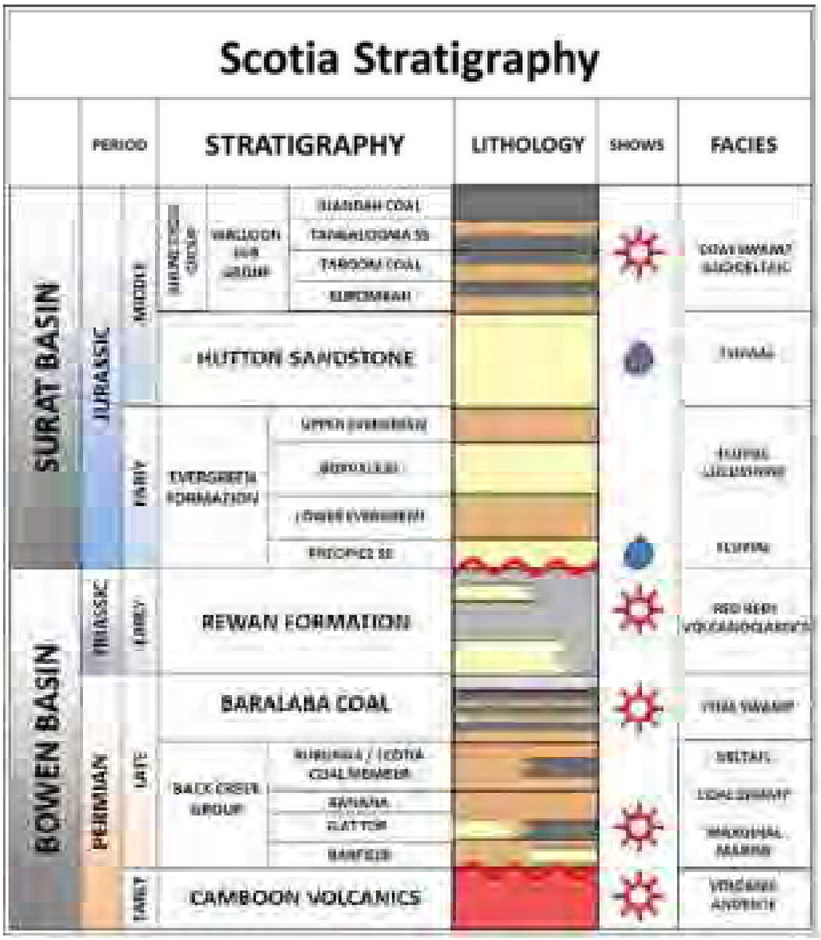
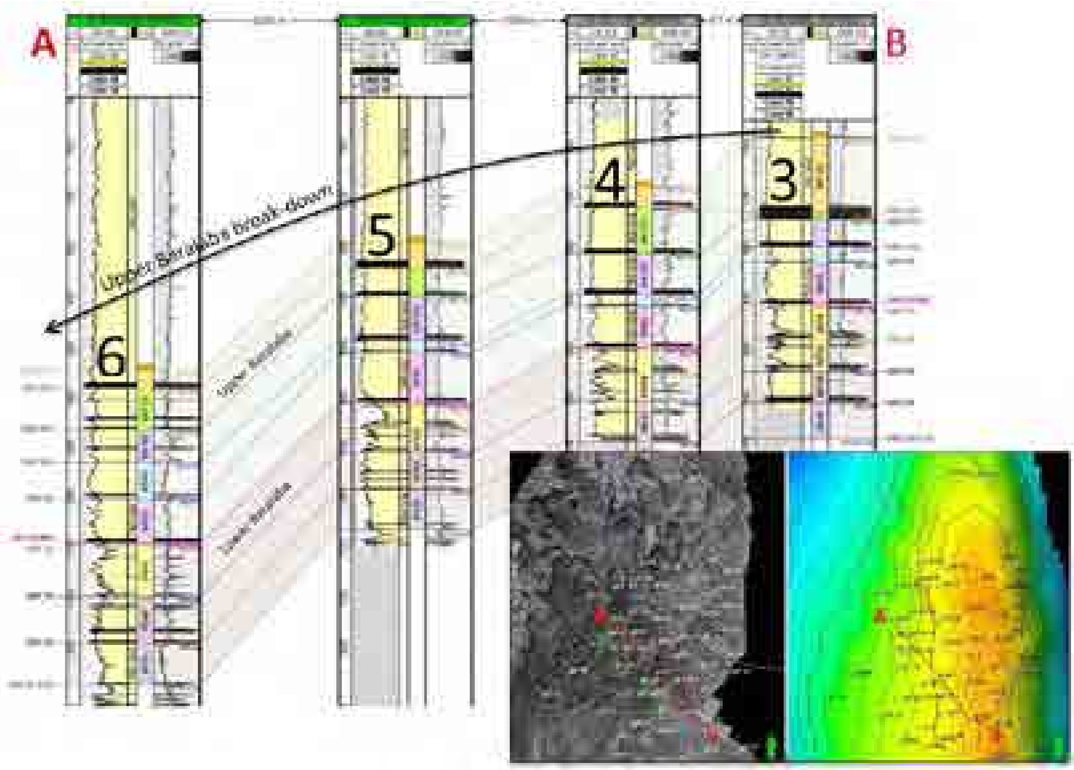
Figure 5.70: Scotia Stratigraphy



Gaffney Cline

Seismic amplitude analysis has provided further understanding regarding coal distribution, with notable signatures of fluvial channels in the North-Western flank of the field. This complements log data (**Figure 5.71**) which has shown evidence of coal splitting and breakdown towards the North-Western Flank, where coals are less continuous and net pay is split over many thin seams. Understanding of this variability allows for better well design selection in different parts of the field – namely the applicability of horizontal drilling being considered by Santos.

Figure 5.71: Break-Down of Upper Baralaba Coals Away from Crest



Source: Santos

Gaffney Cline

5.4.1.3.2 Scotia Development

Santos Scotia Field development strategy is to maximise field value and production through the existing infrastructure. This is planned with the development of the remaining 2P undeveloped reserves and conversion of 2C resources through appraisal and development of the deeper, lower permeability flanks.

The gas from future developments in Scotia will be processed through the existing Scotia compression facility, which has a capacity of 80TJ/d. Future program will backfill legacy projects as they decline, with the aim to continue high utilization of the facility.

While the strategy prioritises the best reservoirs first it must also address a number of other constraints:

1. Subsurface knowledge: as development moves down the deeper, lower permeability flanks there is uncertainty as to what depth of development will still have economic rates. This is being addressed by the dual lateral SIS appraisal wells that will appraise the well design in lower permeability coals before development.
2. Approval timeframes: all approvals (including land access, environment and cultural heritage) are required before development can commence.

The current phase of development is vertical, with ongoing appraisal of horizontal well performance. The next phase of development is planned as a horizontal well development.

5.4.1.3.3 GaffneyCline Technical Review

<u>Geology and Geophysics Discussion</u>

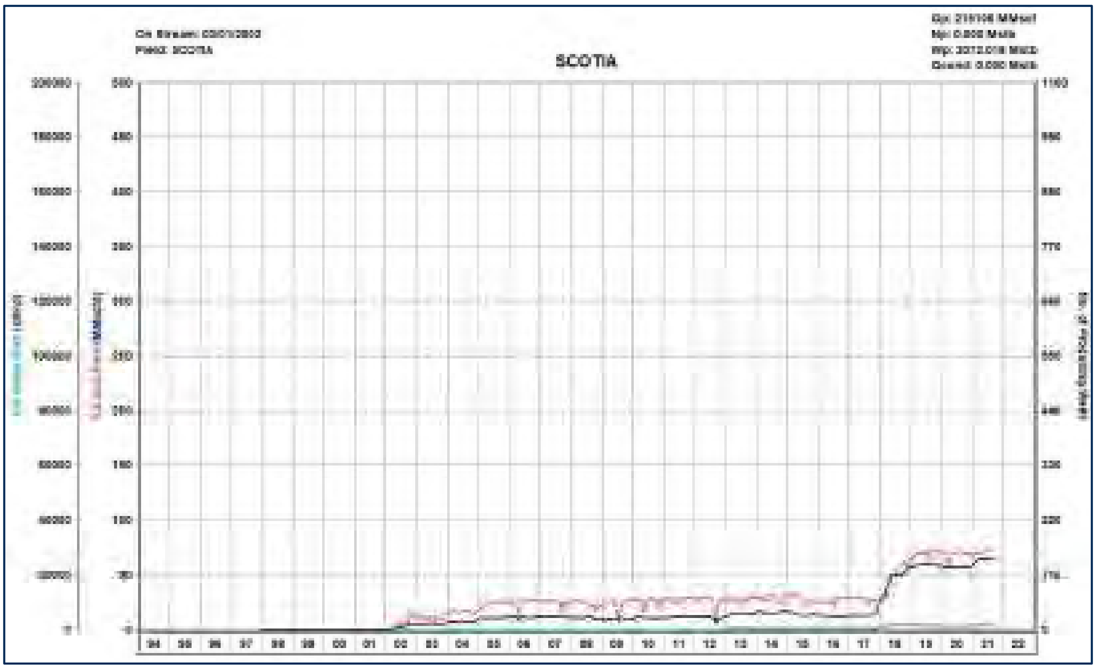
GaffneyCline has only focused on the decline curve review of the technical data with high level general geoscience reconciliation to understand production type curve distributions as presented by Santos.

<u>Reservoir Engineering Discussion</u>

Figure 5.72 shows gas and water production history and well count for Scotia, from start of production in 2002 to September 2021. Scotia currently has over 140 production wells delivering some 79 MMscfd of raw gas and 1,500 Bbls/d of water. Cumulative production from the field nears 160 Bscf.

Gaffney Cline

Figure 5.72: Production history and well count for the Scotia area



Santos' LTSP21 estimated 2021 average production rate forecast of 64 MMcfd for Scotia has already been exceeded as of September 2021, with a year to date average production rate of 69 MMscfd.

The first 28 production wells, drilled between 2001 and 2014, are currently declining after a period of 9-10 years at a fairly constant rate of 2 MMscfd on average as a group. Some 112 additional wells have been brought online since with average rates around 500 Mscfd.

Scotia production profile has been divided into the sub-projects shown in **Table 5.37**. A total of 445 wells are planned as part of these sub-projects. Phases 3, 4 and 5 go into coal depths between 1,000 and 1,300 mGL, located North and West of the producing areas.

Table 5.37: LTSP21 sub-projects for the Arcadia Area

Sub-project	Name	Status
SP27	Scotia Existing	Developed/Sanctioned
SP28	Scotia SD21 (Phase 2B/2C)	Developed/Sanctioned
SP29	Scotia SD23 (Phase 3)	Undeveloped
SP30	Scotia SD25 (Phase 4)	Undeveloped
SP31	Scotia SD27 (Phase 5)	Undeveloped
SP32	Scotia Growth (Wandoan)	Undeveloped

GaffneyCline conducted performance analysis in the developed areas of the field and reconciliation with the type curves proposed by Santos in the undeveloped areas. Checks were conducted for different geodomains and depth ranges, comparing Santos' expected peak rates and EURs versus performance from existing wells. Based on overall performance of the producing areas, GaffneyCline has accepted Santos' estimates and has accepted Santos' LTSP21 forecast for the purposes of valuation.

Chance of Development

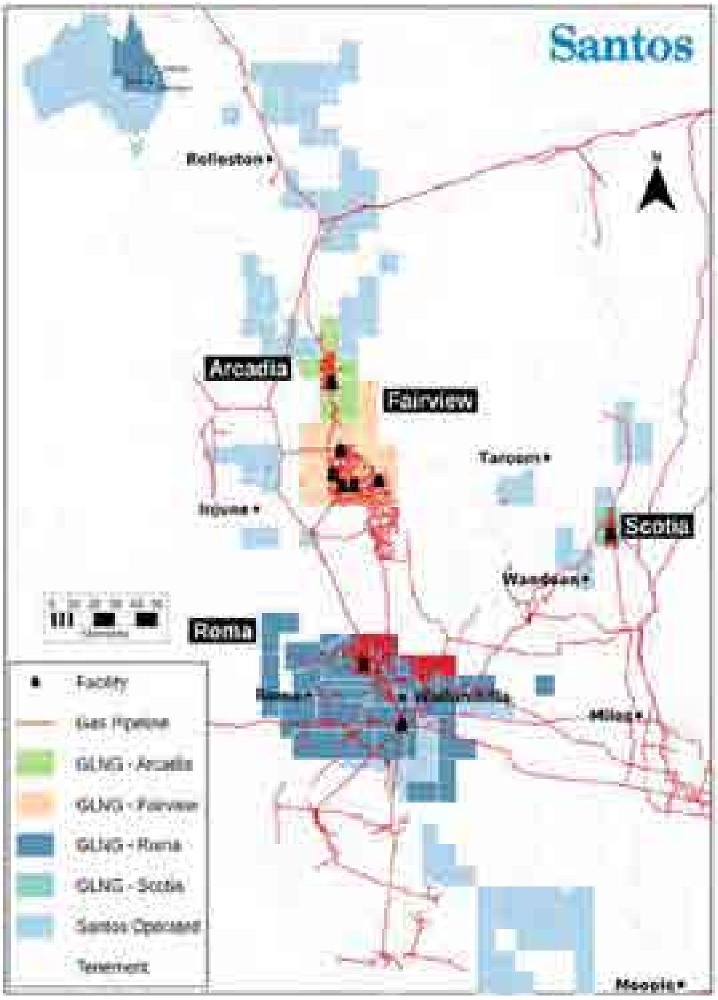
Santos management has documented for GaffneyCline that they and all JV partners are committed to developing the GLNG sub projects with possible substitutions if appraisal results change. They have documented for GaffneyCline that "should any projects prove to be economically unviable we would expect these to be substituted by other sub projects that may not currently be in the plan". GaffneyCline has opined for Scotia that the production performance and forecasts supports all sub projects being included after confirmation from Santos Management of their commitment.

5.4.1.4 Arcadia

5.4.1.4.1 Arcadia Overview

The Arcadia Field is situated in south-central Queensland, approximately 400 km northwest of Brisbane. It is one of several Coal Seam Gas (CSG) projects operated by Santos in Queensland and located north of the Fairview Field. Land tenure is a mixture of Santos owned properties, privately-owned properties, and state-owned properties, including State Forests and the Expedition National Park, and leasehold. The area is covered by ATP 653P, PL 440, PL 420, PL 421, ATP 526P, PL 234, PL90 and PL 1059 (**Figure 5.73**).

Figure 5.73: Arcadia Tenements



Source: Santos

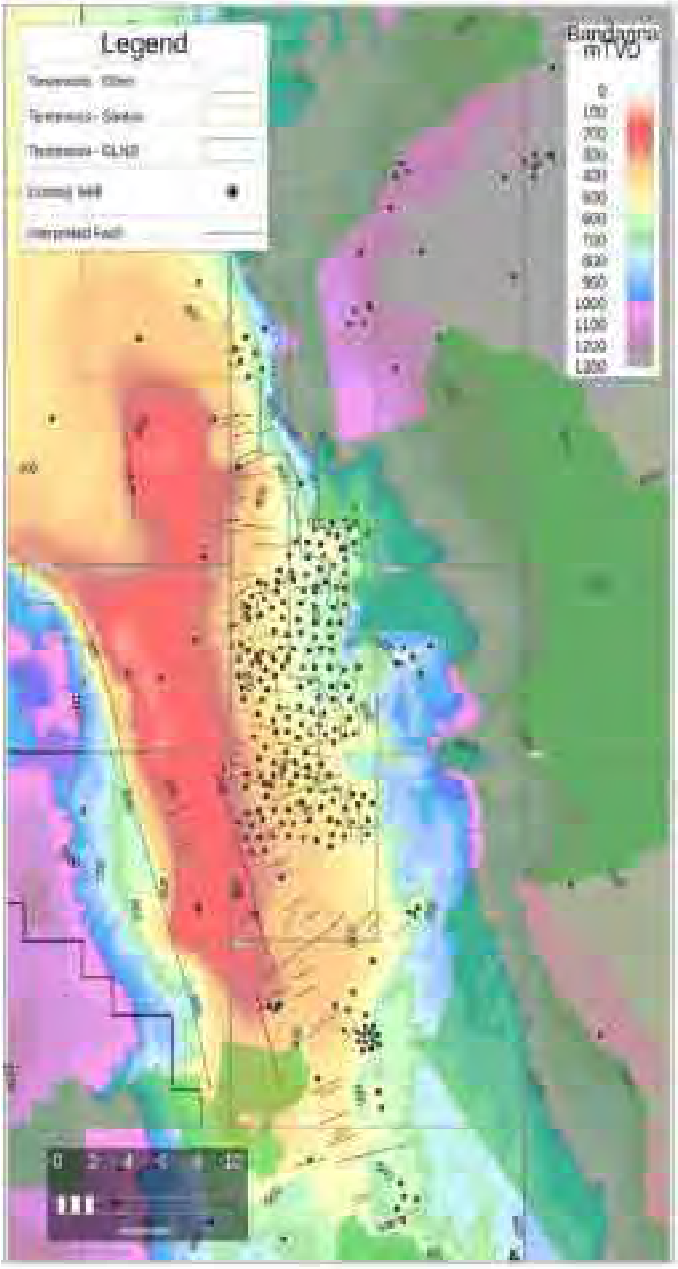
Table 5.38: Arcadia Summary

Field Data	
Permit(s)	ATP 653P, PL 440, PL 420, PL 421, ATP 526P, PL 234, PL90 and PL 1059
Location	400 km northwest of Brisbane
CSG Depths	~150 (west)-1300 m (north east)
Santos Working Interest	Arcadia 22.8%, Towrie 22.8%, Fairview 22.7%
JV Partners	Petronas 20.9 %, Total 20.9%, Kogas 11.4%, APLNG ~23.8%

The Arcadia primary reservoir targets are the coals of the Late Permian Bandanna Formation. The Bandanna Formation consists of a series of interbedded lithic sandstones, siltstones, claystones, carbonaceous shales, and multiple coal seams distributed over an interval of 60 - 80 m. Total net coal thickness ranges from 5 – 13 m. Individual seams can be up to 8 m thick, although they are more commonly 1 - 2 m thick. The coals dip from west to east across Arcadia and are found at depths between 150 m TVD in the west and more than 1,300 m TVD the north east. Faults with throws up to 50 m can be observed on seismic data.

The coals are relatively continuous and can be correlated with confidence over distances of several kilometres or more. The two main Bandanna coal seams in the Arcadia Field are the BA60 and BA30, also referred to as Bandanna A-seam and D-seam respectively. Palynology work has been completed on 14 wells in the Arcadia Field. Structural dip is generally low (3-5 degrees to the east) but the overburden thickness increases sharply along the western edge of the tenure because of the Arcadia Valley escarpment where there is up to 300 m local relief. **Figure 5.74** depicts the wells in Arcadia to date.

Figure 5.74: Arcadia CSD Development



Source: Santos

5.4.1.4.2 Arcadia Development

The Santos development plan provided for the Arcadia Field takes a strategy of managed growth through two key phases:

1. Expansion to fill the valley floor
   a. AVPh2 (SD21) & AVPh3 (SD23)
   b. Valley Edge Deviated (SD24)
2. Appraisal and development of adjacent growth opportunities; (below in order of maturity);

Valley Edge SIS (Growth)

An eastern extension of the valley floor that passes through the deep faults that cause the surface expression of the valley escarpment. This phase will initially be targeted by deviated wells (SD24) from the Valley Floor, followed by SIS wells from the Valley Floor (Growth) extending reach beneath the escarpment.

Clematis Creek (Growth)

Clematis Creek (Growth): A Bandanna play continuous with the valley floor but at greater depth and predicted to be of a higher saturation. This play is atop the escarpment but located in accessible land outside of National Park.

High Country (Growth)

An accessible area atop the valley escarpment that has similar coals to the valley floor at an intermediate depth range. Rig access to this area remains a challenge, so this play is considered a long term growth opportunity. This play has not yet been assessed so remains conceptual and therefore no volumes are currently carried in LTSP.

Dawson (Growth)

This is an exploration play located approximately 40 km to the North of the Arcadia Field within ATP's 2012 and 745. This is included in the Arcadia Growth program to maintain LTSP coverage of GLNG's Contingent Resource position.

5.4.1.4.3 GaffneyCline Technical Review

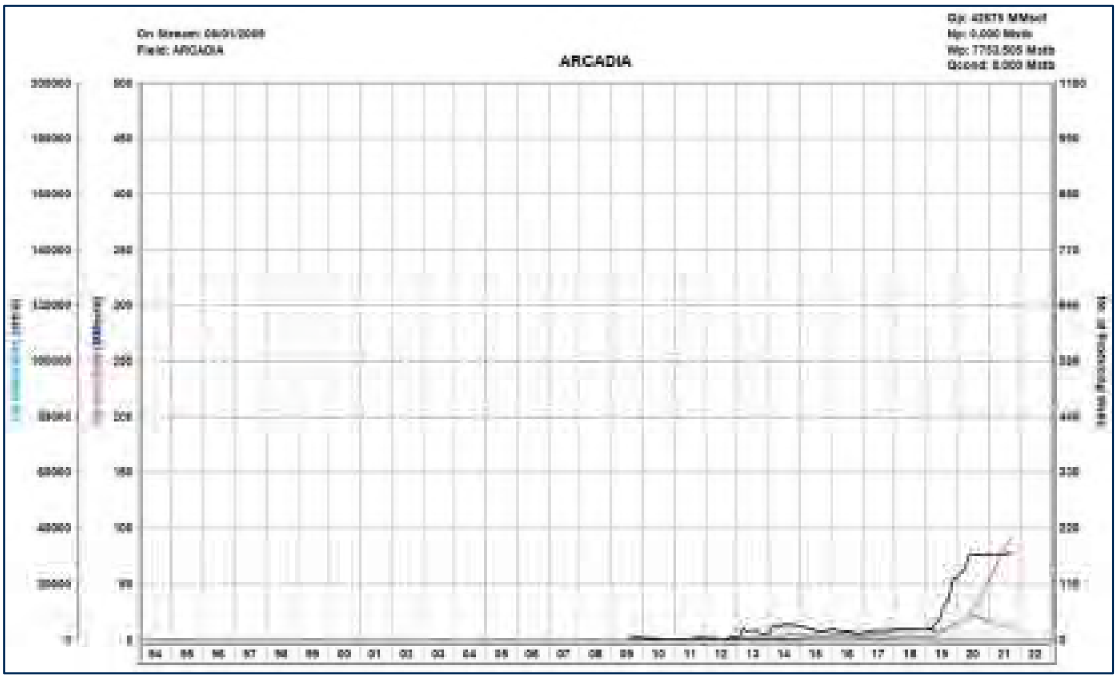
<u>Geology and Geophysics Discussion</u>

GaffneyCline has only focused on the decline curve review of the technical data with high level general geoscience reconciliation to understand production type curve distributions as presented by Santos.

<u>Reservoir Engineering Discussion</u>

Figure 5.75 shows gas and water production history and well count for Arcadia, from start of production in 2009 to September 2021. Arcadia currently has over 167 production wells delivering some 104 MMscfd of raw gas and 5,000 Bbl/d of water.

Figure 5.75: Production history and well count for the Arcadia area



Santos' LTSP21 estimated 2021 average production rate forecast of 64 MMcfd for Arcadia has already been exceeded as of September 2021, with a yearly average production rate of 72 MMscfd.

The first set of 13 production wells drilled between 2009 and 2014 are currently declining at an approximate rate of 12% per annum. Based on a plot of calendar day gas rate versus normalized time online, these wells had an average peak over 600 Mscfd.

Some 145 additional wells have been brought online since 2019 as part of Arcadia Phase 1. On average, these wells have built gas rate up to 600 Mscfd within approximately 24 months.

A total of 708 additional wells are proposed by Santos between 2021 and end of filed life in LTSP21. Based on overall performance of the producing areas, GaffneyCline has accepted the developed forecast.

Arcadia production forecast has been divided into the sub-projects shown in **Table 5.39**.

Table 5.39: LTSP21 sub-projects for the Arcadia Area

Sub-project	Name	Status
SP35	Arcadia Existing	Developed/Sanctioned
SP36	Arcadia SD21	Developed/Sanctioned
SP37	Arcadia SD23	Developed/Sanctioned
SP38	Arcadia SD24	Undeveloped
SP39	Arcadia Growth	Undeveloped

Arcadia Phase 2 envisages 203 wells to be drilled between 2021 and 2023 around the current core area of the field, with the highest number of wells targeting the southern part of the field towards Fairview. Additional development in Arcadia targets ATP526 areas.

In order to validate Santos' LTSP21 production forecast, GaffneyCline conducted performance analysis in the developed areas of the field and reconciled such performance with the type curves proposed by Santos in the undeveloped areas. Checks were conducted at geodomain and project area levels.

GaffneyCline has accepted Santos' LTSP21 forecast for the purposes of valuation.

Chance of Development

Santos management has documented for GaffneyCline that they and all JV partners are committed to developing the GLNG sub projects with possible substitutions if appraisal results change. They have documented for GaffneyCline that "should any projects prove to be economically unviable we would expect these to be substituted by other sub projects that may not currently be in the plan". GaffneyCline has opined for Arcadia that the production performance and forecasts supports all sub projects being included after confirmation from Santos Management of their commitment.

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5.4.2 Eastern Queensland

5.4.2.1 Eastern Queensland Overview

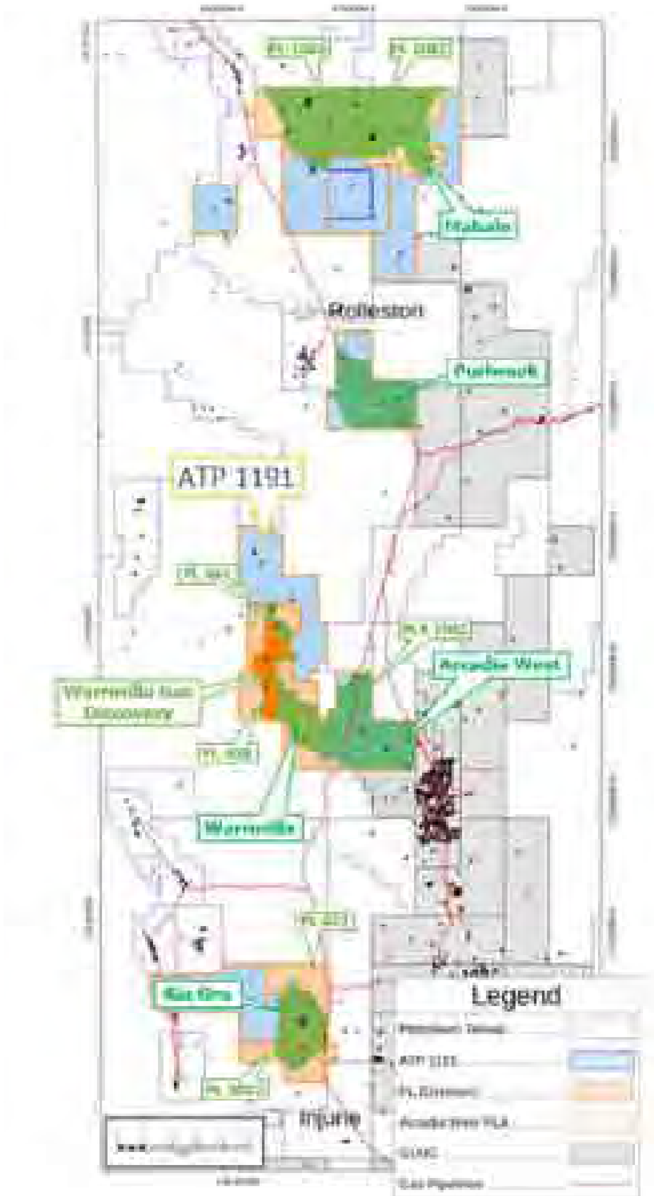
The Eastern Queensland assets are primarily CSG assets in Eastern Queensland that are not part of the GLNG Joint Venture. The main fields are located to the north and west of Arcadia (**Figure 5.76**) with the main asset areas being the Denison assets (Kia Ora, Waranilla (non CSG) and Arcadia West) and Mahalo. Santos is partnered with APLNG in the Denison assets and Comet Ridge in Mahalo.

Table 5.40: Eastern Queensland Summary

Field Data	
Permit(s)	ATP 1191, ATP 2033 + Figure 5.106 outlining all Santos database permits provided
Santos Working Interest	refer to Figure 5.106
JV Partners	Various including APLNG
Valuation Scenario Volumes	
Net Valuation Scenario Volume Base	86 MMboe
Net STO Valuation Scenario Volume Stretch	136 MMboe

The primary reservoir targets are the coals of the Late Permian Bandanna Formation. The Bandanna Formation consists of a series of interbedded lithic sandstones, siltstones, claystones, carbonaceous shales, and multiple coal seams distributed over an interval of 60 - 80 m. Total net coal thickness ranges from 5 - 13 m. Individual seams can be up to 8 m thick, although they are more commonly 1 - 2 m thick. The coals dip from west to east across Arcadia and are found at depths between 150 m TVD in the west and more than 1,300 m TVD the north east

Figure 5.76: Santos' Eastern Queensland Acreage



Source: Santos

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5.4.2.1.1 *Eastern Queensland Development*

Denison

The Denison asset is located to the north and west of Arcadia. The Arcadia West area is immediately northwest of the main Arcadia Field and is a continuation of the subsurface reservoirs. While Arcadia West is shallower than the main Arcadia Field it has been derisked by recent development in Arcadia, which targeted similarly shallow coal measures.

The remainder of the Denison assets are further to the west of Arcadia, with CSG targets in the Bandanna Formation, conventional and tight gas in the Late Permian Mantuan Beds and conventional targets in the Early-Late Permian Aldebaran Sandston.

Santos' documented highest priority development area in Denison is Arcadia West.

Mahalo

The Mahalo asset is located approximately 40 km north of Rolleston in Central Queensland. Comet Ridge Ltd farmed into northern ATP 1191, formerly ATP 337 (the Mahalo FO area) in 2003.

Mahalo is close to existing infrastructure including PPL 10 (~7lm tie-in) and the GTP. Mahalo has had success in appraisal drilling with the first 2P booked in 2018.

The next steps in the Mahalo development include further delineation of the reservoir through appraisal drilling with both lateral and vertical wells. The lateral well design has been successfully tested in Mahalo and is a key component in development of the field.

The Santos' Eastern Queensland acreage is listed in **Figure 5.77** and is presented as provided for reference.

Figure 5.77: Santos' Eastern Queensland Acreage

Tenure Number	Name	Portfolio Function	Organisational Asset	Interest	Status	Grant Date	Expiration Date	Santos WI	Gross Area km2 or acres
ATP 1191	EQ - Denison	Eastern Queensland Exploration	Denison	Operated	Active	9/25/2015	9/30/2023	50%	1654km2
ATP 2033	EQ - Arcadia	Eastern Queensland Exploration	Arcadia	Operated	Active	9/5/2018	9/4/2022	22.85%	86km2
ATP 2040	EQ - Roma	Eastern Queensland Exploration	Bowen Tight Gas	Operated	Active	1/1/2019	12/31/2024	50%	393km2
ATP 2045	EQ - Roma	Eastern Queensland Exploration	Roma	Operated	Active	7/1/2019	6/30/2025	50%	1212km2
ATP 2052	EQ - Roma	Eastern Queensland Exploration	Roma	Operated	Active	3/23/2020	3/22/2026	30%	89km2
ATP 2053	EQ - Roma	Eastern Queensland Exploration	Roma	Operated	Active	3/23/2020	3/22/2026	30%	12km2
ATP 2054	EQ - Roma	Eastern Queensland Exploration	Bowen Tight Gas	Operated	Active	6/30/2020	6/29/2026	100%	230km2
ATP 2055	EQ - Roma	Eastern Queensland Exploration	Roma	Operated	Active	6/30/2020	6/30/2026	100%	333km2
ATP 2056	EQ - Roma	Eastern Queensland Exploration	Bowen Tight Gas	Operated	Active	3/3/2021	3/4/2027	100%	764km2
ATP 2057	EQ - Roma	Eastern Queensland Exploration	Bowen Tight Gas	Operated	Active	6/30/2020	6/29/2028	100%	911km2
ATP 592P	EQ - OBO - Spring Gully	Eastern Queensland Exploration	Denison	Non-operated	Active	9/1/1994	8/31/2023	4%	1206km2
ATP 606P	EQ - OBO - Combabula	Eastern Queensland Exploration	Denison	Non-operated	Active	11/1/1994	10/31/2018	7.28%	315km2
ATP 685	EQ - Tardrum	Eastern Queensland Exploration	Tardrum	Operated	Active	5/1/2000	12/7/2025	100%	
ATP 972	EQ OBO - Ramyard	Eastern Queensland Exploration	Denison	Non-operated	Active	4/28/2011	4/30/2024	7.28%	

Note: Information presented as provided by Santos without any independent confirmations

5.4.2.1.2 GaffneyCline Technical Review

Geology and Geophysics Discussion

GaffneyCline has only focused on the decline curve review of the technical data with high level general geoscience reconciliation to understand production type curve distributions as presented by Santos.

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Reservoir Engineering Discussion

GaffneyCline reviewed the information made available from Santos, which included the YE 2020 Reserves and Resources audit from NSAI to establish what volumes are suitable for inclusion in the valuation Base Case forecast.

Santos' proposed forecast for Eastern Queensland is divided into the sub-projects shown in **Table 5.41**.

Table 5.41: LTSP21 Sub-projects for Eastern Queensland

Sub-project	Name	Status
SP1	Mahalo	Undeveloped
SP2	Arcadia West	Undeveloped
SP3	Warrinilla	Undeveloped
SP5	Kia Ora	Undeveloped
SP12	Spring Gully - Contracted Base	Developed / Sanctioned
SP13	Spring Gully - Contracted Base	Developed / Sanctioned
SP14	Spring Gully – Horizon	Undeveloped
SP15	Spring Gully – 2P Volumes	Undeveloped
SP16	Combalula – Contracted Base	Developed / Sanctioned
SP17	Combalula – Horizon	Developed / Sanctioned
SP18	Combalula – 2P Volumes	Undeveloped
SP19	Ramyard – Horizon	Undeveloped
SP20	Ramyard – 2P Volumes	Undeveloped
SP25	Tardum	Undeveloped

GaffneyCline included in its base forecast those areas that have volumes classified by NSAI as Reserves, as these offer sufficient level of technical certainty. These include APLNG producing areas Spring Gully and Combabula APLNG undeveloped area Ramyard, and the Mahalo project where Comet Ridge acts as Exploration Operator before Santos takes over as Development Operator. Volumes associated with the other sub-projects have been only considered for the Stretch Case due to their technical uncertainty.

For the areas included in the Base Case, GaffneyCline checked the alignment between Santos' production forecast and NSAI's Reserves estimates. For the APLNG areas, these figures were reasonably close when assuming an ELT cut-off year between 2040 and 2045 to the technical forecasts, which is a realistic cut-off range for fields of this nature.

Well count for the APLNG assets was kept as per Santos' forecast (281 wells for Spring Gully, 1,325 wells for Combalula and 1,193 wells for Ramyard).

In summary, GaffneyCline accepted Santos' production profiles for Spring Gully, Combalula and Ramyard, and included an edited forecast for Mahalo in its Base Case valuation scenario profile. Arcadia West, Warrinilla, Kia Ora and Tardrum were included in the Stretch Case valuation scenario profile. GaffneyCline estimates a total sales gas EUR net to Santos of 510 PJ (or 88 MMboe) in Eastern Queensland as of 1 January 2021.

Bowen Basin Tight Gas

The Bowen Basin contains multiple proven source rocks. Potential source rocks of relevance to shale and tight gas exploration are likely to be present within both coal-rich and marine Late Permian units, particularly the Black Alley Shale. Between 2010 and 2015, Shell's QGC undertook a tight gas exploration drilling program in the Taroom Trough which demonstrated the presence of the necessary ingredients for a large tight gas play with thick low permeability reservoirs, mature source rocks and anomalous pressures which commence at depths of 2,500 m. The Bowen basin is still in early stages of exploration for tight gas plays and due to limited drilling, the full extent of shale and tight gas resources in the basin is not well understood. As a result, any estimates of potential resources would have a high degree of uncertainty without further exploration and/or appraisal.

5.4.3 NSW- Narrabri

5.4.3.1 Narrabri Overview

The Narrabri Field lies within PEL 238 of the Bohena Trough in the Gunnedah Basin, approximately 20 km southwest of the Narrabri Township and 55 km northwest of the Gunnedah Township. This coal seam gas (CSG) proposed project has excellent coal thickness, permeability, gas content and large gas volumes recoverable. It is the first field proposed for development in the New South Wales (NSW) Long Term Plan.

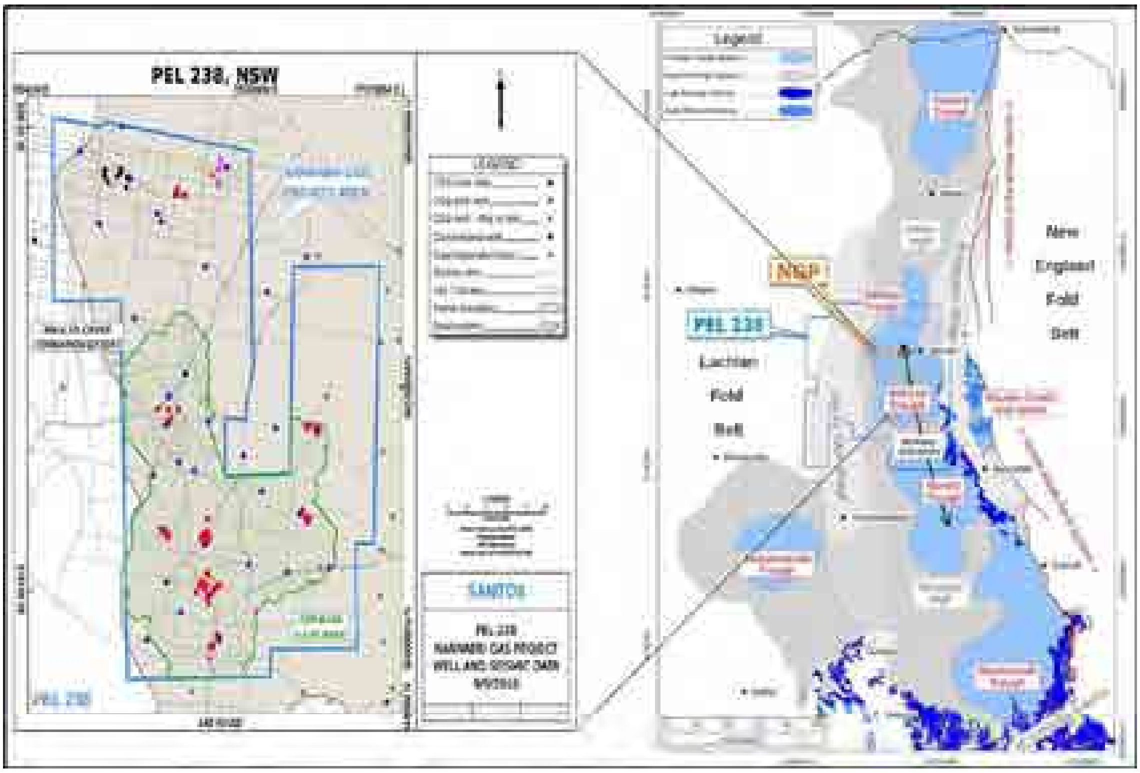
Table 5.42: Narrabri Summary

Field Data	
Permit(s)	PEL 238, and PPLA 13, 14, 15, 16 (replacing PAL 2 and PPL 3)
Location	20 km southwest of the Narrabri township
CSG Depths targeted	~300 m and 1,000 m
Santos Working Interest	80 % (See Appendix IV)
JV Partners	Energy Australia Narrabri Gas P/L (30.20 %),
Valuation Scenario Volumes	
Net Valuation Scenario Volume-Base	103 MMboe
Net Valuation Scenario Volume - Stretch	170 MMboe

The Gunnedah Basin in NSW represents the central portion of the regionally extensive Permo-Triassic Bowen-Gunnedah-Sydney basin system of Eastern Australia (**Figure 5.78**). It covers an area of more than 50,000 km^2 between the townships of Moree and Muswellbrook and can be divided into a series of connected sedimentary troughs or sub-basins separated by basement highs. The most prominent of these is the Mullaley Sub-basin which extends along the central depositional axis and includes the Bohena, Bando, and Murrurundi Troughs. Santos has a strong working interest and operatorship presence in permits throughout the basin.

The Bohena Trough is a broad depositional low. It extends for more than 60 km in a N-S orientation, from northwest of Narrabri to the southwest of Boggabri. It contains up to 800 m of alluvial, lacustrine, marine, and volcanic sediment of Permian to Triassic age (the Gunnedah Basin sequence). This is unconformably overlain by up to 500 m of alluvial and lacustrine sediment of the Jurassic to Cretaceous Surat Basin, part of the of the much larger Great Artesian Basin. The trough is moderately structured and contains a series of N-S trending structural highs separated by depositional lows believed to represent Early Permian graben and half-graben rift features. The structure of the trough is complicated by the presence of igneous intrusive of Triassic to Tertiary age.

Figure 5.78: PEL 238 and the Various Types of Wellbores Drilled Over the Years



Source: Santos

Primary target seams for development include the coal seams of the Maules Creek Formation, being the Bohena, Parkes, Namoi and Rutley seams. These were deposited in rifting induced grabens and half grabens and attain aggregate thicknesses of up to 25 m in the project area. Additional upside may exist in the Late Permian Hoskisson's seam, however this seam is classified as a secondary target and has not been included in the initial development. While the Hoskissons may attain a thickness of up to 10 m, its composition is predominantly high in CO_2 and the only prospective area to date lies to the North, outside of the primary initial development area, and in an area with low Maules Creek prospectivity. Existing pilots produce gas from the Bohena, Namoi and Hoskissons coal seams (**Figure 5.79**).

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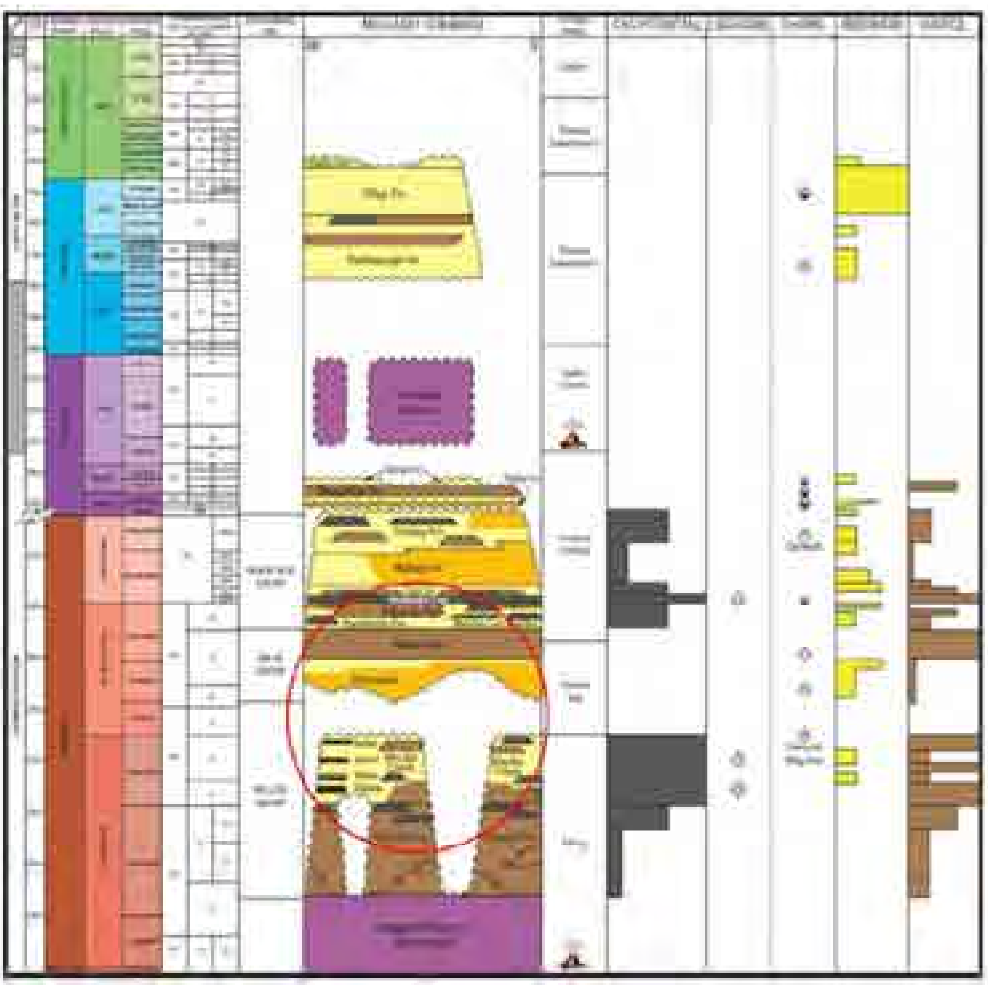
Figure 5.79: Gunnedah Basin and overlying Surat Basin Stratigraphy

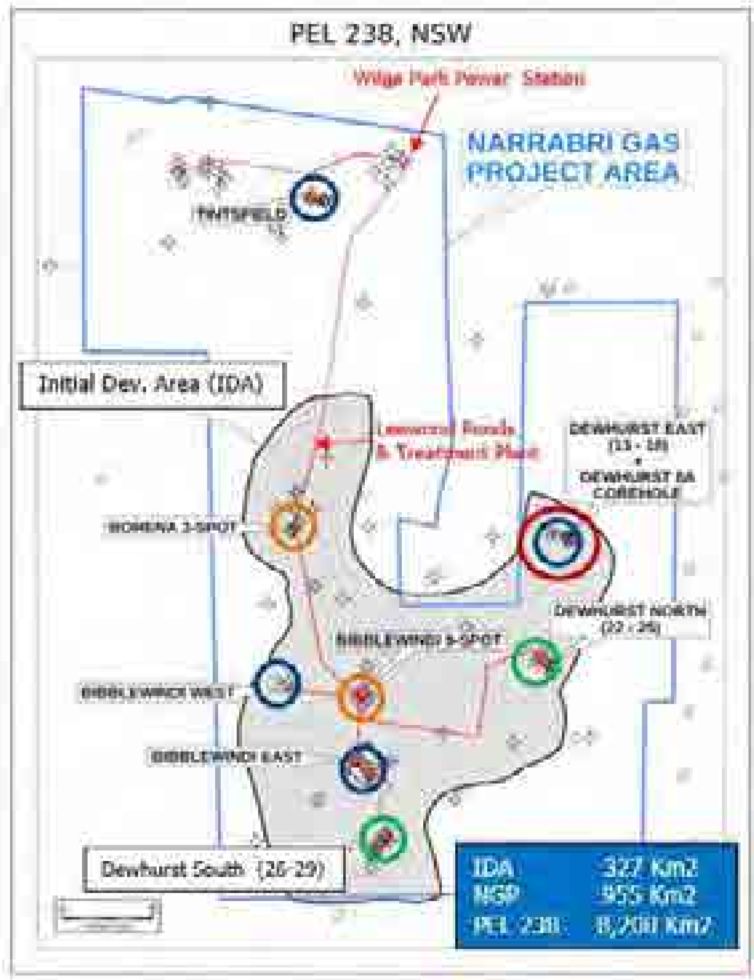


Source: Santos

5.4.3.2 Narrabri Development

Santos purchased Eastern Star Gas (ESG) in late 2011. In 2014 the field was reactivated, and Santos commenced a drilling program in PEL 238. Within the NGP area (**Figure 5.80**), there are 22 core holes within the immediate project area, and 8 pilots.

Figure 5.80: PEL 238 Existing Appraisal Wells and Pilots



Source: Santos

Field production between 2014 and 2018 was focussed on obtaining appraisal production data and from late 2018 onwards, the focus has been on production to the Wilga Park Power Station (WPPS) with no flaring.

Of the eight appraisal pilots:

- 4 are producing lateral pilots (Bibblewindi East, Bibblewindi West, Dewhurst South and Tintsfield)
- 2 lateral pilots are shut in (Dewhurst East & North) and
- 2 two vertical pilots are shut in (Bohena 3 spot and Bibblewindi 9 spot).

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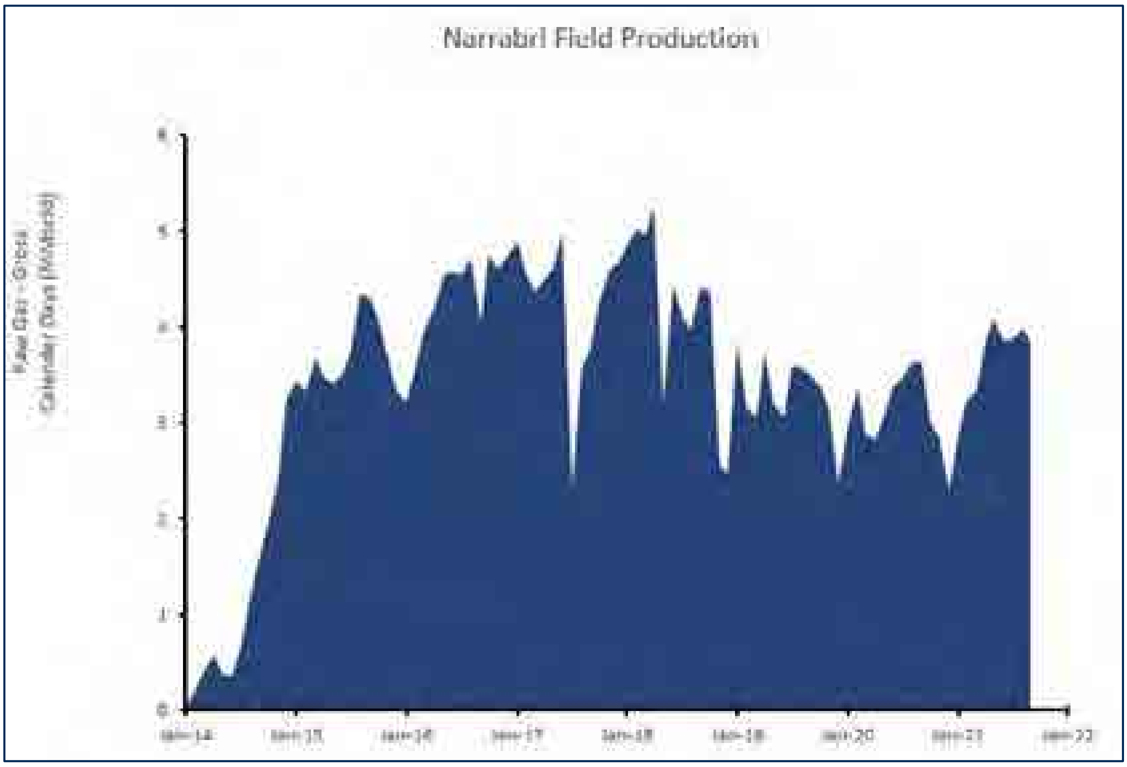
The lateral well design has exhibited strong production performance, far exceeding (5 to 30 times) that of vertical wells due to improved reservoir connectivity with the lateral wellbores intersecting more fractures in the reservoir's directional permeability system. The pilots that remain shut in are a result of poor productivity due to low permeability and/or poor reservoir connectivity making them uneconomic to produce. Current lateral appraisal wells produce from the Maules Creek (Bohena and Namoi seams) and Black Jack (Hoskisson's).

The following pilots are being commercialised through Wilga Park Power Station.

- Bibblewindi East (12 wells)
- Bibblewindi West (5 wells)
- Dewhurst South (4 wells)
- Tintsfield (6 wells)

Figure 5.81 shows Narrabri gross raw gas average rate to date.

Figure 5.81: Narrabri Production History



5.4.3.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

GaffneyCline has only focused on the decline curve review of the technical data with high level general geoscience reconciliation to understand production type curve distributions as presented by Santos.

Reservoir Engineering Discussion

GaffneyCline reviewed relevant information provided by Santos, which included YE2020 Reserves and Resources audit, Field Development Plan and pilot production data.

Santos' proposed profile for Narrabri is divided into the sub-projects for GaffneyCline's review.

Santos has defined Narrabri geodomains taking into account not only coal properties but also expected CO_2 content.

GaffneyCline reviewed Santos' EUR in the FDP for each area/geodomain and reconciled these with Santos LTSP21 forecasts and the production data available. GaffneyCline checked the field EUR after excluding area/geodomain volumes based on the following technical criteria:

- Volumes from the Northeast and South geodomains based on the performance of pilots located in this area.
- Volumes for the growth areas due to lack of information and technical uncertainty around deliverability in these areas.
- Volumes from geodomains located in the other areas and having higher CO_2 concentration.

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5.5 Santos' Northern Australia and Timor-Leste

5.5.1 Overview of Assets

Santos' Northern Australia assets include producing fields, undeveloped fields with FID approval and additional discoveries and exploration assets which offer future development potential.

Darwin LNG (DLNG), which is located at Wickham Point is a single train liquefaction and storage facility that started production in 2006. Gas is supplied to DLNG from the Santos operated Bayu-Undan Field located approximately 500 km north-west of Darwin in Timor-Leste offshore waters. The Bayu-Undan Field has been producing since 2004. The Bayu-Undan development includes a central production and processing complex with a Floating Storage and Offloading (FSO) vessel for condensate and LPG products and an unmanned wellhead platform. Gas is supplied to DLNG via a 26-inch subsea pipeline. Santos operates both the DLNG plant and Bayu-Undan facility.

The undeveloped Barossa gas field is located 300 km north of Darwin and will be developed to backfill DLNG when the Bayu-Undan Field ceases production. FID on Barossa was made in March 2021. The undeveloped Caldita field is located 35 km from Barossa and any future development could also supply Darwin LNG. Santos' working interest is currently 62.5% which will decrease to 50% once the JERA sell-down is concluded.

The undeveloped Petrel and Tern Fields are located 250 km west of Darwin and could either feed into domestic or export markets. In addition, Santos holds significant exploration positions in offshore Northern Australia.

In addition to its main Northern Australia assets, Santos holds interests in four hubs that contain both discovered resources and prospective exploration areas in offshore Northern Australia. These are split into four hub areas: Vulcan Sub-basin, Browse Hub, Barossa Hub and the Petrel, Tern and Frigate (PTF) Hub.

Santos also has a potential CCS project, the Bayu-Undan CCS project in Northern Australia. The envisaged Bayu-Undan CCS facility would be located in Northern Australia around Darwin and would involve converting the near-depleted Bayu-Undan to CCS.

A location map of Santos' main offshore Northern Australia and Timor-Leste assets is given in **Figure 5.82**.

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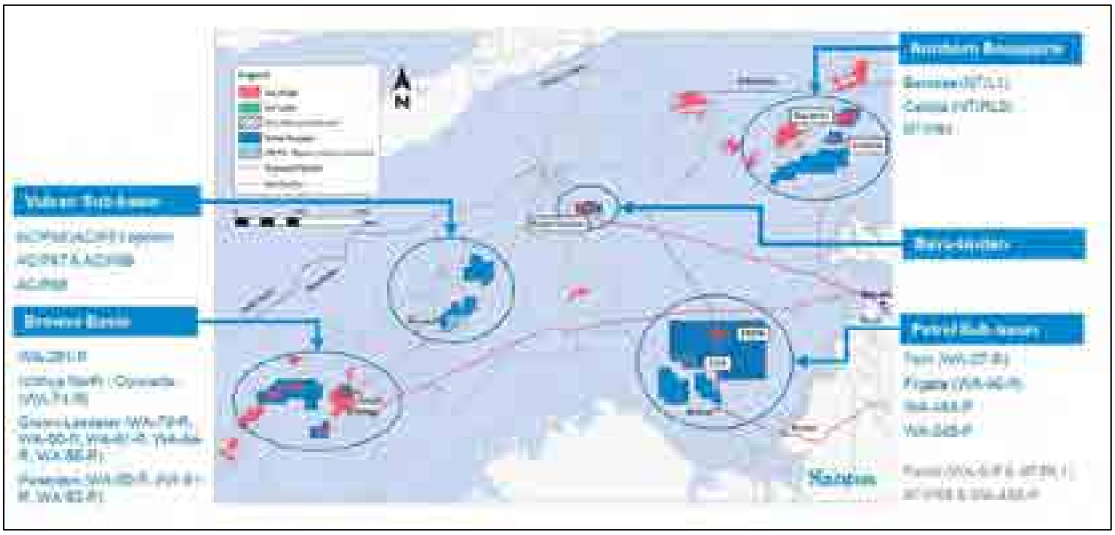
Figure 5.82: Location Map of Santos' Northern Australia and Timor-Leste Assets

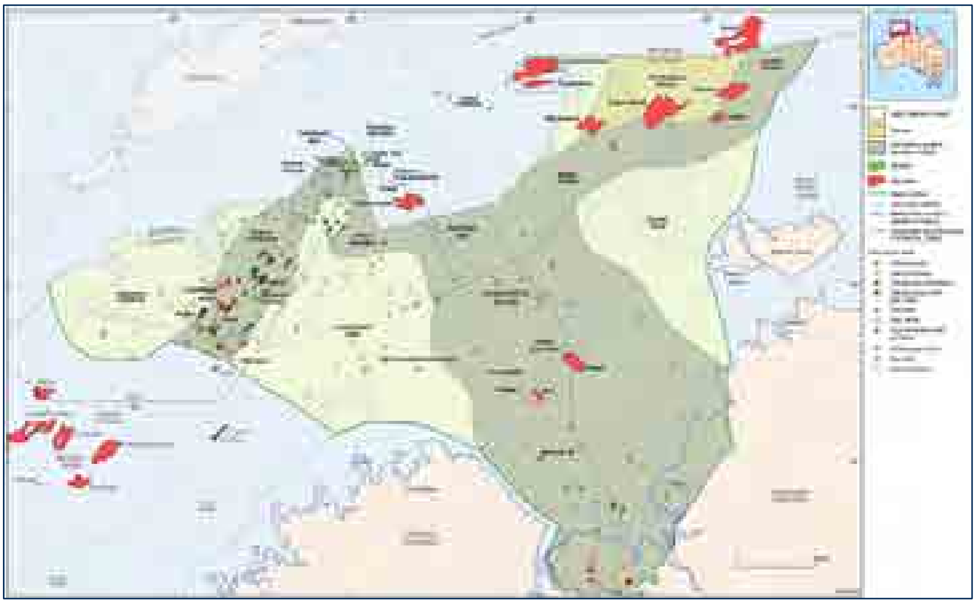


Source: Santos

5.5.1.1 Geology of the Bonaparte Basin

The Bonaparte Basin is a large fan shaped sedimentary basin which covers an area of 270,000 km^2 in the northwest offshore and onshore of Australia (**Figure 5.83**). The basin formed as a result of Pangea breakup and the opening of the Neotethys Ocean. Basin development occurred in two phases of Paleozoic extension and Late Triassic compression prior to the onset of further extension in the Mesozoic. The basin is filled with sediments that reach in excess of 17 km in thickness.

Figure 5.83: Tectonic Elements of the Bonaparte Basin



Source: Geoscience Australia

During the Cambrian – Devonian, the area underwent a period of non-deposition or erosion and Devonian evaporites directly overly basement rocks formed of Cambrian volcanics and sandstones.

Form the Late Devonian to Early Carboniferous, NE-SW extension created the proto-Petrel trend and formed a series of NW-SE trending structural features which included the Goulburn Graben and the Petrel sub-basin. This was orthogonally overprinted in the Late Cretaceous to Early Permian by NW-SE extension which formed the proto-Vulcan and Malita trends and resulted in the formation of a series of NE-SW trending structural features including the initiation of the Malita Graben.

The extension was associated with syn-rift deposition of evaporates and rift-fill sediments ranging from marine to nearshore clastic and carbonates which continued from the Upper Devonian, through the Carboniferous and into the Permian. Upper Devonian Carbonates developed on structurally high fault blocks, other syn-rift deposits included shallow marine clastics, shelf carbonates and clastics and basinal clastics.

The Permian–Triassic was dominated by a post-rift sag phase and resulted in the deposition of shallow marine, deltaic and coastal plain sediments. Sediments deposited in the sag basin overlying the earlier rift include thick Early Triassic marine shales of the Mount Goodwin formation and Middle Triassic fluvial and deltaic deposits of the Cape Londonderry, Malita, Plover and Elang Formations. During this period, the western margin of the rift system coincided with the Sahul and Flamingo Synclines which separated the Sahul Platform to the east from the Londonderry High to the west.

During the Late Triassic, regional N-S compression resulted in widespread uplift and erosion, which together with salt tectonics produced inversion structures and anticlines in the Petrel Sub-basin. Erosion and collapse of these uplifted areas led to the widespread deposition of Lower-Middle Jurassic red-beds and fluvio-deltaic clastics.

Between the Middle Jurassic to Early Cretaceous, NW-SE extension associated with rifting between Australia and India was the predominant tectonic event shaping the NW shelf. This was accompanied with a change in structural trends in the Bonaparte Basin from NW-SE to NE-SW. The Callovian Unconformity marks the beginning of continental breakup and is preserved in basinal lows while the cessation of the rift event is marked by the Valanginian unconformity. Subsidence of the Malita Graben resulted in deposition of the Flamingo Group sediments on the flanks of the Shahul Platform and in the Malita Graben. Jurassic-Cretaceous deposition consisted of fluvial, deltaic and shallow marine sandstones.

Post-rift, passive margin thermal subsidence continued through the Cretaceous with deposition of thick marine mudstones flanked by fan deposits within the Jurassic depocentres. The rapid deposition and burial lead to overpressure and the creation of a basinwide seal.

Following Paleocene deposition of a basinwide, progradational carbonate wedge, late Miocene collision of the Australian and South-East Asian plates resulted in widespread reactivation of pre-existing fault systems and the formation of inversion structures. This tectonism continues to the present day and in places has been responsible for the breach of hydrocarbon accumulations.

The stratigraphy of the Bonaparte Basin is summarised in **Figure 5.84**.

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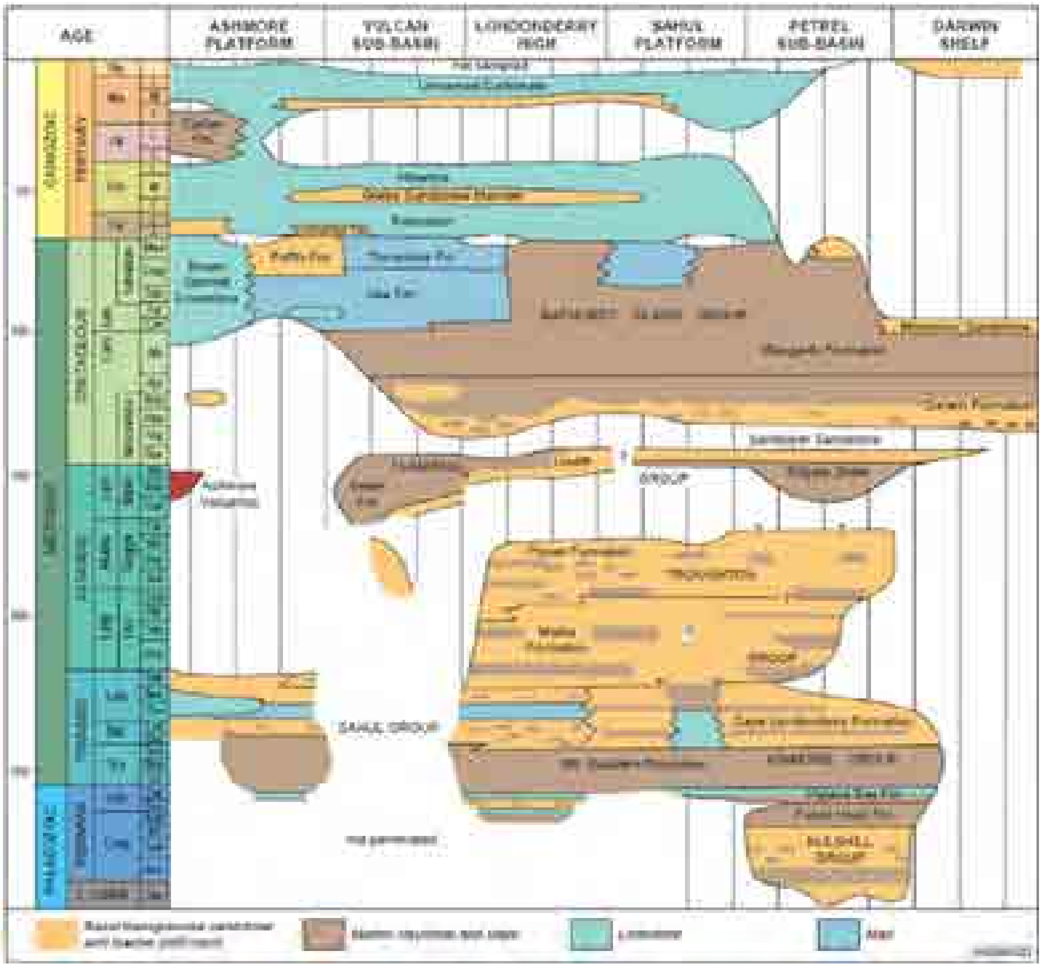
Figure 5.84: Stratigraphy of the Bonaparte Basin



Source: Geoscience Australia

5.5.1.2 Petroleum Systems of the Bonaparte Basin

The most prospective parts of the Bonaparte Basin include the Vulcan Sub-basin, laminaria-Flamingo High and the northern Sahul Platform. Reservoir rocks range in age from the Carboniferous-Permian in the Petrel Sub-basin and Londonderry High, Triassic to Cretaceous in the Vulcan Sub-basin and Jurassic in the north of the basin. The Late Jurassic marine section is the major source interval in the outboard grabens together with Middle-Lower Jurassic marine shales and coastal plain coals. In the Petrel Sub-basin, the main source rocks are Lower Carboniferous marine shales and coastal plain coals and pro-delta shales. Discoveries are generally located in structurally high fault blocks, horsts and inverted grabens where trapping structures overlie or are adjacent to subsided areas with mature source rocks.

5.5.2 Bayu Undan

5.5.2.1 Bayu Undan Overview

Table 5.43: Bayu-Undan Summary

Field Data	
Permit	PSC-TL-SO-T 19-12 and PSC-TL-SO-T 19-13
Location	500 km NNW of Darwin
Water Depth	80-100 m
Santos Working Interest	43.4% (Operator)
JV Partners	SK E&S (25%), INPEX (11.4%), Eni (11%), JERA (6.1%), Tokyo Gas (3.1%)
Discovery Date	1995 (Bayu-1)
First Production	2004
Valuation Scenario Volumes	
GaffneyCline Net STO Valuation Scenario Volume	23 MMboe
Status/Chance of Development	Producing

The Bayu-Undan Field is a gas condensate field lying in the Timor Sea approximately 500 km northwest of Darwin (**Figure 5.82**). The field is held under a Production Sharing Contract (PSC) with the Timor-Leste Government.

The field is formed of a broad east-west trending horst block which is fault bound to the north and south and dip closed to the east and west. The field was discovered in 1995 by Phillips Petroleum Company with the drilling of Bayu-1 which intersected a gross 155 m gas condensate column within fluvial and deltaic sandstones of the Jurassic Flamingo, Elang and Plover Formations (**Figure 5.85**).

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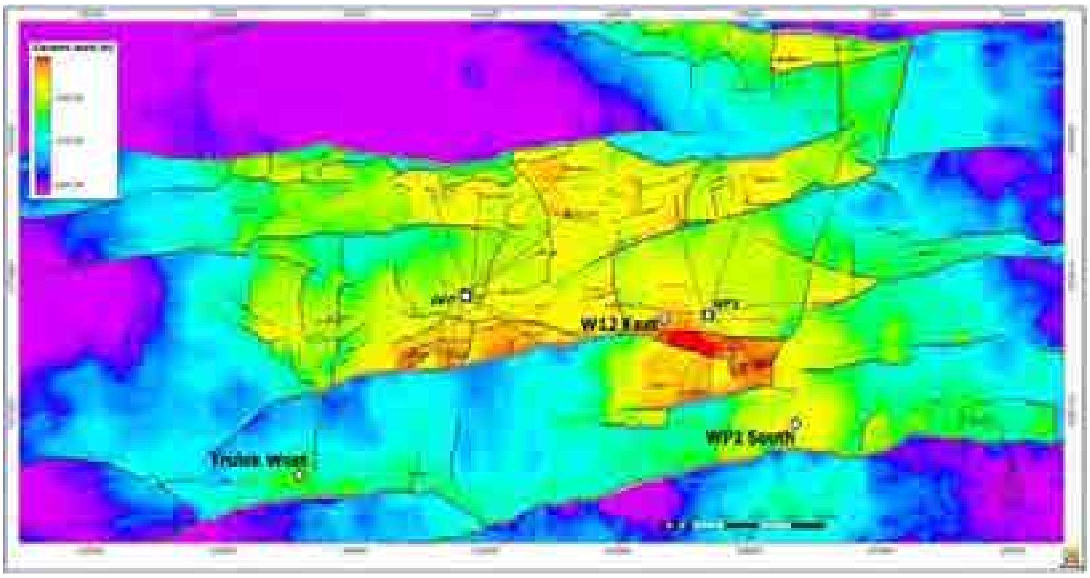
Figure 5.85: Top Structure Map of the Bayu-Undan Field with Phase 3C Development Wells



Source: Santos

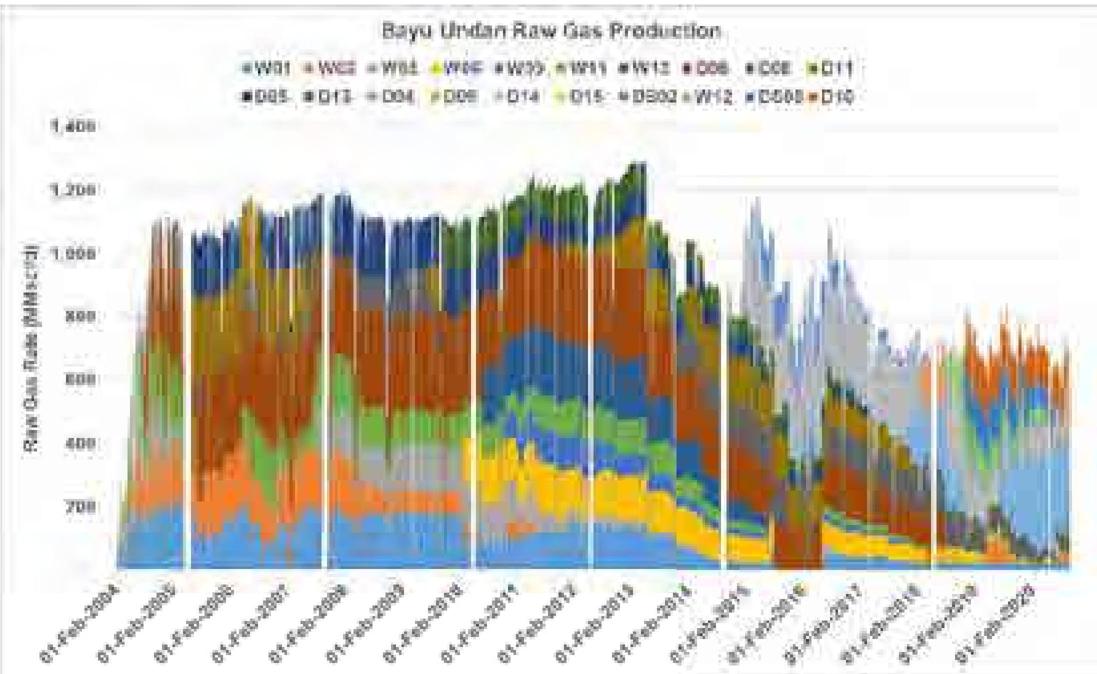
5.5.2.2 Bayu-Undan Development

First hydrocarbons were produced in 2004 and the field currently supplies gas to DLNG via a 26 inch subsea pipeline. The first LNG cargo from DLNG occurred in 2006. The field development includes a normally unmanned wellhead platform and central production and processing complex. The complex consists of a drilling, production and processing platform in addition to a compression, utilities and quarters platform. The field has been developed via 19 wells which include, 9 producers, 3 gas injectors, 1 suspended well and 4 shut-in wells (excluding Phase 3C infill wells).

Production from the field is supported by a strong aquifer and partial recycling of lean gas via the injection wells. Whilst on plateau (until 2014), total raw gas production (**Figure 5.86**) capacity was ~1.1 Bcfd with produced gas being stripped of liquids via an offshore processing and stored in an in-field FSO. Approximately 550 MMscfd of lean gas is exported to the DLNG plant and the remaining lean gas is re-injected.

In January 2021, Santos announced FID for a US$235 MM Phase 3C infill drilling program for the field (**Figure 5.85**). The program comprises three production wells (two platform and one subsea) and is designed to extend field life. In July 2021, Santos announced that production from the first Phase 3C well had begun. The first well was brought online at 178 MMscfd of gas and 11,350 bbld of liquids. Drilling has commenced on the third of the three wells with the program expected to be completed by early 2022.

Figure 5.86: Bayu-Undan Field Raw Gas Production



Source: Santos

5.5.2.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

The Bayu-Undan Field is a mature field and Santos' estimates of Reserves are based on a combination of DCA and dynamic modelling, as such GaffneyCline has not carried out a review of the Bayu-Undan Field GIIP estimate. Using production from the developed wells, end of field life was expected as early as December 2021, in order to address this and to extend this to the end of the PSC, Santos has begun its three well Phase 3C infill drilling campaign.

The W12 East well targets attic gas within the core area of the field, it is approximately 2 km from well control. The main risks associated with the well are anticipated to be early water breakthrough. The WP1 South well targets a dip closure against the southern bounding fault. This target was originally a Phase 1 target however was not reached due to drilling issues. The main uncertainties associated with the well are reservoir quality and the potential of early water breakthrough. The Trulek West well targets the southwest extremity of the field approximately 3 km from current well control and which is likely undrained by existing production. Uncertainties are associated with reservoir presence and quality as well as the risk of early water breakthrough.

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In addition, the structural interpretation impacts the GIIP estimates of all three infill wells. This is most significant in the Trulek West area as it is further from well control. GIIP estimates for the three infill wells have been calculated based on high, mid and low case structural models generated using local model updates based on Santos' latest seismic interpretation. The ranges of GIIP estimates for the three infill wells are given in **Table 5.44**. GaffneyCline was not provided with the Bayu-Undan static model and so presented herein are Santos' estimates.

Table 5.44: GIIP Estimates for the Bayu-Undan Phase 3C Infill Wells

Infill Well	GIIP (Bscf)
	Best
W12 East	295
WP1 South	345
Trulek West	116

Reservoir Engineering Discussion

GaffneyCline has reviewed presentations provided by Santos together with production profiles and an Independent Reserves and Resources Audit Report by RISC.

Santos has estimated the remaining resource volumes using a combination of DCA and dynamic modelling. Santos has used DCA for production forecasting of declining wells and has used simulation models to guide DCA for wells which haven't shown any decline in gas rates. GaffneyCline examined Santos' technical slide presentations on its DCA forecast together with gas and water rate history match plots from the Eclipse simulation model. GaffneyCline determined these to be reasonable as the DCA forecast is within the range of Eclipse simulation forecasts. GaffneyCline has therefore accepted Santos' estimates for the developed wells.

In its review of the infill wells, Santos' forecast is based on history matched simulation models, historical well performance (type curves from offset wells), decision tree analysis and capturing static and dynamic sensitivities. GaffneyCline opines that Santos approach is reasonable and accepts its profiles. The production profiles extend the field life from December 2021 to April 2023 beyond the PSC expiry.

After considering Santos' technical work and the third-party audit results by RISC, GaffneyCline has accepted Santos' estimates of remaining volumes for both the developed wells and the Phase 3C infill wells.

Production Profiles for Evaluation

GaffneyCline's has accepted Santos' production Profiles for the GaffneyCline valuation scenarios.

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5.5.3 Barossa

5.5.3.1 Barossa Overview

Table 5.45: Barossa Summary

Field Data	
Permit	NT/L1
Location	300 km NNW of Darwin
Water Depth	220 – 280 m
Santos Working Interest	50% post JERA sell-down (Operator), currently 62.5%
JV Partners	SK Australia (37.5%), JERA(Proposed12.5%)
Discovery Date	1973 (Lynedoch-1)
First Production	Scheduled for Q4 2024, FID March 2021
Valuation Scenario Volumes	
Net Valuation Scenario Volume	348 MMboe
Chance of Development	Approved for Development

The Barossa Field is a gas condensate field in the Timor Sea (**Figure 5.82**). The field is formed of a tilted fault block which is dip closed to the north and west and fault closed to the south and east. The field was discovered in 1973 by the Lyndoch-1 exploration well and has subsequently been appraised by seven further wells: Lynedoch-2, Barossa-1ST1, Barossa-2, Barossa-3, Barossa-4ST1, Barossa-5A and Barossa-6 (**Figure 5.87**).

The primary reservoir in the Barossa field is the Middle Jurassic Eland C Sand which is approximately 40 m thick. The reservoir is formed of a clean, high NTG sand which is present across the whole of the field and can be correlated regionally. The Elang C Sand was deposited as a series of deltaic and shoreface sands ranging from tidal distributary channels to distal marine deposits. Porosity and permeability are variable across the field, mainly driven by the degree of quartz cementation.

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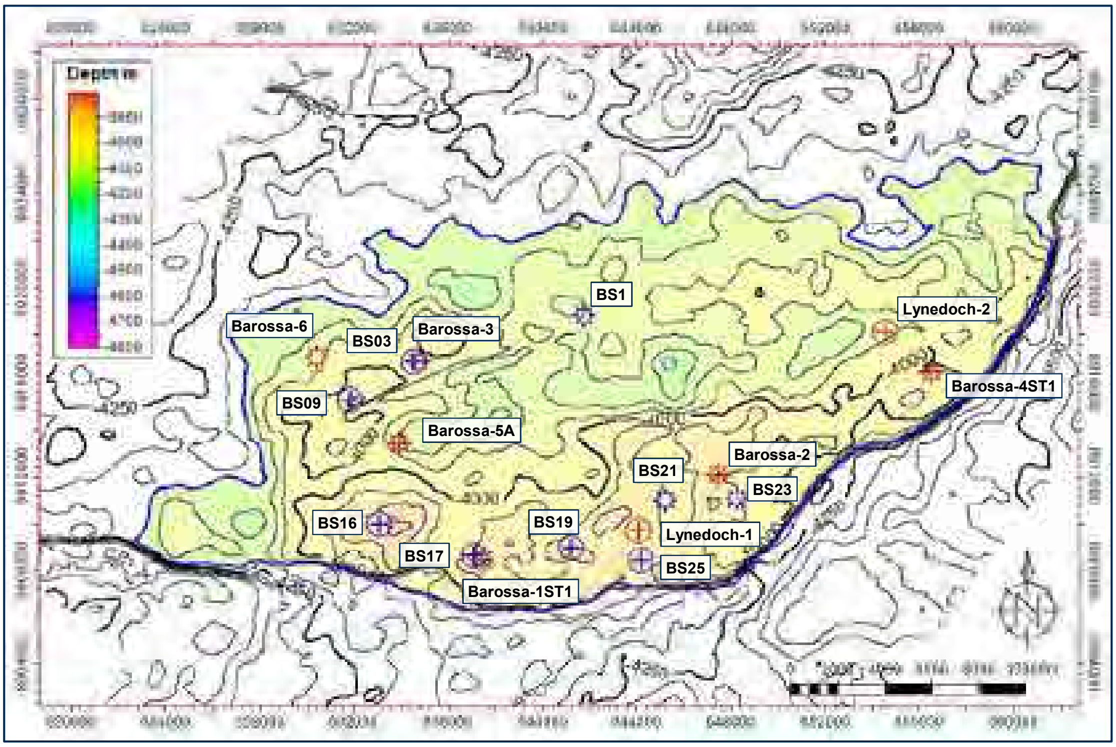
Figure 5.87: Barossa Top Structure Map Showing Drilled Appraisal and Proposed Development Wells



5.5.3.2 Barossa Development

The Barossa Field will be developed to backfill the existing DLNG facility by transporting gas via a pipeline to tie-in to the existing Bayu Undan to Darwin Pipeline (Darwin Pipeline) as the current supply from the Bayu Undan Field is anticipated to cease in late 2022. FID on the Barossa Field was announced by Santos in March 2021. The Barossa development wells and facilities are designed to deliver an annual average LNG production of approximately 3.5 MMtpa depending on downtime and seasonal impacts. Santos plans to commence production from Barossa in December 2024.

The Barossa Field will be developed in two phases:

Phase 1 – Six subsea production wells tied back via 14" internal diameter subsea flowlines to a centrally located FPSO. Wells will be connected via three, four-slot manifolds with two wells planned for each manifold with the remaining slots being left for drilling or reservoir related contingencies. Preliminary processing on the FPSO will separate gas, condensate and produced water. Liquids and a portion of CO_2 will be removed offshore prior to exporting lean gas to DLNG at a 6 mol% CO_2 specification. A new 260 km diameter Gas Export Pipeline (GEP) is planned from the FPSO to a new tie-in point on the existing Darwin Pipeline.

Phase 2 – Nominally consists of 3 additional subsea wells tied back to the FPSO via an independent subsea infrastructure, flowlines and risers to prolong the field production plateau. Low Pressure (LP) compression will be required after Phase 2 drilling to lower arrival pressures and lengthen the plateau period. A further step down to a Low-Low Pressure (LLP) mode of operations later in field life will be required to lower field abandonment pressures and maximise resource recovery.

5.5.3.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

GaffneyCline has undertaken a review of the volumetrics for Barossa based on data provided by Santos which included P90, P50, P10 and Reference Case static models.

GaffneyCline performed a petrophysical review of two wells, Barossa-2 and Barossa-6, evaluating the volume of shale using the gamma ray method, total and effective porosity using the density log and water saturation derived from the Archie equation. Based on this review, the interpreted logs provided in the Santos static models appear to be reasonable.

Santos has incorporated Low, Base and High Case interpretations of the top reservoir surface in its static model sensitivity analysis. GaffneyCline reviewed the seismic interpretations used for each case and found them to sufficiently cover the uncertainty associated with the top reservoir pick. GaffneyCline independently depth converted the Base Case top reservoir surface. This produced a lower GRV estimate within 10% of the Santos Base Case structure map.

The P50 FWL has been taken as 4,152 m TVDss, this is based on available wireline pressure data from the Barossa and nearby Caldita wells. GaffneyCline has reviewed this and agrees with this interpretation based on the intersection of the water pressure gradient from Barossa and Caldita and the gas pressure gradient from Barossa. In the P90 Case the GDT of 4,136 m TVDss has been used. Based on the pressure plot, the WUT is seen in at 4,208 m TVDss in the Plover Formation and this has been used as the P10 Case FWL.

GaffneyCline's review shows that the range of GRV's calculated from the Low, Best and High surfaces using the P90, P50 and P10 FWLs sufficiently covers the range of uncertainty associated with the GRV. GaffneyCline has used these GRV's together with reservoir parameters ranges which incorporate both the averages calculated from the Santos static model and GaffneyCline's own petrophysical averages to estimate the GIIP. The review suggests that the Santos estimate of GIIP is reasonable (i.e. within 10%). GaffneyCline Have used a lower base case GIIP of 6,207 Bscf and a lower EUR of 4,717 Bscf.

Reservoir Engineering Discussion

GaffneyCline has reviewed the engineering data and dynamic simulation models together with integrated production modelling provided by Santos. An audit check of PVT data shows that Santos' ideal CGR is reasonable. Considering the low content of C5+ in the gas, oil based mud contamination will have a significant impact on the estimation of ideal CGR (which is based on C5+ content) using a contaminated sample. GaffneyCline acknowledges that as part of its reservoir management plan, Santos plans to monitor field composition/CGR variations via an

FPSO laboratory. Santos' observation of an inverse relationship between CO_2 content and ideal CGR is reasonable and the delineation of CGR between north and south of the field is practical.

The Lynedoch-2 and Barossa-4ST1 area in the northeast of the field has different PVT from the rest of the field. The Lynedoch-2 MDT pressure is also off the field trend, higher by 15-20 psia, no MDT pressures however were acquired for Barossa-4ST1 with all measurements being tight and dry. This suggests that there is a possibility the northeast Lynedoch-2 and Barossa-4ST1 area is in a separate compartment and may not be connected to the rest of the field.

Elang C sand productivity has been demonstrated from the Barossa-1ST1 well DST#2 in the south and from Barossa-3 DST#2 and Barossa-6 DST#1 in the northwest of the field. Barossa-6 flowed at a high rate of 55 MMscfd with low drawdown indicating very good reservoir deliverability. The radius of investigation for all tests is consistent with the build-up duration. The Barossa-1ST1 test shows a near-by intersecting fault which correlates with end of radial flow, no depletion is observed suggesting a large connected GIIP. The Barossa-3 and Barossa-6 well tests see significant radial flow distances before observing any baffles and no depletion observed also suggests a large connected GIIP. The Barossa-3 Kh from log and test data compares very well and the boundary model suggests that nearby faults are conductive. The tested Barossa-6 Kh is ~2.2 greater than in log and core due to significant fracturing, as observed in significant mud losses observed during drilling. No formation water was produced during any of the tests and analysis shows only condensed water was produced.

GaffneyCline opines that Santos' dynamic simulation sensitivity analyses captures the uncertainties associated with the EUR. The main sensitivities used to determine the EUR are, the connected GIIP (highest impact on project value), full isolation of south and north fault, with and without aquifer support, conductive fault zones along the main fault (south and north fault) and vertical flow barrier (Kv/Kh). The EURs resulting from these runs are very similar. GaffneyCline has carried out additional sensitivity runs, a complete isolation of the Lynedoch-2 area which resulted in minimal impact on EUR and the sealing of all faults however this did not match the DST derivative suggesting the faults are non-sealing and therefore Santos' EUR range is reasonable.

GaffneyCline agrees with Santos' range of gas recovery factor between 71% and 81% based on the coupled Eclipse/IPM model runs with compression (LP and LLP). GaffneyCline has used best estimate recovery factor of 76% to generate the best estimate deterministic technical EUR 4,717 Bscf.

Production Profiles for Evaluation

GaffneyCline generated the Best Case raw gas production valuation scenario profiles by scaling down Santos' Best Case profile. The condensate recovery is based on initial CGR of 12 stb/MMscf and the decline trend over production period is based on Santos' dynamic simulation output.

5.5.4 Caldita

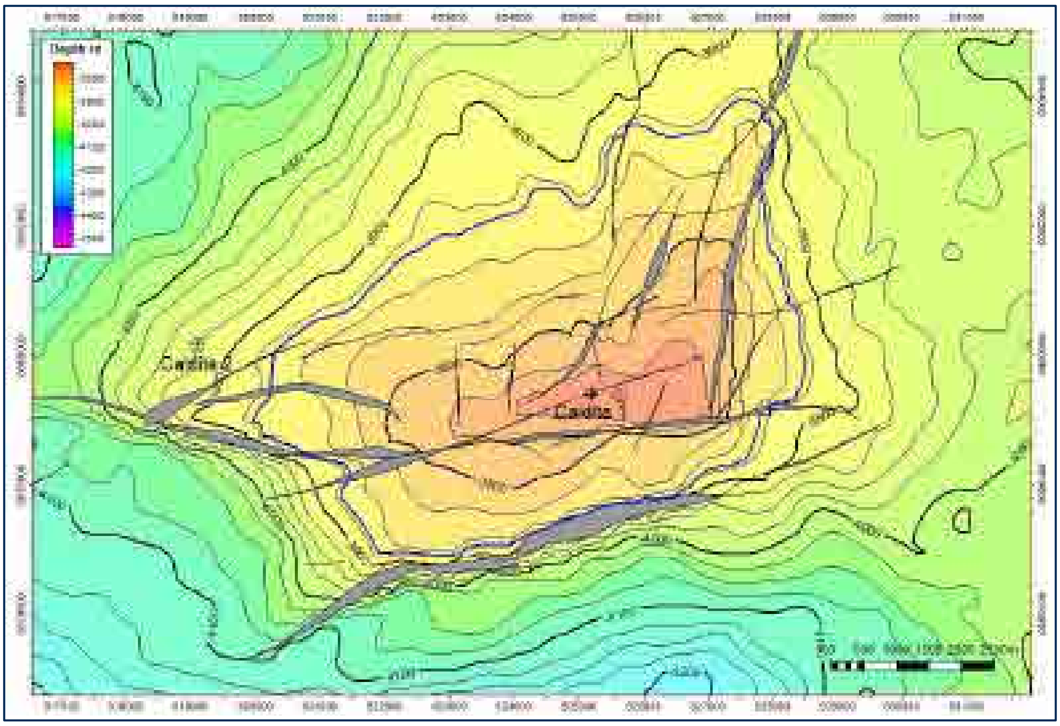
5.5.4.1 Caldita Overview

Table 5.46: Caldita Summary

Field Data	
Permit	NT/RL6
Location	300 km NNW of Darwin
Water Depth	135 m
Santos Working Interest	50%
JV Partners	SK Australia (37.5%), JERA (12.5%)
Discovery Date	2005 (Caldita-1)
First Production	Anticipated 2037 as backfill to Barossa
Valuation Scenario Volumes	
Net Santos Valuation Scenario Volume	28 MMboe (Stretch Case only, the addition of Caldita volumes extends the Barossa ELT by one year, the associated additional volumes are included here)
Chance of Development	This is considered in a Stretch Case only

The Caldita Field is located approximately 35 km southwest of the Barossa Field (**Figure 5.82**). The field was discovered in 2005 with the drilling of the Caldita-1 well which penetrated gas bearing reservoirs within the Elang, Plover and the overlying Flamingo Formations. This was followed in 2007 with the drilling of the Caldita-2 appraisal well which was classified as a dry hole with gas shows (**Figure 5.88**). The retention lease (NT/RL6) over the field was renewed in May 2018 for a period of five years. The field is currently viewed as a potential late field life tie-back opportunity to Barossa, subject to further subsurface and engineering studies and the assessment of its technical and commercial viability.

Figure 5.88: Caldita Top Elang C Structure Map



5.5.4.2 Caldita Development

A development concept study was carried out in 2019 to assess and select a preferred development concept for Caldita and to provide a cost estimate for commercial assumptions for Caldita. Three development scenarios were reviewed:

Option 1 – Subsea wells tied back via a 3-phase subsea flowline to the Barossa FPSO. Two tie back options were evaluated:

- **Option 1A** - a 43 km tie back distance
- **Option 1B –** a 51 km tie back distance

Option 2 – Standalone facilities with full processing and with dry gas directly tied into the Barossa export pipeline. Two processing options were assessed:

- **Option 2A –** Well Head Platform (WHP) and FPSO
- **Option 2B –** WHP and Gravity Based Structure

Option 3 – A Not Normally Manned platform with partial processing to send dehydrated gas and condensate to the Barossa FPSO.

The study outcomes included:

- Option 1B has the lowest CAPEX and manageable technical risks. Option 1A requires a more aggressive approach angle to the Barossa FPSO and so higher technical risks of liquids slug and surge volumes.
- Option 2 is a well proven concept with low technical risk however incurs high CAPEX due to the need for standalone facilities. Having a permanently manned facility also increases the safety risk relative to other options.
- Option 3 gives mid ranged CAPEX, technical and safety risk

The study recommendations included:

- Option 1B is the preferred development option due to low CAPEX (US$ 443 MM) and manageable technical risk.
- Option 2 it too expensive (US$ 1,048 MM).
- Option 3 has balanced CAPEX (US$ 612 MM) and risk. The additional processing removes hydrate and liquid management concerns and provides more flexibility with well phasing, intervention requirements, water handling and compression.

5.5.4.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

GaffneyCline has undertaken a review of the volumetrics for Caldita based on data provided by Santos which included P90, P50, P10 and Reference Case static models. The model includes all gas bearing zones: Upper and Lower Flamingo, Elang and Plover Formations.

The Middle Jurassic Plover – Elang succession represents an overall transgression from fluvial to shoreface environment and is unconformably overlain by the marine Early Cretaceous Flamingo Formation. The Flamingo and Plover Formations are typically poorer reservoirs than the Elang Formation. Santos has used a reference case top reservoir surface to build its static model and has incorporated deep and shallow top reservoirs to build P90 and P10 cases respectively. Facies modelling was caried out for all zones which also incorporated low and high case facies interpretations. Porosity and permeability models were conditioned to the facies model. Water saturation was calculated using a saturation height function based on permeability classes. A net to gross cut-off was applied for the GIIP calculation.

GaffneyCline back-calculated reservoir averages from the Reference Case static model provided and compared these to averages calculated by GaffneyCline from the Caldita-1 and Caldita-2 well logs. While some variations at the individual reservoir levels were noted, mainly around water saturations in the Upper Flamingo, Elang Cd and Plover Formations and to a lesser extent the NTG, in general, summed averages for Total Elang/Plover and Total Flamingo match well.

No fluid contacts have been observed in either well. Formation pressure data interpretation suggests a FWL of ~ 3,868 m TVDss, based on established gas and water gradients in the two Caldita wells. This FWL has been used in Santos' Reference Case model.

GaffneyCline tested the Santos GIIP estimate of the Elang C reservoir by using the verified GRV from the Santos Reference Case static model and GaffneyCline calculated reservoir parameters to deterministically estimate the Base Case GIIP. GaffneyCline's estimate was within 7% of Santos'. GaffneyCline has therefore accepted the Santos GIIP estimate for the Caldita Field.

The Santos development scenario incudes the development of the Lower Flamingo and Elang C-C Sands are 1,191 Bscf for the Lower Flamingo and 455 Bscf for Elang C-A.

Reservoir Engineering Discussion

GaffneyCline has reviewed the conceptual Caldita development which is described in the Barossa FDP together with supporting presentations.

Two DSTs were conducted in Caldita-1, DST-1 and DST-2 which flowed at 31.2 and 32.9 MMscf/d respectively followed by build-ups. The Caldita reservoir has lower CO_2 content than Barossa, with 13 mol% CO_2 content in the raw gas stream based on the available Caldita-1 compositional analysis. From this report, an ideal condensate yield of 9 stb/MMscf was derived and has been used to forecast Caldita condensate recovery. The GaffneyCline calculated ideal CGR matches the Santos estimate. Gas gradients from compositional data and MDT match suggesting gas samples are representative of in-situ reservoir gas.

The Santos dynamic modelling study was conducted using experimental design (over 200 runs) capturing static and dynamic uncertainties. The major sensitivities are structure, facies and permeability distribution, fault transmissibility and the FWL. The model was calibrated to the Caldita-1 well test KH. A Reference Case model was generated and the optimum development well locations were identified. Although there is significant GIIP in the Lower Flamingo, recovery from this zone is low due to poorer reservoir quality. The model excludes the Upper Flamingo and Plover as these have little or no recoverable gas due to very poor reservoir quality.

Based on the preferred subsea tie back development option and the drilling of two producing wells, Santos' Best Case gas recovery factor is assuming back pressure (THP) of 350 psia with plateau rate of 100 MMscf/d. GaffneyCline agrees with Santos' estimated recovery factor and accepts the Best Case EUR.

Production Profiles for Evaluation

GaffneyCline's gas and condensate production valuation scenario profile is based on the Santos best estimate profile. Assuming a 2024 start-up for Barossa, the Caldita Field is expected to be online for back fill in 2037 and will extend the plateau rate for approximately 20 months.

5.5.5 Bayu Undan, Barossa and Caldita Valuation Scenario Profiles

GaffneyCline has built Base Case and Stretch Case production and cost valuation scenario profiles for the Bayu-Undan, Barossa and Caldita Fields. The profiles have been built based on the following scenarios:

Base Case: Bayu-Undan + Barossa. This assumes production from the development of Barossa will backfill DLNG when the Bayu-Undan field ceases production.

Stretch Case: Bayu-Undan + Barossa + Caldita. This assumes production from the development of Barossa will backfill DLNG when the Bayu-Undan Field ceases production. In turn, production from the development of Caldita will backfill DLNG when Barossa production begins to decline.

Based on GaffneyCline's valuation scenario profiles, the Bayu-Undan Phase 3C infill wells, extend the field life, and consequently supply of gas to DLNG, from December 2021 to April 2023 beyond the PSC expiry. Barossa gas will be available to backfill DLNG in Q4 2024 and GaffneyCline's test shows the ELT of the Barossa development is 2047. The Caldita Field has reasonably small volumes and is only marginally economical, consequently it has only been included in GaffneyCline's Stretch Case. Assuming a 2024 start-up for Barossa, the Caldita Field is expected to be online for backfill in 2037 and will extend the plateau rate for approximately 20 months. Caldita production extends the ELT of the Barossa and Caldita development to 2048.

5.5.5.1 Production Profiles

GaffneyCline has built production profiles based on the scenarios outlined above.

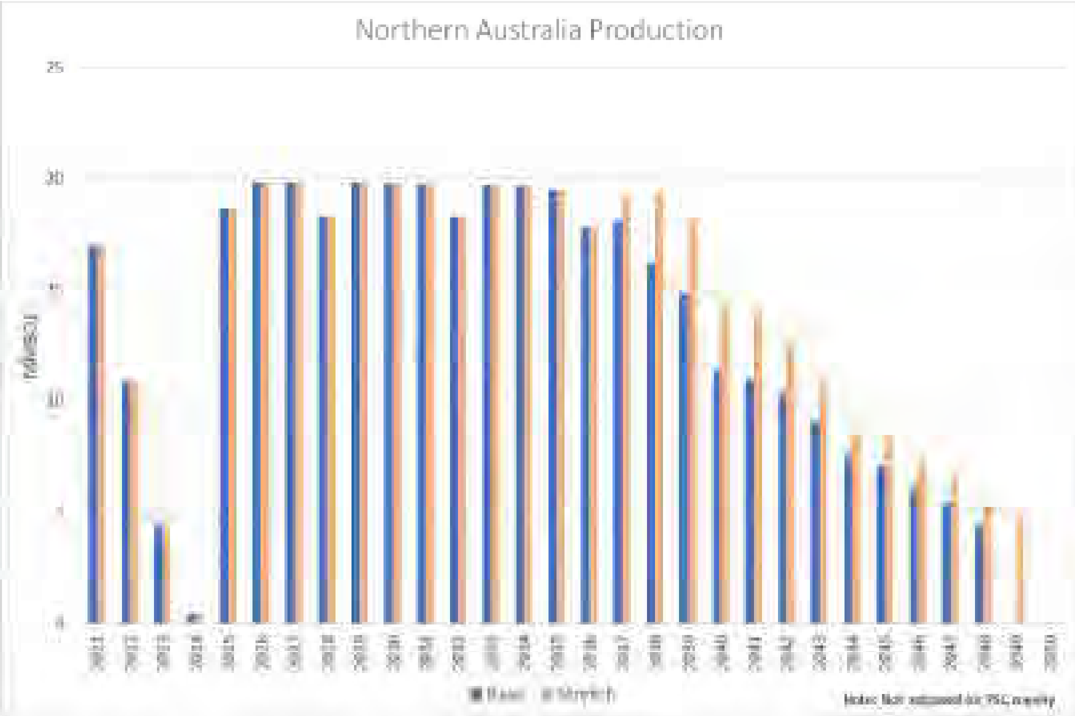
For the Bayu-Undan Field, GaffneyCline review shows Santos' production profiles are reasonable for both producing and planned infill wells, GaffneyCline has accepted the Santos profiles in both its Base and Stretch Case.

For the Barossa Field, GaffneyCline has scaled its production profiles to account for differences in GIIP and EUR estimates. This has been used in both the Base and Stretch Case scenarios.

For the Caldita Field, GaffneyCline's review shows Santos' production forecasts are reasonable and has GaffneyCline accepted the Santos forecast which has been used only in GaffneyCline's Stretch Case forecast.

GaffneyCline's Base Case and Stretch Case valuation scenario profiles for the Bayu-Undan, Barossa and Caldita Fields are given in **Figure 5.89**. The profiles are aggregated due to commercial sensitivities declared by Santos.

Figure 5.89: GaffneyCline's Base and Stretch Case Production Valuation Scenario Profiles for the Bayu-Undan, Barossa and Caldita Fields



5.5.5.2 Facilities and Cost Estimation

GaffneyCline has reviewed the cost forecasts and a range of supporting documentation provided by Santos and adjusted the costs and/or the phasing in line with GaffneyCline's view of the development plan, production profiles, and costs.

Costs can by divided into:

i. Capital costs (CAPEX) including the costs for drilling, new facilities, and ongoing improvements to existing operating assets

ii. Operating costs (OPEX) which include the costs for field and processing plant operations, lease costs for leased facilities, and tariffs paid for production services

iii. Decommissioning and Restoration (D&R) costs (often termed "ABEX") being the costs to plug and abandon (P&A) all wells; and to decommission, remove, and carry out site restoration for all installed production facilities in accordance with the currently prevailing regulations and good industry practise.

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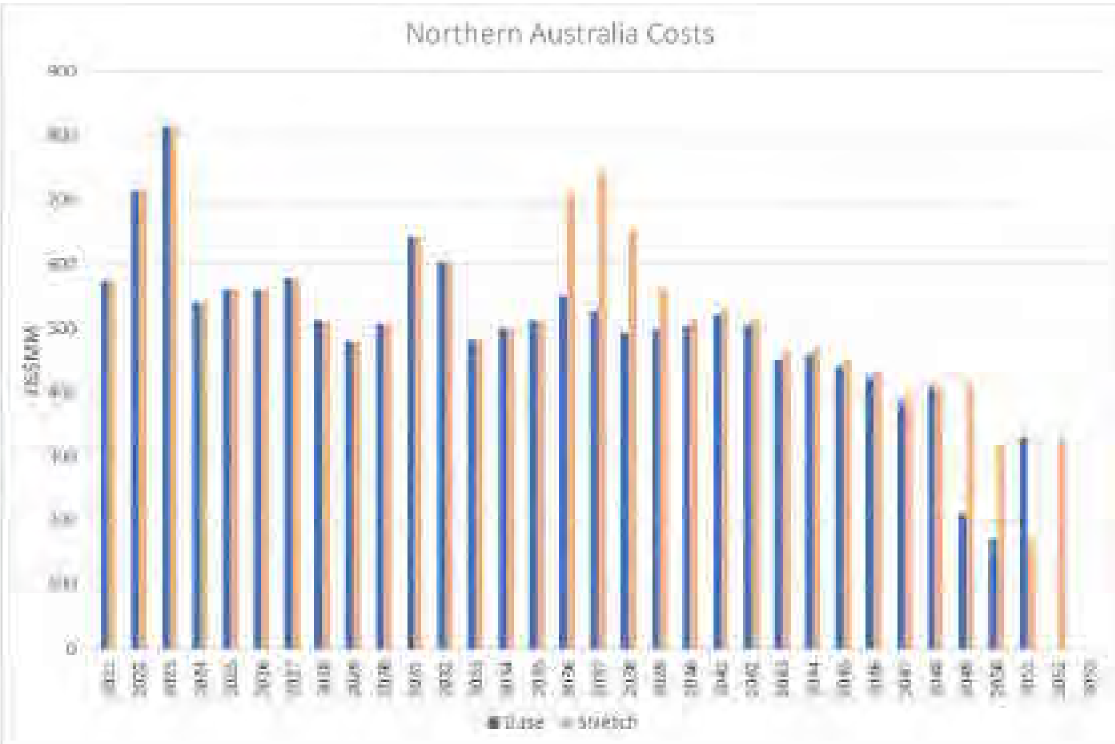
iv. Carbon Emissions costs are estimated applying the Santos carbon cost forecast to those emissions forecast to above the permitted baseline. GaffneyCline has accepted the Santos provided "baseline" emissions forecast without review.

Each of the sections below provides additional field-specific facilities information and the cost profiles used. Costs are provided in millions of U.S. dollars (US$ MM), Santos Working Interest share, and in Nominal (i.e. escalated) terms. An escalation rate of 2% p.a. has been applied throughout.

Total costs for Barossa, Bayu-Undan and Caldita Fields Base and Stretch Cases are shown in **Figure 5.90**. The profiles are aggregated due to commercial sensitivities declared by Santos.

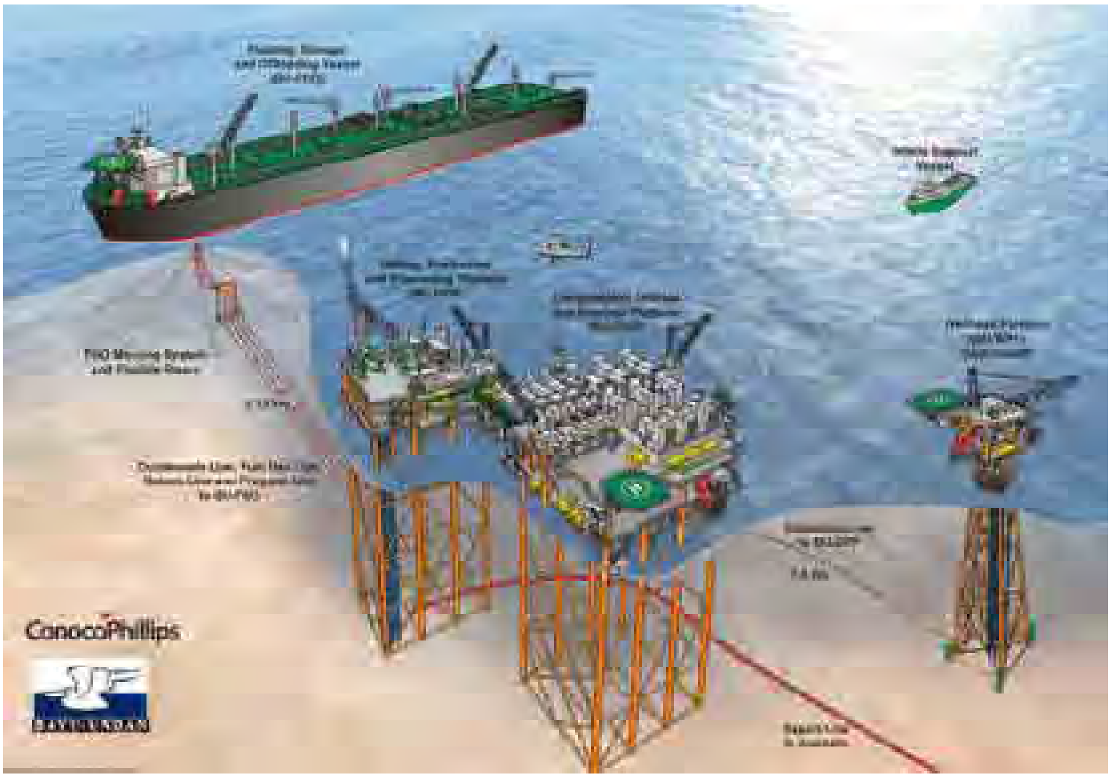
Figure 5.90: GaffneyCline's Base and Stretch Case Cost Profiles for the Bayu-Undan, Barossa and Caldita Fields (US$ MM, Santos Share, Nominal)



5.5.5.2.1 Bayu Undan

The Bayu Undan facilities are extensive, comprising an FSO, two major production platforms, a wellhead platform and an export pipeline to Darwin. The facilities are shown in **Figure 5.91**.

Figure 5.91: Bayu Undan Development Facilities



Source: Santos

The Bayu Undan costs relate to the ongoing operation, infill drilling, and D&R of the current development only. Costs related to the potential re-use of the facilities and reservoir for CCS have not been included. The D&R costs of the onshore DLNG plant, which will be backfilled by the Barossa development are also excluded here. Santos is the Operator and holds a 43.4% Working Interest.

The Santos CAPEX costs have been accepted without modification.

The Santos OPEX profiles have been accepted without modification.

D&R costs have been reviewed and accepted without modification.

No emissions above baseline and therefore no emissions costs are forecast.

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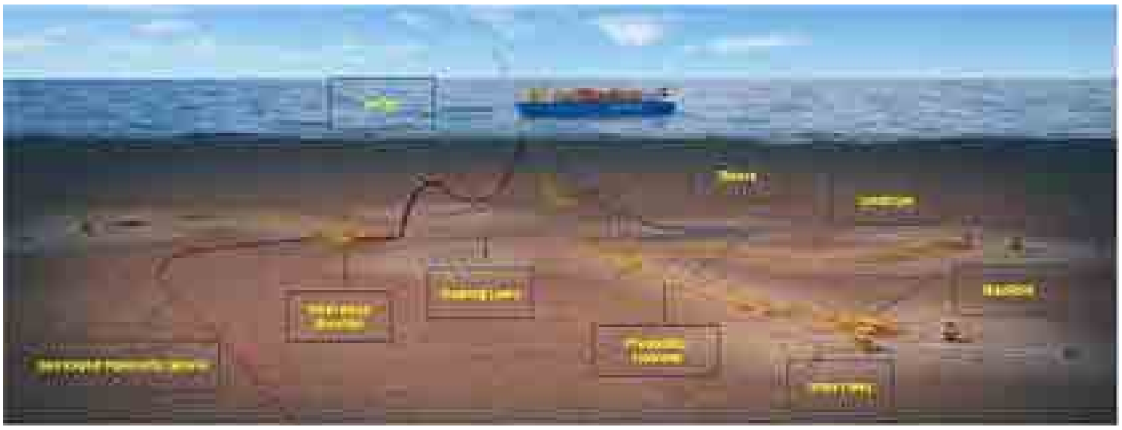
5.5.5.2.2 Barossa

The Barossa development is based on subsea wells tied back to a leased FPSO, producing gas through the existing Bayu Undan to Darwin LNG pipeline. As a part of the Barossa development, the service life of the DLNG plant will be extended to accommodate the additional years of Barossa production. The Barossa development is shown in **Figure 5.92**.

Figure 5.92: Barossa Development Facilities



Source: Santos

The costs of the Barossa development are split between the upstream Barossa development (Santos 50% WI) and the midstream DLNG Pipeline and DLNG Plant components (Santos 43.44% WI). Santos is the Operator of all three parts of the development.

GaffneyCline carried out an independent cost estimate of the Barossa offshore development CAPEX, OPEX, FPSO lease cost, and D&R costs.

The Santos CAPEX costs have been accepted without modification.

The Santos OPEX profiles have been accepted without modification.

D&R costs of the upstream and midstream pipeline have been reviewed and accepted without modification. GaffneyCline has added in additional costs at the end of the production profile to cover D&R of the DLNG plant.

The Santos baseline carbon emissions, and carbon price (above baseline) were accepted. Carbon emissions above baseline were calculated to determine a net carbon cost to the venture.

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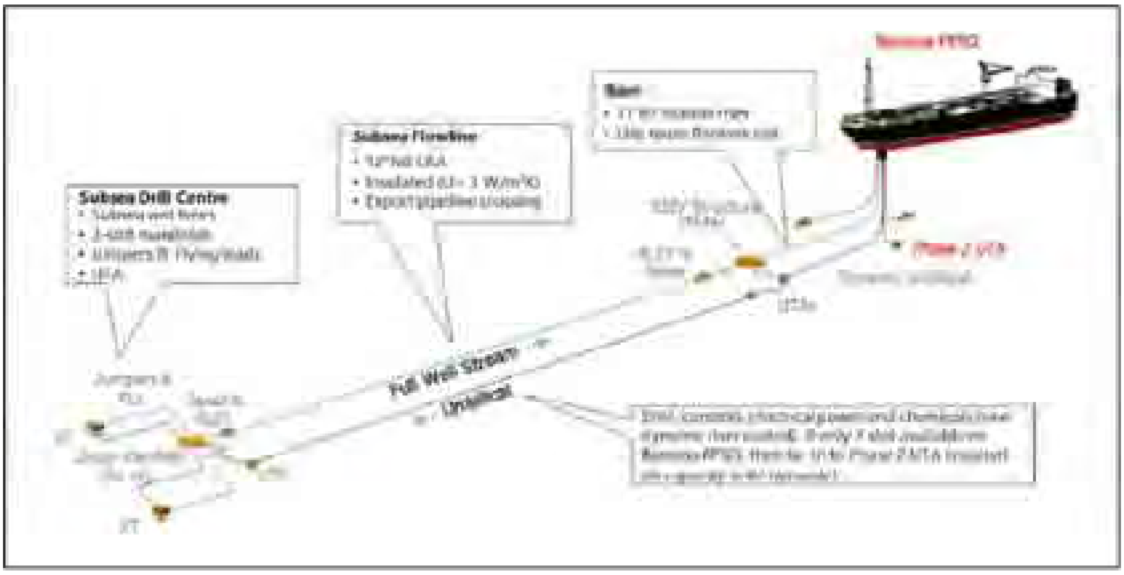
5.5.5.2.3 *Caldita*

The Caldita Field is a small discovery some 45 km distant from Barossa and is proposed to be developed as a subsea tieback, backfilling the Barossa profile and extending the technical and economic limit of Barossa Field production. The currently preferred Caldita Field development concept is shown in **Figure 5.93**.

Figure 5.93: Caldita Development Concept



Source: Santos

The costs for the Caldita development are incremental to the Barossa development and assume the Barossa development proceeds. Thus, Caldita will extend the Barossa technical and economic limit by one year allowing production of additional Barossa volumes and deferring the D&R expenditure on Barossa and DLNG. Santos is Operator of the Caldita Field and holds a 50% Working Interest.

GaffneyCline carried out an independent cost estimate of the Caldita tieback CAPEX, OPEX, and D&R costs.

The Santos CAPEX costs have been accepted without modification.

The Santos OPEX profiles have been accepted without modification.

The D&R costs have been accepted without modification.

The Santos baseline carbon emissions, and carbon price (above baseline) were accepted. Carbon emissions above baseline were calculated to determine a net carbon cost to the venture.

5.5.6 Petrel

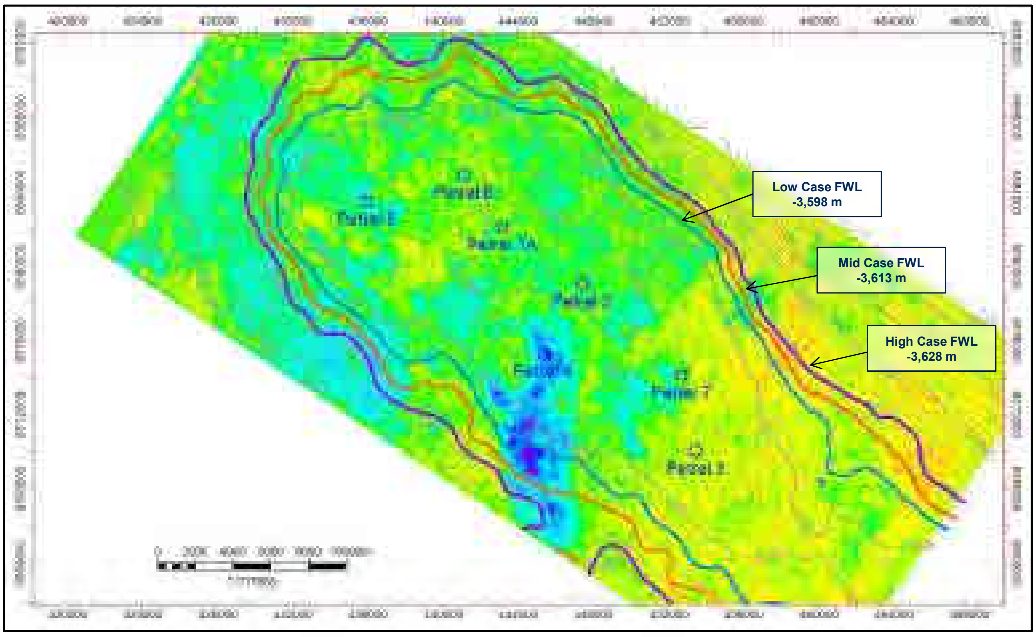
5.5.6.1 Petrel Overview

Table 5.47: Petrel Summary

Field Data	
Permit	WA-6-R & NT/RL1
Location	250 km WSW of Darwin
Water Depth	100 m
Santos Working Interest	40.25%
JV Partners	Neptune (54% & Operator), Beach Energy (5.75%)
Discovery Date	1969 (Petrel-1)
First Production	2029
Valuation Scenario Volumes	
Net Valuation Scenario Volume	Included with Tern

The Petrel Field is a dry gas field which straddles the WA-6-R and NT/RL1 leases in the Bonaparte Basin (**Figure 5.82**). The field is formed of an un-faulted northwest – southeast trending anticline which was induced by salt tectonics and requires stratigraphic closure to the southeast. The field was discovered by Arco Australia in 1969. To date, seven wells have been drilled on the field. The primary reservoir is the Permian Cape Hay Formation, which was deposited as tide dominated, heterolithic estuarine sands (**Figure 5.94**).

Figure 5.94: Top Reservoir Structure Map



5.5.6.2 Petrel Development

Petrel Field development is modelled as backfill for the Yelcherr Gas Plant (YGP) once the Blacktip Field production declines. Petrel is anticipated to come online in 2029 ramping up to 120 MMscf/d within two years. A riser platform will host facilities and a 181 km export pipeline will deliver gas to TGP at a deliver pressure of 80 bar. Phase 1 of the development will see the drilling of 2 vertical wells to be followed by 1-3 horizontal wells in Phase 2 dependent upon initial well performance. Phase 1 wells will target the high permeability Petrel-4 sand bar while Phase 2 wells will target lower permeability areas.

5.5.6.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

The Cape Hay Formation in the Petrel Field is split into three main reservoirs. The uppermost R1 reservoir is formed of tidal and shoreface sands and is laterally extensive across the field however reservoir quality is variable due to a diagenetic overprint corresponding to areas of poorer reservoir quality. The middle R2 reservoir is formed of shoreface and fluvial sands, the reservoir is subdivided into three sub-layers, the deepest R2C and R2B layers are separated by a correlatable shale layer and are both present across the whole field, the shallower R2A is mainly non-reservoir and pinches out westwards between Petrel-1A and Petrel-6. Both the R2B and R2C reservoirs are laterally heterogeneous with the best reservoir quality in the west of the field. The lower R3 reservoir is formed of tidal delta and shoreface sands which coarsen upwards. The best reservoir quality is developed at the top of the interval however in general, reservoir quality in R3 is poor.

The GIIP estimate for the Petrel field has a large range between the P90 and P10. This is primarily due to GRV uncertainty. This is contributed to by both depth conversion and FWL uncertainties. The R1 Top Reservoir has been mapped using a range of depth conversion techniques: seismic velocities, Vavg and a time depth function. Low, base and high case FWLs have also been estimated. No pressures have been taken in the R1 water leg and a range of possible R1 water lines encompassing R2 and R3 water pressures results in a large range of FWLs. Furthermore, lateral facies changes are also incorporated into the uncertainty. The Petrel-4 well penetrates a good reservoir quality tidal bar sand however amplitude data shows this is restricted to the Petrel-4 well area and is not very laterally extensive. Other wells penetrate sands of varying quality and seismic inversion cubes have been interpreted to show more cemented rock in the southeast of the field. This reduction in reservoir quality likely results in stratigraphic pinchout in the southeast where the field does not have a structural closure. GaffneyCline has accepted Santos' estimates of GIIP of 3,633 Bscf.

Reservoir Engineering Discussion

GaffneyCline's engineering review has been based on presentations provided by Santos and the preliminary FDP for the Petrel, Tern and Frigate Fields. The development plan only covers the R1 reservoir.

The R1 reservoir is a dry gas reservoir with Ideal CGR of 4.2 stb/MMscf (averaged from Petrel-3, Petrel-4 and petrel-7). The R1, R2 and R3 reservoirs are distinct reservoirs with different gas compositions. Variable formation capacity (KH) and reservoir heterogeneity is evident from DST's with KH ranging from 0 - 3,500 mD.m. The Petrel-4 well area has the highest KH, the average KH outside of this area is 250 mD.m.

The R1 FWL has a large uncertainty range as no pressures are available in the R1 water leg. Pressures from the R2 and R3 water leg have been used to estimate the FWL however pressure communication between R1 and R2/R3 is not clear. The R1 pressures are scattered and the RCI pressures from Petrel-7 indicate higher pressures than the DST build up pressure. The Petrel-7 pressure data further increases FWL uncertainty. Lateral reservoir communication is also an uncertainty, the Petrel-7 and Petrel-3 wells are located in the southeast of the field while Petrel-1 is in the northwest. Petrel-1 experienced a blow-out and pressure depletion seen in Petrel-3 is interpreted to be a result of this. Petrel-7 however does not see the same pressure depletion.

GaffneyCline has utilised Santos' IPM model which was calibrated to simulation work (matched to simulator rate vs cum behaviour) for the Petrel and tern Fields to generate profiles assuming depletion drive as the primary drive mechanism. GaffneyCline has generated production profiles based on the reviewed recovery factor. The condensate forecast has been generated using a constant CGR of 4.2 stb/MMscf.

Production Profiles for Evaluation

GaffneyCline's gas and condensate production profile is based on the Best Case recovery factor provided.

5.5.7 Tern

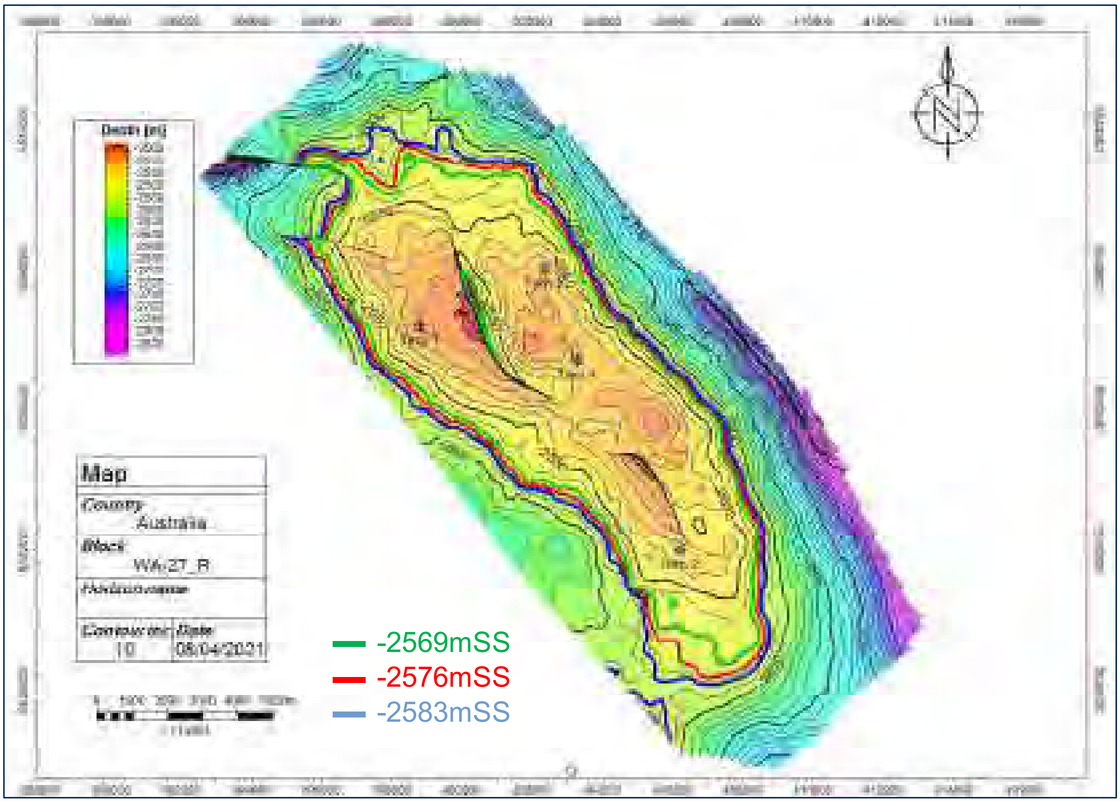
5.5.7.1 Tern Overview

Table 5.48: Tern Summary

Field Data	
Permit	WA-27-R
Location	300 km WSW of Darwin
Water Depth	80 m
Santos Working Interest	100% (Operator)
JV Partners	N/A
Discovery Date	1971 (Tern-1)
First Production	2040's
Valuation Scenario Volumes	
Net Valuation Scenario Volume	149 MMboe (Combined volume for joint Petrel and Tern development)

The Tern Field is a dry gas field which lies approximately 60 km to the southwest of the Petrel Field (**Figure 5.82**). The field is formed of a northwest – southeast trending, 4-way dip closed anticline formed on the flank of a salt diapier (**Figure 5.95**). The field was discovered in 1971 and has been appraised by three further wells. The primary reservoir is the Upper Permian Tern Formation of the Hyland Bay Group which was deposited in a wave dominated prograding shoreface environment.

Figure 5.95: Top Reservoir Structure Map



Source: Santos

5.5.7.2 Tern Development

The development of Tern is modelled as backfill to the Yelcherr Gas Plant once the Petrel Field begins to decline and to maintain the 120 MMscf/d plateau rate for an additional 8 years. The field will be developed with 4 horizontal wells, each with 1.5 km horizontal section and gas will be exported via a 57 km pipeline to the Petrel platform.

5.5.7.3 GaffneyCline Technical Review

Geology and Geophysics Discussion

The Tern Field was discovered with the drilling of the Tern-1 well which drilled the crest of the anticline interpreted from 2D seismic data. The field has been appraised by three further wells, Tern-2, Tern-4 and Tern-5. A fifth well, Tern-3, was drilled on a satellite structure located to the south and separated from the main structure by a saddle but encountered mainly tight, water bearing sands.

The Tern Formation reservoir (Top Hyland Bay Formation) is formed of wave dominated shoreface sands with NTG ranges of 35-75%, porosities between 16-18% and average permeabilities of 5- 50 mD and is split into an Upper and Lower Tern Sand. Gross reservoir thickness is approximately 30 m. Lateral reservoir quality is variable with poorer permeabilities seen in Tern-4 and Tern-5 due to diagenesis. Santos' GIIP estimate for the field is given in **Table 5.49**.

Table 5.49: GIIP Estimate for the Tern Field

Field	GIIP (Bscf)		
	Low	Best	High
Tern	-	818	-

Reservoir Engineering Discussion

GaffneyCline's engineering review has been based on presentations provided by Santos and the preliminary FDP for the Petrel, Tern and Frigate Fields.

The Tern Field is a dry gas field with average Ideal CGR of 8.4 stb/MMscf containing inerts of 1.6 mol% CO_2 and 4.9 mol% N2. Well test results from all four wells indicate the reservoir has variable permeability in the range of 1-100 mD with KH ranges between 78-1,648 mDft. Gas rates vary between 5 – 15.3 MMscf/d.

The FWL in the Tern Field is defined by a single gas line going through the RFT and DST pressure data with the gas gradient calculated using the PVT data. RFT water points measured in Tern-2, Tern-3, Tern-4 and Tern-5 define a range of water lines (with gradient calculated from water salinity and temperature) that are used for maximum and minimum FWL estimation. The Base Case is taken as the Mid Case.

Santos ran an IPM model with pipeline to Petrel with 75 realisations incorporating a GIIP range of 579 – 976 Bscf. The resulting gas recovery factor ranges between 38 – 57%. GaffneyCline believes Santos' approach in determining recovery is reasonable. GaffneyCline has therefore utilised Santos' IPM model which was calibrated to simulation work (matched to simulator rate vs cumulative behaviour) to generate Base Case production profiles assuming a four horizontal well development. GaffneyCline's production profiles use the Santos Best Case recovery factor. The condensate forecast has been generated using a constant CGR of 8.4 stb/MMscf.

Production Profiles for Evaluation

GaffneyCline's gas and condensate production profile is based on the Santos' Best Case recovery factor.

5.5.8 Petrel and Tern Forecasts

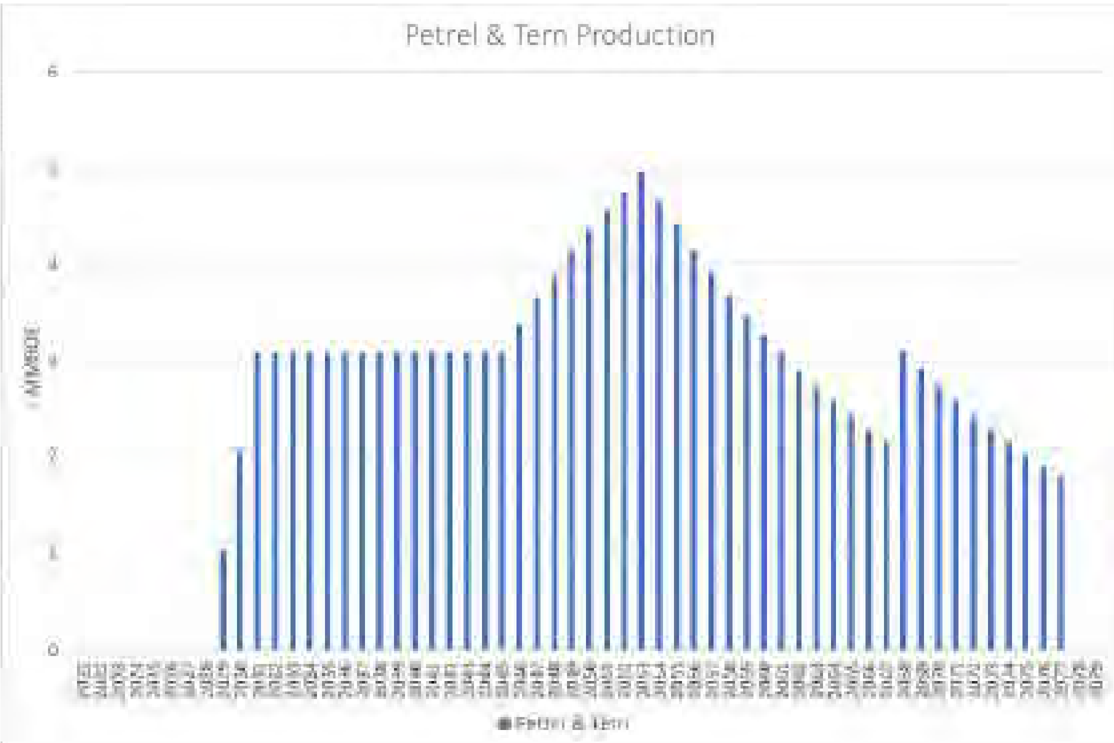
GaffneyCline has built production and cost valuation scenario profiles for the fields based on a joint development which sees the Petrel Field being developed first before the Tern Field is developed to backfill declining Petrel production. GaffneyCline has built the profiles using a single scenario with the same profiles being supplied for the Base and Stretch Cases.

5.5.8.1 Production Profiles

For the Petrel Field and Tern Fields, GaffneyCline's production forecast applied utilises a combination of Operator and Santos production profiles.

GaffneyCline's production forecast for the Petrel and Tern Fields for the Base and Stretch Cases is presented in **Figure 5.96.** The profiles are aggregated due to commercial sensitivities declared by Santos.

Figure 5.96: GaffneyCline's Production Valuation Scenario Profile for the Petrel and Tern Fields



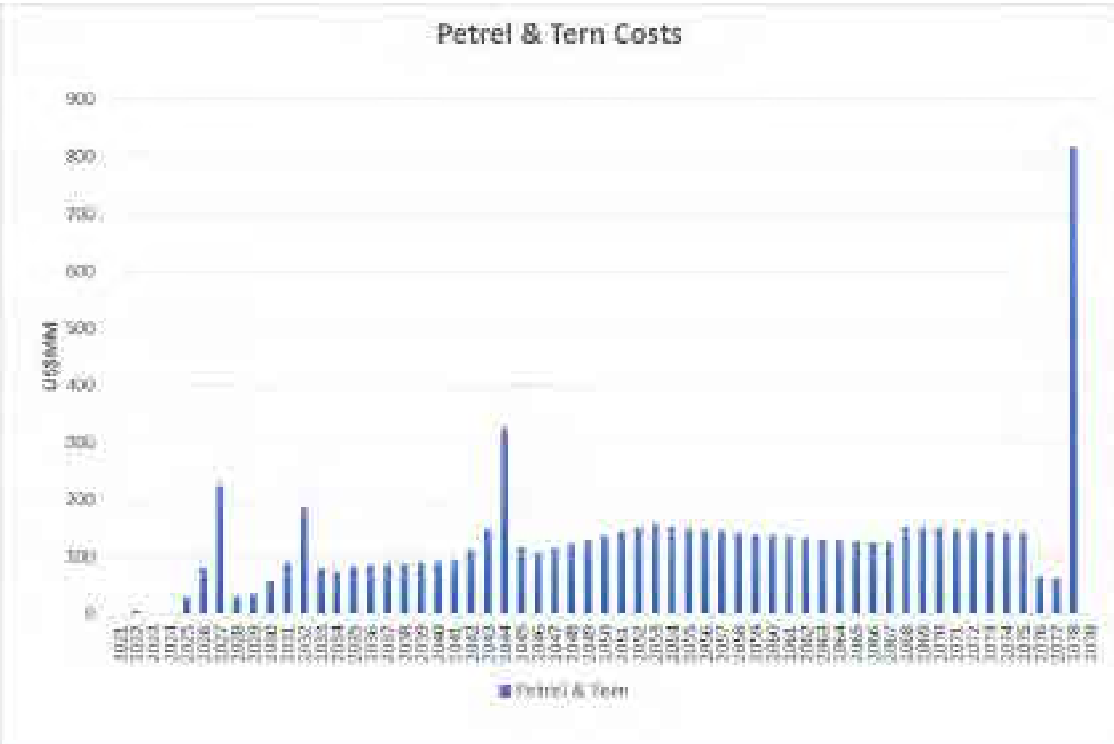
5.5.8.2 Facilities and Cost Estimation

GaffneyCline has reviewed the cost profiles and a range of supporting documentation provided by Santos and adjusted the costs and/or the phasing in line with GaffneyCline's view of the development plan and production profile.

The section below provides additional specific facilities information and the cost profiles used. Costs are provided in millions of U.S. dollars (US$MM), Santos Working Interest share, and in Nominal (i.e. escalated) terms. An escalation rate of 2% p.a. has been applied throughout.

Total costs for Santos' Petrel and Tern Base Case are shown in **Figure 5.97**. The profiles are aggregated due to commercial sensitivities declared by Santos.

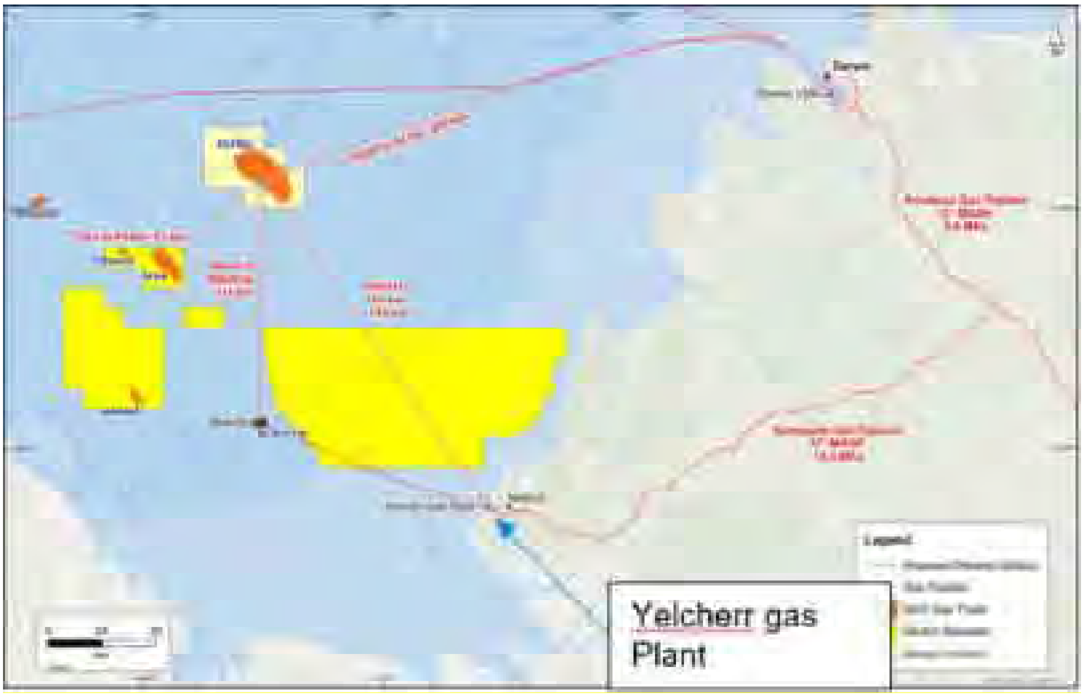
Figure 5.97: GaffneyCline's Cost Profiles for the Petrel and Tern Fields (US$ MM, Santos Share, Nominal)



5.5.8.2.1 Petrel and Tern

The Petrel and Tern Fields are modelled as an unmanned wellhead platform at Petrel producing through a new pipeline to the existing onshore Yelcherr Gas Plant (YGP) as backfill to the mature Blacktip development. The Tern Field would be developed as a subsea tieback to Petrel. As production rates are constrained to YGP capacity an exceptionally long production forecast results. The development concept is, at this stage, conceptual (**Figure 5.98**).

Figure 5.98: Petrel and Tern Development Overview



Source: Santos

The costs provided here relate to the development and operation of the Tern and Petrel Fields, the onshore gas plant, and gas delivery to DLNG. Santos is the Operator of both fields and holds a 40.25% Working Interest in the Petrel Field and a 100% Working Interest in Tern.

Santos CAPEX costs related to the above fields have been crosschecked with an independent estimate and accepted without modification. CAPEX phasing has been adjusted to suit the assumed development timing.

Santos OPEX profiles have been generally accepted. The transport toll from YGP to DLNG has been accepted and used with the GaffneyCline production profile.

D&R costs have been reviewed and recalculated based on unit costs consistent with other Santos D&R estimates.

The Santos estimate of emissions above baseline and emissions costs have not been reviewed but accepted as provided.

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5.5.9 Bayu Undan CCS

Bayu-Undan has been on production since 2004, with rates of ~1,200 MMscfd for nine years followed by reduced rates of ~750 MMscfd for seven years. Gas cycling was implemented at inception with the first two years being full cycling to aid condensate recovery, followed by partial cycling from January 2006 when gas was first delivered to DLNG. Gas has been exported to DLNG at the rate of approximately ~600 MMscfd since 2006. Bayu-Undan is now nearing the end of its life and provides a suitable storage facility for CO2 to allow Barossa to take over supply to DLNG.

Barossa wellstream gas contains ~18% CO_2 and the plan would be to reduce this to below 6% before delivery to the LNG plant. Raw gas production rates of approximately 700 MMscf are envisage for 15 years, resulting in the production of approximately 2.2 to 2.4 Mtpa CO_2, before declining. The total storage requirement for this project would not exceed 45 Mt.

Santos has also conceptually considered the storage of CO_2 from other sources, potentially contributing an additional 2.3 to 4.0 Mtpa.

The suitability of the site is discussed below in terms of storage, injectivity and containment.

- **Storage.** The potential storage capacity in Bayu-Undan exceeds the anticipated requirements of the various identified sources of CO_2. Storage is not considered to be a major risk.
- **Injectivity.** The project is not sufficiently mature for specific injection well count and locations to be specified. However, the reservoirs are very good quality and production wells had high productivity indices. Injectivity is not considered to be a major risk
- **Containment.** Storage is intended to take place in the pore volume containing depleted hydrocarbon gas, within the structures that contained the hydrocarbon gas over geological time. Containment is not considered to be a major risk.

5.5.9.1 Bayu-Undan CCS Evaluation

CO_2 supply to Bayu-Undan CCS is anticipated to come initially from the Barossa development, with backfill from other (non-Santos, yet to be approved) high CO_2 developments in the region. Long term CO_2 supplies to the project, therefore, depends on 3rd party approvals of development projects.

Bayu-Undan CCS is subject to a number of other contingencies related to its location in Timor-Leste. The fiscal and regulatory framework of a CCS project in Timor-Leste will need to be established and the PSC (or equivalent "Injection Licence") extended or agreed. The validity of international ACCU's for CCS will need to be recognized by the Australian authorities, as will approvals to export (waste) CO_2 internationally. Partner approvals will be required, and FID taken. GaffneyCline considers this project immature for valuation purposes currently.

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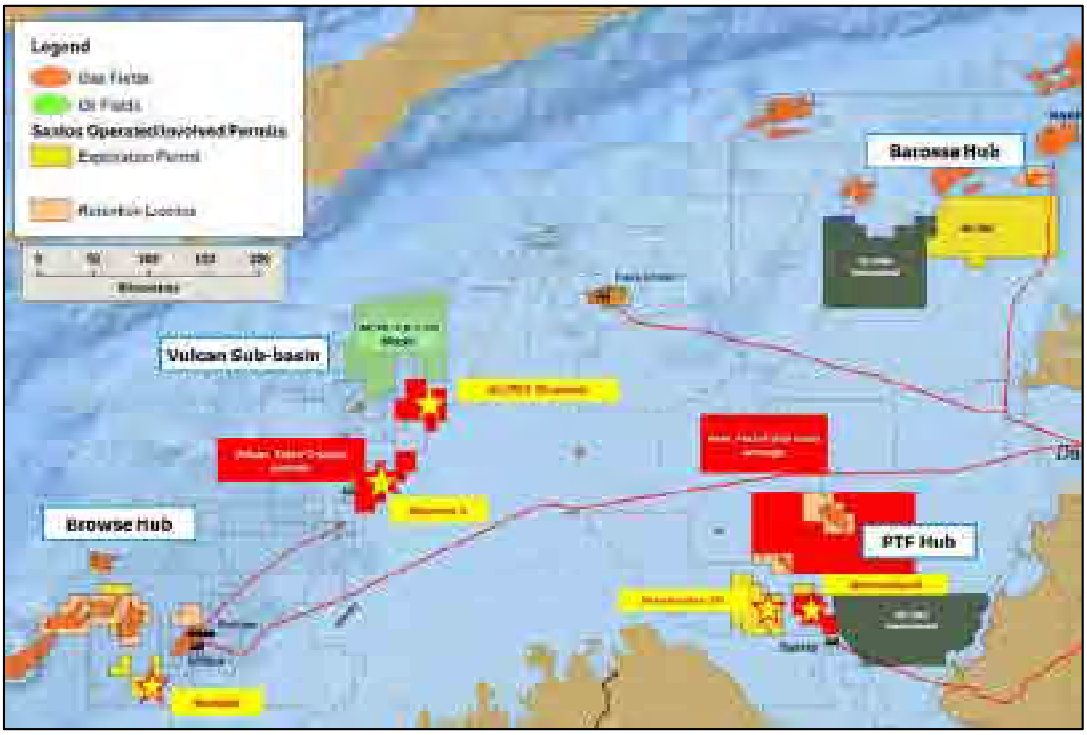
5.5.10 Additional Assets

In addition to its main Northern Australia assets, Santos holds interests in four hubs that contain both discovered resources and prospective exploration areas in offshore Northern Australia. These are split into four hub areas: Vulcan Sub-basin, Browse Hub, Barossa Hub and the PTF Hub. A location map of these areas is given in **Figure 5.99**.

Figure 5.99: Location Map of Santos' additional offshore assets



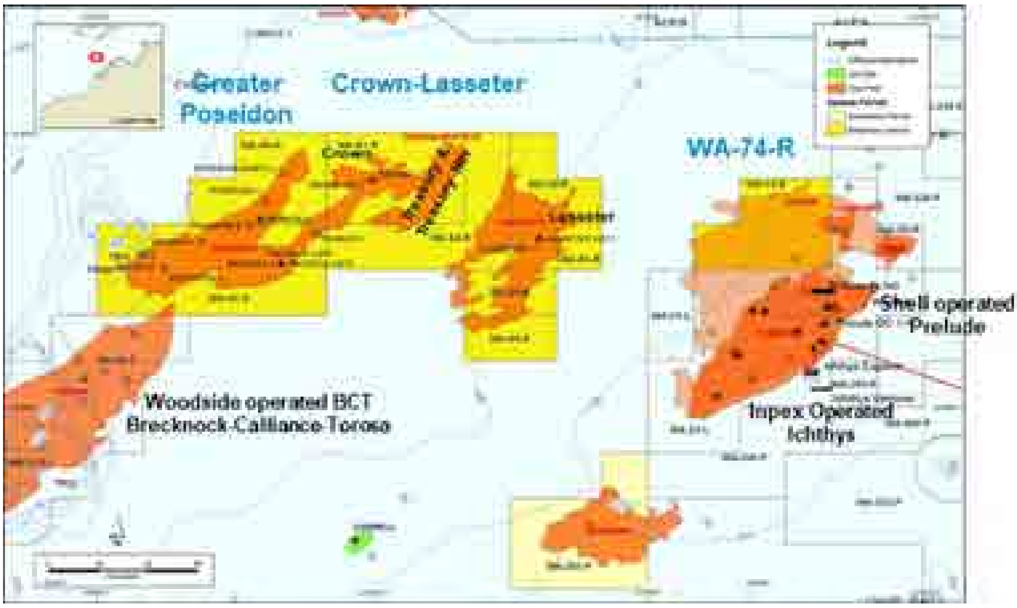
Source: Santos

Santos' 2022 – 2026 exploration in offshore Norther Australia includes Vulcan sub-basing Stairway 1 Well and PTF Hub Breakwater 3D seismic.

5.5.10.1 Browse Hub

The Browse Hub area holds discovered resources which include the Greater Poseidon and the Crown and Lasseter Fields which are both operated by Santos (**Figure 5.100**).

Figure 5.100: Location Map of the Browse Hub Assets



Source: Santos

5.5.10.1.1 Greater Poseidon

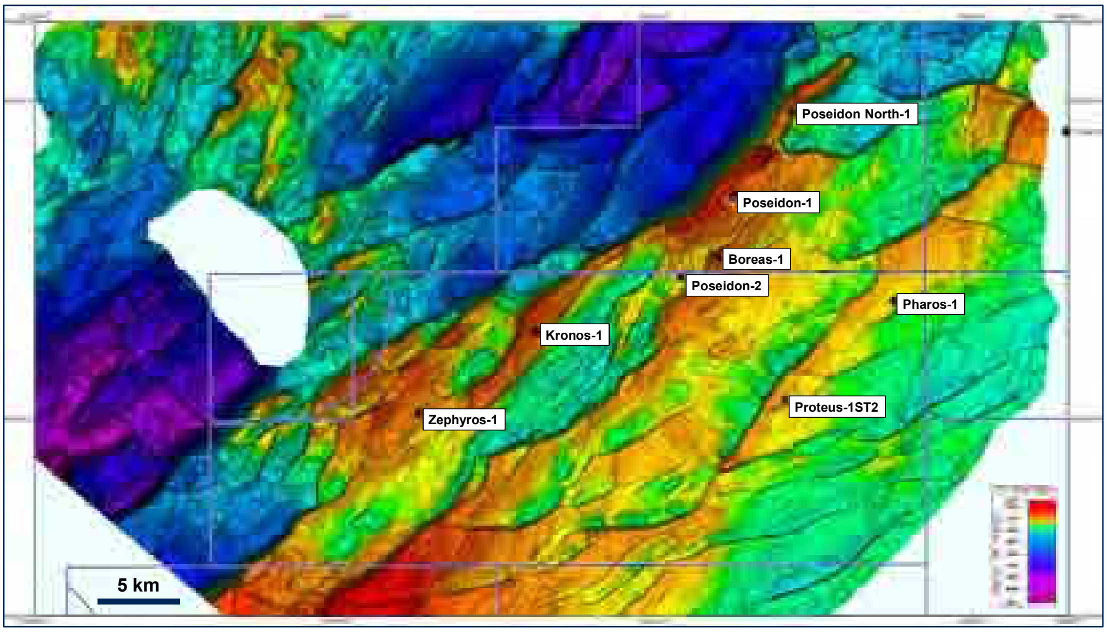
Santos acquired the Greater Poseidon blocks from ConocoPhillips in May 2020 (**Table 5.50**). The blocks include 6 discoveries in 5 retention leases which are currently in year 2 of the permit and which lie within the Browse Basin approximately 950 km ESE of Darwin. The WA-90-R, WA-91-R and WA-92-R blocks lie in Commonwealth waters while the TR/7 and TR/8 blocks lie in WA state waters. A total of 8 exploration and appraisal wells have been drilled to date with no dry holes.

Table 5.50: Greater Poseidon Blocks

Lease	Permit Expiry	Renewal Submission	Santos WI	Origin WI	PetroChina WI
WA-90-R	02-Mar-25	03-Sep-24	40%	40%	20%
WA-91-R	02-Mar-25	03-Sep-24	40%	40%	20%
WA-92-R	02-Mar-25	03-Sep-24	40%	40%	20%
TR/7	02-Mar-25	03-Sep-24	40%	40%	20%
TR/8	02-Mar-25	03-Sep-24	40%	40%	20%

The Greater Poseidon discoveries include Poseidon and Poseidon North as well as Kronos, Boreas, Zephyros, Proteus and Pharos (**Figure 5.101**). The discoveries are a complex series of faulted structures within a half graben rift system. The individual fields are controlled by different fault terraces and have different structural spill points. As a result, it is likely the fields have different GWCs. Despite the structural complexity, individual structures are reasonably well defined by 3D seismic data. The reservoirs are formed of Early Jurassic Lower Plover Formation and late Jurassic Lower Vulcan Montara Formation.

Figure 5.101: Lower Plover Depth Map of the Greater Poseidon Discoveries



Source: Santos

Santos' current reference case field development plan includes a two-phase subsea development with a single FPSO. Phase 1 includes the development of the Proteus-Pharos area with 4 wells and the Poseidon area with 3 wells. Phase 2 includes the development of Kronos with 2 wells and Zephyros with 2-4 wells. Gas will be exported via a 100 km tie-back to the Ichthys pipeline and then on to Ichthys LNG in Darwin where ullage is available from early 2030's.

5.5.10.1.2 Crown-Lasseter

The Crown-Lasseter blocks include 2 gas condensate discoveries in 6 retention leases (**Table 5.51**) and lie within the Browse Basin approximately 480 km NNE of Broome.

Table 5.51: Crown-Lasseter Blocks

Lease	Permit Expiry	Renewal Submission	Santos WI	Inpex WI	Beach WI
WA-79-R	20-Sep-22	24-Mar-22	60.0%	40.0%	0.0%
WA-80-R	20-Sep-22	24-Mar-22	63.6299%	26.6064%	9.7637%
WA-81-R	20-Sep-22	24-Mar-22	60.0%	40.0%	0.0%
WA-84-R	19-Dec-22	22-Jun-22	60.0%	40.0%	0.0%
WA-85-R	19-Dec-22	22-Jun-22	60.0%	40.0%	0.0%
WA-86-R	19-Dec-22	22-Jun-22	60.0%	40.0%	0.0%

The Crown-1 well was drilled in 2012 in water depths of 440 m. Wireline logging shows 61 m of net gas pay in the Jurassic aged Montara, Plover and Malita reservoirs. The Lasseter-1 well was drilled in 2014 in water depths of 404 m and intersected 78 m of net pay within the Jurassic aged Lower Vulcan and Plover intervals.

5.5.10.1.3 Other Discoveries

Other discoveries which Santos holds interests in within the Browse Hub include Burnside, Argus, Concerto Extension and Ichthys North (SA-74-R). No details of these discoveries were provided.

5.5.10.1.4 Near-Field Exploration

Santos also holds an inventory of near-field exploration prospects within the Browse Hub which includes Treasury, Treasury North, Grand and Crown West. None of the prospects appear in Santos' 2022-2026 exploration program.

5.5.10.1.5 Browse Hub Resource Estimate

Due to the limited data set provided for the Browse Hub assets, GaffneyCline has not reviewed Santos' resource estimates in detail and has accepted the provided volumes.

5.5.10.2 Barossa Hub

The Barossa Hub includes the NT/P82 Block which was recently granted renewal with a work program to include G&G studies which will include seismic reprocessing. The block contains the Anglianico Prospect however this is not part of Santos' 2022-2026 exploration program (**Figure 5.102**).

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Figure 5.102: Santos' Barossa Hub Assets

Source: Santos

5.5.10.3 Vulcan Sub-basin

Santos holds interests in five newly acquired permits which target an emerging Triassic oil play which will be tested with the drilling of the Stairway-1 well planned for 2022 (**Figure 5.103**).

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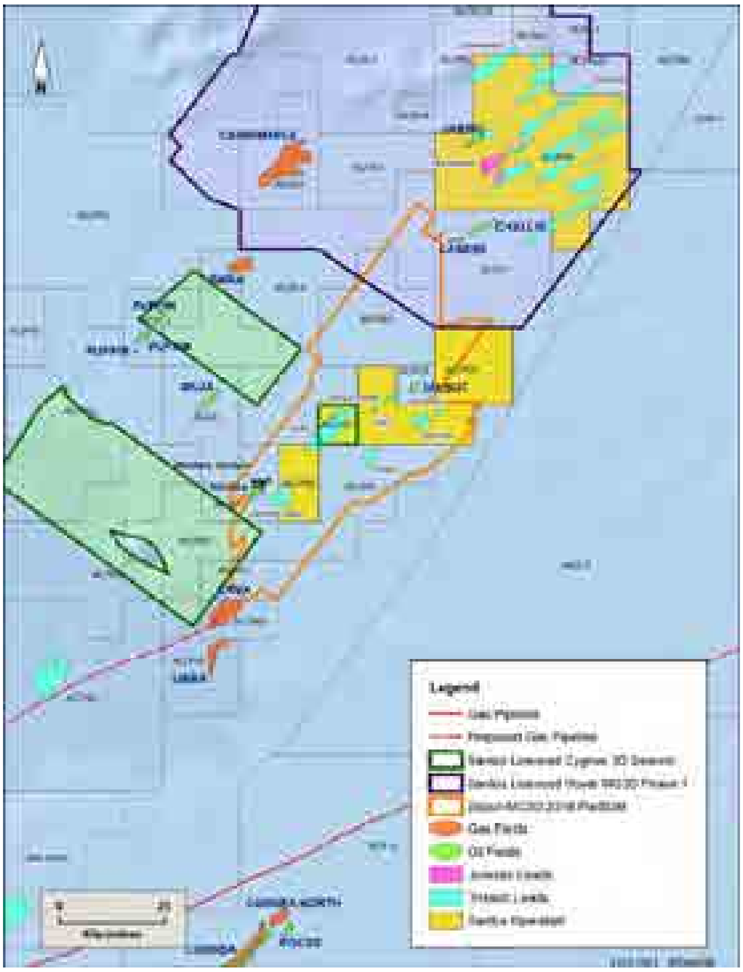
Figure 5.103: Santos' Vulcan Sub-basin Assets



Source: Santos

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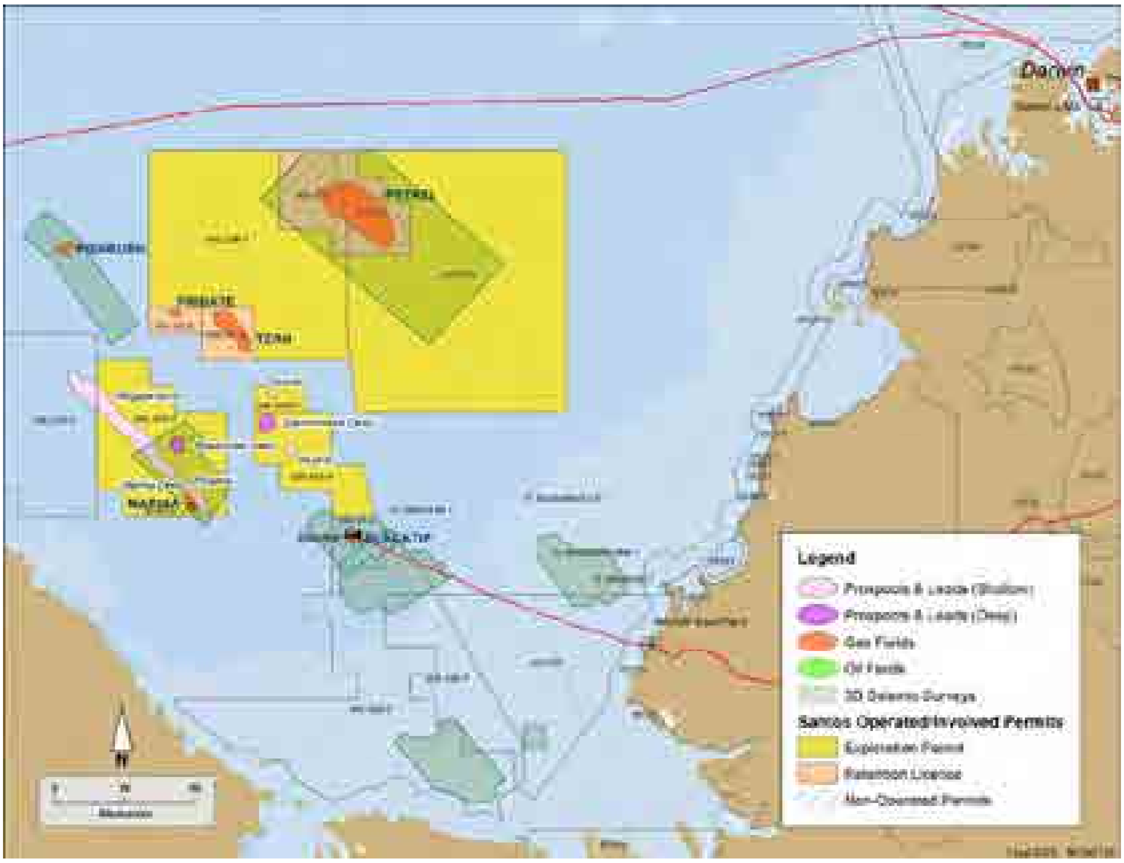
5.5.10.4 PTF Hub

The PTF Hub includes three recently acquired permits in the Petrel Sub-basin with minimal work obligations plus the WA-454-P Block which contains the Breakwater Prospect which together with the Sparrowhawk Prospect could be aggregated into the Petrel and Tern developments (**Figure 5.104**).

Figure 5.104: Santos' Vulcan PTF Hub Assets



Source: Santos

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5.5.11 Valuation of Additional Norther Australia Assets - Browse Hub: Greater Poseidon, Crown and Lasseter

Santos has identified various development concepts for Greater Poseidon that depend on backfill options to either Barossa, Ichthys or Prelude, both with and without co-development of the neighbouring Crown and Lasseter fields. In all development cases, there is significant uncertainty on timing, costs, and potential commercial arrangements with other operators. The anticipated field development dates for these scenarios are significantly far into the future with likely development in late 2030s and early 2040s. None of the development scenarios are sufficiently defined to be considered an economic project at this stage.

Notably, with offshore gas CO_2 concentrations for these assets in the range of 11% to 17% with an average of 13.4%, capital expenditures will likely increase in the future as required CO_2 abatement will also be needed to align with Santos' net zero strategy. The growing environmental scrutiny for high CO_2 developments provides additional risk. Considering the uncertainties in development it is not appropriate to value these assets using an income approach.

Santos commissioned and provided an independent certification of Greater Poseidon's "Fair Market Value" (FMV) by an independent party dated June 1, 2020.

GaffneyCline's approach is based on data provided in the same independent report to derive an estimate with public domain cross-checks. The document cites transaction multiples of 0.06 US$/mcfe.

Based on this transaction multiple and eliminating non-viable smaller discovered resources, the GaffneyCline recommended evaluation is shown in **Table 5.52**. This is further supported by comparison to the Santos Barossa FID with appropriate risk for time and chance of development. Individual discovery values are not included due to commercial sensitivity.

Table 5.52: GaffneyCline Proposed Valuation Case

Asset	Net Santos 2C (MMboe)	Multiple (US$/boe)	Value (US$ MM)
Aggregated Total	**303.5**	0.36	**109**

GaffneyCline therefore recommends a valuation range of **US$109 MM** to **US$226 MM** for the Browse Hub discovered resources for Grant Samuel's consideration. GaffneyCline considers the independent based Santos value as a Stretch view of comparable transactions. Detail regarding valuation assumptions has been removed due to commercial sensitivity.

5.6 Santos' PNG LNG

Santos' business in PNG also includes a share of the PNG LNG project with Oil Search as a JV partner. Santos has a 13.5321% interest in PNG LNG. As discussed, the LNG plant produced a record 8.8 million tonnes of LNG in 2020. Annual LNG production was higher than the previous year (8.5 million tonnes) due to high plant uptime and throughput. Santos' strategy in PNG is to work with its partners to align interests, and support and participate in backfill and expansion opportunities at PNG LNG. PNG LNG Net Santos' 2020 production was 13.2 MMboe with a sales volume 12.5 MMboe. The LNG plant produced 4.1 million tonnes in the first half of 2021, 6% lower than the prior corresponding period due to planned maintenance and shipped 52 cargoes (2020 first half 57 cargoes). Net Santos H1 2021 production was 6.1 MMboe and a Sales Volume of 5.8 MMboe.

GaffneyCline has provided one set of forecasts to Grant Samuel based on updated volumes for the foundation PNG LNG project. Santos provided geological and dynamic digital models to opine on the volumes and compare with other operator and partner models received. Additional reconciliation was also carried out with other 3rd party auditors. This process has been discussed in detail in the Oil Search section of this report.

5.7 Santos' Amadeus, McArthur and South Nicholson Exploration Assets

5.7.1 Amadeus Basin Exploration

The Amadeus Basin is a large, intracratonic basin in central Australia which lies primarily in the south of the Northern Territory but also extends into eastern Western Australia. In 2012, Santos farmed-in to a number of blocks in the Amadeus Basin through a deal with Central Petroleum Group (Central). A location map of the blocks is given in **Figure 5.105**. Santos has recently executed a binding Term Sheet to farm-down some interests to Peak Helium. Santos' working interest is shown in **Table 5.53.**

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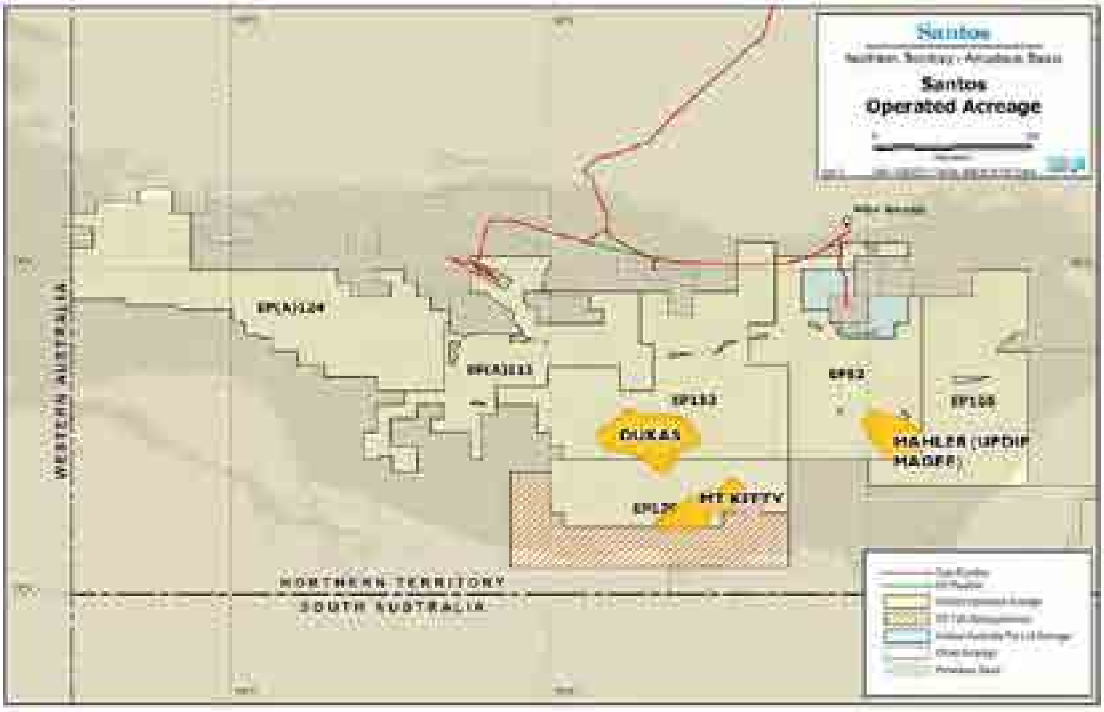
Figure 5.105: Santos' Amadeus Basin Blocks



Source: Santos

Table 5.53: Santos' Working Interests in Amadeus Basin Exploration Blocks

Permit	Santos WI	Central WI
EP 82	40%	60%
EP 105	40%	60%
EP 112	55%	45%
EP 125	70%	30%
EP(A) 111[i]	50%	50%
EP(A) 124[i]	50%	50%

Note: Permit not yet awarded (under application)

The primary exploration objective is the Heavitree Formation which lies beneath a thick, regional evaporite seal. Prior to Santos' entry in 2012, only the Magee-1 well had tested the sub-salt play. This flowed low-rate gas including helium and to a lesser extent, naturally occurring hydrogen.

In 2014, the Mt Kitty-1 well tested a large sub-salt structure. The Heavitree Formation was not present but the well flowed low-rate gas, including helium and hydrogen from fractured granitic basement. In 2019, the Dukas-1ST1 well was drilled to test a large sub-salt structure. The well was suspended prior to reaching the target reservoir after pressures approaching system limits were encountered.

Due to the lack of detailed data available, GaffneyCline does not believe the Amadeus permits are sufficiently mature to add value.

5.7.2 McArthur Exploration

Santos holds a 75% WI in EP 161 in the Beetaloo Sub-basin of the McArthur Basin (**Figure 5.106**). The Beetaloo Sub-basin lies approximately 600 km south of Darwin and covers 28,000 km^2. It contains two intervals, the Kyalla and the middle Velkerri Formations of the Roper Group which are some of the oldest proven hydrocarbon source rocks in Australia. Both contain favourable properties for the generation of shale gas including mineralogy, organic chemistry and maturity. In the Beetaloo Sub-basin, gross thickness of the Velkerri Formation has been recorded at 270 m and the Kyalla Formation at over 900 m. Net thicknesses of each interval range between 75-125 m.

In 2019 Santos conducted a successful four stage fracture stimulation of the Velkerri Shale in the Tanumbirini-1 well which had been drilled in the EP 161 block in 2014. Production testing and gas flow rates were above initial expectations for the vertical well with an initial peak gas rate of ~10 MMscfd and an average rate of 2.3 MMscfd over the first 90 hours of testing.

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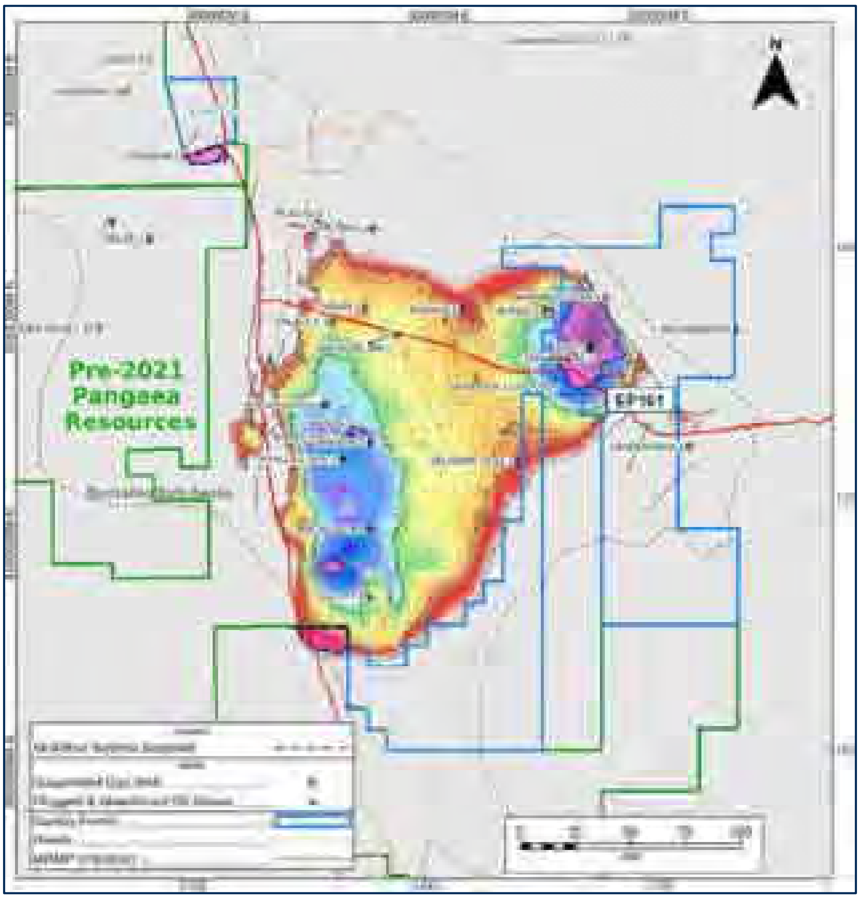
Figure 5.106: Velkerri A Shale Depth Map



Source: Santos

Due to the lack of detailed data provided, GaffneyCline believes there is insufficient information to use a cash flow approach. GaffneyCline valuation is discussed in **Section 5.8**.

5.7.3 South Nicholson Exploration

In February 2021, Santos acquired a 100% interest in the South Nicholson Basin exploration project onshore in the Northern Territory and Queensland after completing a deal with Armour Energy. The project covers the 906 km^2 ATP (A) 1087 block. Santos also holds 100% interest in the rights to application blocks ATP 1192, ATP 1193, ATP 172 and EP 177 (**Figure 5.107**).

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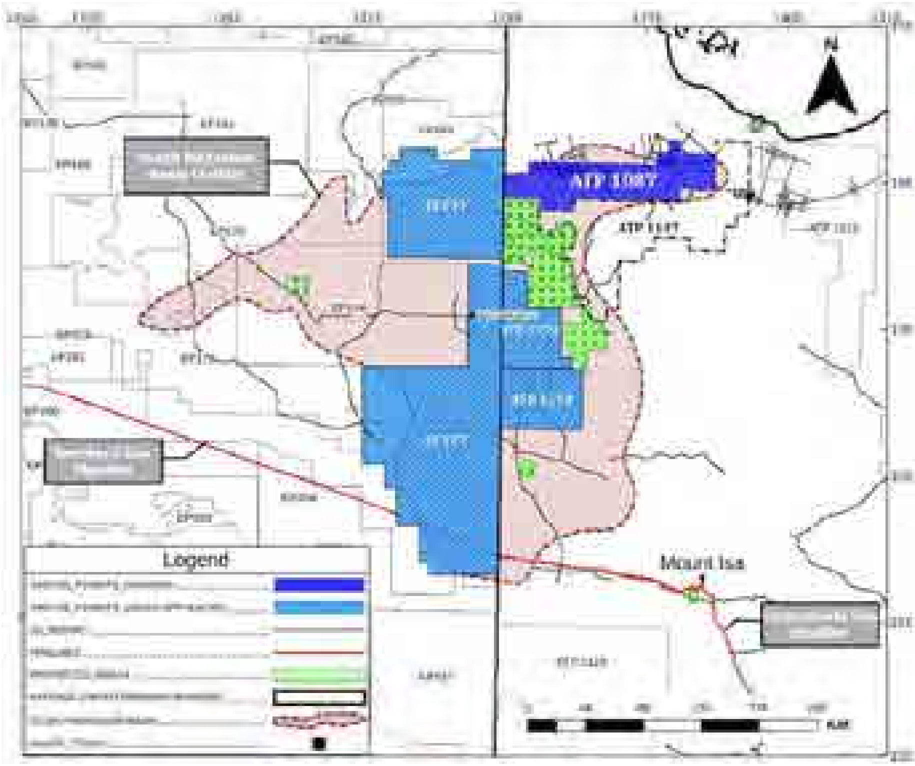
The South Nicholson Basin is a large basin approximately the size of Tasmania. The blocks are potentially prospective for unconventional shale gas however currently there is limited geological understanding of the basin. Santos does not have any wells planned for the South Nicholson Basin in the short term and as such GaffneyCline has not reviewed it in any detail.

Figure 5.107: Santos' South Nicholson Basin Blocks



Due to the lack of detailed data provided, GaffneyCline believes there is insufficient information to use a cash flow approach. GaffneyCline's valuation is discussed in **Section 5.8**.

5.8 Santos Exploration Valuation

GaffneyCline divided Santos' exploration assets into four main categories based on the business areas and similarity of risks. These are Onshore New Ventures, PNG, Australian Offshore Exploration, and Cooper Basin Near Field Exploration (NFE).

5.8.1 Onshore New Ventures

GaffneyCline reviewed unconventional onshore exploration areas in Australia that are not yet commercially viable but are being actively pursued by Santos in its exploration program for the next five years. These areas are the South Nicholson Basin permits, McArthur Basin permits, Bowen Basin tight gas, and the Deep Coal and Moomba Granite Wash plays in the Cooper Basin.

Due to the early exploration nature of these basins and plays and the remote nature of the assets, there are considerable risks and uncertainties related to any potential development programs for these areas. Therefore, it is not recommended to value these assets using an income approach.

Exploration sunk costs for these assets are currently being incurred, resulting in a de-risking of resources. Total cost incurred to date is US$189 MM. These exploration plays are promising but still in an early stage of exploration. In GaffneyCline's opinion, cost spent on these assets is a reasonable reflection of the asset value. GaffneyCline has therefore considered the onshore assets as a portfolio and has aggregated them for valuation due to similar issues regarding standalone commercial production. GaffneyCline does not consider the mixing of valuation methodologies (sunk cost with market multiple US $/boe) for individual areas appropriate and treats the portfolio as a whole using a cost-based approach.

In valuing an exploration portfolio, it is important to consider that exploration is undertaken in campaigns followed by periods of analysis. Thus, various assets within the portfolio will be at various/unequal stages of maturity. When viewed as a portfolio, GaffneyCline considers it appropriate to aggregate the valuations to account for these effects over a reasonable period of time as each of the assets is matured. A market multiple basis valuation for the assets has been reviewed. After consideration of the transactions, GaffneyCline opined that the market multiple basis is not directly comparable and more aligned with a stretch/upside view. Accordingly, GaffneyCline has accepted and used a comparable transaction view of these asset values as a Stretch Case scenario.

GaffneyCline recommends a value range **of US$189 MM** in the Base Case (sunk costs) to **US$378 MM** in the Stretch Case (market multiple approach) and that the assets are valued on a portfolio basis without the need for mixing of methodologies.

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5.8.2 PNG

Santos has identified two EMV positive exploration targets, the Hides FW and Karoma prospects. Both align with Oil Search's exploration drilling plans. These exploration prospects are evaluated using an EMV10 methodology which is consistent with GaffneyCline's view of Oil Search's PNG exploration inventory with an appropriate adjustment for Santos' equity.

The cost spent on the permits based on the exploration wells drilled by Oil Search results in a proportional cost spend by Santos of US$53 MM. The GaffneyCline calculated EMV10 values are within range of the sunk costs for these assets supporting the approach utilised. GaffneyCline considers the EMV10 approach to be a good basis for the Base Case valuation. This is summarised in **Table 5.54**.

Santos proposed an EMV10 value of US$145 MM for the Hides FW. No EMV was provided for the Karoma prospect. Santos' evaluation could be considered a Stretch Case for valuation. GaffneyCline could not identify suitable market comparable for these prospects.

GaffneyCline recommends a value range of **US$51 MM** to **US$145 MM** for Santos' PNG exploration assets.

Table 5.54: GaffneyCline's EMV10 Valuation of Santos' PNG Assets

Prospect	Drilling Plan	Net Unrisked Prospective Resources (MMboe)	Net NPV Unrisked 10% (US$MM)	Net NPV Failure (US$MM)	Chance of Success (%)	Net EMV 10% (US$MM)
Hides FW	2024	19	111	-6	45	47
Karoma	2025	55	37	-13	34	4
Total	-	-	-	-	-	**51**

Note: 'Chance of Success' calculated as 'Geological Chance of Success' x 'Chance of Development'

5.8.3 Offshore Exploration

Santos has a large inventory of exploration leads and prospects offshore. GaffneyCline has reviewed the exploration targets provided they are sufficiently mature and included by Santos in their five-year drilling program. Santos EMV10 for Santos' offshore assets with positive EMV10s was utilised excluding Baxter of which GaffneyCline independently estimated the Baxter EMV10. Based on EMV10 a value of US$722 MM is derived.

Santos proposed a comparable transaction using a market multiple basis valuation for its offshore exploration portfolio which provides a value of US$563 MM. GaffneyCline has accepted Santos' view of offshore asset values as an alternate case using the market approach based on the transactions reviewed. GaffneyCline does not consider a sunk cost approach appropriate for Western Australia offshore due to the area's exploration history and discoveries to date.

GaffneyCline has considered the value range of **US$563 MM** to **US$722 MM** for Santos' offshore exploration assets; however, **a US$722 MM** Base Case value is recommended for these assets due to the exploration history of the area and the excellent discoveries to date.

5.8.4 Cooper Basin Near Field Exploration (NFE)

The Cooper Basin is a mature basin where Santos' short-term focus is on Near Field Exploration. On average 12 exploration wells per year were drilled by Santos during 2018 to 2021. Santos provided an EMV10 value of US$ 20.3 MM for twelve prospects in the 2022 drilling program with a net risked resource volume of 2.7 MMboe. For valuation purposes, GaffneyCline accepted Santos' plan that this rate of exploration activity will be continued until the current available Cooper NFE opportunities with a prospective risked resource size of 32 MMboe (99 MMboe unrisked), is exhausted. GaffneyCline assumed an EMV10 value of US$20.3 MM with 2% p.a. escalation for each successive year for a period of 12 years. This EMV10 value generation is discounted at 10% to calculate the EMV10 of the full hopper of the Cooper NFE. Based on these assumptions the GaffneyCline estimated value for the Cooper NFE is US$151 MM. GaffneyCline accepted the Santos volumes as being reasonable based on a comparison to the producing assets.

Santos' proposed market multiple basis valuation for Cooper NFE is US$ 271 MM. GaffneyCline has accepted Santos' view of these asset values as a Stretch Case using the market approach after consideration of the transactions provided. Note that this excludes Granite Wash and Deep Coal.

GaffneyCline recommends a value range **of US$151 MM** to **US$271 MM** for the Cooper NFE.

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Appendix I
Glossary

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October 2021

GLOSSARY
List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design

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FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GDT	Gas Down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)

Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OBO	Operated by Others
OCM	Operating Committee Meeting
ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
PI	Productivity Index
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)

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AI.3

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Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
USGS	United States Geological Survey
US$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
1H05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage

Appendix II
Abbreviated 2018 SPE PRMS Definitions and Guidelines

Grant Samuel & Associates Pty. Limited
October 2021

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([3])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

[3] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

Class/Sub-Class	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

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Class/Sub-Class	Definition	Guidelines
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

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Table 2—Reserves Status Definitions and Guidelines

Status	Definition	**Guidelines**
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

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Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

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Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

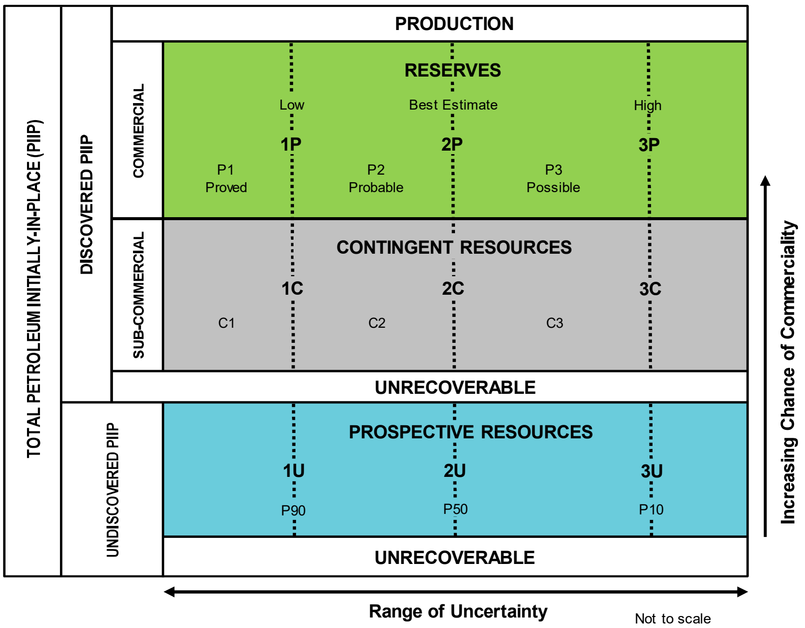
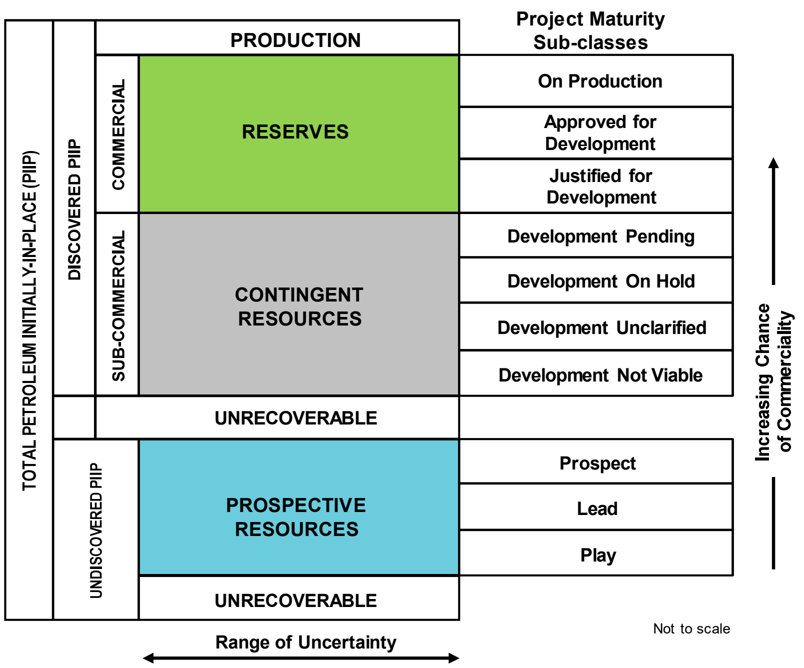


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



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October 2021

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Appendix III
Oil Search's Documented Development Licence Interests as of 31 January 2021

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Licence	Field/Project	Oil Search Interest %	Operator
PNG Petroleum Development Licences (PDL)			
PDL 1	Hides	16.66	ExxonMobil
PDL 2	Kutubu, Moran	60.05	Oil Search
PDL 2 - SE Mananda JV	SE Mananda	72.27	Oil Search
PDL 3	SE Gobe	36.36	Santos
PDL 4	Gobe Main, SE Gobe	10.00	Oil Search
PDL 5	Moran	40.69	ExxonMobil
PDL 6	Moran	71.07	Oil Search
SE Gobe Unit (PDL 3/PDL 4)		22.34	Oil Search
Moran Unit (PDL 2/PDL 5/PDL 6)		49.51	Oil Search
Hides Gas to Electricity Project (PDL 1)		100.00	Oil Search
PDL 7	South Hides	40.69	ExxonMobil
PDL 8	Angore	40.69	ExxonMobil
PDL 9	Juha	24.42	ExxonMobil
APDL13	P'nyang	38.51[1]	ExxonMobil
PNG LNG Project	**PNG LNG Project**	**29.00**	**ExxonMobil**
PNG Pipeline Licences (PL)			
PL 1	Hides	100.00	Oil Search
PL 2	Kutubu	60.05	Oil Search
PL 3	Gobe	17.78	Oil Search
PL 4	PNG LNG Project	29.00	ExxonMobil
PL 5	PNG LNG Project	29.00	ExxonMobil
PL 6	PNG LNG Project	29.00	ExxonMobil
PL 7	PNG LNG Project	29.00	ExxonMobil
PL 8	PNG LNG Project	29.00	ExxonMobil
PNG Petroleum Processing Facility Licence			
PPFL 2	PNG LNG Project	29.00	ExxonMobil

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Appendix IV
Documented JVs in which Santos carries Reserves/Resources as of 31 December 2020

JV Licence	Asset Group	Santos Net Share
Bonaparte Basin		
NT/L 1 (Barossa)	Northern Australia	62.50%
NT/RL 6 (Caldita)	Northern Australia	62.50%
WA-6-R (Petrel)	Northern Australia	40.25%
WA-27-R (Tern)	Northern Australia	100.00%
WA-40-R (Frigate)	Northern Australia	100.00%
Bowen & Surat Basins		
ATP 336P (Roma Conventional)	QLD - GLNG	30.00%
ATP 336P (Roma)	QLD - GLNG	30.00%
ATP 526P (Arcadia)	QLD - GLNG	22.82%
ATP 526P (Comet Ridge North)	QLD - GLNG	22.82%
ATP 526P (Fairview Early Permian)	QLD - GLNG	22.82%
ATP 526P (Fairview)	QLD - GLNG	22.82%
ATP 592P (Spring Gully)	QLD - Other	4.00%
ATP 606P (Combabula)	QLD - Other	7.28%
ATP 631P (Roma)	QLD - GLNG	22.91%
ATP 653P (Arcadia)	QLD - GLNG	22.85%
ATP 685P (Tardrum, Yoorooga East, Scotia North)	QLD - Other	100.00%
ATP 701P (Spring Gully)	QLD - Other	0.20%
ATP 708P (Roma)	QLD - GLNG	30.00%
ATP 745P (Bundaburra)	QLD - GLNG	22.85%
ATP 803P (Bridge Creek)	QLD - GLNG	30.00%
ATP 868P (Wandoan)	QLD - GLNG	30.00%
ATP 889P (Roma)	QLD - GLNG	30.00%
ATP 972P (Ramyard)	QLD - Other	7.28%
ATP 1187 (Roma)	QLD - GLNG	30.00%
ATP 1191 (Denison)	QLD - Other	50.00%
ATP 2033 (Arcadia)	QLD - GLNG	22.85%
ATP 2052 (Roma)	QLD - GLNG	30.00%
ATP 2053 (Roma)	QLD - GLNG	30.00%
ATP 2054 (Roma)	QLD - Other	100.00%
ATP 2055 (Roma)	QLD - Other	100.00%
Mahalo	QLD - GLNG	30.00%
PL 176 (Scotia)	QLD - GLNG	30.00%
PL 200 (Durham South)	QLD - Other	2.68%

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Browse Basin		
WA-74-R (Ichthys, Luxor)	Northern Australia	30.00%
WA-79-R (Lasseter)	Northern Australia	30.00%
WA-80-R (Lasseter)	Northern Australia	47.83%
WA-81-R (Crown)	Northern Australia	30.00%
WA-84-R (Lasseter)	Northern Australia	60.00%
WA-85-R (Lasseter)	Northern Australia	60.00%
WA-90-R (Poseidon)	Northern Australia	40.00%
WA-92-R (Kronos, Pharos/Proteus, Zephyros)	Northern Australia	40.00%
WA-281-P (Burnside)	Northern Australia	70.50%
Canning Basin		
WA-435-P (Phoenix South)	Western Australia	80.00%
WA-437-P (Dorado, Roc)	Western Australia	80.00%
Carnarvon Basin		
Barrow Island JV	Western Australia	28.57%
Davis	Western Australia	100.00%
Harriet JV	Western Australia	100.00%
John Brookes	Western Australia	100.00%
Maitland	Western Australia	100.00%
Spar/Halyard	Western Australia	100.00%
Spartan	Western Australia	100.00%
TL/1 (Denver, Ginger)	Western Australia	100.00%
WA-35-L & WA-55-L (Coniston Novara, Van Gogh)	Western Australia	52.50%
WA-41-L (Reindeer)	Western Australia	100.00%
WA-42-L (Macedon, Pyrenees)	Western Australia	28.57%
WA-43-L (Pyrenees)	Western Australia	31.50%
WA-45-L (Spar Deep)	Western Australia	100.00%
WA-45-R (Corvus)	Western Australia	100.00%
WA-49-R (Antiope, Bianchi, Zola)	Western Australia	77.78%
WA-55-R (Kultarr)	Western Australia	100.00%
Cooper & Eromanga Basins		
50/40/10 (Munro)	Cooper	60.00%
Aquitaine B	Cooper	55.00%
Aquitaine C (Marengo)	Cooper	47.80%
ATP 752P (Barta)	Cooper	54.64%
ATP 752P (Wompi)	Cooper	44.42%
Derrilyn	Cooper	65.00%

FFA	Cooper	66.60%
Innamincka	Cooper	70.00%
Naccowlah	Cooper	55.50%
Nockatunga	Cooper	100.00%
Patchawarra East	Cooper	72.32%
PEL 114 (JALBU Flank)	Cooper	100.00%
PEL 570 (Washington)	Cooper	52.50%
Southwestern Joint Venture	Cooper	60.00%
SWQ Unit	Cooper	60.06%
Tintaburra	Cooper	60.00%
Total 66	Cooper	70.00%
Wareena	Cooper	61.20%
YFJ (Yarrow, Flax, Juniper)	Cooper	80.00%
Gunnedah Basin		
PEL 1 (Bando)	NSW	65.00%
PEL 12 (Bando)	NSW	65.00%
PEL 238 (Coonarah, Narrabri)	NSW	80.00%
PEL 452 (Bando)	NSW	100.00%
PEL 456 (Brawboy)	NSW	15.00%
McArthur Basin		
EP 161 (Tanumbirini)	NT Onshore	75.00%
Timor Basin		
Bayu Undan Unit	Northern Australia	65.98%
JPDA 03-12 (Firebird)	Northern Australia	21.43%
PNG – Papuan Foldbelt		
PDL 1 (Hides)	Papua New Guinea	24.03%
PDL 3 (Gascap)	Papua New Guinea	7.45%
PDL 3 (SE Gobe Unit)	Papua New Guinea	7.45%
PNG LNG	Papua New Guinea	13.53%
PPL 402 (Muruk A)	Papua New Guinea	11.96%
PPL 402 (Muruk B)	Papua New Guinea	10.06%

Note: GaffneyCline has not verified the veracity of this information but has accepted it as provided by Santos.

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10 November 2021

The Board of Directors
Oil Search Limited
1 Bligh Street
Sydney NSW 2000

The Board of Directors
Santos Limited
60 Flinders Street
Adelaide SA 5000

Dear Directors

Independent Limited Assurance Report on the pro forma historical statement of financial position

1. Introduction

We have been engaged by Oil Search Limited ("Oil Search") and Santos Limited ("Santos") (collectively the "Merged Group") to report on the pro forma historical statement of financial position as at 30 June 2021 of the Merged Group for inclusion in the scheme booklet to be dated on or about 10 November 2021 (the "Scheme Booklet") and issued by Oil Search, in respect of the proposal from Santos to acquire all of the shares in Oil Search by way of a scheme of arrangement under Part XVI of the Companies Act 1997 (PNG) between Oil Search Limited and its shareholders (the "Scheme"). Expressions and terms defined in the Scheme Booklet have the same meaning in this report.

2. Scope

Pro Forma Historical Statement of Financial Position

You have requested Ernst & Young to review the following financial information of the Merged Group consisting of:

- the pro forma historical consolidated statement of financial position as at 30 June 2021 as set out in Section 6.8 (d) of the Scheme Booklet.

(Hereafter the "Pro Forma Historical Statement of Financial Position").

The Pro Forma Historical Statement of Financial Position has been derived from the Santos historical consolidated statement of financial position as at 30 June 2021 as referenced in section 5.11 of the Scheme Booklet and adjusted for the effects of the pro forma adjustments described in 6.8 (b) of the Scheme Booklet.

The historical consolidated statement of financial position of Santos has been prepared in accordance with the significant accounting policies described in the interim consolidated financial statements of Santos for the half financial year ended 30 June 2021.

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The historical consolidated statement of financial position of Santos as at 30 June 2021 was derived from the interim consolidated financial statements of Santos for the half year ended 30 June 2021, which were reviewed by Ernst & Young in accordance with Australian Auditing Standards and issued an unqualified review conclusion on these interim consolidated financial statements.

The Pro Forma Historical Statement of Financial Position has been prepared in accordance with the stated basis of preparation, being the recognition and measurement principles contained in Australian Accounting Standards other than that it includes adjustments which have been prepared in a manner consistent with Australian Accounting Standards, that reflect the impact of certain transactions as if they occurred as at 30 June 2021 in the Pro-Forma Historical Statement of Financial Position.

Due to its nature, the Pro Forma Historical Statement of Financial Position does not represent Santos's actual or prospective financial position.

The Pro Forma Historical Statement of Financial Position is presented in the Scheme Booklet in an abbreviated form, insofar as it does not include all of the presentation and disclosures required by Australian Accounting Standards and other mandatory professional reporting requirements applicable to general purpose financial reports prepared in accordance with the *Corporations Act 2001*.

3. Directors' Responsibility

The directors of Santos (the "Directors") are responsible for the preparation and presentation of the Pro Forma Historical Financial Information, including the basis of preparation, selection and determination of pro forma adjustments made to the Santos historical consolidated statement of financial position and included in the Pro Forma Historical Statement of Financial Position. This includes responsibility for such internal controls as the Directors determine are necessary to enable the preparation of the Pro Forma Historical Statement of Financial Position that are free from material misstatement, whether due to fraud or error.

4. Our Responsibility

Our responsibility is to express a limited assurance conclusion on the Pro Forma Historical Statement of Financial Position based on the procedures performed and the evidence we have obtained.

We have conducted our engagement in accordance with the Standard on Assurance Engagements ASAE 3450 *Assurance Engagements involving Corporate Fundraisings and/or Prospective Financial Information*.

Our limited assurance procedures consisted of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other limited assurance procedures. A limited assurance engagement is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain reasonable assurance that we would become aware of all significant matters that might be identified in a reasonable assurance engagement. Accordingly, we do not express an audit opinion.

Our engagement did not involve updating or re-issuing any previously issued audit or limited assurance reports on any financial information used as a source of the Pro Forma Historical Statement of Financial Position.

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5. Conclusions

Pro Forma Historical Statement of Financial Position

Based on our limited assurance engagement, which is not an audit, nothing has come to our attention that causes us to believe that the financial information of the Merged Group comprising:

- the pro forma historical consolidated statement of financial position as at 30 June 2021 as set out in Section 6.8 (d) of the Scheme Booklet,

is not presented fairly, in all material respects, in accordance with the stated basis of preparation, as described in Section 6.8 (a) of the Scheme Booklet.

6. Restriction on Use

Without modifying our conclusions, we draw attention to Section 6.8 of the Scheme Booklet, which describes the purpose of the Pro Forma Historical Statement of Financial Position. As a result, the Pro Forma Historical Statement of Financial Position may not be suitable for use for another purpose.

7. Consent

Ernst & Young has consented to the inclusion of this limited assurance report in the Scheme Booklet in the form and context in which it is included.

8. Independence or Disclosure of Interest

Ernst & Young does not have any interests in the outcome of the Scheme other than in the preparation of this report for which normal professional fees will be received.

Yours faithfully

Ernst & Young

Ernst & Young

Scheme of Arrangement pursuant to section 250(1) of the *Companies Act 1997* (PNG)

Between

Oil Search Limited (ARBN 055 079 868) of Ground Floor, Harbourside East Building, Stanley Esplanade, Port Moresby, Papua New Guinea (***OSH***).

And

Each Scheme Shareholder.

Recitals

A OSH is a public company limited by shares, incorporated in Papua New Guinea. OSH Shares are quoted for trading on the ASX and PNGX.

B STO is a company incorporated in South Australia, Australia (***STO***). STO Shares are quoted for trading on the ASX.

C OSH and STO have entered into a Merger Implementation Deed dated 10 September 2021 (the ***Merger Implementation Deed***) pursuant to which STO and OSH have agreed to combine in an all scrip merger pursuant to the Scheme (***Merger***) and:

(a) OSH has agreed to propose the Scheme to OSH Shareholders; and

(b) OSH and STO have agreed to take certain steps to give effect to this Merger.

D If this Scheme becomes Effective, then:

(c) all of the Scheme Shares and all of the rights and entitlements attaching to them on the Implementation Date will be transferred to STO; and

(d) the Scheme Consideration will be provided to the Scheme Shareholders in accordance with the terms of this Scheme and the Deed Poll; and

(e) OSH will enter the name and address of STO or its nominee in the OSH Register as the holder of all of the Scheme Shares.

E By executing the Merger Implementation Deed, OSH has agreed to propose and implement this Scheme, and STO has agreed to assist with that proposal and implementation, on and subject to the terms of the Merger Implementation Deed.

F The Scheme attributes actions to STO but does not itself impose an obligation on it to perform these actions. STO has entered into the Deed Poll for the purpose of covenanting in favour of the Scheme Shareholders that STO will observe and perform the obligations contemplated of it under this Scheme.

It is agreed as follows.

1 Definitions and interpretation

1.1 Definitions

In this document, unless the context requires otherwise:

ASX means ASX Limited (ABN 98 008 624 691) or, as the context requires, the financial market known as the 'ASX' operated by it.

ASX Listing Rules means the official listing rules of ASX.

ASX Settlement means ASX Settlement Pty Limited (ACN 008 504 532).

ASX Settlement Operating Rules means the operating rules of ASX Settlement.

Australian Corporations Act means the *Corporations Act 2001* (Cth), as amended by any applicable ASIC class order, ASIC legislative instrument or ASIC relief.

Australian Register means OSH's share register comprising OSH Shareholders designated in the OSH Register as being on the 'Australian Register' and holding OSH Shares that are capable of being traded on the ASX.

Business Day means any day that is each of the following:

(a) a Business Day within the meaning given in the ASX Listing Rules and the PNGX Listing Rules; and

(b) a day that banks are open for business in Sydney, Australia, Adelaide, Australia and Port Moresby, Papua New Guinea.

CHESS means the Clearing House Electronic Subregister System for the electronic transfer of securities, operated by ASX Settlement Pty Limited (ABN 49 008 504 532).

Constitution means the constitution establishing OSH, as amended from time to time.

Controlled Entity means, in relation to a party:

(a) a related body corporate of that party; or

(b) an entity, fund or partnership over which a party (or a related body corporate of a party) exercises control, or by which a party is controlled, within the meaning of section 50AA of the Australian Corporations Act (but read as though section 50AA(4) were omitted).

Court means the National Court of Papua New Guinea or such other court of competent jurisdiction as STO and OSH may agree in writing.

Deed Poll means the deed poll substantially in the form of Annexure 3 of the Merger Implementation Deed (or in such other form as STO and OSH may agree in writing) executed on or about the date of this document by STO in favour of the Scheme Shareholders.

Effective means, when used in relation to the Scheme, the coming into effect, pursuant to section 250 of the PNG Companies Act, of the orders of the Court under section 250(1) of the PNG Companies Act in relation to the Scheme, but in any event at no time before a certified copy of the orders of the Court are lodged with the PNG Registrar of Companies.

Effective Date means the date on which this Scheme becomes Effective.

Encumbrance means any mortgage, lien, charge, pledge, assignment by way of security, security interest, preferential right or trust arrangement, claim, covenant, profit a prendre, easement, overriding royalty, production payment, net profits interest or any other security arrangement or any other arrangement having the same effect.

End Date means the date that is 9 months after the date of the Merger Implementation Deed, or such later date as STO and OSH may agree in writing.

Governmental Agency means any government or representative of a government or any governmental, semi-governmental, administrative, fiscal, regulatory or judicial body, department, commission, authority, tribunal, agency or similar entity or organisation, or securities exchange, in each case in any part of the world or in any federation, state, province or legal government area of any part of the world.

Implementation Date means the date that is five Business Days after the Record Date, or such other date as STO and OSH may agree in writing.

Ineligible Foreign Shareholder means a Scheme Shareholder whose address as shown in the OSH Register is a place outside Australia and its external territories, New Zealand, Papua New

Guinea and the United States of America (unless otherwise agreed by the parties in writing, acting reasonably) or any other jurisdictions agreed by the parties in writing (each acting reasonably), unless STO is satisfied that the laws of that place permit the allotment and issue of STO Shares to that Scheme Shareholder under the Scheme, either unconditionally or after compliance with conditions that STO regards as acceptable and not unduly onerous or impracticable.

Message has the meaning given to that term in the ASX Settlement Operating Rules.

New STO Share means an STO Share to be issued to Scheme Shareholders under the terms of this Scheme.

Opt-in Notice means a notice by an Unmarketable Parcel Shareholder requesting to receive the Scheme Consideration as New STO Shares pursuant to clause 5.2 of the Scheme.

OSH Register means the register of members of OSH maintained in accordance with the PNG Companies Act.

OSH Share means a fully paid ordinary share in OSH.

OSH Shareholder means a person who is registered in the OSH Register as a holder of an OSH Shares from time to time.

Participant has the meaning given to that term in the ASX Settlement Operating Rules.

PNG Broker means a stock broker to be appointed by OSH on or before the Business Day before the First Court Date (as approved by STO in writing) registered to operate on PNGX under Papua New Guinea law and being a participating organisation for the purposes of and as defined in the business rules of PNGX.

PNG Companies Act means the *Companies Act 1997* (PNG).

PNG Register means that part of OSH's share register comprising OSH Shareholders designated in the OSH Register as being on the 'PNG Register' and holding OSH Shares that are capable of being traded on the PNGX.

PNG Registrar of Companies means the Registrar of Companies appointed under section 394(1) of the PNG Companies Act.

PNGX means PNGX Markets Limited or, as the context requires, the financial market operated by it.

Record Date means 7:00pm on the date that is five Business Days after the Effective Date, or such other date as may be agreed in writing between STO and OSH.

Registered Address means, in relation to an OSH Shareholder, the address of that Scheme Shareholder shown in the OSH Register as at the Record Date.

Related Company has the meaning given in the PNG Companies Act, except that references to 'subsidiary' have the meaning given to 'Subsidiary' in this document.

Sale Agent means a person appointed by STO to sell the New STO Shares that are attributable to Ineligible Foreign Shareholders (and any Unmarketable Parcel Shareholders who have not provided an Opt-in Notice by the Opt-in Notice Date if applicable).

Scheme means the scheme of arrangement under Part XVI of the PNG Companies Act between OSH and Scheme Shareholders substantially in the form of this document or in such other form as STO and OSH may agree in writing (each acting reasonably).

Scheme Consideration means the consideration to be provided by STO to each Scheme Shareholder for the transfer of the Scheme Shares, as set out in clause 5.

Scheme Meeting means the meeting of OSH Shareholders to be ordered by the Court to be convened under section 250(2)(b) of the PNG Companies Act in relation to the Scheme, and includes any adjournment of that meeting.

Scheme Shareholders means each person who is registered in the OSH Register as a holder of Scheme Shares as at the Record Date.

Scheme Shares means the OSH Shares on issue as at the Record Date.

Scheme Transfer means a duly completed and executed proper instrument of transfer in respect of the Scheme Shares in the form prescribed in Appendix 8B of the PNGX Listing Rules, in favour of STO as transferee, which may be a master transfer of all or part of the Scheme Shares.

Second Court Date means the first day of hearing of an application made to the Court by OSH for orders for the Second Court Order or, if the hearing of such application is adjourned for any reason, means the first day of the adjourned hearing.

Second Court Order means an order, pursuant to section 250(1) of the PNG Companies Act, approving the Scheme.

STO means Santos Limited (ABN 80 007 550 923).

STO Group means STO and its Controlled Entities.

STO Share means a fully paid ordinary share issued in the capital of STO.

Subsidiary has the meaning given in the PNG Companies Act, provided that an entity will also be taken to be a Subsidiary of another entity if it is controlled by that entity (as 'control' is defined in section 6 of the PNG Companies Act) and, without limitation:

(a) a trust may be a Subsidiary, for the purposes of which a unit or other beneficial interest will be regarded as a share;

(b) an entity may be a Subsidiary of a trust if it would have been a Subsidiary if that trust were a corporation; and

(c) an entity will also be deemed to be a Subsidiary of an entity if that entity is required by the accounting standards to be consolidated with that entity.

Transmit has the meaning given to that term in the ASX Settlement Operating Rules.

Unmarketable Parcel Shareholder means a Scheme Shareholder (other than an Ineligible Foreign Shareholder) who, based on their holding of Scheme Shares on the Record Date, would, on Implementation, be entitled to receive less than a marketable parcel (as that term is defined in the ASX Listing Rules) of New STO Shares (assessed by reference to price of STO Shares on the ASX as the close of trade on the trading day prior to the Record Date) as Scheme Consideration.

1.2 Interpretation

(a) Headings are for convenience only and do not affect interpretation.

(b) Mentioning anything after includes, including, for example, or similar expressions, does not limit what else might be included.

(c) The following rules apply unless the context requires otherwise.

(i) The singular includes the plural, and the converse also applies.

(ii) A gender includes all genders.

(iii) If a word or phrase is defined, its other grammatical forms have a corresponding meaning.

(iv) A reference to a person includes a corporation, trust, partnership, unincorporated body or other entity, whether or not it comprises a separate legal entity.

(v) A reference to a clause or Schedule or Annexure is a reference to a clause or Schedule or Annexure of this document.

(vi) A reference to an agreement or document (including a reference to this document) is to the agreement or document as amended, supplemented, novated or replaced, except to the extent prohibited by this document or that other agreement or document.

(vii) A reference to writing includes any method of representing or reproducing words, figures, drawings or symbols in a visible and tangible form.

(viii) A reference to a party to this document or another agreement or document includes the party's successors, permitted substitutes and permitted assigns (and, where applicable, the party's legal personal representatives).

(ix) A reference to legislation or to a provision of legislation includes a modification or re-enactment of it, a legislative provision substituted for it and a regulation or statutory instrument issued under it.

(x) A reference to an agreement includes any undertaking, deed, agreement and legally enforceable arrangement, whether or not in writing, and a reference to a document includes an agreement (as so defined) in writing and any certificate, notice, instrument and document of any kind.

(xi) A reference to *dollars* or *$* is to Australian currency and a reference to *US dollars* or *US$* is to the currency of the United States of America.

(xii) Words and phrases not specifically defined in this document have the same meanings (if any) given to them in the PNG Companies Act.

(xiii) A reference to time is to Port Moresby, Papua New Guinea time. If a period of time is specified and dates from a given day or the day of an act or event, it is to be calculated exclusive of that day. A reference to a day is to be interpreted as the period of time commencing at midnight and ending 24 hours later.

(xiv) If the day on which any act, matter or thing is to be done is a day other than a Business Day, such act, matter or thing must be done on the immediately succeeding Business Day.

(xv) A reference to the ASX Listing Rules, the ASX Settlement Operating Rules or the PNGX Listing Rules includes any variation, consolidation or replacement of those rules and is to be taken to be subject to any waiver or exemption granted by the ASX to the compliance of those rules.

(xvi) Any agreement, representation, warranty or indemnity in favour of two or more parties (including where two or more persons are included in the same defined term) is for the benefit of them jointly and severally.

2 Conditions

2.1 Conditions Precedent

This Scheme is conditional upon, and will have no force or effect until, the satisfaction of each of the following conditions precedent:

(a) as at 8:00am on the Second Court Date each of the conditions precedent set out in clause 3.1 of the Merger Implementation Deed (other than the condition precedent relating to the approval of the Court set out in clause 3.1(b) of the Merger Implementation Deed) has been satisfied or waived in accordance with the Merger Implementation Deed;

(b) as at 8:00am on the Second Court Date, neither the Merger Implementation Deed nor the Deed Poll has been terminated in accordance with its terms;

(c) the Court makes orders approving the Scheme under section 250(1) of the PNG Companies Act, including with such alterations made or required by the Court under section 251(1) of the PNG Companies Act as are acceptable to STO and OSH (each acting reasonably);

(d) such other conditions made or required by the Court under section 250 or section 251 of the PNG Companies Act in relation to this Scheme as are acceptable to STO and OSH (each acting reasonably) have been satisfied or waived in accordance with the Merger Implementation Deed; and

(e) the orders of the Court made under section 250(1) of the PNG Companies Act approving the Scheme coming into effect on or before the End Date.

2.2 Certificate

(a) OSH and STO will provide to the Court on the Second Court Date a certificate (or such other evidence as the Court may request) confirming (in respect of matters within its knowledge) whether or not all of the conditions precedent in clauses 2.1(a) and (b) have been satisfied or waived in accordance with the Merger Implementation Deed as at 8.00am on the Second Court Date.

(b) The certificate referred to in clause 2.2(a) constitutes conclusive evidence that such conditions precedent were satisfied, waived or taken to be waived in accordance with the Merger Implementation Deed.

2.3 Lapsing

This Scheme will lapse and be of no further force or effect if:

(a) the Effective Date does not occur on or before the End Date; or

(b) the Merger Implementation Deed or the Deed Poll is terminated in accordance with its terms unless OSH and STO otherwise agree in writing.

3 Scheme becoming Effective

Subject to clause 2.3, this Scheme will take effect on and from the Effective Date.

4 Implementation of Scheme

4.1 Lodgement of Court order

OSH must lodge with the PNG Registrar of Companies, in accordance with section 250(4) of the PNG Companies Act, an office copy of the Court orders approving the Scheme as soon as possible after the Court approves the Scheme and in any event by no later than 5.00pm on the first Business Day after the date on which the Court makes the Second Court Order, or such other date as agreed by OSH and STO in writing.

4.2 Transfer of Scheme Shares

On the Implementation Date, subject to the provision of the Scheme Consideration in the manner contemplated in clause 5, all of the Scheme Shares, together with all rights and entitlements attaching to the Scheme Shares as at the Implementation Date, will be transferred to STO (or, if STO has nominated a nominee, to its nominee), without the need for any further act by any

Scheme Shareholder (other than acts performed by OSH or any of its directors and officers as attorney and agent for Scheme Shareholders under clause 8.3 in accordance with clauses 4.3 and 4.4.

4.3 PNG Register

(a) In respect of Scheme Shareholders holding Scheme Shares on the PNG Register, each such Scheme Shareholder, as transferor, authorises and directs the PNG Broker to effect a transfer of their Scheme Shares on the PNG Register to STO on the Implementation Date and for that purpose each such Scheme Shareholder authorised and directs the PNG Broker to execute a transfer of the Scheme Shares on the PNG Register on their behalf.

(b) OSH must enter STO in the PNG Register as the holder of all of the Scheme Shares on the PNG Register as soon as practicable on the Implementation Date.

(c) OSH is liable for, and must arrange for payment of, any fees, costs or expenses incurred by the PNG Broker in connection with the transfer contemplated in clause 4.3(a).

4.4 Australian Register

(a) In respect of Scheme Shareholders holding Scheme Shares on the Australian Register, each such Scheme Shareholder, as transferor, authorises and directs OSH to enter STO in the Australian Register as holder of those Scheme Shares, or to procure those Scheme Shares are otherwise transferred to STO on the Implementation Date by any means reasonably determined by OSH (after having consulted in good faith with STO) including but not limited to:

(i) a transfer in accordance with the *Corporations Regulations 2001* (Cth) and ASX Settlement Operating Rules;

(ii) a Holding Adjustment; or

(iii) a Scheme Transfer,

and each such Scheme Shareholder further authorises and directs OSH to take any action which OSH reasonably determines is necessary or appropriate to give effect to the entry in the Australian Register or transfer (as applicable), including but not limited to:

(iv) executing and delivering, or causing to be executed and delivered, any documents;

(v) giving instructions to any relevant Participant under the ASX Settlement Operating Rules; or

(vi) Transmitting, or causing to be Transmitted, any Message.

(b) OSH must enter STO in the Australian Register as the holder of all of the Scheme Shares on the Australian Register as soon as practicable on the Implementation Date.

(c) Notwithstanding clause 4.4(a), OSH or STO may take any and all further action (including but not limited to the execution of a Scheme Transfer) which it deems necessary or advisable in order to validly effect the transfer of the Scheme Shares on the Australian Register to STO.

5 Scheme Consideration

5.1 Entitlement to Scheme Consideration

Subject to the terms of the Scheme, on the Implementation Date and in consideration for the transfer to STO of the Scheme Shares, each Scheme Shareholder (other than an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who has not provided an Opt-in Notice by the Opt-in Notice Date) will be entitled to receive as Scheme Consideration 0.6275 New STO Shares for each Scheme Share held by that Scheme Shareholder at the Record Date, as adjusted in accordance with clause 4.7 of the Merger Implementation Deed (if applicable).

5.2 Provision of Scheme Consideration

Subject to clauses 5.3 to 5.9 (inclusive), STO must:

(a) on or before the Implementation Date:

(i) issue and allot to each Scheme Shareholder such number of New STO Shares (if any) to which that Scheme Shareholder is entitled under this clause 5;

(ii) enter into the register of members of STO the name and address of each Scheme Shareholder in respect of the aggregate number of New STO Shares issued to them under clause 5.2(a)(i);

(b) subject to clause 5.5, as soon as practicable after the Implementation Date and no later than 10 Business Days after the Implementation Date, send or procure the dispatch to each Scheme Shareholder, to their Registered Address as at the Record Date, a share certificate or holding statement (or equivalent document) representing the number of New STO Shares issued to that Scheme Shareholder pursuant to this Scheme.

5.3 Ineligible Foreign Shareholders

(a) STO will be under no obligation under the Scheme to issue, and will not issue, any New STO Shares under this Scheme to any Ineligible Foreign Shareholder, and instead STO will subject to clauses 5.7 and 5.9 issue to the Sale Agent on or before the Implementation Date the New STO Shares to which each Ineligible Foreign Shareholder, having regard to the operation of clause 5.1, would otherwise have been entitled under this Scheme (if they were a Scheme Shareholder that was not an Ineligible Foreign Shareholder).

(b) STO will procure that, as soon as reasonably practicable after the Implementation Date, the Sale Agent sells or procures the sale (including on an aggregated or partially aggregated basis), of all the New STO Shares issued to the Sale Agent in the manner, and on the terms the Sale Agent determines in good faith. For the purpose of this clause 5.3, the **Proceeds** will be the proceeds of the sale by the Sale Agent of all of the New STO Shares contemplated by this clause 5.3 (after deduction of any applicable brokerage, stamp duty and other costs, taxes and charges incurred in connection with the sale of the New STO Shares).

(c) STO will procure that the Sale Agent pay, or procure the payment, to each Ineligible Foreign Shareholder of the amount calculated in accordance with the following formula and rounded down to the nearest cent:

A=(B/C) x D

where:

A is the amount to be paid to the Ineligible Foreign Shareholder;

B is the number of New STO Shares attributable to, and that would otherwise have been issued to, that Ineligible Foreign Shareholder had it not been a Ineligible Foreign Shareholder and which are instead issued to the Sale Agent;

C is the total number of New STO Shares attributable to, and which would otherwise have been issued to, all Ineligible Foreign Shareholders collectively and which are instead issued to the Sale Agent; and

D is the Proceeds (as defined in clause 5.3(b)).

(d) The Ineligible Foreign Shareholders acknowledge that none of STO, OSH or the Sale Agent gives any assurance as to the price that will be achieved for the sale of New STO Shares described in clause 5.3(b), and the sale of the New STO Shares under this clause 5.3 will be at the risk of the Ineligible Foreign Shareholder.

(e) If STO or the Sale Agent receives professional advice that any withholding or other tax is required by law or by a Governmental Agency to be withheld from a payment to an Ineligible Foreign Shareholder, the Sale Agent is entitled to withhold the relevant amount before making the payment to the Ineligible Foreign Shareholder (and payment of the reduced amount shall be taken to be full payment of the relevant amount for the purposes of this Scheme, including clause 5.3(c)). STO or the Sale Agent must pay any amount so withheld to the relevant taxation authorities within the time permitted by law, and, if requested in writing by the relevant Ineligible Foreign Shareholder, provide a receipt or other appropriate evidence of such payment (or procure the provision of such receipt or other evidence) to the relevant Ineligible Foreign Shareholder.

(f) Each Ineligible Foreign Shareholder appoints STO as its agent to receive on its behalf any financial services guide (or similar or equivalent document) or other notices (including any updates of those documents) that the Sale Agent is required to provide to Ineligible Foreign Shareholders under the Australian Corporations Act or any other applicable law.

(g) Payment of the amount calculated in accordance with clause 5.3(c) to an Ineligible Foreign Shareholder in accordance with this clause 5.3 satisfies in full the Ineligible Foreign Shareholder's right to Scheme Consideration.

(h) Where the issue of New STO Shares to which a Scheme Shareholder would otherwise be entitled under this Scheme would result in a breach of law**:**

(i) STO will issue the maximum possible number of New STO Shares to the Scheme Shareholder without giving rise to such a breach; and

(ii) any further New STO Shares to which that Scheme Shareholder is entitled, but the issue of which to the Scheme Shareholder would give rise to such a breach, will instead be issued to the Sale Agent and dealt with under the preceding provisions in this clause 5.3, as if a reference to Ineligible Foreign Shareholders also included that Scheme Shareholder and references to that person's New STO Shares in that clause were limited to the New STO Shares issued to the Sale Agent under this clause.

5.4 Election by Unmarketable Parcel Shareholders

(a) OSH must provide each Unmarketable Parcel Shareholder with, or procure the provision to each Unmarketable Parcel Shareholder of, an Opt-in Notice.

(b) An Unmarketable Parcel Shareholder may elect to receive the Scheme Consideration as New STO Shares pursuant to clause 5.2 of the Scheme by providing OSH with a duly completed Opt-in Notice prior to 5:00pm on the Business Day prior to the Record Date (the **Opt-in Notice Date**).

(c) Unless an Unmarketable Parcel Shareholder provides OSH with a duly completed Opt-in Notice by the Opt-in Notice Date pursuant to clause 5.4(b), STO will be under no obligation under this Scheme or Deed Poll to issue, and will not issue, any New STO Shares to any Unmarketable Parcel Shareholder, and instead, unless STO and OSH otherwise agree, OSH must procure that the New STO Shares that each Unmarketable Parcel Shareholder who would otherwise be entitled to receive as Scheme Consideration are dealt with in accordance with clause 5.3 of this Scheme (as if a reference in that clause to an 'Ineligible Foreign Shareholder' was a reference to an 'Unmarketable Parcel Shareholder').

5.5 Unknown Registered Address

Clause 5.2(b) does not apply to a Scheme Shareholder who does not have a Registered Address or where OSH and STO reasonably believe that such Scheme Shareholder is not known at their Registered Address.

5.6 Joint holders

In the case of Scheme Shares held in joint names:

(a) the New STO Shares to be issued under this Scheme must be issued to and registered in the name of the joint holders;

(b) any cheque required to be sent under this Scheme will be made payable to the joint holders and sent to either, at the sole discretion of OSH, the holder whose name appears first in the OSH Register as at the Record Date or to the joint holders; and

(c) holding statements or notices confirming the issue of the STO New Shares (or any other documents required to be sent under this Scheme), will be forwarded to either, at the sole discretion of OSH, the holder whose name appears first in the OSH Register as at the Record Date or to the joint holders.

5.7 Fractional entitlements

(a) Where the calculation of the number of New STO Shares to be issued to a particular Scheme Shareholder would result in the Scheme Shareholder becoming entitled to a fraction of a New STO Share, that fractional entitlement will be rounded down to the nearest whole number of New STO Shares with fractions of 0.5 or more being rounded up.

(b) If STO and OSH are of the opinion, formed reasonably, that two or more Scheme Shareholders, each of which holds a holding of Scheme Shares which results in rounding in accordance with clause 5.7(a) have, before the Record Date, been party to a shareholding splitting or division in an attempt to obtain an advantage by reference to such rounding, then OSH and STO must consult in good faith to determine whether such matters have arisen and if agreement is reach between OSH and STO following such consultation, OSH must give notice to those Scheme Shareholders:

(i) setting out the names and Registered Address for all of them;

(ii) stating that opinion; and

(iii) attributing to one of them specifically identified in the notice the Scheme Shares held by all of them, and, after the notice has been so given, the Scheme Shareholder specifically identified in the notice will, for the purposes of the Scheme, be taken to hold all those Scheme Shares and each of the other Scheme Shareholder whose names are set out in the notice shall, for the purposes of the Scheme, be taken to hold no Scheme Shares.

(c) STO, in complying with the other provisions of this Scheme relating to it in respect of the Scheme Shareholders specifically identified in a notice given under clause 5.7(b) as the deemed holder of all of the specified Scheme Shares, will be taken to have satisfied and discharged its obligations to the other Scheme Shareholders named in the notice under the terms of this Scheme.

5.8 Unclaimed monies

(a) STO may cancel a cheque issued under this clause 5 if the cheque:

(i) is returned to STO; or

(ii) has not been presented for payment with 12 months after the date on which the cheque was sent.

(b) During the period of one year commencing on the Implementation Date, on request in writing from an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who has not provided an Opt-in Notice by the Opt-in Notice Date, STO must, or must procure the Sale Agent, reissue a cheque that was previously cancelled under this clause 5.8.

(c) The PNG *Unclaimed Monies Act 1963* will apply in relation to any Scheme Consideration which becomes 'unclaimed money' (as defined in that Act).

5.9 Orders of a court

(a) If written notice is given to OSH (or the OSH Share Registry) or STO (or the STO Registry) of an order or direction made by a court that:

(i) requires consideration to be provided to a third party (either through payment of a sum or the issuance of a security) in respect of Scheme Shares held by a particular Scheme Shareholder, which would otherwise be payable or required to be issued to that Scheme Shareholder by OSH in accordance with this clause 5, then OSH shall be entitled to procure that provision of that consideration is made in accordance with that order or direction; or

(ii) prevents OSH from providing consideration to any particular Scheme Shareholder in accordance with this clause 5, or the payment or issuance of such consideration is otherwise prohibitive by applicable law, OSH shall be entitled to (as applicable):

(A) in the case of an Ineligible Foreign Shareholder or an Unmarketable Parcel Shareholder who has not provided an Opt-in Notice by the Opt-in Notice Date, retain an amount, in Australian dollars, equal to the relevant Ineligible Foreign Shareholder's or Unmarketable Parcel Shareholder's share of the Proceeds; and

(B) not issue (or, in the case of OSH, direct STO not to issue), or to issue (or, in the case of OSH, direct STO to issue) to a trustee or nominee, any Scheme Consideration that Scheme Shareholder would otherwise be entitled to under clause 5.1,

until such time as payment of the Scheme Consideration in accordance with this clause 5 is permitted by that (or another) court or direction or otherwise by law.

(b) To the extent that amounts are so deducted or withheld in accordance with clause 5.9(a), such deducted or withheld amounts will be treated for all purposes under this Scheme as having been paid to the person in respect of which such deduction and withholding was made, provided that such deducted or withheld amounts are actually remitted as required.

(c) For the avoidance of doubt, any payment or retention by STO or OSH (as applicable) under clause 5.9(a) will constitute the full discharge of STO's obligations under clause 5.2 with respect to the amount so paid or retained, in the case of clause 5.9(a)(ii), the amount is no longer required to be retained.

6 Dealings in OSH Shares

6.1 Dealings in OSH Shares by Scheme Shareholders

For the purpose of establishing the identity of the persons who are Scheme Shareholders, dealings in OSH Shares or other alterations to the OSH Registry will be only recognised provided that:

(a) in the case of dealings of the type to be effected using CHESS, the transferee is registered in the OSH Register as the holder of the relevant OSH Shares by the Record Date; and

(b) in all other cases, registrable transfers or transmission applications in respect of those dealings, or valid requests in respect of other alterations, are received by the OSH Share Registry by 5.00pm on the day which is the Record Date at the place where the OSH Register is located (in which case OSH must register such transfers or transmission applications before 7.00pm on that day),

and OSH will not accept for registration, nor recognise for the purpose of establishing the persons who are Scheme Shareholders nor for any other purpose (other than to transfer to STO pursuant to this Scheme and any subsequent transfers by STO and its successors in title), any transfer or transmission application or other request in respect of OSH Shares received after such times, or received prior to such times but not in actionable or registrable form (as appropriate).

6.2 Register

(a) OSH must register registrable transmission applications or transfers of the Scheme Shares that are received in accordance with clause 6.1(b) before the Record Date provided that, for the avoidance of doubt, nothing in this clause 6.2(a) requires OSH to register a transfer that would result in a OSH Shareholder holding a parcel of OSH Shares that is less than a 'marketable parcel' (for the purposes of this clause 6.2(a) 'marketable parcel' has the meaning given in the operating rules of the ASX).

(b) OSH will, until the Scheme Consideration has been provided and the name and address of STO has been entered in the OSH Register as the holder of all of the Scheme Shares, maintain, or procure the maintenance of, the OSH Register in accordance with this clause 6, and the OSH Register in this form and the terms of this Scheme will solely determine entitlements to the Scheme Consideration.

(c) As from the Record Date (and other than for STO following the Implementation Date), each entry in the OSH Register as at the Record Date relating to Scheme Shares will cease to have any effect other than as evidence of the entitlements of Scheme Shareholders to the Scheme Consideration in respect of those Scheme Shares.

(d) As soon as possible on or after the Record Date, and in any event by 5.00pm on the first Business Day after the Record Date, OSH will ensure that details of the names, Registered Addresses and holdings of OSH Shares for each Scheme Shareholder as shown in the OSH Register are available to STO in the form STO reasonably requires.

6.3 Effect of share certificates and holding statements

As from the Record Date (and other than for STO following the Implementation Date), all share certificates and holding statements for Scheme Shares (other than statements of holding in favour of STO) will cease to have effect as documents of title in respect of those Scheme Shares.

6.4 No disposals after Record Date

If this Scheme becomes Effective, each Scheme Shareholder, and any person claiming through that Scheme Shareholder, must not dispose of or purport or agree to dispose of any Scheme Shares or any interest in them after 5.00pm on the Record Date (other than to STO in accordance with this Scheme and any subsequent transfers by STO and its successors in title), and any attempt to do so will have no effect and OSH shall be entitled to disregard any such disposal, purported disposal or agreement.

7 Suspension and termination of quotation of OSH Shares

(a) OSH must apply to the ASX and PNGX to suspend trading in OSH Shares with effect from the close of trading on the Effective Date.

(b) On a date after the Implementation Date to be determined by STO, OSH must apply to ASX and PNGX for termination of official quotation of the OSH Shares on ASX and the removal of OSH from the official list of ASX and PNGX.

8 General provisions

8.1 Further assurances

(a) Each Scheme Shareholder and OSH will do all things and execute all deeds, instruments, transfers or other documents as may be necessary or desirable to give full effect to the terms of this Scheme and the transactions contemplated by it.

(b) Without limiting OSH's other powers under this Scheme, OSH has power to do all things that it considers necessary or desirable to give effect to this Scheme and the transactions contemplated by it.

8.2 Scheme Shareholders' agreements and consents

Each Scheme Shareholder (and the Sale Agent on behalf of all Ineligible Foreign Shareholders and Unmarketable Parcel Shareholders who have not provided an Opt-in Notice by the Opt-in Notice Date, as applicable) irrevocably:

(a) agrees to the transfer of their Scheme Shares, together with all rights and entitlements attaching to those Scheme Shares, to STO in accordance with the terms of this Scheme;

(b) agrees to the variation, cancellation or modification of the rights attached to their Scheme Shares constituted by or resulting from this Scheme;

(c) agrees to become a member of STO and to be bound by the terms of the constitution of STO and to have their name registered in the STO Register as a holder of STO Shares (in respect of the New STO Shares which they are issued pursuant to the Scheme);

(d) acknowledges and agrees that this Scheme binds OSH and all Scheme Shareholders (including those that were excluded from attending and voting at the Scheme Meeting, or who did not attend the Scheme Meeting or did not vote at that meeting or voted against this Scheme at that Scheme Meeting) and, to the extent of any inconsistency, overrides the Constitution; and

(e) consents to OSH and STO doing all things and executing all deeds, instruments, transfers or other documents as may be necessary or desirable to give full effect to the terms of the Scheme and the transactions contemplated by it,

without the need for any further act by that Scheme Shareholder.

8.3 Appointment of OSH as attorney for implementation of Scheme

(a) Each Scheme Shareholder, without the need for any further act by that Scheme Shareholder, on the Effective Date, irrevocably appoints OSH and each of its directors and officers (jointly and each of them severally) as that Scheme Shareholder's agent and attorney for the purpose of:

(i) doing all things and executing all deeds, instruments, transfers or other documents as may be necessary or desirable to give full effect to the terms of this Scheme and the transactions contemplated by it, including the effecting of a valid transfer or transfers (or the execution and delivery of any Scheme Transfers) under clause 4.2; and

(ii) enforcing the Deed Poll against STO,

and OSH accepts such appointment. OSH, as agent and attorney of each Scheme Shareholder, may sub delegate its functions, authorities or powers under this clause 8.3 to all or any of its directors and officers (jointly, severally, or jointly and severally).

(b) For the avoidance of doubt, nothing in this clause 8.3 shall impact the authorisation under clause 4.3(a).

8.4 Warranty by Scheme Shareholders

Each Scheme Shareholder is deemed to have warranted to STO on the Implementation Date, and, to the extent enforceable, to have appointed and authorised OSH as that Scheme Shareholder's agent and attorney to warrant to STO on the Implementation Date, that all of their Scheme Shares (including all rights and entitlements attaching to those Scheme Shares) will, at the time of the transfer of them to STO pursuant to this Scheme, be fully paid and free from all mortgages, charges, liens, encumbrances, pledges, security interests (including 'security interests' within the meaning of section 12 of the *Personal Property Securities Act 2009* (Cth)) and other interests of third parties of any kind, whether legal or otherwise, and restrictions on transfer of any kind, and that they have full power and capacity to sell and to transfer their Scheme Shares (together with any rights and entitlements attaching to those Scheme Shares) to STO pursuant to this Scheme, and as at the Record Date, they have no existing right to be issued any other Scheme Shares or any other form of securities in OSH. OSH undertakes in favour of each Scheme Shareholder that it will provide such warranty, to the extent enforceable, to STO on behalf of that Scheme Shareholder.

8.5 Title to and rights in Scheme Shares

(a) To the extent permitted by law, the Scheme Shares (including all rights and entitlements attaching to the Scheme Shares) transferred under this Scheme to STO will, at the time of transfer of them to STO, be fully paid and free from all mortgages, charges, liens, encumbrances, pledges, security interests (including 'security interests' within the meaning of section 12 of the *Personal Property Securities Act 2009* (Cth)) and other interests of third parties of any kind, whether legal or otherwise, and restrictions on transfer of any kind.

(b) Immediately upon the provision of the Scheme Consideration in the manner contemplated by clause 5, STO will be beneficially entitled to the Scheme Shares transferred to it under this Scheme pending registration by OSH of the name and address of STO in the OSH Register as the holder of the Scheme Shares.

(c) For the avoidance of doubt, notwithstanding clause 8.5(b), to the extent that clause 5.8(a) applies to any Scheme Shareholder, STO will be beneficially entitled to any Scheme Shares held by that Scheme Shareholders immediately upon compliance with clause 5.8 on the Implementation Date as if STO had provided the Scheme Consideration to that Scheme Shareholder.

8.6 Appointment of STO as sole proxy

(a) From the time that STO has provided the Scheme Consideration to each Scheme Shareholder in the manner contemplated in clause 5.2 and until STO is registered in the OSH Register as the holder of all Scheme Shares, each OSH Shareholder:

(i) without the need for any further act by that OSH Shareholder, is deemed to irrevocably appoint STO as its sole proxy to (and irrevocably appoints STO as its agent and attorney for the purpose of appointing any director or officer of STO as that OSH Shareholder's sole proxy and, where appropriate, its corporate representative to):

(A) attend shareholders' meetings of OSH;

(B) exercise the votes attaching to the OSH Shares registered in the name of the OSH Shareholder; and

(C) sign any OSH Shareholders' resolution or document (whether in person, by proxy or by corporate representative);

(ii) must take all other action in the capacity of an OSH Shareholder as STO reasonably directs; and

(iii) acknowledges and agrees that in exercising the powers referred to in clause 8.6(a), STO and any person nominated by STO under clause 8.6(a) may act in the best interests of STO as the intended registered holder of the Scheme Shares.

(b) From the time that STO has provided the Scheme Consideration to each Scheme Shareholder in the manner contemplated in clause 5.2 until STO is registered in the OSH Register as the holder of all Scheme Shares, no OSH Shareholder may attend or vote at any meetings of OSH Shareholders or sign any OSH Shareholders' resolution (whether in person, by proxy or by corporate representative) other than under clause 8.6)(a).

8.7 Alterations and conditions to Scheme

If the Court proposes to approve this Scheme subject to any alterations or conditions:

(a) OSH may, by its counsel or solicitors, and with the prior written consent of STO, consent on behalf of all persons concerned, including each OSH Shareholder, to those alterations or conditions; and

(b) each Scheme Shareholder agrees to any such alterations or conditions which OSH has consented to.

8.8 Enforcement of Deed Poll

OSH undertakes in favour of each Scheme Shareholder that it will enforce the Deed Poll against STO on behalf of and as agent and attorney for the Scheme Shareholders.

8.9 Instructions and Elections

If not prohibited by law (and including where permitted or facilitated by relief granted by a Governmental Agency), all instructions, notifications or elections by a Scheme Shareholder to OSH that are binding or deemed binding between the Scheme Shareholder and OSH relating to OSH or OSH Shares, including instructions, notifications or elections relating to:

(a) whether dividends are to be paid by cheque or into a specific bank account;

(b) payments of dividends on OSH Shares; and

(c) notices or other communications from OSH (including by email),

will be deemed from the Implementation Date (except to the extent determined otherwise by STO in its sole discretion), by reason of this Scheme, to be made by the Scheme Shareholder to STO and to be a binding instruction, notification or election to, and accepted by, STO in respect of the New STO Shares issued to that Scheme Shareholder until that instruction, notification or election is revoked or amended in writing addressed to STO at its registry.

8.10 Binding effect of Scheme

This Scheme binds OSH and all of the Scheme Shareholders (including those who did not attend the Scheme Meeting to vote on this Scheme, did not vote at the Scheme Meeting, or voted against this Scheme at the Scheme Meeting) and, to the extent of any inconsistency, overrides the constitution of OSH.

8.11 Consent

Each of the Scheme Shareholders consents to OSH doing all things necessary or incidental to the implementation of this Scheme, whether on behalf of the Scheme Shareholders, OSH or otherwise.

8.12 Notices

(a) Where a notice, transfer, transmission application, direction or other communication referred to in this Scheme is sent by post to OSH, it will not be deemed to be received in the ordinary course of post or on a date and time other than the date and time (if any) on which it is actually received at OSH's registered office or by the OSH Share Registry, as the case may be.

(b) The accidental omission to give notice of the Scheme Meeting or the non-receipt of such notice by an OSH Shareholder will not, unless so ordered by the Court, invalidate the Scheme Meeting or the proceedings of the Scheme Meeting.

8.13 Duty

STO will pay all duty (including stamp duty and any related fines, penalties and interest) payable on or in connection with the transfer by Scheme Shareholders of the Scheme Shares to STO pursuant to this Scheme.

8.14 Governing law and jurisdiction

This document is governed by the laws of the Independent State of Papua New Guinea. Each party submits to the non-exclusive jurisdiction of courts exercising jurisdiction there and courts of appeal from them in connection with matters concerning this document. The parties irrevocably waive any objection to the venue of any legal process in these courts on the basis that the process has been brought in an inconvenient forum.

8.15 No liability when acting in good faith

Each Scheme Shareholder agrees that neither OSH, STO nor any director, officer, secretary or any of those companies shall be liable for anything done or omitted to be done in the performance of this Scheme or the Deed Poll in good faith.

Deed Poll

This Deed Poll is made on 9 November 2021

Parties

Santos Limited (ABN 80 007 550 923) (a company incorporated under the laws of the Commonwealth of Australia) of 60 Flinders Street, Adelaide, SA 5000, Australia (***Santos***).

In favour of

Each Scheme Shareholder.

Recitals

A Santos and Oil Search Limited (a company incorporated in and domiciled in Papua New Guinea) (***Oil Search***) have entered into a merger implementation deed dated 10 September 2021 (the ***Merger Implementation Deed***).

B Oil Search has agreed in the Merger Implementation Deed to propose the Scheme, pursuant to which, subject to the satisfaction or waiver of certain conditions precedent, Santos will acquire all of the Scheme Shares from Scheme Shareholders for the Scheme Consideration.

C In accordance with the Merger Implementation Deed, Santos is entering into this Deed Poll for the purpose of covenanting in favour of the Scheme Shareholders that it will observe and perform the obligations contemplated of it under the Scheme.

It is agreed as follows.

1 Definitions and Interpretation

1.1 Definitions

Terms defined in the Merger Implementation Deed have the same meaning in this Deed Poll, unless the context requires otherwise.

1.2 Interpretation

The provisions of clause 1.2 and 1.3 of the Merger Implementation Deed form part of this Deed Poll as if set out in full in this Deed Poll, and on the basis that references to 'this deed' in that clause are references to 'this Deed Poll'.

2 Nature of Deed Poll

Santos acknowledges that:

(a) this Deed Poll may be relied on and enforced by any Scheme Shareholder in accordance with its terms, even though the Scheme Shareholder are not party to it; and

(b) under the Scheme, each Scheme Shareholder irrevocably appoints Oil Search as its agent and attorney to enforce this Deed Poll against Santos on behalf of that Scheme Shareholder.

3 Conditions Precedent and Termination

3.1 Conditions precedent

This Deed Poll and Santos's obligations (as relevant) under this Deed Poll are subject to the Scheme becoming Effective.

3.2 Termination

If the Merger Implementation Deed is terminated before the Effective Date or the Scheme does not become Effective on or before the End Date, the obligations of Santos under this Deed Poll will automatically terminate and the terms of this Deed Poll will be of no further force or effect, unless Oil Search and Santos otherwise agree in writing in accordance with the Merger Implementation Deed.

3.3 Consequences of termination

If this Deed Poll is terminated under clause 3.2, then, in addition and without prejudice to any other rights, powers or remedies available to it:

(a) Santos is released from its obligations under this Deed Poll; and

(b) each Scheme Shareholder retains any rights, powers or remedies that Scheme Shareholder has against Santos in respect of any breach of its obligations under this Deed Poll that occurred before termination of this Deed Poll.

4 Compliance with Scheme Obligations

4.1 Obligations of Santos

Subject to clause 3, in consideration for the transfer to Santos (or its nominee) of the Scheme Shares in accordance with the Scheme, Santos covenants in favour of each Scheme Shareholder that it will observe and perform all obligations contemplated of it under the Scheme, including the relevant obligations relating to the provision of the Scheme Consideration, subject to and in accordance with the terms of the Scheme.

4.2 Provision of Scheme Consideration

(a) Subject to clause 3, Santos will, on the Implementation Date, provide, or procure the provision of, the Scheme Consideration to each Scheme Shareholder in accordance with the terms of the Scheme; and

(a) the New STO Shares to be issued to each Scheme Shareholder under the Scheme will be:

  (i) validly issued and fully paid up and will rank equally in all respects with all other STO Shares on issue as at the Implementation Date; and

  (ii) free from any Encumbrance or other security interest.

5 Representations and Warranties

Santos makes the following representations and warranties.

(a) (**Status**) It is a corporation duly incorporated and validly existing under the laws of the place of its incorporation.

(b) (**Power**) It has the corporate power to enter into and perform its obligations under this Deed Poll and to carry out the transactions contemplated by this Deed Poll.

(c) (**Corporate authorisations**) It has taken all necessary corporate action to authorise the entry into this Deed Poll and has taken or will take all necessary corporate action to authorise the performance of this Deed Poll and to carry out the transactions contemplated by this Deed Poll.

(d) (**Document binding**) This Deed Poll is valid and binding on it and enforceable against it in accordance with its terms.

(e) (**Transactions permitted**) The execution and performance by it of this Deed Poll and each transaction contemplated by this Deed Poll does not and will not violate in any respect a provision of:

(i) a law, judgment, ruling, order or decree binding on it; or

(ii) its constitution or other constituent documents.

6 Continuing Obligations

This Deed Poll is irrevocable and, subject to clause 3, remains in full force and effect until the earlier of:

(a) Santos having fully performed its obligations under this Deed Poll; and

(b) termination of this Deed Poll under clause 3.

7 Further Assurances

Santos will, on its own behalf and, to the extent authorised by the Scheme, on behalf of each Scheme Shareholder, do all things and execute all deeds, instruments, transfers or other documents as may be necessary or desirable to give full effect to the provisions of this Deed Poll and the transactions contemplated by it.

8 General

8.1 Notices

Any notice, demand, consent or other communication (a ***Notice***) given or made under this Deed Poll:

(a) must be in writing and signed by the sender or a person duly authorised by the sender;

(b) must be delivered to the intended recipient by prepaid post (or if posted to an address in another country, by registered airmail) or by hand or email to the address or email address (as applicable) below or the address or email address (as applicable) last notified by the intended recipient to the sender:

Santos:	Address:	60 Flinders Street Adelaide SA 5000
	Email:	Jodie.Hatherly@santos.com
	Attention:	Jodie Hatherly, Vice President ESG & Legal

with a copy to (which by itself does not constitute a Notice) tony.damian@hsf.com and amelia.morgan@hsf.com

(c) will be conclusively taken to be duly given or made:

(i) in the case of delivery in person, when delivered;

(ii) in the case of delivery by post, six Business Days after the date of posting (if posted to an address in the same country) or ten Business Days after the date of posting (if posted to an address in another country); and

(iii) in the case of delivery by email, at the earliest of:

(A) the time that the sender receives an automated message from the intended recipient's information system confirming delivery of the email;

(B) the time that the email is first opened or read by the intended recipient, or an employee or officer of the intended recipient; and

(C) two hours after the time the email is sent (as recorded on the device from which the sender sent the email) unless the sender receives, within that two hour period, an automated message that the email has not been delivered,

but if the result is that a Notice would be taken to be given or made:

(iv) on a day that is not a business day in the place to which the Notice is sent or later than 5:00pm (local time), then it will be taken to have been duly given or made at the start of business on the next business day in that place; or

before 9:00am (local time) on a business day in the place to which the Notice is sent, then it will be taken to have been duly given or made at 9:00am (local time) on that business day in that place other than in respect of any Notice given on, and prior to 8.00am on, the Second Court Date.

8.2 No waiver

No failure to exercise nor any delay in exercising any right, power or remedy by Santos or by any Scheme Shareholder operates as a waiver. A single or partial exercise of any right, power or remedy does not preclude any other or further exercise of that or any other right, power or remedy. A waiver of any right, power or remedy on one or more occasions does not operate as a waiver of that right, power or remedy on any other occasion, or of any other right, power or remedy. A waiver is not valid or binding on the person granting that waiver unless it is in writing and signed by the person granting the waiver.

8.3 Remedies cumulative

The rights, powers and remedies of Santos and of each Scheme Shareholder under this Deed Poll are in addition to, and do not exclude or limit, any right, power or remedy provided by law or equity or by any agreement independently of this Deed Poll.

8.4 Amendment

No amendment or variation of this Deed Poll is valid or binding unless:

(a) either:

(i) before the First Court Date, the amendment or variation is agreed to in writing by Oil Search and Santos; or

(ii) on or after the First Court Date, the amendment or variation is agreed to in writing by Oil Search and Santos, and is approved by the Court; and

(b) Santos enters into a further deed poll in favour of the Scheme Shareholders giving effect to that amendment or variation.

8.5 Assignment

(a) The rights and obligations of Santos and of each Scheme Shareholder under this Deed Poll are personal. They cannot be assigned, encumbered or otherwise dealt with and no person may attempt, or purport, to do so without the prior consent of Santos.

(b) Any purported dealing in contravention of clause 8.5(a) is invalid.

8.6 **Duty**

(a) All duty (including stamp duty and any fines, penalties and interest) payable on or in connection with this Deed Poll and any instrument executed under or any transaction effected by this Deed Poll must be borne by Santos.

(b) Santos must indemnify each Scheme Shareholder on demand against any liability arising from failure to comply with clause 8.6(a).

8.7 **Governing law and jurisdiction**

This Deed Poll is governed by the laws of New South Wales, Australia. Santos submits to the non-exclusive jurisdiction of courts exercising jurisdiction there in connection with matters concerning this Deed Poll.

Executed and **delivered as a Deed**.

Executed as a **deed** for **Santos Limited** by its attorney in the presence of

Attorney Signature	Witness Signature
Jodie Hatherly	Alexander Djurasevich
Print Name	Print Name

Annexure E Notice of Meeting

Oil Search Limited (ARBN 055 079 868)

Notice of Meeting of Registered Holders of Fully Paid Ordinary Shares in Oil Search.

Notice is hereby given, that by an Order of the National Court of Papua New Guinea (**Court**), made on 11 November 2021 under section 250(2)(b) of the *Companies Act 1997* (PNG), a Scheme Meeting of Oil Search Shareholders will be held virtually at 11:00am (Sydney time) / 10:00am (Port Moresby time) on Tuesday, 7 December 2021.

As a result of the potential health risks associated with large gatherings and the ongoing COVID-19 pandemic, the Scheme Meeting will be a virtual (online only) meeting. Instead, Oil Search Shareholders are invited to participate in the Scheme Meeting using an online platform. This online platform will enable participants to view the Scheme Meeting live, ask questions online and vote on the Scheme Resolution in real time.

Business

The purpose of the Scheme Meeting to be held pursuant to this Notice of Meeting is to consider, and if thought fit, to agree (with or without modification) to a scheme of arrangement pursuant to the *Companies Act 1997* (PNG) proposed to be made between Oil Search and Oil Search Shareholders.

Scheme Resolution

To consider and, if thought fit, to pass the following resolution:

*That, pursuant to and in accordance with, section 250 of the Companies Act 1997 (PNG), the scheme of arrangement proposed to be entered into between Oil Search Limited (**Oil Search**) and the holders of its fully paid ordinary shares, the terms of which are contained in and more particularly described in the Scheme Booklet of which the notice convening this meeting forms part, is approved (with or without alteration or conditions as approved by the National Court of Papua New Guinea and agreed to by Oil Search and Santos) and, subject to approval of the Scheme by the Court, the Oil Search Board is authorised to implement the Scheme with any such alterations or conditions.*

There are no relevant voting exclusions that apply to this Scheme Meeting.

Chair

The Court has directed that Richard Lee is to act as chair of the Scheme Meeting and if Richard Lee is unable or unwilling to act, Agu Kantsler is to act as chair of the Scheme Meeting.

Webcasting

In addition to the above, an archived recording of the webcast will also be available to Oil Search Shareholders after the Scheme Meeting at https://www.oilsearch.com/investors.

By order of the Court and the Oil Search Board.

Richard Lee
Chairman
Oil Search Limited

Notes to the Notice of Meeting

These explanatory notes relate to the Scheme and should be read in conjunction with the Notice of Meeting and the information in the Scheme Booklet of which that notice forms part. The Scheme Booklet contains important information to assist you in determining how to vote on the Scheme Resolution.

Unless the context requires otherwise, terms used in the Notice of Meeting and in these notes have the same meaning as set out in section 10 (Glossary and interpretation) of the Scheme Booklet.

Requisite Majority

The Scheme Resolution must be approved by at least 75% of the votes cast on the Scheme Resolution by eligible Oil Search Shareholders (either in person, by proxy or corporate representative).

Entitlement to vote

The time for the purposes of determining voting entitlements will be 7:00pm (Sydney time) / 6:00pm (Port Moresby time) on Sunday, 5 December 2021 (being the Scheme Meeting Record Date).

Accordingly, share transfers registered after that time will be disregarded in determining entitlements to attend and vote at the Scheme Meeting.

Quorum

Rule 12.2 of the Oil Search Constitution provides that the quorum for a meeting of Oil Search Shareholders is five natural persons each of which is or represents an Oil Search Shareholder under Rule 12.1 of the Oil Search Constitution.

Online Platform

Oil Search Shareholders, authorised proxies, attorneys and corporate representatives can attend and participate in the Scheme Meeting via the online Lumi platform at https://web.lumiagm.com/399778470. You will need the latest versions of Chrome, Safari, Edge or Firefox. Please ensure your browser is compatible.

The meeting ID for the Scheme Meeting is: **399778470**

Your **username** is your Securityholder Reference Number (**SRN**) or Holder Identification Number (**HIN**).

Your **password** is the postcode of your registered address for your holding if you are an Australian shareholder. If you are an overseas shareholder, your password is your three-character country code. For example, Papua New Guinea (PNG), United Kingdom (GBR), United States of America (USA) and Canada (CAN).

Please refer to the Virtual Meeting Guide (which has been released to the ASX and PNGX) and is available at www.computershare.com.au/virtualmeetingguide) for further details.

It is recommended that Oil Shareholders, authorised proxies, attorneys and corporate representatives login to the online platform at least 15 minutes prior to the scheduled start time for the Scheme Meeting.

Please monitor Oil Search's Website, ASX and PNGX announcements where updates will be provided if it becomes necessary or appropriate to make alternative arrangements for the holding or conduct of the Scheme Meeting.

Voting at the Scheme Meeting

You can vote in either of the following ways:

- by virtually attending the Scheme Meeting scheduled to be held at 11:00am (Sydney time) / 10:00am (Port Moresby time) on Tuesday, 7 December 2021 through an online platform (details of which are set out below); or
- by appointing a proxy, attorney or, if you are a body corporate, a duly appointed corporate representative to virtually attend and vote at the Scheme Meeting on your behalf.

If you hold Oil Search Shares jointly with one or more other persons, only one of you may vote. If more than one Oil Search Shareholder votes in respect of jointly held Oil Search Shares, only the vote of the Oil Search Shareholder whose name appears first in the Oil Search Share Register will be counted.

Voting will be conducted by poll.

Voting yourself

You will be able to attend and vote at the Scheme Meeting virtually through the online platform via the online Lumi platform at https://web.lumiagm.com/399778470.

Online voting will be open between the start of the Scheme Meeting and the closing of voting as announced by the Chair during the Scheme Meeting.

If you attend the Scheme Meeting and vote in your capacity as an Oil Search Shareholder, any votes cast by your proxy or attorney (if any) will not be counted.

Proxies

If you are unable to attend the Scheme Meeting, you are encouraged to appoint a proxy to attend online and vote on your behalf. If you wish to appoint a proxy, please complete the enclosed proxy form.

Oil Search Shareholders are notified that:

- a member who is entitled to attend and cast a vote at the meeting may appoint a proxy to attend and vote for the member;
- the appointment may specify the proportion or number of votes that the proxy may exercise;
- a member who is entitled to cast two or more votes at the meeting may appoint two proxies and may specify the proportion or number of votes each proxy is entitled to exercise. If you appoint two proxies and the appointment does not specify the proportion or number of votes each proxy may exercise, each proxy may exercise half of the votes; and
- a proxy may be an individual or a body corporate and need not be a member of Oil Search. If an eligible Oil Search Shareholder appoints a body corporate as a proxy, the body corporate will need to ensure that it appoints an individual as the corporate representative and provides satisfactory evidence of that appointment.

Voting by proxy

You can direct your proxy to vote by following the instructions on the proxy form.

If the Chair of the meeting is appointed as your proxy (or is appointed your proxy by default), they can be directed how to vote by ticking the relevant boxes next to the Scheme Resolution on the proxy form (ie, 'for', 'against' or 'abstain'). The Chair of the meeting is required to cast all votes as directed. The Chair of the Scheme Meeting intends to vote all undirected and available proxies in favour of the Scheme Resolution.

Any directed proxies that are not voted on a poll at the Scheme Meeting by an Oil Search Shareholder's appointed proxy will automatically default to the Chair of the meeting, who is required to vote proxies as directed on a poll.

How to appoint a proxy

To appoint a proxy, you should complete and return your proxy form either electronically or in hard copy, in accordance with the instructions on that form. You must deliver the signed and completed proxy form to Computershare by 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021 (or, if the Scheme Meeting is adjourned or postponed, no later than 48 hours before the resumption of the meeting in relation to the resumed part of the meeting) in any of the ways set out below.

Proxy forms received after this time will be ineffective.

- (**Online**) at www.investorvote.com.au. You will need your Holder Identifier (SRN/HIN) and the postcode for the shareholding (or if your registered address is outside of Australia, you will need to select the country). You will be taken to have signed the proxy form if you lodge in accordance with the instructions on the website;
- (**By mobile device**) if you have a smartphone, you can now lodge your vote at www.investorvote.com.au or by scanning the QR code on the proxy form. You will need your Holder Identifier (SRN/HIN as shown on your proxy form) and postcode for the shareholding (or if your registered address is outside of Australia, you will need to select the country). You will be taken to have signed the proxy form if you lodge in accordance with the instructions on the mobile website;
- (**By mail**) using the reply-paid envelope with the Scheme Booklet to:
  - for Australian based Oil Search Shareholders, Oil Search Limited, C-Computershare Investor Services Pty Limited, GPO Box 1282, Melbourne, VIC 3001;
  - for PNG based Oil Search Shareholders, PO Box 842, Port Moresby, Papua New Guinea; or
- (**By fax)** to Computershare Investor Services Pty Limited on 1800 783 447 within Australia or +61 3 9473 2555.

Oil Search Shareholders should contact the Oil Search Shareholder Information Line on 1300 150 530 (within Australia) or +61 2 9066 4081 (outside Australia), Monday to Friday between 9.00am and 5.00pm (Sydney time) other than public holidays in Sydney, Australia, with any queries regarding the number of Oil Search Shares they hold, how to vote at the Scheme Meeting or how to lodge the proxy form.

A replacement proxy form may be obtained from the Oil Search Share Registry, Computershare.

Further details in respect of the Scheme Resolution to be put to the Scheme Meeting are set out in the accompanying Scheme Booklet.

Voting by corporate representative

If you are a body corporate, you may appoint a corporate representative to attend and vote at the Scheme Meeting on your behalf. The appointment must comply with rule 13.11 of the Oil Search Constitution.

To vote by corporate representative, a corporate representative must provide written evidence of their appointment by obtaining and completing a 'Certificate of Appointment of Corporate Representative' form from Computershare or online at www.investorcentre.com under the help tab, 'Printable Forms'. Corporate representative forms must be provided to the Oil Search Share Registry by no later than 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021. A corporate representative form may be submitted in the same manner as a completed proxy form, as described above.

A validly appointed corporate representative wishing to attend and vote at the Scheme Meeting will require the name, SRN/HIN of the holding and postcode of the body corporate that appointed it in order to access the online platform.

Voting by power of attorney

You may appoint an attorney to attend and vote at the Scheme Meeting on your behalf.

The power of attorney appointing your attorney to attend and vote at the Scheme Meeting must be duly executed by you and specify your name, the company (ie, Oil Search Limited) and the attorney, and also specify the meeting(s) at which the appointment may be used.

Certified copies of powers of attorney must be received by the Oil Search Share Registry by no later than 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021. A certified copy of a power of attorney may be submitted in the same manner as a completed proxy form, as described above.

The appointment of an attorney does not preclude you from attending the Scheme Meeting online and voting at the Scheme Meeting.

Appointed Proxies

To participate in the meeting, appointed proxies will need a unique username and password. To receive your unique username and password, please contact Computershare Investor Services Pty Limited on +61 3 9415 4024 during the online registration period which will open one hour before the start of the meeting.

Court approval

In accordance with section 250(1) of the *Companies Act 1997* (PNG), the Scheme (with or without modification) must be approved by an order of the Court. If the Scheme Resolution put to this Scheme Meeting is passed by the Requisite Majority and the other conditions are satisfied or waived (if applicable), Oil Search intends to apply to the Court on or around Thursday, 9 December 2021 for approval of the Scheme.

Questions

Oil Search Shareholders and authorised proxies will have a reasonable opportunity to ask questions during the Scheme Meeting via the online platform.

Oil Search Shareholders who prefer to register questions in advance of the Scheme Meeting are also invited to do so by submitting questions online at www.investorvote.com.au. Questions must be submitted to the Oil Search Share Registry by 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021.

The Chair will endeavour to address as many of the more frequently raised relevant questions as possible during the course of the Scheme Meeting. However, there may not be sufficient time available during the Scheme Meeting to address all of the questions raised. Please note that individual responses will not be sent to Oil Search Shareholders.

Technical difficulties

Technical difficulties may arise during the course of the Scheme Meeting. The Chair has discretion as to whether and how the Scheme Meeting should proceed in the event that a technical difficulty arises. In exercising this discretion, the Chair will have regard to the number of Oil Search Shareholders impacted and the extent to which participation in the business of the Scheme Meeting is affected. Where the Chair considers it appropriate, the Chair may continue to hold the Scheme Meeting and transact business, including conducting a poll and voting in accordance with valid proxy instructions.

For this reason, Oil Search Shareholders are encouraged to lodge a proxy form by no later than 11:00am (Sydney time) / 10:00am (Port Moresby time) on Sunday, 5 December 2021, even if they plan to attend the Scheme Meeting.

Corporate Directory

Registered office
Ground Floor, Harbourside East Building
Stanley Esplanade, National Capital District
Port Moresby, Papua New Guinea

Australian office
1 Bligh Street, Sydney NSW 2000 Australia

Anchorage office
900 East Benson Blvd Anchorage
Alaska 99508, United States of America

Tokyo office
Level 25, Marunouchi Trust Tower–Main
1–8–3 Marunouchi Chiyoda–ku
Tokyo 100–0005 Japan

Abu Dhabi office
Level 9, Office 904, Tower 3, Etihad Towers
Corniche Road Abu Dhabi
United Arab Emirates

Financial advisers
Goldman Sachs Australia Pty Ltd
Governor Phillip Tower
1 Farrer Place Sydney NSW 2000

Macquarie Capital (Australia) Limited
50 Martin Place
Sydney NSW 2000

Rothschild & Co Australia Limited
Level 34, 88 Phillip Street
Sydney NSW 2000 Australia

Australian and PNG legal adviser
Allens
Level 28, Deutsche Bank Place
Corner Hunter and Philip Streets
Sydney NSW 2000

Independent Expert
Grant Samuel & Associates Pty Limited
ABN 28 050 036 372, AFSL No. 240985
Level 6, 1 Collins Street
Melbourne VIC 3000

Investigating Accountant
Ernst & Young
121 King William Street
Adelaide SA 5000 Australia

Oil Search Share Registry
Computershare Investor Services Pty Limited
GPO Box 2975
Melbourne VIC 3001 Australia

Oil Search ADR program
Bank of New York Mellon
American Depositary Receipts Division,
22nd Floor, 101 Barclay Street
New York, NY 10286

Stock exchange listing
Oil Search's ordinary fully paid shares are listed on the ASX and the PNGX (OSH). Shares are also traded on the "over the counter" market in the United States of America, via American Depositary Receipts (OISHY).

Oil Search website
https://www.oilsearch.com/

Oil Search Investor website
https://www.oilsearch.com/investors

www.investorvote.com.au